BASELOAD TASK FORCE REPORT

2013 Update

Submitted to the
Idaho Strategic Energy Alliance Board of Directors

October 17, 2013

Prepared by the ISEA Baseload Task Force
# TABLE OF CONTENTS

**Introduction** ..........................................................................................................................1

**Coal Resources**............................................................................................................................2
- Conventional Coal Technology ........................................................................................................3
- Integrated Gasification Combined-Cycle Technology ................................................................. 5
- Risk, Uncertainty, and Future Regulations .................................................................................. 7
- Environmental Regulations ......................................................................................................... 7
- Greenhouse Gas Emissions ........................................................................................................... 9
- Carbon Capture and Sequestration ............................................................................................. 11

**Natural Gas Resources** .........................................................................................................14
- Simple-Cycle Combustion Turbines ............................................................................................ 15
- Industrial Frame ........................................................................................................................... 16
- Aeroderivative ............................................................................................................................... 17
- Externally Intercooled .................................................................................................................... 18
- Combined-Cycle Combustion Turbines ....................................................................................... 19
- Reciprocating Engine-Generators ............................................................................................... 20
- Combined Heat and Power ........................................................................................................... 22
  - Combined Heat & Power Technologies....................................................................................... 23
  - Policy Impact on Combined Heat & Power ................................................................................. 23
- Natural Gas Supply and Prices .................................................................................................... 24
  - Opportunities and Risks ............................................................................................................. 28

**Nuclear** ...................................................................................................................................28
- Small Modular Nuclear Reactors ................................................................................................. 29
  - Basic Description of SMRs, and Idaho-Specific Context .......................................................... 30
  - Proposed Federal Government Legislation on SMRs ............................................................... 32
  - Key Issues for Consideration ...................................................................................................... 32

**Resource Types Covered by Other ISEA Task Force Reports** .............................................33
- Hydropower ................................................................................................................................ 33
  - Small Hydroelectric .................................................................................................................... 33
  - Pumped Storage ........................................................................................................................... 33
- Wind ............................................................................................................................................. 34
- Solar .............................................................................................................................................. 34
- Geothermal .................................................................................................................................... 35
- Biomass, Biogas, and Biofuels ....................................................................................................... 36

**Public Policy Issues** ..............................................................................................................38
- Water Policy and Impact on Baseload Resources .......................................................................... 38
- Renewable Energy Certificates (RECs) ......................................................................................... 39
- Public Utility Regulatory Policies Act of 1978 (PURPA) ................................................................. 40
- Federal Climate Change Legislation ............................................................................................. 40

**Electrical System Operational Issues** ..................................................................................41
Integration of Variable and Intermittent Resources ................................................................. 41
Storage Technologies .................................................................................................................. 42
Hydroelectric Pumped Storage ................................................................................................. 43
Batteries ................................................................................................................................. 44
V2G (“vehicle to grid”) Concept ............................................................................................... 44
Compressed Air ...................................................................................................................... 45
Thermal ................................................................................................................................ 46
Hydrogen ............................................................................................................................... 47
Flywheel Energy Storage (FES) ............................................................................................... 49
Public Utility Ratemaking ....................................................................................................... 50
  Traditional Ratemaking Formula .......................................................................................... 50
  Test Year .............................................................................................................................. 51
  Revenue Requirement ......................................................................................................... 52
  New Resource Rate Impact ................................................................................................. 53
Electric Service Providers in Idaho ........................................................................................ 55
  Idaho Power Company ........................................................................................................ 55
  PacifiCorp/Rocky Mountain Power ...................................................................................... 56
  Avista .................................................................................................................................. 57
  Municipals and Cooperatives .............................................................................................. 58
Forecast Electrical Demand in Idaho ..................................................................................... 59
Conclusion ............................................................................................................................. 61

LIST OF FIGURES AND TABLES

Figure 1 – Pulverized Coal Process Diagram ......................................................................... 4
Figure 2 – Fluidized Bed Process Diagram ............................................................................. 4
Figure 3 - Gasification-based Process Diagram..................................................................... 6
Figure 4 – Gasification-based Process Diagram with Carbon Capture ............................... 6
Figure 5 - Natural Gas Supply Areas, Pipelines and Trading Hubs .................................... 25
Figure 6 – Forecast Natural Gas Prices ............................................................................. 27
Figure 7 – Pumped Storage Plant Configuration .............................................................. 43
Figure 8 – 1.5 Megawatt VRB with One Hour of Storage ................................................. 44
Figure 9 – Vehicle to Grid Concept .................................................................................... 45
Figure 10 – Compressed Air Storage Concept .................................................................... 46
Figure 11 – Using Molten Salt for Thermal Storage............................................................... 47
Figure 12 – A Wind/Hydrogen Power Plant ....................................................................... 48
Figure 13 A Superconducting Magnetic Energy System .................................................... 49
Figure 14 – A Flywheel Energy Storage System .................................................................. 49
INTRODUCTION

In the electric utility industry, the term “baseload” refers to electric generation resources that are typically operated 24 hours a day throughout most if not all months of the year. As such, baseload resources tend to have relatively high annual capacity factors when compared to other generation resources that are only operated during times of peak demand or in the case of renewable resources, when the motive force is available to allow the generation of electricity. Baseload resources significantly contribute to the reliability of the electrical system and are generally only shut down for scheduled maintenance or emergency repairs. Conventional baseload resources typically require significant initial capital investment, but have relatively low variable operating costs. Therefore, baseload resources provide reasonably low-cost electricity over the life of the resource. For this reason, these resources are also commonly referred to as “energy” resources as the overall cost of production is generally low.

In contrast to baseload power plants, peaking resources typically run only when demand for electricity is high, such as during hot summer afternoons when air conditioning and irrigation loads are the highest in Idaho. While the initial investment for some peaking resources is less than that required for a baseload resource, the variable operating costs tend to be higher and therefore so is the per unit cost of production. For these reasons, peaking resources typically only run during times of peak demand and are commonly referred to as “capacity” resources.

The primary baseload resources addressed in this report are coal, natural gas (combined-cycle combustion turbine), and nuclear. Hydroelectric resources can be considered baseload; however, the amount of energy they produce is limited by the available water supply. Although wind is considered a good energy resource, the variable and intermittent nature of the generation precludes it from being considered a baseload resource. Solar technologies provide more capacity and energy during the daytime hours; however, because they are not able to generate electricity at night (without storage capability), solar resources are also not considered to be baseload. Geothermal and biomass resources do provide baseload energy; however, the typical smaller sizes of these resources make them difficult to develop on a utility scale.

In addition to traditional baseload resources, this report provides an overview of resource types that are covered in more detail in reports published by other Idaho Strategic Energy Alliance (ISEA) task forces because some of them possess the characteristics of a baseload resource. This is followed by a discussion of some of the current public policy issues that impact the current or future operation of all generation resources including: state of Idaho
water policy, the development of renewable resources, and policy implications surrounding climate change.

The operation of an electrical system is complex and not easily understood by consumers. In recent years, the development of variable and intermittent renewable resources has compounded the complexity. Therefore, this report also attempts to explain, at a high level, how the introduction of variable and intermittent resources impacts the operation of the electrical system. Specifically, in southern Idaho there has been substantial development of wind resources which are far more variable and intermittent than other renewable resource types. A solution to this issue resides in the development of an economical storage technology that would allow electricity to be stored and used when needed. In light of this, a summary of the current state of development of storage technologies has also been included in this report.

The majority of electrical consumers in Idaho are served by investor-owned utilities (IOUs), which include Idaho Power Company and Rocky Mountain Power in southern Idaho, and Avista in northern Idaho. Because these companies are regulated by the Idaho Public Utilities Commission, this report includes a section which details important information on how utilities are regulated and how rates are determined for consumers.

This report concludes with a description of each of the IOUs that have an obligation to serve electrical customers in Idaho, as well as the municipalities and cooperatives that serve the remaining customers in the state. The final section of the report presents the forecast of future electrical demand in Idaho for each of the IOUs, municipalities, and cooperatives.

Growth in the demand for electricity in Idaho is both inevitable and desirable in order for the State and its citizens to prosper economically. The Baseload Task Force hopes this report highlights many of the issues that must eventually be resolved in order for the state of Idaho to maintain its long-standing reputation as having some of the lowest cost electricity in the nation.

**COAL RESOURCES**

In-ground coal resources in the United States are vast. The United States Energy Information Administration\(^1\) estimates that the United States has approximately 7.3 billion tons of recoverable coal reserves. To reduce transportation costs, coal-fired plants are often located near mining operations. Because these sites are often hundreds of miles from large load centers, high-voltage transmission lines are necessary to move the energy to load. Although

---

there are no coal-fired power plants located in Idaho, coal plants located in surrounding states provide a substantial amount of Idaho’s baseload energy supply.

Though coal-fired power plants require significant capital investment to develop, coal resources take advantage of a low cost fuel and provide reliable and dispatchable energy that can be ramped up or down as needed. Coal supplies are abundant in the Intermountain Region and are sufficient to fuel the region’s existing plants for many years to come.

Recently, coal-fired electricity generation has been dropping as a percent of overall generation in the nation. Natural gas supplies have dramatically increased with a corresponding significant drop in price. Natural gas generation is the new baseload resource of choice and existing under-utilized capacity is displacing coal due to lower dispatch costs. For new resources, natural gas power plants are less expensive to build, easier to permit, can be built in smaller increments, and have lower carbon emissions on a per kWh basis than coal-fired plants.

Electricity generation using coal as a fuel can be divided into two broad categories: conventional combustion technology and gasification. These two technologies are explained in the following sections.

**Conventional Coal Technology**

Conventional coal-fired generation is a mature technology and has been the primary source of commercial power production in the United States for many decades. There are two primary types of conventional combustion coal technologies, pulverized and fluidized-bed. Both use coal which is ground into a dust-like consistency and burned to heat water and produce steam which drives a steam turbine and generator. A variety of emissions control technologies are available to comply with air emission standards related to mercury, \( \text{SO}_2 \), \( \text{NO}_x \), particulate matter and other impurities resulting from the combustion of coal. A simplified diagram of a pulverized coal plant is shown in Figure 1 below.
In addition to pulverized coal boilers, fluidized bed combustion with supercritical steam cycles are used to produce electricity from coal. The fluidized bed technology provides more efficient heat transfer and lower NOx emissions levels. A simplified diagram of a fluidized bed coal plant is shown in Figure 2 below.
Both of these conventional technologies face uncertainty and risk associated with environmental regulations related to emissions and the potential for future federal carbon regulation. Environmental regulations are discussed later in this section as well as carbon capture and sequestration which is an emerging technology that may provide a solution to the carbon issue for these conventional resources.

**Integrated Gasification Combined-Cycle Technology**

Integrated Gasification Combined-Cycle (IGCC) technology is an evolving coal-based technology designed to substantially reduce CO₂ emissions. If the cost of CO₂ emissions eventually makes conventional coal resources obsolete, the commercialization of this technology may allow the continued use of the country’s coal resources. IGCC technology is also dependent on the development of carbon capture and sequestration technology that would allow CO₂ to be stored underground for long periods of time.

Coal gasification is a relatively mature technology, but it has not been widely adapted as a resource to generate electricity. IGCC technology involves turning coal into a synthetic gas or “syngas” that can be processed and cleaned to a point that it meets pipeline quality standards. To produce electricity, the syngas is burned in a conventional combined-cycle combustion turbine that drives a generator.

Gasification-based power generation first changes the coal into a synthetic gas (syngas). This is accomplished by exposing the coal to an oxygen lean environment with high temperature and pressure. The resulting syngas is then cleaned of sulfur compounds and particulate matter. The cleaned syngas is then fed to a gas turbine where it is burned and the heat and pressure energy are used to create electricity similar to the natural gas technologies discussed later in this report. The gas turbine exhaust is still typically hot enough to be a heat source for a steam cycle, which is why the combined-cycle natural gas technology is normally utilized. A simplified diagram of a gasification-based system is shown below in Figure 3. The system is similar to a natural gas combined-cycle plant, with the major difference being the use of coal gasification to produce the gaseous fuel instead of using natural gas.
Gasification-based power is more efficient than combustion-based systems, but they are also more costly to construct. One potential advantage of gasification systems is the possibility of retrofitting pre-combustion carbon capture technology into the system, which is illustrated in Figure 4 below.
The National Energy Technology Laboratory has produced a series of baseline plant designs that show the technology, economic, and environmental impact of a variety of coal and natural gas-based systems.²

**Risk, Uncertainty, and Future Regulations**

The future of coal as a baseload power source is uncertain because of increasingly strict environmental requirements and the potential for federal carbon regulation. Both issues are putting upward pressure on the cost of producing electricity at coal-fired power plants. The following sections describe existing and potential environmental regulations and greenhouse gas emissions.

**Environmental Regulations**

**Final Mercury and Air Toxic Standards (MATS) Rule:** In April 2010, the U.S. District Court for the District of Columbia approved, by consent decree, a timetable that would require the EPA to finalize a standard to control mercury emissions from coal-fired power plants by November 2011. In March 2011, the EPA released the rule to control emissions of mercury and other Hazardous Air Pollutants (HAPs) from coal- and oil-fired electric utility steam generating units (EGUs) under the federal Clean Air Act (CAA). In the same notice, the EPA further proposed to revise the New Source Performance Standards (NSPS) for fossil fuel-fired EGUs. Both the proposed HAPs regulation and the associated NSPS revisions were finalized on February 16, 2012.³ The regulation imposes maximum achievable control technology and NSPS on all coal-fired EGUs and replaces the former Clean Air Mercury Rule. Specifically, the regulation sets numeric emission limitations on coal-fired EGUs for total particulate matter (a surrogate for non-mercury HAPs), hydrochloric acid (HCL), and mercury. In addition, the regulation imposes a work practice standard for organic HAPs, including dioxins and furans. For the revised NSPS, for EGUs commencing construction of a new source after publication of the final rule, the EPA has established amended emission limitations for particulate matter, sulfur dioxide, and nitrogen oxides.

**National Ambient Air Quality Standards (NAAQS) for NOₓ:** In February 2010, the EPA revised the NAAQS for NOₓ, establishing a one-hour standard at a level of 100 parts per billion. In connection with the new NAAQS, in February 2012 the EPA issued a final rule designating certain areas in Idaho, Nevada, Oregon, and Wyoming as “unclassifiable/attainment” for NOₓ.⁴ The EPA indicated it will review the designations after 2015, when three years of air quality

³ [http://www.epa.gov/mats/actions.html](http://www.epa.gov/mats/actions.html)
⁴ [http://www.epa.gov/air/criteria.html](http://www.epa.gov/air/criteria.html)
monitoring data are available, and may formally designate the areas as attainment or non-attainment for NOx.

**NAAQS for Particulate Matter:** On June 29, 2012, the EPA published proposed revisions to the primary and secondary NAAQS for fine particulate matter (PM$_{2.5}$). The EPA also proposed revisions to the Prevention of Significant Deterioration permitting program with respect to the proposed NAAQS revisions. The EPA's proposed primary standard for fine particles was between 12 and 13 micrograms per cubic meter ($\mu$g/m$^3$), calculated as a three-year average. The EPA proposed to retain the exiting 24-hour primary standard for fine particular matter at 35 $\mu$g/m$^3$. The EPA proposed to remain unchanged the secondary standards for PM2.5 and which are identical to the primary standards. Once finalized, the revisions to the NAAQS would trigger a process under which states will make recommendations to the EPA regarding designations of attainment or non-attainment. States also will be required to review, modify, and supplement their existing state implementation plans (SIP). The revised NAAQS would also have an impact on the applicable air permitting requirements for new and modified facilities. The EPA has stated that it plans to issue nonattainment designations by late 2014, with states having until 2020 to comply with the standards.

**Clean Water Act Section 316(b):** In March 2011, the EPA issued a proposed rule that would establish requirements under Section 316(b) of the federal Clean Water Act for all existing power generating facilities and existing manufacturing and industrial facilities that withdraw more than 2 million gallons per day (MGD) of water and use at least 25 percent of the water they withdraw exclusively for cooling purposes. The proposed rules would establish national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at these facilities by setting requirements that reflect the Best Technology Available (BTA) for minimizing adverse environmental impact. In June 2012, the EPA released new data, requested further public comment, and announced it plans to finalize the cooling water intake structures rule by June 2013.

**New Source Performance Standards (NSPS) for Greenhouse Gas Emissions for New EGUs:** In March 2012, the EPA proposed NSPS limiting Carbon Dioxide (CO$_2$) emissions from new fossil fuel-fired power plants. The proposed requirements would require new fossil fuel-fired EGUs greater than 25 MW to meet an output-based standard of 1,000 pounds of CO$_2$ per MWh. The EPA did not propose standards of performance for existing EGUs whose CO$_2$ emissions increase as a result of installation of pollution controls for conventional pollutants.

---

5 http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_index.html  
6 http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/basic.cfm  
7 http://www.epa.gov/airquality/cps/settlement.html
**Clean Air Act (CAA) - Regional Haze Rules:** In accordance with federal regional haze rules under the CAA, coal-fired utility boilers are subject to regional haze - best available retrofit technology (RH BART) if they were built between 1962 and 1977 and affect any Class I areas. Under the CAA, states are required to develop a SIP to meet various air quality requirements and submit them to the EPA for approval. The CAA provides that if the EPA deems a SIP submittal to be incomplete or "un-approvable", then the EPA will promulgate a federal implementation plan (FIP) to fill the deemed regulatory gap.

In May 2012, the EPA proposed to partially reject Wyoming's regional haze SIP, submitted in January 2011, for NOx reduction at the Jim Bridger plant, instead proposing to substitute the EPA's own RH BART determination and FIP. The EPA's primary proposal would result in an acceleration of the installation of Selective Catalytic Reduction (SCR) additions for Jim Bridger 1 and 2 to within five years after the FIP, or a SIP revised to be consistent with the proposed FIP, is adopted by the EPA. The EPA has stated that it plans to adopt the FIP, or approve the revised Wyoming SIP, by late 2012. The EPA recognized that this accelerated schedule may create a hardship for the owners of the Jim Bridger plant, including Idaho Power and its customers, and has requested the submission of comments on whether the Wyoming schedule that would not require installation of the SCR on Jim Bridger 1 and 2 until late 2021 and 2022, respectively, is more appropriate.

**Coal Combustion Residuals (CCR):** The EPA has proposed federal regulations to govern the disposal of coal ash and other CCR’s under the Resource Conservation and Recovery Act (RCRA). The agency is weighing two options: regulating CCR’s as hazardous waste under RCRA Subtitle C, or regulating them as non-hazardous waste under RCRA Subtitle D.

**Greenhouse Gas Emissions**

Uncertainty surrounding many aspects of federal and state carbon policy and carbon sequestration technology has had a negative impact on the future prospects for coal-fired generation. Any significant carbon policy (carbon tax, cap and trade, inclusion of externalities in permitting, etc.) could have a large negative impact on coal resources in the future.

Carbon policy at the federal level has focused on two major alternatives: a carbon tax or a carbon emissions cap-and-trade framework. Because coal-fired generation emits the most carbon on a CO2/kWh basis, implementation of any restrictive carbon policy will have a negative impact on coal-based power generation. The impact on coal resources under a carbon policy is projected to go through several stages. First, natural gas generation would continue to displace coal because a carbon policy would increase the economic gap between natural gas and coal-fired generation. Second, the construction of new coal facilities would slow and

---

8  http://www.epa.gov/air/caa/
eventually stop in the absence of proven commercial capture and sequestration technology. Third, existing coal plants would be shut down or retrofitted with carbon capture technology if proven commercial sequestration technology becomes viable.

Assuming a federal carbon policy is implemented, a key consideration for the future of coal-based generation is the technology and policy surrounding carbon sequestration. Significant research is ongoing at the federal level and in private industry. The National Energy Technology Center is the lead agency within the US Department of Energy for various sequestration programs including the Regional Carbon Sequestration Partnerships. The regional partnerships are presently engaged in several sequestration demonstrations that are providing data and practical experience for large scale geologic sequestration of carbon dioxide.

Beyond the technology of carbon capture and sequestration, there are policies that need to be developed and implemented before large scale sequestration can be fully commercialized. First, states and/or the federal government need to implement policies on the ownership of the porous rock layers where carbon may be sequestered. This is similar to the various mineral rights policies that determine ownership of oil, natural gas, coal, or other subsurface commodities. Second, the federal government needs to develop and implement a long-term liability policy related to sequestration, monitoring, and verification of the sequestered carbon dioxide. Private industry is not going to commercialize a technology without knowing the long term liability potential. Third, the primary driver for commercial sequestration would be the implementation of a federal carbon policy. Carbon capture, transport, and geologic sequestration will lower efficiency and raise the cost of producing electricity and private industry will not do this unless mandated by the federal government.

Owners of coal-fired resources have several strategies that could be implemented under a federal carbon policy. Higher efficiency steam cycles and carbon separation/sequestration were discussed above. Another strategy is the substitution/supplemental use of biomass as a fuel. This use of a “green” fuel has the potential to reduce the greenhouse gas emissions from a power plant. The potential policy negatives associated with changing the fuel would be to re-open existing permits (such as air quality permit) and subject the plant to a federal New Source Performance Review (NSPS). Plant owners/operators will need to fully understand the potential operational changes, delays, and expense involved in redoing permits or complying with a NSPS review before considering implementing the addition of biomass as a fuel source.

Emissions controls at coal plants have become increasingly important in recent years, and many units in the region have been upgraded to include the latest scrubber and low-NOx burner technology to help reduce harmful emissions and particulates. Coal has the highest

---

10 http://www.eia.doe.gov/cneaf/electricity/epm/table1_1.html
ratio of carbon to hydrogen of all fossil fuels, and significant research is being done to develop carbon capture and sequestration technology that can be economically added to existing coal facilities.

**Carbon Capture and Sequestration**¹¹

A technology answer for coal-fired generation resources is the implementation of carbon separation technology at the power production facility and subsequent sequestration of the carbon. For combustion-based coal systems, the separation technology uses a solvent or other physical means to separate CO₂ from the rest of the flue gas after the heat energy has been transferred to the steam cycle. The carbon separation technology requires a large amount of energy to regenerate and reuse the solvent, reducing the overall efficiency of the system. The technology is also capital intensive causing the cost of generated electricity to increase.

Carbon sequestration involves taking captured CO₂ and storing it away from the atmosphere by compressing and pumping it into underground geologic formations. If compression and pumping costs are charged to the plant, the overall efficiency of the plant is reduced by an additional 15 to 20 percent. Sequestration methods are currently being developed and tested; however, commercialization of the technology is not expected to happen for some time. CO₂ has been injected into existing oil fields to enhance oil recovery; however, if the sequestration technology were widely adopted by utilities for power production, the large quantities of CO₂ produced would require the development of dedicated underground storage methods.

Geologic carbon sequestration (GCS) involves compressing CO₂ to elevated pressures and injecting it into geological formations that are from 3,000 to 20,000 feet deep. The most promising reservoirs are porous and permeable rock bodies, generally at 1 km or greater depth where CO₂ would be in a supercritical phase where it behaves like a dense, liquid-like gas. These potential reservoirs include:

- **Saline formations**, which contain brine in their pore volumes, commonly of salinities greater than 10,000 ppm.
- **Depleted oil and gas fields** which have some combination of water and hydrocarbons in their pore volumes and a demonstrated seal. Injection of CO₂ into these reservoirs can stimulate enhanced oil recovery (EOR) or enhanced gas recovery and increase domestic fuel supply; substantial CO₂-EOR already occurs in the US with both natural and anthropogenic CO₂.

• Deep coal seams, often called un-mineable coal seams, which comprise organic minerals with brines and gases in their pore and fracture volumes.

Once the CO₂ is injected into the subsurface, it will flow throughout the storage formation where it will remain trapped indefinitely. The Intergovernmental Panel on Climate Change (IPCC) issued a special report in 2005\(^\text{12}\) on the topic of carbon sequestration, suggesting that if a site is chosen well and operated well, then it is highly likely (>90%) to store 99.9% of injected CO₂ in place for 100’s of years, and likely to store 99% for thousands of years.

The Earth’s shallow crust is well suited to the indefinite trapping and storage of CO₂ because of its physical and chemical properties. This is because four different mechanisms trap CO₂ in the subsurface. To begin, CO₂ sequestration targets will have physical barriers to CO₂ migration out of the crust to the surface. These barriers will commonly take the form of impermeable layers (e.g., shales, evaporites) overlying the reservoir target and act immediately to limit CO₂ migration. At the pore scale, capillary forces will immobilize a substantial fraction of CO₂ as tiny, isolated bubbles in a residual phase.

Over a period of tens to hundreds of years, CO₂ in the formation will dissolve into other pore fluids, including hydrocarbon species (oil and gas) or brines, where the CO₂ cannot be released without active intervention. Over longer time scales (hundreds to thousands of years) the dissolved CO₂ may react with minerals in the rock volume to precipitate the CO₂ as new carbonate minerals. Finally, in the case of organic mineral frameworks such as coals, the CO₂ will physically adsorb onto the rock surface, sometimes displacing other gases (e.g., methane, nitrogen). These trapping mechanisms have been documented and observed in natural analogs (e.g., the natural CO₂ domes in Colorado) and laboratory experiments, and they have been simulated in integrated geological models. Although substantial work remains to characterize and quantify these mechanisms, they are sufficiently well understood today to trust estimates of the percentage of CO₂ stored over the timeframes discussed by the IPCC.

Because of their large storage potential and broad distribution, saline formations are likely sites for most geological sequestration. However, initial projects probably will occur in depleted oil and gas fields, accompanying enhanced oil recovery (EOR), due to the density and quality of existing subsurface data and the potential for economic return; the Weyburn EOR and storage project in Saskatchewan is one example. Availability of pore volumes in suitable formations for sequestration may be considered a natural resource. Areas that have this resource in abundance have a competitive advantage in a carbon constrained world compared to those that lack storage capacity.

At its heart, GCS is similar to oil and gas production (especially EOR), natural gas storage, hazardous waste disposal, and acid gas management. It is highly analogous to the injection of

\(^{12}\) http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf
CO₂ for EOR, which has been done in the US for over 30 years. These activities use the same technologies as GCS, and their technical basis provides confidence in the viability of commercial GCS deployment. In addition, natural accumulations of CO₂ have demonstrably retained large CO₂ volumes for tens to hundreds of millions of years. This provides confidence in the possibility of long-term storage of CO₂ in suitable rock formations.

A key difference between GCS and applications mentioned above is that the GCS goal is to keep the CO₂ in the reservoir. This new application will have new requirements, such as a monitoring and verification program. A site monitoring and verification program to support GCS should provide these services:

- to identify any early concerns or problems (as mentioned below) and protect public health and safety;
- to assign credits or offsets for commercial GCS, especially under a cap-and-trade regime;
- to validate simulations and current understanding of sequestration science; and
- to guide any necessary mitigation efforts.

There are many technologies used in industry today that can monitor CO₂ in the subsurface and the surface, including time-lapse reflection seismic surveying, use of tracers, and electrical soundings. Some of these approaches have been tested in commercial and experimental projects. However, there has been little comprehensive application of these technologies to monitor CO₂ to date.

Several hazards could affect CCS operations at a site. These hazards, such as well failure or CO₂ seepage along faults, could lead to problems such as atmospheric release of CO₂ or groundwater contamination. Pre-existing wells present the largest risks as potential leakage paths, but leakage through wells is the simplest to detect and mitigate. Preliminary analyses through analog studies and simulation, which have been performed by industry, academia and national laboratories, suggest that the risks posed by these hazards are both very small and manageable.

Carbon capture and sequestration can be safely and effectively deployed widely within the US. Key steps to avoiding hazards are careful site characterization before injection, and appropriate monitoring and verification programs during injection. Additional information regarding carbon capture and sequestration can be found in the Carbon Issues Task Force Report at http://www.energy.idaho.gov/energyalliance/d/carbon_issues_report.pdf.

NATURAL GAS RESOURCES

Raw natural gas is a mixture of gases and volatile liquids, including methane, ethane, propane, butane, isobutene, pentanes, water and carbon dioxide. Raw gas is found in porous geologic structures, often in association with petroleum or coal deposits. Raw natural gas is extracted from the ground by means of wells, and is processed to remove the condensable organic fractions (propane, butane, isobutene and pentanes), carbon dioxide, water, and impurities.

The resulting product, consisting of methane (~90 percent) and ethane, is odorized and compressed for transportation through pipelines to end users. Historically, natural gas markets have largely been regional or continental in scope, defined by contiguous pipeline networks. In recent years, markets are increasingly global as natural gas liquefaction and re-gasification terminals are being developed to accommodate intercontinental transportation of liquefied natural gas (LNG).

Natural gas is a valuable energy source because of its clean-burning properties, ease of transportation, wide variety of applications and conversion technologies, and lower CO₂ emissions when combusted. Natural gas is used directly for residential, commercial, and industrial end uses as well as to produce electricity using steam, turbines, reciprocating engines and fuel cell technologies. Natural gas is also the principal feedstock in the manufacture of ammonia and ammonia-based fertilizers as well as a wide variety of industrial chemicals.

Natural gas and liquid petroleum products are the most flexible energy sources in terms of available technologies and applications. Generating technologies that can be fueled by natural gas include steam-electric plants, simple-cycle combustion turbines, combined-cycle combustion turbines, reciprocating engines, fuel cells, and micro turbines. Applications include baseload, intermediate and peak-hour electricity generation, capacity reserves, regulation and load-following reserves, cogeneration, and distributed generation. Simple-cycle combustion turbines, combined-cycle combustion turbines, and reciprocating engines are expected to continue to play a major role in electricity production. Fuel cells and micro turbines may see some specialized applications, but are unlikely to be major players in the near-term because of cost and reliability issues. Gas-fired steam-electric units are being phased out in favor of more efficient and flexible combined-cycle plants.

Low natural gas prices and the introduction of efficient, low-cost, environmentally attractive gas turbines led to a surge of combined-cycle plant construction early in the 1990s and again following the 2000/2001 western energy crisis. Natural gas power plants now represent about 15 percent (9,383 megawatts) of generating capacity in the Pacific Northwest. Of this, 7,677 megawatts are combined-cycle units and 1,706 megawatts are

14 http://www.nwcouncil.org/energy/powersupply/
peaking units (primarily simple-cycle turbines, but a few reciprocating engine plants). Table 1 below provides a list of power plants operating in Idaho that use natural gas as a primary fuel.

Table 1 – Natural Gas Power Plants Located in Idaho

<table>
<thead>
<tr>
<th>Plant</th>
<th>Capacity (MW)</th>
<th>Type</th>
<th>Location</th>
<th>Year</th>
<th>Owner</th>
<th>Customer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bennett Mountain</td>
<td>173</td>
<td>SCCT</td>
<td>Mountain Home</td>
<td>2005</td>
<td>Idaho Power</td>
<td>Idaho Power</td>
</tr>
<tr>
<td>Danskin 1</td>
<td>170</td>
<td>SCCT</td>
<td>Mountain Home</td>
<td>2008</td>
<td>Idaho Power</td>
<td>Idaho Power</td>
</tr>
<tr>
<td>Danskin 2</td>
<td>50</td>
<td>SCCT</td>
<td>Mountain Home</td>
<td>2001</td>
<td>Idaho Power</td>
<td>Idaho Power</td>
</tr>
<tr>
<td>Danskin 3</td>
<td>50</td>
<td>SCCT</td>
<td>Mountain Home</td>
<td>2001</td>
<td>Idaho Power</td>
<td>Idaho Power</td>
</tr>
<tr>
<td>Don Phosphate Plant</td>
<td>16</td>
<td>CHP</td>
<td>Pocatello</td>
<td>1986</td>
<td>Simplot Leasing Corp</td>
<td>Idaho Power (QF)</td>
</tr>
<tr>
<td>Glenn’s Ferry Cogen</td>
<td>10</td>
<td>CHP</td>
<td>Glenn’s Ferry</td>
<td>1996</td>
<td>Black Hills Energy (50%)</td>
<td>Idaho Power (QF)</td>
</tr>
<tr>
<td>Lancaster</td>
<td>270</td>
<td>CCCT</td>
<td>Rathdrum</td>
<td>2001</td>
<td>Energy Investor Funds (80%)</td>
<td>Tolling PPA w/AvistaUtilities</td>
</tr>
<tr>
<td>Rathdrum 1</td>
<td>83</td>
<td>SCCT</td>
<td>Rathdrum</td>
<td>1994</td>
<td>Avista</td>
<td>Avista Utilities</td>
</tr>
<tr>
<td>Rathdrum 2</td>
<td>83</td>
<td>SCCT</td>
<td>Rathdrum</td>
<td>1994</td>
<td>Avista</td>
<td>Avista Utilities</td>
</tr>
<tr>
<td>Rupert Cogeneration</td>
<td>10</td>
<td>CHP</td>
<td>Rupert</td>
<td>1996</td>
<td>Black Hills Energy (50%)</td>
<td>Idaho Power (QF)</td>
</tr>
</tbody>
</table>

Simple-Cycle Combustion Turbines

Simple-cycle combustion turbines (SCCT) consist of a single combustion turbine driving an electric generator. SCCTs are compact, modular units with rapid startup and load-following capability, widely used for meeting short-duration peak loads. An extensive range of unit sizes are available, from sub-megawatt to about 280 megawatts. Low to moderate capital costs and superb operating flexibility make SCCTs attractive for peaking capacity reserves and electrical system support applications. The inherent operating flexibility of gas turbines is suitable for providing regulation and load following (balancing reserves). However, SCCTs are not often used for this purpose for extended periods if other sources of balancing reserves are available because of their relatively low efficiency and resulting high cost of energy. SCCTs are rarely used for baseload energy production, unless they are being used in a combined heat and power application.

SCCTs have been built in the Pacific Northwest in recent years to provide capacity and energy during poor water years, as cogeneration plants, to provide capacity for summer peak-hour loads, and to provide short-term balancing reserves necessary for integrating wind power.

SCCTs are generally divided into three classes: industrial frame machines specifically designed for stationary application, “aeroderivative” machines using aircraft gas-turbine engines adapted to stationary applications, and external, intercooled machines with high part-load efficiency intended for intermediate dispatch and balancing reserves.

Industrial Frame

Industrial Frame SCCTs are designed specifically for stationary installations. Industrial frame machines are available in a wide range of unit sizes (about 40 to 280 MW) and are designed for long life and reliability. Pressure (compression) ratios are lower than for aeroderivative machines, resulting in less demanding design conditions, but produce a bulkier, less efficient turbine. More robust construction improves durability, but constrains operational flexibility.

Start time to full load typically exceeds ten minutes, so industrial frame SCCTs must be operating to provide spinning reserve capacity. Major maintenance is accomplished on site in contrast to the component swap out common for aeroderivative units. Because of economies of scale and less demanding design conditions, industrial frame machines cost less per-kilowatt than aeroderivative units. While NO\textsubscript{x} production can be controlled to moderate levels by low NO\textsubscript{x} fuel combustors and water injection, the high exhaust temperatures of industrial frame SCCTs preclude catalytic control of NO\textsubscript{x}, CO and VOCs.\textsuperscript{18} Like all gas turbines, power declines with increasing elevation and increasing ambient air temperature. Inlet air coolers are often installed on units expected to serve summer peak loads.

A typical industrial frame SCCT might consist of a single gas turbine generator of 85 MW nominal capacity. The net, maintenance-adjusted degraded lifecycle average full load capacity is 81 MW (ISO conditions\textsuperscript{19}). This rating will be progressively lower at higher elevations (increasing the effective capacity cost of the machine), though the thermal efficiency will remain fairly constant. The combustion turbine and generator are enclosed for weather protection and acoustic control, and are typically equipped with inlet air filters and exhaust silencers. The plant also includes lube oil, starting, fuel forwarding, and control systems; a control building; step-up transformers, and a switchyard. Dry low-NO\textsubscript{x} combustors are used for NO\textsubscript{x} emissions control. Because of their relatively low efficiency, operation of industrial frame SCCTs is normally limited to seasonal daily peak loads, and in the Pacific Northwest, occasional extended operation during poor water years.

Siting requirements for industrial frame SCCTs include proximity to high-voltage transmission for interconnection to the electrical grid and natural gas pipeline service. Gas turbines require high inlet fuel pressure and where feasible, plants are located near high-pressure natural gas main lines or laterals to avoid the cost and power consumption of fuel gas booster compressors. Water supply and treatment facilities are required for plants using water injection for NO\textsubscript{x} control. Lack of catalytic control for NO\textsubscript{x}, CO, and VOCs may limit siting and operating hours in sensitive or non-attainment areas. While industrial frame SCCTs are often

\textsuperscript{18} NO\textsubscript{x} – Oxides of nitrogen (a smog precursor); CO - Carbon monoxide; VOCs - Volatile organic compounds. All three are regulated air pollutants.

\textsuperscript{19} Sea level location, at 59 degrees Fahrenheit ambient air temperature.
cited in urban areas, noise has been an issue for some plants located near residences or recreational areas.

**Aeroderivative**

Aeroderivative SCCTs are based on aircraft jet engines adapted for stationary applications. Aeroderivative gas turbines feature high pressure ratios and light-weight construction. Higher pressure ratios increase thermal efficiency and produce a more compact unit compared to frame machines and light-weight construction improves operational flexibility. Start times to full load are ten minutes or less, allowing aeroderivative SCCTs to provide “virtual” spinning reserves (spinning reserve without the need to be operating).20 Optional water injection inter-cooling is available to boost peak power output.

Aeroderivative SCCTs can be equipped with heat recovery steam generators to supply steam for cogeneration facilities. The lighter and more highly stressed components of aeroderivative turbines result in higher per-kilowatt initial investment cost than industrial frame machines. Aeroderivative turbines are highly modular and maintenance can be accomplished by swapping out components, or even the entire unit, thereby shortening maintenance outages. Aeroderivative turbine exhaust temperatures are sufficiently low to permit the use of selective catalytic reduction for NOx, CO and VOC control. Like all gas turbines, aeroderivative power output declines with increasing elevation and increasing ambient air temperature. Inlet air coolers are often installed on units expected to serve summer peak loads. Like other gas turbines, aeroderivative SCCTs require a high fuel supply pressure and fuel gas booster compressors may be required in locations away from natural gas mainlines.

A typical aeroderivative SCCT plant might consist of two aeroderivative turbine generator sets of 47 megawatt nameplate capacity each, equipped with water injection inter-cooling. The net, maintenance-adjusted degraded lifecycle average full load capacity is about 90 megawatts (ISO conditions). The gas turbine generators are enclosed for weather protection and acoustic control, and are provided with inlet air filters and exhaust silencers. The plant will typically include an injection water treatment system; lube oil, starting, fuel forwarding, and control systems; a control building; step-up transformers and a switchyard. Dry low- NOx combustors and selective catalytic reduction are used for NOx control and an oxidation catalyst for CO and VOC control. Aeroderivative SCCTs will typically be located near a natural gas mainline with sufficient pressure for operation without fuel gas booster compression.

Stand-alone (non-cogeneration) plants are normally operated seasonally to serve daily peak loads. Because of the higher efficiency and greater flexibility compared to industrial frame

---

20 Though physically capable of achieving full load in less than 10 minutes, startup emission limits are reported to have precluded the use of non-operating aeroderivative turbines for spinning reserves (Keyspan, 2007).
machines, aeroderivative units may also be economically operated for extended periods at partial load to provide balancing reserves, and in the Pacific Northwest might occasionally operate for extended periods at full load during poor water years. Cogeneration units would normally operate as baseload plants in order to provide constant steam for the industrial process.

Siting requirements for aeroderivative SCCTs include proximity to high-voltage transmission for interconnection to the electrical grid and natural gas service. Location near a high-pressure natural gas mainline or lateral is desirable to avoid the cost and power consumption of fuel gas booster compressors. Water supply and treatment facilities are required for plants using water injection for NOx control or inter-cooling. NOx, CO, and VOCs can be controlled to very low levels using catalytic control for sites in sensitive or non-attainment areas. While aeroderivative SCCTs are often cited in urban areas, noise has been an issue for some units located near residences or recreational areas.

**Externally Intercooled**

Combustion air compression consumes about two-thirds of the total power produced by a gas turbine. This energy consumption can be reduced by cooling the compressed air at intermediate stages of compression. Intercooling improves thermal efficiency by reducing the energy needed for air compression. Also, power output for a given size turbine is increased by the greater density of air flowing through the high pressure stages of the compressor and turbine. Intercooling can be accomplished by direct injection of water into the compressed air stream or by routing the compressed air through an external cooler. Only one commercial gas turbine using external intercooling is available - the General Electric LMS100™. The LMS100, introduced in 2004, is a hybrid intercooled design because it uses a combination of aeroderivative and industrial frame components and design practices. The combination of external intercooling and lightweight aeroderivative components improves thermal efficiency and operating flexibility, including a flatter heat rate curve (better efficiency), faster ramping, faster cold start, and reduced maintenance due to cycling.

A typical external intercooled SCCT plant using a single GE LMS100 gas turbine generator would have a nominal rating of 100 megawatts. The maintenance-adjusted degraded lifecycle average full load capacity is 94 megawatts (ISO conditions). The gas turbine generator is enclosed for weather protection and acoustic control, and is provided with inlet air filters and exhaust silencers. The plant also includes an outboard intercooler, a mechanical draft evaporative intercooler cooling system, a makeup cooling water treatment plant; lube oil, starting, fuel forwarding, and control systems; a control building and switchyard. Natural gas is supplied through a firm transportation contract with capacity release capability. No backup fuel is provided. Dry low- NOx combustors and selective catalytic reduction are used for NOx control and an oxidation catalyst for CO and VOC control. The plant is assumed to be located
near a natural gas mainline with sufficient pressure for operation without fuel gas booster compression.

Because of their relatively high efficiency and operating flexibility, external intercooled gas turbines can economically serve peak and intermediate loads, and can economically operate for extended periods at partial load to provide balancing reserves. Pacific Northwest plants could also operate for extended periods during poor water years.

Siting requirements for a gas-fired external intercooled gas turbine plant include proximity to high-voltage transmission for interconnection and natural gas service. Location near a high-pressure natural gas mainline or lateral is desirable to avoid the cost and power consumption of fuel gas booster compressors. Makeup water supply and treatment facilities are required for the cooling system. NOx, CO, and VOCs can be controlled to very low levels using catalytic control for sites in sensitive or non-attainment areas. While intercooled SCCTs are often cited in urban areas, noise has been an issue for some gas turbines located near residences or recreational areas.

**Combined-Cycle Combustion Turbines**

Combined-cycle combustion turbine (CCCT) plants consist of one or more natural gas turbine generators with exhaust heat recovery steam generators. Waste heat from the combustion turbine is used in the heat recovery units to power a steam turbine generator. This productive use of otherwise wasted energy greatly increases the overall thermal efficiency of the plant compared to an SCCT. Combined-cycle plants can be constructed in a wide range of sizes and configurations, ranging from plants of less than 10 megawatts for special industrial applications to utility-scale plants of 130 to 550 megawatts, or larger. Additional generating capacity (power augmentation) can be obtained at low cost by over sizing the steam turbine generator and providing the heat recovery steam generator with supplementary natural gas burners (duct firing). The resulting capacity increment operates at a lower thermal efficiency level than the baseload plant, but provides relatively inexpensive capacity for peak-hour load periods.

Combined-cycle plants can also serve cogeneration loads (at some loss of electricity production) by extracting steam from the heat-recovery steam generator or steam turbine. Because of their reliability and efficiency, low capital costs, short lead-time, operating flexibility, and low air emissions, gas-fired combined-cycle plants have been the bulk power generation resource of choice since the early 1990s.

A typical combined-cycle plant would consist of one “H-class” gas turbine generator, a heat recovery steam generator with duct firing and a steam turbine generator. The maintenance-adjusted degraded lifetime average baseload capacity of this plant would be 390 megawatts with an additional 25 megawatts with duct firing. Natural gas would be supplied
through a firm transportation contract with capacity release capability. Air emission controls include dry low-NOx combustors and catalytic reduction of NOx, CO, and VOCs. Condenser cooling could be provided by wet mechanical draft cooling towers, or, in water-constrained locations, dry mechanical draft radiators. However, dry cooling reduces overall plant capacity and efficiency somewhat.

In the Pacific Northwest, a typical CCCT plant would operate at full output during the summer and winter high load seasons, and in the spring and fall would either be shut off or reduced to minimum output during light load hours. A CCCT can also operate at partial load for extended periods to provide regulation and load-following services. The cost of natural gas is a primary factor in the overall cost of production for a CCCT because of the higher volumes of gas these plants burn as a result of operating as baseload resources.

Siting requirements for a utility-scale combined-cycle plant include proximity to a high-pressure natural gas mainline or high-capacity lateral, high-voltage transmission for interconnection to the electrical grid and a water supply for condenser cooling and steam plant makeup water. Air emissions can be controlled to very low levels so air quality is usually not limiting. Noise has been an issue at plants located near residences or recreational areas.

Reciprocating Engine-Generators

Reciprocating-engine generators (also known as internal combustion engines, ICs or gensets) consist of a compression or spark-ignition reciprocating engine driving a generator. Reciprocating units are typically frame-mounted and are supplied as modular units. Unit sizes for power system applications range from about one to 15 megawatts. Reciprocating engine generators have been used for small isolated power systems, emergency capacity at sites susceptible to transmission outages, and to provide emergency power and black start capacity at larger power plants. Other applications include units operating on biogas from landfills or anaerobic digestion of waste biomass, and mobile units for emergency service. Reciprocating units also provide backup power for hospitals, elevators, and emergency lighting in high-occupancy buildings and other critical loads.

The introduction of more efficient and cleaner reciprocating engine generators in recent years, coupled with increasing need for balancing reserves for wind integration has increased interest in the use of arrays of gas-fired reciprocating engine generators to provide peaking and load-following services. A typical plant for this purpose might consist of five to 20 units of 3 to 16 megawatts capacity each. The resulting plant is highly reliable, efficient over a wide range of output, and flexible. Reciprocating units can also be fitted with exhaust, turbocharger, and lube oil heat recovery for low-temperature cogeneration loads.

Unlike other gas turbines, the output of reciprocating engines is relatively insensitive to elevation. For this reason, they may be a better choice for high-elevation locations than gas
Because fuel supply pressure requirements are lower than for other gas turbines, reciprocating engines do not need fuel pressure booster compressors when sited away from high pressure gas pipelines. Moreover, reciprocating engines are normally air-cooled and require little in the way of water supply, treatment and disposal facilities. The modular nature of these plants permits great sizing flexibility and plants can be sized for system interconnection at sub transmission or distribution system voltages.

A typical reciprocating engine plant would consist of 12 natural gas fired 8.25 megawatt capacity, spark ignition, engine-generators comprising a plant of 100 megawatts of nominal capacity. The plant would include a generator and control building, the reciprocating engine-generator units, fuel, electrical, control and instrumentation systems, closed-cycle (radiator) cooling, and a switchyard. Air emission controls include selective catalytic reduction for NO\textsubscript{x} control and an oxidation catalyst for CO and VOC control.

Reciprocating engine plants can provide regulation and load following, contingency reserves and other ancillary services. The relatively high efficiency (41 percent) allows the plant to economically serve peak and even intermediate loads.

Siting requirements for a reciprocating engine plant include proximity to transmission or sub transmission for interconnection, and natural gas service. NO\textsubscript{x}, CO, and VOCs can be controlled to low levels using catalytic control for sites in sensitive or non-attainment areas.

The performance and cost characteristics of natural gas technology resources are summarized in Tables 2 and 3 below.\textsuperscript{21}

\textit{Table 2 – Operational Characteristics of Natural Gas Resources}

<table>
<thead>
<tr>
<th>Type</th>
<th>Plant Size (Nameplate MW)</th>
<th>Heat Rate (Btu/kWh)</th>
<th>Availability for Operation (%</th>
<th>Total Plant Capital Cost ($/kW)</th>
<th>Fixed O&amp;M Cost ($/kW-yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial frame SCCT</td>
<td>85</td>
<td>11,960</td>
<td>91%</td>
<td>$610</td>
<td>$11</td>
</tr>
<tr>
<td>Aero derivative SCCT</td>
<td>2 × 47</td>
<td>9,370</td>
<td>91%</td>
<td>$1,050</td>
<td>$13</td>
</tr>
<tr>
<td>Intercooled SCCT</td>
<td>100</td>
<td>8,870</td>
<td>91%</td>
<td>$1,130</td>
<td>$8</td>
</tr>
<tr>
<td>Reciprocating Engine</td>
<td>12 × 8.3</td>
<td>8,850</td>
<td>93%</td>
<td>$1,150</td>
<td>$13</td>
</tr>
<tr>
<td>Combined-cycle (Baseload Increment)</td>
<td>390</td>
<td>6,930</td>
<td>89%</td>
<td>$1,160</td>
<td>$14</td>
</tr>
<tr>
<td>Combined-cycle (Duct-Firing Capacity)</td>
<td>25</td>
<td>9,500</td>
<td>89%</td>
<td>$465</td>
<td>N/A</td>
</tr>
</tbody>
</table>

\textsuperscript{21} Maintenance-adjusted degraded values for capacity and costs over the estimated 30-year economic life of the plant.
Combined Heat and Power

Combined heat and power (CHP) is defined as the sequential production and use of both shaft horsepower and thermal energy. The most common example of a combined heat & power system is a vehicle. In a typical automotive system, gasoline or diesel is first used to fuel a reciprocating engine that creates shaft horsepower to propel the vehicle. During periods when comfort heating is needed within the vehicle, some of the fluid associated with cooling the engine is redirected through a series of pipes and heat exchangers to provide warm air to the interior of the vehicle. This process is a classic heat & power application. In this case, shaft horse “power” was the first step in the system with “heat” for the interior of the car being the second step – or “combined heat and power”.

Combined heat & power systems are also referred to as “cogeneration” – the two co-products being electricity and steam. Some installations also use byproduct thermal energy for cooling purposes as well and are categorized as tri-generation.

The technical and economic incentive associated with combined heat and power systems is energy efficiency. In this context, energy efficiency is defined as the percent of input fuel used that ends up being available for output purposes. Modern standalone natural gas-fired combined-cycle power plants (which only make electricity) achieve a thermal efficiency of approximately 50 percent. In contrast, there are many older combined heat & power systems operating today in the US that achieve thermal efficiencies of over 75 percent. Wasted energy is minimized with the use of a combined heat & power system. There is no better technology for achieving high levels of energy efficiency in large commercial and industrial setting than using combined heat and power systems.
Clearwater Paper, a major electricity consumer, also operates the largest combined heat & power system in Idaho (Lewiston). This system can generate up to 62 MW of electrical power while supplying over a million pounds of high pressure steam an hour that is used to make paper and other wood products.

**Combined Heat & Power Technologies**

There are several technologies that can be used as part of a successful combined heat & power system. Sometimes the thermal energy is used first, with heat recovery following, to provide shaft horsepower. Other applications utilize shaft horsepower first with heat recovery following. As long as there is sequential use of both forms of energy, the system generally qualifies as combined heat & power.

Traditional combined heat & power applications include:

- Reciprocating engines can be fired with natural gas, propane or oil with the recovery of hot water or steam from exhaust gases, lube oil coolers and water jackets.
- Combustion gas turbines can be fired with natural gas, synthetic gas, or oil with the recovery of steam from exhaust gases. Many systems then use the recovered steam to generate more electricity using steam turbines coupled to generators and steam to industrial processes – these are referred to as “combined” cycle systems.
- Boilers fired by natural gas, biomass, coal, and/or by product fuels (black liquor from paper making, refinery gases, etc) with steam flowing through steam turbines coupled to generators are a common system configuration. Steam is usually “extracted” from the steam turbine at one or more intermediate pressures to meet the demand of an industrial process or is used for commercial heating.

**Policy Impact on Combined Heat & Power**

The economics of combined heat & power systems are determined largely on the value of the electrical power that the developing entity is able to realize for the generated electricity. Because combined heat & power plants must often continue to generate electricity at times when it is less valuable (in order to provide a constant supply of steam), the economics can be less favorable than building a stand-alone gas plant that can be dispatched down or off when it is not needed or the electricity is less valuable.

Under the Public Utility Regulatory Policies Act (PURPA), public utilities are mandated by federal law to purchase the output of combined heat & power projects that meet a minimum efficiency standard at the utility’s “avoided” cost. These “qualifying facilities” or QFs are permitted to sell all of the output of their projects at rates established by public utility
commissions for investor-owned utilities or individually determined for publically owned utilities.

As one can imagine, the “avoided” cost of an individual utility, investor owned or public, is subject to wide variability based on location, growth projections, type of avoided generation and the appetite of an individual utility to enter into agreements with non-utility developers of power resources. The lack of a regionally based marginal cost of power inhibits the uniform development of combined heat & power projects. If a region’s marginal cost of power was generally available to project developers, more systems would be constructed and there would be a societal benefit accruing though higher energy efficiency systems being installed.

Any new federal green house gas regulatory program could significantly benefit or hinder the development and efficacy of currently operating combined heat & power systems. As an example, if the energy efficiency of combined heat & power is recognized under a carbon regulatory program and allowances are granted based on both the electrical generation and thermal use, combined heat & power would be incentivized.

Natural Gas Supply and Prices

Natural gas is an abundant resource. Proved U.S. reserves in 2010 were 318 trillion cubic feet (tcf). Worldwide, proved reserves were estimated to be 6,254 tcf in 2008, representing a 63 year supply at the 2008 global production rate.

Proved reserves are estimated quantities of natural gas recoverable under existing economic and operating conditions with reasonable certainty. Reserves are proven by drilling in promising formations. Drilling is expensive, and companies prove out resources only as needed in advance of forecast demand. As a result, technically recoverable reserves are much larger than proved reserves. Estimates of total U.S. technically recoverable reserves in 2008 (including proved reserves) were 1,774 tcf, representing 87 years of production at 2008 rates.

U.S. proved reserves have increased in recent years even with increasing gas consumption. This increase has resulted from previously higher natural gas prices, and from the application of hydraulic fracturing and horizontal drilling technology to previously undeveloped, but very abundant gas shales. Commercialization of shale gas production is significantly expanding both domestic and global estimates of recoverable reserves.

Despite the rapid growth of shale gas production, U.S. natural gas production remains subject to several potential constraints. Among these are short well lives with corresponding

22 http://www.eia.gov/naturalgas/crudeoilreserves/
24 Ibid.
need for rapid well replacement. Moreover, though horizontal drilling facilitates use of multi-well drill pads, thereby reducing land use impacts, concerns regarding groundwater contamination and waste disposal issues associated with fracturing are increasing at some shale gas plays.

Though natural gas has been produced in Montana, and to a limited extent in local areas west of the Cascades, the Pacific Northwest does not have significant indigenous gas resources. Rather, gas is imported by pipeline from the Western Canada Sedimentary Basin of Alberta and British Columbia, the Rocky Mountain Basin of Wyoming and Colorado, and the San Juan Basin of New Mexico. The major gas supply areas, pipelines and trading hubs serving the Northwest are shown in Figure 5 below (trading hubs are shown as yellow dots).

![Figure 5 - Natural Gas Supply Areas, Pipelines and Trading Hubs](image)

Over the past 40 years North American natural gas has experienced two major periods of high prices, interspersed with one extended low. High prices of the late 1970s to the mid-1980s were attributable to cartel-driven run-up in oil prices and wellhead price controls. Removal of price controls and declining oil prices led to an extended period of low natural gas prices (the so-called “gas bubble”). Lack of exploration, coupled with increasing demand due to the economic expansion of the 1990s, increasing penetration of gas-fired power generating

---

25 Adapted from Northwest Gas Assn., 2010 Gas Outlook.
capacity and market speculation led to the second major price run-up, beginning in 2000. The
global economic recession and increasing domestic production prompted collapse of the record
high gas prices of 2008 to current moderate to low levels.

Past natural gas prices were closely coupled to oil prices due to widespread
substitutability in the industrial and power generation sectors. This linkage has weakened with
the losses of industrial boiler capacity and the retirement of dual-fuel steam-electric power
plants. With the expansion of natural gas combined-cycle generating capacity in recent years,
gas and coal consumption are increasingly coupled to gas prices. Recent low natural gas prices
and high storage levels have increased gas combined-cycle plant operation and displaced coal
plant operation to some extent.

The Northwest Power and Conservation Council, working with an advisory committee of
industry experts, prepares a long-term forecast of natural gas prices based on a forecast
prepared by the Northwest Gas Association. The Council’s latest forecast was prepared in
August 2011 and is presented in Table 4 and Figure 6 below. The Council prepares natural gas
price forecasts for numerous locations and the forecast presented is for “East-Side Delivered”
which is representative of the expected, delivered price of natural gas in the state of Idaho.

Table 4 – Forecast Natural Gas Prices

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>$4.05</td>
<td>2021</td>
<td>$5.24</td>
</tr>
<tr>
<td>2012</td>
<td>$4.18</td>
<td>2022</td>
<td>$5.39</td>
</tr>
<tr>
<td>2013</td>
<td>$4.28</td>
<td>2023</td>
<td>$5.53</td>
</tr>
<tr>
<td>2014</td>
<td>$4.37</td>
<td>2024</td>
<td>$5.68</td>
</tr>
<tr>
<td>2015</td>
<td>$4.47</td>
<td>2025</td>
<td>$5.84</td>
</tr>
<tr>
<td>2016</td>
<td>$4.58</td>
<td>2026</td>
<td>$5.99</td>
</tr>
<tr>
<td>2017</td>
<td>$4.70</td>
<td>2027</td>
<td>$6.15</td>
</tr>
<tr>
<td>2018</td>
<td>$4.84</td>
<td>2028</td>
<td>$6.32</td>
</tr>
<tr>
<td>2019</td>
<td>$4.97</td>
<td>2029</td>
<td>$6.49</td>
</tr>
<tr>
<td>2020</td>
<td>$5.10</td>
<td>2030</td>
<td>$6.66</td>
</tr>
</tbody>
</table>

27 http://www.nwga.org/
Long-term North American natural gas prices will ultimately be driven by supply and demand. Increasing substitution of gas electric power generation for coal because of reduced CO₂ emissions, increased use of flexible gas generation for balancing of wind and other variable renewable resources, and conversion of electrical end users to direct use of gas in response to higher electricity prices are among the uncertainties affecting long-term demand. Marginal prices could be set by the cost of production from any of several sources of supply, including Frontier Gas from the Alaskan North Slope or the McKenzie Delta, shale gas, tight sands gas or LNG imports. The long-term cost of gas from these various sources is not well-understood. For example, break-even estimates for shale gas production range from $3 to $8 per MMBtu at the wellhead. In addition to the long-term uncertainty in the price of natural gas, periodic unpredictable short-term price excursions will undoubtedly occur.

The Northwest historically has enjoyed lower natural gas prices than national averages because of delivery constraints from the production areas supplying the Northwest to the eastern centers of gas consumption. Additional eastbound delivery capacity from western Canada and Rocky Mountain production areas has eroded the Northwest’s pricing advantage. However, the Rocky Mountain supply area is a growing production area, and its prices are still relatively low. New British Columbia shale plays, Alberta coal bed methane, and future pipeline access to McKenzie delta and Alaskan North Slope supplies may augment supplies from the north. Increasing production in these supply regions, and shale gas production in the eastern
consuming regions, should help maintain current negative pricing differentials between eastern and northwest gas trading hubs.

**Opportunities and Risks**

Because of a reasonably abundant fuel supply, low CO₂ and other air emissions, low capital cost, short construction lead time, siting flexibility, high reliability, low water requirements, and diversity of generating technologies providing a variety of capacity and energy services, natural gas is expected to be an important power supply resource for many years. Continued efforts toward reducing CO₂ production is expected to lead to expansion of natural gas generation as a substitute for aging, high- CO₂ producing baseload coal-fired units and as a source of firm capacity and balancing reserves for wind power.

The principal risk associated with natural gas power generation is future natural gas price volatility and uncertainty. Gas price risk is, in fact, relatively minor for gas turbine or reciprocating engine plants intended for peak load service or backing up hydro during the occasional poor water year. These plants are expected to operate infrequently, minimizing gas price exposure. Moreover, a relatively small capital investment is at risk compared to other generating technologies.

Gas price risk is greater for plants intended to provide balancing reserves or baseload power. The costs of balancing services are minimized when the plant providing the services operates at or near prevailing market prices. A baseload plant must operate below prevailing market prices for most of the hours of the year. In the West, power prices are set for most hours of the year by gas-fired, combined-cycle plants. For this reason, combined-cycle plants compete with one another on thermal efficiency and relative fuel pricing. The higher efficiency of new plants may put them in a favorable competitive position relative to older gas-fired units. Higher partial load efficiency improves the competitive position of plants providing balancing reserves. Like peaking plants, gas price risk associated with plants providing balancing services or baseload energy are offset by low capital cost. Less investment is at stake compared to other technologies that could provide these services.

**NUCLEAR**

Evaluating the broader context of the Nuclear Energy option, today in the United States, 100 nuclear power plants in 31 states generate nearly 20% of the nation’s electricity at a low cost with a high level of safety and reliability. The focus on safety remains first and foremost, with continued excellence and positive trends as measured by industry and regulatory performance indicators related to nuclear, radiation and industrial safety. Currently, existing plants continue to perform well, setting new records for output and capacity factors.

---

In March 2000, the U.S. Nuclear Regulatory Commission (NRC) began to approve 20-year renewals of nuclear power plants’ original 40-year operating licenses. This allows those plants that have compiled detailed applications and undergone rigorous review to operate for a total of 60 years. Since then, the NRC has approved license renewals for 49 nuclear reactors. To date, the owners of almost one hundred nuclear units have decided to pursue license renewal.

Nuclear energy is the only major source of baseload electricity generation that does not emit criteria air pollutants or greenhouse gases. As discussions of both tighter emissions controls and greenhouse gas reductions continue at the national, state and regional levels, nuclear energy’s environmental benefits take on more significance. In 2007 alone, operating nuclear power plants prevented the emission of three million tons of sulfur dioxide and one million tons of nitrous oxide. Nuclear energy is perhaps even more important when considering CO2 emissions, with nuclear plants preventing emission of 693 million metric tons in 2007.

The U.S. nuclear power industry continues to make progress toward the construction of new nuclear power plants in the United States. Given the current business environment, a reasoned perspective on the “renaissance” of nuclear power suggests that it will unfold slowly over time. Some observers feel that a successful nuclear renaissance will see, at best, four to eight plants in commercial operation by 2016. The exact number will, of course, depend on many factors: electricity market conditions, capital costs of nuclear and other comparable baseload technologies, commodity costs, environmental compliance costs for fossil-fueled generating capacity, natural gas prices, customer growth, customer usage patterns (which would be heavily influenced by lower economic growth), availability of federal and state support for financing and investment recovery, and more.

If, however, those first plants are completed on schedule, within budget estimates, and without licensing difficulties, a second wave could be under construction as the first wave reaches commercial operation. The confidence gained by completing first projects on time and within budget estimates will support the decision-making process for the follow-on projects, and provide incentive for companies to invest in the expansion of the U.S. nuclear component manufacturing sector.

**Small Modular Nuclear Reactors**

A potential option that may provide a better match in the future for states with low electric power consumption or growth rates are small modular nuclear reactors. Small modular

---


30 Ibid.
nuclear reactors (SMRs) require a context as to what is meant by “small” and “modular”. To begin with, there is no exact definition for what constitutes a “small” reactor. The International Atomic Energy Agency defines them to be less than 300 MW,\(^{31}\) based mainly on two factors: (1) liability insurance, and (2) factory fabrication and portability to a site by rail or truck. SMRs are fabricated offsite in a factory setting and then transported by rail or truck, rather than by barge, to an approved site for assembly.

**Basic Description of SMRs, and Idaho-Specific Context\(^{32}\)**

The term “modular” implies several things that could create a potential advantage over larger plants. First, modular reactors can be linked together to create a larger power plant. This is potentially advantageous because it allows an owner to incrementally increase the size of a plant. As demand increases, the owner can add more modules. Secondly, a smaller plant requires less initial capital outlay or investment. The existing operating modules can then be used to finance future additions. Multiple units are also important during refueling or maintenance because taking single modules off-line does not require the shutdown of the entire plant.

The term “modular” also refers to potentially faster and more efficient construction techniques using factory fabrication. The U.S. defense nuclear shipbuilding industry is an excellent example where modular construction techniques have been proven to be highly successful. These same techniques can be applied to the commercial nuclear industry. This fabrication technique has the potential to make nuclear energy more economical and appealing to investors because it removes the perceived “risks” associated with new nuclear builds such as construction delays and schedule uncertainty.

There are several reasons why small modular reactors may prove advantageous compared to the “Generation III+” nuclear plants in terms of economics, performance, and security. First, the high capital cost for new nuclear reactors has been a challenge for private entities to finance. Smaller projects would carry lower investment risk and be more affordable to smaller utilities. This reduction in investment risk also provides an advantage in rate recovery, regardless of whether the licensee is regulated through state public utility commissions or whether it must sell the electricity in unregulated commercial markets.

Second, there are areas in this country and the world where large plants are not needed or their existing infrastructure cannot support the larger capacity. Small modular reactors could be used to provide power to these smaller electrical markets, isolated areas or smaller

\(^{31}\) http://www.iaea.org/NuclearPower/SMR/index.html

\(^{32}\) In an Idaho context, aggregate demand may be such that a smaller number of modules are initially required as compared to other locations.
there is both a domestic and international market for small modular reactors and U.S. industry is well-positioned to lead and compete for these markets. Third, some of the SMR designs offer significant environmental or safety benefits or advantages where water for cooling is a problem. Some reactor designs produce a higher temperature outlet heat that can be used for either electricity or process heat for nearby industries while others use little or no water for cooling. Third, some of the SMR designs offer significant environmental or safety benefits or advantages where water for cooling is a problem. Some reactor designs produce a higher temperature outlet heat that can be used for either electricity or process heat for nearby industries while others use little or no water for cooling. In addition, the relatively smaller geographical footprint and extent of evacuation zone are considered by some as an advantage versus more conventionally sized reactors.

Fourth, there are also some potential non-proliferation benefits to the international use of small reactors that could be designed to operate for 10 to 30 years without refueling. These reactors could be fabricated and fueled in a factory, sealed and shipped to the site for power generation, generate electricity for decades, and then shipped back to the factory to be defueled. This system could minimize the spread of both nuclear material and nuclear expertise. Fifth, small reactors could also enter into traditionally non-nuclear energy markets for applications beyond electricity production. The possibilities include low carbon process heat for: fossil fuel recovery and refinement, synthetic or biofuels production, water desalination, hydrogen production, and a range of other petrochemical applications.

Finally, while traditional economy-of-scale concepts favor larger nuclear plants, there are a number of reasons why SMRs may have some economic advantages. As mentioned previously, a sizeable portion of the cost and schedule vulnerability for building large nuclear plants is the amount of work that must be performed on site. Factory production and fabrication, and transport to and assembly onsite can significantly reduce that vulnerability. Supply chain choke points are also vulnerable for new builds. For example, modern large light water reactors require large forgings that can only be provided by one or two manufacturers which are outside of the United States. This is a well-known bottleneck for the expected new nuclear plant worldwide orders over the next several years. SMRs would eliminate the number of large forgings that are required, and the remaining components would be within the existing production capability of U.S. manufacturing industry.

It is hoped that SMRs will have a simplified licensing process. For example, small reactors will have smaller amounts of nuclear material at risk and have simpler and more passive safety systems to prevent or mitigate accidents. Small reactors could also have a smaller emergency planning zone, which means that there could be less emergency planning. If they are air cooled, then licensing issues regarding water use could be reduced. All told, there could be significant changes in licensing issues compared to larger reactors that could work in favor of small reactor designs.

---

33 An Idaho limitation on water availability, as well as its inland geography, tends to lend itself towards SMR deployment in this context.
Proposed Federal Government Legislation on SMRs

Pending legislation in the Nuclear Energy Research Initiative Improvement Act of 2009, Senate Bill 2052, would provide broad authority to conduct research into small modular reactors, as well as other connected issues. S.2812, the Nuclear Power 2021 Act, would require the Department of Energy to carry out a program to develop and demonstrate two small modular reactor designs. If passed, several factors would be important to consider:

- The licensing would likely include at least two designs, and probably more.
- The program should initially be focused on light water reactor technology based on the large amount of experience – both design and licensing – with such reactors.
- The requirement that at least one of the designs be less than 50 MW is too restrictive; simply having an upper bound of approximately 400 MW would be more appropriate. Cost-shared design development and licensing will be based on competitive procurements and the market place will establish the appropriate design parameters.
- The design certification date of 2018 and the COL [Combined Operating License] deadline of 2021 should be made more ambitious by moving them up 1 or 2 years. More ambitious schedules for licensing are achievable based on current vendor business cases.

Key Issues for Consideration

- What are the best available unit (overnight and life-cycle) cost and deployment (time to actual market) metrics to use for serious consideration of modular nuclear plant investments, and how can we use these metrics to compare to other options available in Idaho? Key constraints on alternatives to modular nuclear plants in the Idaho context could include for example continued opposition to Idaho based coal plant investments, the relative perceived risk of natural gas availability for Idaho customers, uncertainty of effectiveness of conservation measures in Idaho, and uncertainty of aggregate renewable market share. Also, aggregate electric demand and local market forces may be such that installed cost estimates will vary from a national average and therefore are not easily obtainable at this time, either for larger nuclear units or for SMRs.
- Keeping in mind the twenty-year time horizon mandate of the Task Force, how close are we to major capital energy investments decisions currently, in light of both forecasted grid generation shortfalls as well as the current and ongoing financial market volatility?
Given prior and current involvement of the state of Idaho with the federal government regarding nuclear waste storage issues, would the deployment of SMRs be considered a relative advantage since their waste generation may be less in absolute volume terms versus larger nuclear units (depending upon the design chosen)?

**RESOURCE TYPES COVERED BY OTHER ISEA TASK FORCE REPORTS**

The focus of this report is on baseload generation resources that have not been covered by other ISEA task forces. Because other technologies such as hydroelectric, geothermal, biomass, wind and solar are either baseload resources or have an impact on the operation of other baseload resources, they are summarized in this report. For more detailed information regarding these resource types, please reference the reports prepared by the individual task forces which can be found at [http://www.energy.idaho.gov/energyalliance/taskforce.htm](http://www.energy.idaho.gov/energyalliance/taskforce.htm).

**Hydropower**

Significant hydroelectric power generation has been developed along the Snake River in southern Idaho. Idahoans have benefited from hydroelectric generation because of its low cost and lack of potentially harmful pollutants. The development of new large hydroelectric projects is limited because most appropriate sites have already been developed and numerous environmental and permitting issues are associated with new, large facilities. However, small hydroelectric sites have been extensively developed in southern Idaho on irrigation canals and other sites through the Public Utility Regulatory Policies Act of 1978 which is explained later in this report.

**Small Hydroelectric**

Small hydroelectric projects, such as run of river and projects requiring small or no impoundments, do not have the same level of environmental and permitting issues as large hydroelectric projects. The potential for new, small hydroelectric projects was studied by the Idaho Strategic Energy Alliance’s Hydropower Task Force, and the results released in May 2009 indicate between 150 MW to 800 MW of new small hydroelectric resources could be developed in Idaho. These figures are based on potential upgrades to existing facilities, undeveloped existing impoundments and water delivery systems, and smaller in-stream flow opportunities.

**Pumped Storage**

Pumped storage is a type of hydroelectric power generation used to change the “shape” or timing when electricity is produced. The technology stores energy in the form of water, pumped from a lower elevation reservoir to a higher elevation. Lower-cost, off-peak electricity is used to pump water from the lower reservoir to the upper reservoir. During higher-cost
periods of high electrical demand, the water stored in the upper reservoir is used to produce electricity.

For pumped storage to be economical, there must be a significant differential in the price of electricity between peak and off-peak times in order to overcome the costs incurred due to efficiency and other losses that make pumped storage a net consumer of energy overall. Historically, the differential between peak and off-peak energy prices in the Pacific Northwest has not been sufficient to make pumped storage an economically viable resource; however, with the recent increase in the number of wind projects, the amount of intermittent generation provided, and the ancillary services required, this may change.

Wind

A typical wind project consists of an array of wind turbines ranging in size from 1–3 megawatts each. The majority of potential wind sites in southern Idaho lie between the south central and the most southeastern part of the state. Areas that receive consistent, sustained winds greater than 15 miles per hour are prime locations for wind development. There has been a significant amount of wind generation developed in southern and eastern Idaho predominantly through the Public Utility Regulatory Policies Act of 1978 which is explained later in this report.

The Pacific Northwest and Intermountain Region are good areas for the development of wind resources, as evidenced by the number of existing and planned projects. However, wind resources present challenges for utilities due to the variable and intermittent nature of the generation. The typical expected annual capacity factor for wind sites in southern Idaho are approximately 30% while utilities typically count on 5% of installed nameplate capacity of wind resources being available to serve peak hour load due to the variable and intermittent nature of the output.

Solar

The primary types of solar electric technology are solar thermal and photovoltaic (PV). Solar thermal technologies use mirrors to focus the sun’s rays onto a central receiver or a “collector” to collect thermal energy that can be used to make steam and power a turbine that creates electricity. PV panels absorb solar energy collected from sunlight shining on panels of solar cells, and a percentage of the solar energy is absorbed into the semiconductor material. The energy accumulated inside the semiconductor material energizes the electrons and creates an electric current.

On cloudy days, solar thermal generation will not produce power. However, thermal storage using molten salt functions as an energy storage system allowing solar thermal generation plants to generate electricity after the sun sets or during brief cloudy periods,
generally for 3–7 hours. PV technology uses panels that convert the sun’s rays directly to electricity. Even on cloudy days, a PV system can still provide about 15 percent of the system’s rated output.

Insolation is a measure of solar radiation reaching the earth’s surface and is used to evaluate the solar potential of an area. Typically, insolation is measured in kWh per m2 per day (daily insolation average over a year). The higher the insolation number, the better the solar power potential for an area. National Renewable Energy Laboratory (NREL) insolation charts show the Desert Southwest has the highest solar potential in the United States.

Solar PV panels absorb solar energy collected from sunlight shining on panels of solar cells, and a percentage of the solar energy is absorbed into the semiconductor material. The energy accumulated inside the semiconductor material energizes the electrons, creating an electric current. The solar cells have one or more electric fields that force electrons to flow in one direction as a direct current (DC). The DC energy is passed through an inverter, converting it to alternating current (AC) that can then be used on site or sent to the grid.

Solar PV technology has existed for a number of years but has historically been cost prohibitive. Recent improvements in technology and manufacturing, combined with increased demand due to state RPS requirements, have made PV resources more cost competitive with other renewable and conventional generating technologies.

**Geothermal**

Potential commercial geothermal generation in the Pacific Northwest includes both flashed steam and binary cycle technologies. Based on exploration to date in southern Idaho, binary cycle geothermal development is more likely than flashed steam. Most optimal locations for potential geothermal development are believed to be in the southeastern part of the state. However, the potential for geothermal generation in southern Idaho is somewhat uncertain. The time required to discover and prove geothermal resource sites is highly variable and can take years, or even decades.

The overall cost of a geothermal resource varies with resource temperature, development size, and water availability. Flashed steam plants are applicable for geothermal resources where the fluid temperature is 300°Fahrenheit (F) or greater. Binary cycle technology is used for lower-temperature geothermal resources. In a binary cycle geothermal plant, geothermal water is pumped to the surface and passed through a heat exchanger where the geothermal energy is transferred to a low boiling point fluid (the secondary fluid). The secondary fluid is vaporized and used to drive a turbine/generator. After driving the generator, the secondary fluid is condensed and recycled through a heat exchanger. The secondary fluid is in a closed system and is reused continuously in a binary cycle plant. The primary fluid (the geothermal water) is returned to the geothermal reservoir through injection wells.
Biomass, Biogas, and Biofuels

Biomass has been an important source of energy worldwide for thousands of years. The earliest form of comfort heating for mankind was almost certainly wood harvested and burned from nearby forests. With the onset of electrical power, wood fuel (biomass) and coal were the primary sources of energy to fire boilers creating steam to power steam turbines and generators.

While the definition of “biomass” fuel varies somewhat, generally speaking residual organic materials used for combustion are considered “biomass” if the carbon within the material was removed from the atmosphere within the last several hundred years. Within the current practice of industrial forestry (harvesting followed by immediate replanting), the carbon removed from the atmosphere and placed in biomass is almost entirely less that 100 years old – generally closer to 20 to 40 years depending on location. With immediate replanting of trees (or other woody species) after harvesting, the capture of carbon back from the atmosphere begins immediately with the objective of minimizing cycle times depending on tree species and geographic location.

Given the current emphasis on the control of fossil fuel related carbon, significant resources are being applied to evaluate the feasibility of even shorter crop rotations to sequester and release on more aggressive time schedules. One example would be the agricultural based ethanol fuel cycle where carbon cycle times are less than two years. Unlike natural gas or coal, where the fuel can be economically transported a thousand or more miles, the source of the biomass must be much closer to where it is processed for energy reclamation due to its lower energy density.

Any woody biomass power plant will have an upper limit on the cost effective distance associated with incremental biomass fuel. In other words, the further the wood is from the power plant, the more it costs to produce power. At today’s marginal value of electricity and expected power plant efficiency, biomass fuel can’t generally be economically transported more than 50 miles.

While there is a large amount of woody biomass in the forests, particularly federal forests, the amount that is economically available is limited. Depending on the specific location within a state, a limited amount of agricultural or forestry by-products can be expected to be available. Again, depending on the economic pressures brought by existing or future plants, the supply and transportation cost limitations can inhibit the viability of multiple biomass operations within the same circle of economic impact. Multiple plants operating within the same economic circle would create supply/demand forces on biomass prices and potentially impact the viability of all sites by increasing the costs of generating the electricity.
Biomass Technologies – Generation technologies which utilize biomass as fuels are quite similar to coal plants and other solid fuel systems. The typical biomass-to-electricity system utilizes a combustion unit and/or boiler, steam turbine and depending on whether the plant utilizes combined heat & power, a surface condenser is used to extract as much energy as possible from the steam. Typically the combustion unit and boiler are designed and fabricated as a common unit. The combustion system can be either one large furnace or combinations of combustion cells. Biomass within the boiler can be burned on a fixed grate arrangement using manual labor to remove the ash; moving grate systems; or more sophisticated systems that create a suspension of multiple types of biomass fuel and ash using combustion air and gasses.

A myriad of fuels make up the general arena of biomass fuel. These generally include:

- Agricultural specific biomass including animal waste
- Residuals from agricultural or biomass related processing (biogases, rice hulls, black liquor from papermaking, straw, etc.)
- Residual wood from forest products manufacturing (bark, sawdust, waste whitewood)
- Residual wood reclaimed from logging operations
- Wood residue segregated from urban refuse streams (demolition, construction, etc.)

As with all renewable forms of energy, government policy can have a profound impact on the speed at which specific energy technologies are implemented at production scale. As with the production tax credit for wind energy, any tax credit associated with biomass specific projects can serve to incentivize the project developer and cause a tipping point for project development. Such incentives, however, can also have unintended and sometimes unforeseen negative consequences. An example would be the actual negative economic effects that occurred when the federal government subsidized the use of corn to produce ethanol. These subsidies increased demand for field corn, driving costs of purchasing corn for non-ethanol related uses such as feed. Already existing markets like dairy production, confined feed lots for cattle production and other feedstock-dependent industries, suffered substantial losses as their corn prices skyrocketed.

Unlike wind and hydro energy projects, biomass projects carry a significant component of their inherent cost structure in the fuel cost component – as noted in the previous section depending on the distance and market pressure on the source of biomass fuel.

It is useful to contrast the fuel cost structure of an incremental biomass plant with that of a utility sized coal plant. Ignoring for a moment the greenhouse gas ramifications of coal as a fuel, the capital costs ($/MW) of a modern, efficient biomass plant are not dissimilar to that of a traditional coal plant. Also, all things being equal, coal can be processed and delivered at a
lower cost and from much greater distances than biomass fuels. This is because of the energy density of coal being higher and the fact that typical woody biomass fuel has moisture content in the 25 to 50% range. Per energy unit, it generally costs much more to move woody biomass than it does to move coal.

Any incentives associated with biomass power plants impact the timing of development of these plants, but seem unlikely to have dramatic effects on the long-run efficacy of biomass power plants. Unlike wind and hydro power, which have comparably much lower operating costs, the fuel and operating maintenance costs of biomass plants are a larger hurdle to the long-term viability of both biomass fuel supply and cost. Policy solutions are unlikely to address this concern.

As noted within the section dealing with Combined Heat & Power, the value of biomass electricity is a lever that policy makers can control and as noted within that section, higher electricity prices will incentivize projects owners with all other concerns being equal.

PUBLIC POLICY ISSUES

Water Policy and Impact on Baseload Resources

Power plants that use steam to generate electricity or for cooling are subject to strict water usage and quality regulations. This is particularly important in the western US where water is scarce and there are many competing interests for water use. Federal and state water policy has a significant impact on the design and cost of existing and future baseload generation facilities. Technologies that could be required to limit water use and eliminate any water discharge would add costs and operational complexity to the facilities.

Hydroelectric power generation on the Snake River is dependent on the state water rights held by Idaho Power for these projects. The long-term sustainability of the Snake River Basin stream flows, including tributary spring flows and the regional aquifer system, is crucial to maintaining generation from these projects. The Snake River Basin Adjudication (SRBA), a general stream flow adjudication process, was started in 1987 to define the nature and extent of water rights in the Snake River Basin. The initiation of the SRBA resulted from the Swan Falls Agreement entered into by Idaho Power and the governor and attorney general of Idaho in October 1984.34

In 1984, the Swan Falls Agreement resolved a struggle between the state of Idaho and Idaho Power over the company’s water rights at the Swan Falls hydroelectric facility. The agreement stated Idaho Power’s water rights at its hydroelectric facilities between Milner Dam

and Swan Falls entitled the company to a minimum flow at Swan Falls of 3,900 cubic feet-per-second (cfs) during the irrigation season and 5,600 cfs during the non-irrigation season.

The agreement placed the portion of the company’s water rights beyond those minimum flows in a trust established by the Idaho Legislature for the benefit of Idaho Power and the citizens of the state. Legislation establishing the trust granted the state authority to allocate trust water to future beneficial uses in accordance with state law. Idaho Power retained the right to use water in excess of the minimum flows at its facilities for hydroelectric generation until it was reallocated to other uses.

Idaho Power filed suit in the SRBA in 2007, as a result of disputes about the meaning and application of the Swan Falls Agreement. The company asked that the court resolve issues associated with Idaho Power’s water rights and the application and effect of the trust provisions of the Swan Falls Agreement. In addition, Idaho Power asked the court to determine whether the agreement subordinated the company’s hydroelectric water rights to aquifer recharge.

A settlement signed in 2009 reaffirmed the Swan Falls Agreement and resolved the litigation by clarifying that the water rights held in trust by the state are subject to subordination to future upstream beneficial uses, including aquifer recharge. It also committed the state and Idaho Power to further discussions on important water management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. Idaho Power and the state are actively involved in those discussions. The settlement also recognizes water-management measures that enhance aquifer levels, springs, and river flows—such as aquifer recharge projects—that benefit both agricultural development and hydroelectric generation. Both parties anticipate water management measures will be developed in the implementation of the Eastern Snake River Plain Aquifer, Comprehensive Aquifer Management Plan (ESPA CAMP) as approved by the Idaho Water Resource Board.

Phase I recommendations resulting from the ESPA CAMP, to be implemented over a 5 to 10-year period, consist of a combination of groundwater to surface water conversions, managed aquifer recharge, demand reduction programs, and weather modification programs designed to produce an increase in average annual aquifer discharge between 200,000 and 300,000 acre feet. Additional funding mechanisms are being explored to implement measures outlined in the ESPA CAMP.

Renewable Energy Certificates (RECs)

To promote the construction of renewable resources, a system was created that separates renewable generation into two parts, 1) the electrical energy produced by a renewable resource, and 2) the renewable attributes of that generation. These renewable attributes are referred to as RECs or green tags. The entity that holds a REC has the right to
make claims about the environmental benefits associated with the renewable energy from the project. One REC is issued for each megawatt-hour of electricity generated by a qualified resource. Electricity that is split from the REC is no longer considered renewable and cannot be marketed as renewable by the entity that purchases the electricity.

A REC must be retired once it has been used for either regulatory compliance or to substantiate a claim regarding renewable energy. Once a REC is retired, it cannot be sold or transferred to another party. The same REC may not be claimed by more than one entity, including any environmental claims made pursuant to electricity coming from renewable energy resources, environmental labeling, or disclosure requirements. State renewable portfolio standards (RPS) also typically specify a “shelf life” for RECs so they cannot be banked indefinitely.

Public Utility Regulatory Policies Act of 1978 (PURPA)

In 1978, Congress passed PURPA requiring investor-owned electric utilities to purchase energy from any qualifying facility (QF) that delivers energy to the utility. A QF is defined by FERC as a small renewable-generation project or small cogeneration project. Individual states were tasked with establishing the PPA terms and conditions, including price, that each state’s utilities are required to pay as part of the PURPA agreements. The table below shows the amount of PURPA generation in Idaho, by utility, as of January 2012.35

Table 5 – PURPA Development in Idaho

<table>
<thead>
<tr>
<th>Utility</th>
<th>PURPA Nameplate Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Idaho Power</td>
<td>940</td>
</tr>
<tr>
<td>Rocky Mountain Power</td>
<td>65</td>
</tr>
<tr>
<td>Avista</td>
<td>7</td>
</tr>
<tr>
<td>Total Idaho PURPA Development</td>
<td>1,012</td>
</tr>
</tbody>
</table>

A key component of PURPA contracts is the energy price contained within the agreements. The federal PURPA regulations specify that a utility must pay energy prices based on the utility’s “avoided” cost. Subsequently, the Idaho PUC has established specific rules and regulations to calculate the avoided cost rate that utilities are required to include in PURPA contracts.

Federal Climate Change Legislation

For the past several years, Congress has considered comprehensive federal energy legislation requiring reductions in greenhouse gas (GHG) emissions. Proposed GHG regulations

---

35 http://www.puc.idaho.gov/fileroom/cases/elec/GNR/GNRE1103/intervenor/IDAHO%20POWER%20COMPANY/20120131STOKES%20DIRECT.PDF
target the reduction of carbon and other GHG emissions nationwide. The most recent and prominent bills that have been proposed are 1) the American Clean Energy and Security Act of 2009 (Waxman–Markey), sponsored by Representatives Henry A. Waxman and Edward J. Markey; 2) the Clean Energy Jobs and American Power Act of 2009 (Boxer–Kerry), sponsored by Senators Barbara Boxer and John Kerry in the Senate; and 3) the American Power Act of 2010 (Kerry–Lieberman), sponsored by Senators John Kerry and Joe Lieberman.

In June 2009, the US House of Representatives narrowly passed the Waxman–Markey bill. The draft bill included a GHG emissions reduction goal of 3 percent below 2005 levels by 2012, 17 percent by 2020, 42 percent by 2030, and more than 80 percent by 2050. The Waxman–Markey bill proposed to accomplish the reductions under a cap-and-trade system that would establish a limit or cap on the total amount of GHG emissions. Although the Waxman–Markey bill passed in the House of Representatives, it did not pass in the Senate.

Under a cap-and-trade system, utilities would be allocated emissions allowances that would be decreased over time to achieve a total emissions reduction goal. A certain amount of allowances would also be auctioned as part of establishing a market where allowances could be bought and sold. In effect, a buyer would be paying a charge for polluting, while a seller would be rewarded for having reduced emissions by more than was required. The theory is those who can reduce emissions most economically will do so, achieving the pollution reduction at the lowest possible cost to society.

In September 2009, the Boxer–Kerry bill was introduced in the Senate. The draft bill included a GHG emissions reduction goal of 20 percent below 2005 levels by 2020. The Boxer–Kerry bill did not include a federal RES provision.

In May 2010, the Kerry–Lieberman bill was introduced in the Senate. The proposed legislation included a cap-and-trade system for reducing GHG emissions by 17 percent in 2020 and by over 80 percent in 2050. None of the proposed federal climate change legislation has been able to gain enough support to be passed by both the House of Representatives and the Senate.

In the summer of 2011, the Environmental Protection Agency (EPA) plans to begin regulating GHG emissions. However, some members of Congress are currently working to remove EPA’s authority to regulate GHGs through legislative action and budget cuts.

**ELECTRICAL SYSTEM OPERATIONAL ISSUES**

**Integration of Variable and Intermittent Resources**

Total installed wind-generation capacity continues to expand in Idaho and the Pacific Northwest. As variable and uncertain generating resources, wind, solar and other alternative resources require an electrical system operator to modify operations to successfully integrate it
without impacting system reliability. The operator must build into its generation scheduling extra operating reserves designed to allow dispatchable generators to respond to the variability and uncertainty of these alternative resources.

Electrical power generated from wind turbines is commonly known to exhibit greater variability and uncertainty than that from conventional generators. Because of the incremental variability and uncertainty, it is widely recognized that electric utilities incur increased operating costs when their systems are called on to integrate wind power. These costs occur because the operation of power systems is de-optimized to successfully integrate wind generation without compromising the reliable delivery of electrical power to customers.

A critical principle in the operation of a bulk power system is that a balance between generation and demand must be maintained at all times. Power system operators have long studied the variability and uncertainty present on the demand side of this balance, and as a matter of standard practice carry operating reserves on dispatchable generators designed to accommodate potential changes in demand. The introduction of significant wind power causes the variability and uncertainty on the generation side of the balance to markedly increase, requiring power system operators to plan for carrying incremental amounts of operating reserves, in this case necessary to accommodate potential changes in wind generation.

The term balancing reserves is used to denote the operating reserves necessary for integrating wind. A document review on wind integration indicates a variety of terms for this quantity. Regardless of term, the property being described is generally the flexibility an electrical system operator must carry to reliably respond to variability and uncertainty in wind generation and load.

Wind integration costs are unique to every power system. In general terms, cost increases as the amount of nameplate wind generation is increased on any particular electrical system. In the Pacific Northwest, wind integration costs of approximately $2 to $8 per megawatt-hour have been calculated by various electrical system operators.36 Wind integration costs are also dependent on and correlated to the price of natural gas and prices in the regional power market.

Storage Technologies

Unlike natural gas or fuel oil, electricity cannot be easily stored. However, interest in developing economical storage capability has been growing with technological advancements that can make storage a more practical and economic means of integrating renewable power into the electrical grid as well as providing other operational benefits. In addition to increasing the reliability of energy supplies, the ability to store electricity would moderate the volatility of

---

36 [Link](http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2013/windIntegrationStudy.pdf)
the market price of electricity and ultimately contribute to the reduction of CO₂ emissions, especially when combined with wind or other renewable energy resources. While the technologies discussed in the following sections are technically feasible, the economics of the various technologies do not currently allow wide-spread adoption by electrical service suppliers.

**Hydroelectric Pumped Storage**

Water is pumped to a high storage reservoir during off-peak hours and weekends, using the excess baseload capacity from coal or renewable resources (see Figure 7 below). During peak hours, this water can be used for hydroelectric generation, often as a high value rapid-response reserve to cover transient peaks in demand. Pumped storage recovers about 75% of the energy consumed, and is currently the most cost effective form of mass power storage. The chief problem with pumped storage is that it usually requires two nearby reservoirs at considerably different heights, and often requires considerable capital expenditure. Moreover, the price differential between peak and off-peak is sometimes not enough to economically justify this method. Additional information on pumped storage can be found in the Hydro Task Force report at http://www.energy.idaho.gov/energyalliance/d/Hydro%20Packet.pdf.

![Figure 7 – Pumped Storage Plant Configuration](image)

A new concept in pumped-storage is utilizing wind energy to pump water. Wind turbines directly drive water pumps to store water in a high storage reservoir. The water is then used for hydroelectric generation as a dispatchable resource instead of an intermittent resource. In effect, the energy from the wind generation is being stored. While technically this process works fine, the economics generally do not justify this method.
**Batteries**

Batteries are generally expensive, have a relatively high efficiency, as high as 90% or better, but have a limited operating time span. Most applications have been in small “off-the-grid” domestic systems.

The nickel-cadmium battery (Ni-CD) is a type of rechargeable battery that uses nickel oxide hydroxide and metallic cadmium as electrodes. The world’s largest Ni-Cd is in Fairbanks, Alaska and has a capacity of 27 MW for 15 minutes and is used to stabilize voltage at the end of a long transmission line.\(^\text{37}\)

A Vanadium redox battery (VRB) is a type of rechargeable flow battery that employs vanadium redox couples in both half-cells, thereby eliminating the problem of cross contamination by diffusion of ions across the membrane (see Figure 8 below). The King Island Wind Farm Wind Farm in Tasmania, Australia is connected to a VRB that allows up to 800kWh of surplus electricity to be stored. The battery has an output power of 200 kW and is used to help maintain the electricity supply when demand exceeds turbine output (load balancing).

![Figure 8 – 1.5 Megawatt VRB with One Hour of Storage](image)

**V2G (“vehicle to grid”) Concept**

When plug-in hybrid and/or electric cars are mass-produced, these mobile energy sinks could be utilized for their energy storage capabilities. Battery, hybrid, and fuel cell vehicles will send or receive power to or from the electric grid (see Figure 9 below). When these vehicles are not being driven, they provide energy storage during periods when renewable energy output is high, and provide electricity to the grid when renewable output is low.

The Harvard Press reported that a few of the residents in Harvard, Massachusetts used their Toyota Prius Hybrid automobiles as emergency generators for their houses when a winter storm knocked out the town’s power for several days. Residents did this by hooking up an inverter to their Prius batteries, which converted the current from 12 volts DC to 120 AC (the current used in homes) and plugging the other end into their house electric socket. One resident said he was able to run his refrigerator, freezer, TV, woodstove fan, and several lights for three days using only five gallons of gas.

**Compressed Air**

Another grid energy storage method is to use wind power to compress air, which is usually stored in an old mine or some other kind of geological feature. As energy is needed, the compressed air is heated with a small amount of natural gas and then goes through an expansion turbine connected to an electrical generator (see Figure 10 below). Intermittent wind is now operated as a baseload wind system. A proposed hybrid power plant utilizing this concept with a 75 - 150 MW wind farm is under consideration in Iowa.

---

Molten salt is used to store heat collected by a solar thermal generation plant to generate electricity after the sun sets or during brief cloudy periods (see Figure 11 below). Molten salt technologies could provide 3 to 7 hours of grid energy storage. Solar Millennium and Abengoa are constructing two 50 MW solar thermal plants in Spain with seven hours of thermal storage.39

Figure 11 – Using Molten Salt for Thermal Storage

1) Single-axis parabolic mirrors heat the transfer fluid.
2) Hot fluid returns from the solar field.
3) The hot fluid transfers its heat energy to water, creating steam at 700° F.
4) Steam is used to drive a turbine, creating electricity.
5) The hot fluid also heats molten salt.
6) After the sun sets, the stored heated molten salt is used to create steam to drive the turbine.

**Hydrogen**

Hydrogen is also being developed as an electrical power storage medium. Electricity from a wind or solar installation is used to produce hydrogen and then the hydrogen is burned in a generator to turn it back into electricity as needed. The hydrogen production uses the electrolysis of water to create hydrogen and oxygen [the decomposition of water (H₂O) into oxygen (O₂) and hydrogen gas (H₂) due to an electric current being passed through the water].

A community based pilot program using wind turbines and hydrogen generators was undertaken in 2007 for five years on Ramea Island, in Newfoundland Canada. In 2004, a wind/hydrogen R&D project was built in Utsira, Norway (see Figure 12 below). Also, in

---

40 http://oweolar.info/diagram-of-a-solar-power-plant/
Mountain Home, Idaho a 100 kW wind farm powers the production of hydrogen that is then sold to Norco Medical.

Superconducting magnetic energy storage systems store energy in the magnetic field created by the flow of direct current in a superconducting coil which has been cryogenically cooled to a temperature below its superconducting critical temperature (see Figure 13). A typical SMES system includes three parts: superconducting coil, power conditioning system and cryogenically cooled refrigerator. Once the superconducting coil is charged, the current will not decay and the magnetic energy can be stored indefinitely. The stored energy can be released back to the network by discharging the coil.

SMES systems are highly efficient; the round-trip efficiency is greater than 95%. The high cost of superconductors is the primary limitation for commercial use of this energy storage method.

SMES is currently being used in a utility application in northern Wisconsin. A string of distributed SMES units were deployed to enhance stability of a transmission loop. This transmission line is subject to large, sudden load changes due to the operation of a paper mill, where there is a potential for uncontrolled fluctuations and voltage collapse.

**Flywheel Energy Storage (FES)**

![Flywheel Energy Storage System](image)

*Figure 14 – A Flywheel Energy Storage System*

---

42 http://2013phys4030.blogspot.com/

Mechanical inertia is the basis of this storage method. A heavy rotating disc (a flywheel) is accelerated by an electric motor, which acts as a generator on reversal; slowing down the disc and producing electricity (see Figure 14). Electricity is stored as the kinetic energy (the extra energy which it possesses due to its motion) of the disc. Friction must be kept to a minimum to prolong the storage time. This is often achieved by placing the flywheel in a vacuum and using magnetic bearings, tending to make the method expensive.

In the Azores, EDA (Electricidade dos Açores) uses a 18MW flywheel to smooth out transient fluctuations in supply and thus allowing increased renewable energy usage. Also, in West Midlands, England, flywheels storing energy through regenerative braking have powered trolleys.

**PUBLIC UTILITY RATEMAKING**

The following describes in basic terms the methods which are traditionally used by the Idaho Public Utilities Commission and other various state utility commissions, to set electric rates for investor owned utilities. In the most general terms, electric rates are designed to recover the cost of providing electrical service and to allow an investor owned utility to earn a reasonable return on its investments.

An historic twelve month test period of actual expenses and investments is used as the basis for determining the level of costs that are subject to recovery through rates. Traditional ratemaking establishes the annual revenue requirement to provide the utility with recovery of its capital investment, a return on its capital investment and recovery of its prudently incurred operating expenses. The revenue requirement for the test period is then divided by the total annual energy consumed during the period by utility customers to derive an average rate per kilowatt hour (kWh). Using the average rate per kWh as the basis for the cost of current electric service, regulators can use the Rate Making Formula to evaluate the rate impact of adding various new baseload generation resources to the existing resource mix.

**Traditional Ratemaking Formula**

The traditional rate making formula is the basis for determining costs that are subject to recovery through electric rates. The formula is as follows:

\[
\text{Revenue Requirement} = \text{Capital Recovery} + \text{Return on Investment} + \text{Operating Expenses}
\]

The components of the formula are aligned to reflect the actual costs for a specific twelve month test period. The Revenue Requirement is the amount of revenue that must be generated from sales in a single year under normal weather, operating and economic conditions.
Capital Recovery is the recovery of a utility's original investment through annual depreciation expense based on the life of the asset. It is usually straight line depreciation for the purpose of setting revenue requirement. In other words, the annual depreciation expense for a given investment does not change on an annual basis over the asset life.

The Return on Investment is essentially the profit that the utility generates from doing business. The level of return is dependent on several factors including the utility capital structure, the interest on debt, and the return required to attract investor capital. The overall return, generally expressed as a percentage, is applied to the total un-depreciated investment or rate base identified for the test period.

The capital structure is the relationship between total debt incurred by the utility and equity investment provided by shareholders. A 50/50 capital structure means 50% of the utility's capital investment is borrowed funds with a return required to pay interest to the lender. The remaining 50% of the capital structure is investment made using investor equity with a return required to pay shareholders a competitive return on their investment. For example, if the weighted average interest on debt was 7%, the return necessary to attract investor capital was 11%, and the capital structure was 50/50, then the overall return on investment would be 9% (0.5 times 7% plus 0.5 times 11%). Consequently, a utility would earn $90 of return on every $1,000 of rate base (0.09 times $1,000).

Operating Expenses include the annual costs incurred for operation and maintenance of utility facilities, fuel to run generation plants, purchased power costs, and other recurring operating costs. This category of costs is generally reduced by any surplus wholesale sales that occur during the test period. Operating expenses included in the ratemaking formula must match both the timing of utility services delivered and the level of capacity and energy provided. This matching of costs components is achieved using a normalized historic test year.

Test Year

Establishing the test period or test year is an important first step in identifying Revenue Requirement. The test year is a representative twelve month period that reasonably aligns in time the energy consumption characteristics of a group of customers and the cost to operate and maintain facilities required to serve those customers. The test year can be an historic period of actual consumption and costs or can be a future period of forecasted consumption and costs. Generally, the test period is a combination of both, a historic period of actual consumption and costs that is modified or proformed to reflect forecasted impacts of more normal weather conditions. The historic information can also be modified to reflect known and measureable changes in the future such as property taxes or contract prices.

The investment used to establish annual depreciation expense and rate base used for return generally starts with total plant in service (original un-depreciated investment).
Depreciation expense, accumulated since the investment was first placed in service, is then subtracted for each month of the test period and the resulting rate base averaged for the year. The plant in service and the rate base changes each month during the test period as new investment is added and depreciation expense accumulates. Rate base associated with a specific investment declines to zero over its useful life.

Total annual depreciation expense is a composite of depreciation expense for all utility investment currently being depreciated on company books. Total annual test year fixed and variable operating expenses are made up primarily of salaries, fuel, purchase power and surplus energy sales. Actual test year variable expenses for fuel, purchased power and surplus sales are usually modified from actual booked expenses to reflect a forecast of normal weather conditions. Weather effects energy consumption, hydro generation, market energy prices and both the volume of energy that must be purchased to meet load and the quantity of energy that can economically be generated and sold on the wholesale market.

Once test year sales and service costs are weather normalized, the revenue requirement is calculated and divided by the normalized energy sales to establish an average embedded cost per kWh. This embedded cost can then be broken down (unbundled) into functions such as power production, transmission, and distribution and customer services. Current generation cost and the effect of new resources on average embedded rates will be discussed later in this section.

### Revenue Requirement

An analysis of 2008 rate cases filed by Idaho investor owned utilities provides a head to head comparison of components found in the traditional rate making formula. It also allows a comparison of the average embedded cost of electrical service in Idaho, how service cost varies for each utility and what portion of the service cost is caused by the power production function.

The attached Table 6 shows that the overall cost to provide service in Idaho on an average embedded basis is 5.39 cents per kWh or $53.92 per MWh. The lion share of the annual revenue requirement is due to annual operation and maintenance expenses (Operating Expenses) with annual depreciation expense (Capital Recovery) representing the smallest component. While the underlying cost structure for each utility varies, the general relationships of the components in the ratemaking formula remain similar.

Table 6 shows the bundled embedded cost of all operating functions provided by an electric utility including generation, transmission, distribution and customer service. Table 7 shows the unbundled embedded cost of the generation or power production function. The average embedded cost of generation in Idaho is 3.36 cents per kWh or $33.60 per MWh and varies from a high for Avista of $42.40 per MWh to a low for Idaho Power of $31.10. Further analysis shows that the power production function represents approximately 62% of the total
cost of service. Figure 15 shows a breakdown of the major revenue requirement components included in average embedded rates for each Idaho utility. Net power supply costs are the variable costs of generation tracked through annual power cost adjustment (PCA) mechanisms.

While average embedded rates are established based on a weather normalized test year of revenues and expenses, a PCA mechanism is utilized each year by each Idaho utility to track actual variable power supply costs that occur as weather conditions deviate from normal. The PCA tracks and compares actual fuel, purchased power, and surplus sales to those cost categories included in average embedded rates. For example, poor water conditions will require a hydro based utility to purchase more fuel for alternative generation, purchase more energy on the wholesale market, and will reduce surplus wholesale energy sales used to offset other power supply expenses. Consequently, revenue requirement for that year will increase and will be recovered through a PCA surcharge rate. On the other hand, a thermal based utility may not see any revenue requirement increase from similar poor weather conditions.

As a utility adds new resources, the impact on existing costs will depend upon the type of new resource added, the associated annual capital and expense revenue requirements, and the amount of new energy sold from the resource to retail customers. Historically, baseload plants such as coal and nuclear have had higher upfront capital cost, relatively low fuel expense and high capacity factors (runs as much as possible). More recently, Idaho utilities have selected a portfolio of resources including wind and combined cycle natural gas plants (CCCTs) to meet baseload requirements.

**New Resource Rate Impact**

The baseload resource of choice for Idaho investor owned utilities seems to be the CCCT. This is the resource that all companies have chosen as the most cost effective to provide baseload needs. The Idaho Public Utilities Commission has also chosen the CCCT as a proxy to represent the generation avoided cost for Idaho regulated utilities. Calculation of a utility’s avoided cost is necessary to establish Public Utility Regulatory Policy Act (PURPA) rates that utilities are required to pay for generation purchased from independent developers of renewable energy. The proxy resource or the Surrogate Avoided Resource (SAR) is assumed to be a 250 MW CCCT operated at a 90% capacity factor with a capital cost of $328 million and first year fuel cost of just over $69 million.

The first year, 2010 revenue requirement for such a generation plant is approximately $117 million at a natural gas price of $4.93/MMBtu. The revenue requirement breakdown based on the traditional ratemaking formula is Capital Recovery of $11 million, Return on Investment of $28 million, and Operating Expenses of $78 million. The average rate for energy produced during the first year of operation is approximately $59.36 per MWh. Annual revenue
requirement and average rate will change each year as natural gas prices change and the return component declines due to declining rate base as the original investment depreciates.

The impact on Idaho utilities of adding this new resource depends upon the existing resource mix and load characteristics. If new load characteristics exactly matched the new resource output, overall Idaho revenue requirement as shown in Table 4 would increase by 10.3%, energy consumption would increase by 9.4% and the average rate would increase by 1% from $53.9/MWh to 54.39/MWh. This assumes no additional distribution, transmission, or customer service costs are incurred to serve the new load.

Average unit production cost as shown in the attached Table 5 would increase by 6.5% from $33.60/MWh to $35.78/MWh with the addition of the CCCT. Clearly, new load rarely matches the output of a new resource. A new CCCT base load plant will generally operate when variable operating costs make it more economical than other more costly generating alternatives. New baseload resources with high initial capital costs and low variable operating costs will operate in almost all load conditions.

Traditional ratemaking is designed to reimburse the utility for costs it actually incurs to provide electric service. While rates are designed to recover costs associated with all utility functions, it is the power production function that makes up the largest portion of the existing embedded rate. At an existing embedded unit price of $33.60/MWh, the addition of baseload resources will have a significant impact on future rates. Tradeoffs between capital investment and variable operating expenses will drive baseload resource decisions and dictate which resources will run most often and how the new resources will most affect customer rates.

Table 6 – 2008 Revenue Requirement and Unit Cost

<table>
<thead>
<tr>
<th></th>
<th>Idaho Power</th>
<th>PacifiCorp</th>
<th>Avista</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate Base (000's)</td>
<td>$2,094,083</td>
<td>$558,247</td>
<td>$577,434</td>
<td>$3,229,764</td>
</tr>
<tr>
<td>Return on Investment (000's)</td>
<td>$171,299</td>
<td>$45,989</td>
<td>$49,370</td>
<td>$266,658</td>
</tr>
<tr>
<td>Depreciation Expense (000's)</td>
<td>$89,977</td>
<td>$22,748</td>
<td>$29,738</td>
<td>$142,463</td>
</tr>
<tr>
<td>O&amp;M Expense (000's)</td>
<td>$431,082</td>
<td>$136,825</td>
<td>$153,692</td>
<td>$721,599</td>
</tr>
<tr>
<td>Retail Rev Req (000's)</td>
<td>$694,049</td>
<td>$205,562</td>
<td>$232,800</td>
<td>$1,132,411</td>
</tr>
<tr>
<td>Energy (MWh)</td>
<td>13,689,145</td>
<td>3,823,637</td>
<td>3,487,746</td>
<td>21,000,528</td>
</tr>
<tr>
<td>Unit Cost ($/MWh)</td>
<td>$50.70</td>
<td>$53.76</td>
<td>$66.75</td>
<td>$53.92</td>
</tr>
</tbody>
</table>
While the previous tables reflect only the components of unbundled production revenue requirement in 2008, the charts below reflect total revenue requirement and the various percentages of the total represented by the various categories. For example, Idaho Power’s net power supply costs represent 19% of the total annual revenue requirement.

**Table 7 – 2008 Production Revenue Requirement and Unit Cost**

<table>
<thead>
<tr>
<th></th>
<th>Idaho Power</th>
<th>PacifiCorp</th>
<th>Avista</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Rate Base (000’s)</td>
<td>$930,292</td>
<td>$256,858</td>
<td>$196,044</td>
<td>$1,383,194</td>
</tr>
<tr>
<td>Production Return (000’s)</td>
<td>$76,098</td>
<td>$21,160</td>
<td>$16,761</td>
<td>$114,019</td>
</tr>
<tr>
<td>Production Depreciation (000’s)</td>
<td>$42,916</td>
<td>$13,053</td>
<td>$9,335</td>
<td>$65,304</td>
</tr>
<tr>
<td>Production O&amp;M Expense (000’s)</td>
<td>$306,431</td>
<td>$96,496</td>
<td>$131,138</td>
<td>$534,065</td>
</tr>
<tr>
<td>Production Rev Req (000’s)</td>
<td>$425,445</td>
<td>$131,510</td>
<td>$147,900</td>
<td>$704,855</td>
</tr>
<tr>
<td>Energy (MWh)</td>
<td>13,689,145</td>
<td>3,823,637</td>
<td>3,487,746</td>
<td>21,000,528</td>
</tr>
<tr>
<td>Unit Production Cost ($/MWh)</td>
<td>$31.10</td>
<td>$34.40</td>
<td>$42.40</td>
<td>$33.60</td>
</tr>
</tbody>
</table>

While the previous tables reflect only the components of unbundled production revenue requirement in 2008, the charts below reflect total revenue requirement and the various percentages of the total represented by the various categories. For example, Idaho Power’s net power supply costs represent 19% of the total annual revenue requirement.

**Figure 15 – Utility Revenue Requirement Breakdown**

**ELECTRIC SERVICE PROVIDERS IN IDAHO**

**Idaho Power Company**

Idaho Power serves approximately 500,000 customers in southern Idaho (95%) and eastern Oregon (5%). Idaho Power’s generation resources consist primarily of 17 hydroelectric projects located in southern Idaho and partial ownership of three coal-fired resources all located outside of Idaho. Idaho Power’s service area and resources are shown in the Figure 16 below:
Combined, PacifiCorp and Rocky Mountain Power serve approximately 1.7 million customers in six western states. Generation resources of more than 10,400 MW include coal, hydroelectric, wind, gas-fired combustion turbines, solar, and geothermal. Rocky Mountain Power serves approximately 72,000 customers in eastern Idaho. PacifiCorp and Rocky Mountain Power’s service area and resources are shown in the figure below:

**Figure 16 – Idaho Power Service Area**

---

44 www.idahopower.com
Avista

Avista serves nearly 340,000 electric customers and 300,000 natural gas customers in northern Idaho and eastern Washington. Avista’s generation resources consist of eight hydroelectric projects along with coal, natural gas, and wood-waste combustion plants. A map of Avista’s service area is shown below.

---

45 www.pacificorp.com
Municipals and Cooperatives

There are 26 rural electric cooperatives and municipalities providing electric service in Idaho. These utilities are customers of the Bonneville Power Administration (BPA), receiving most of their required power resource from BPA. BPA posted a 2010 Resource Program to help determine the amount, type, and timing of new resource acquisitions. The program is guided by and consistent with the Northwest Power and Conservation Council’s Sixth Power Plan, released in February 2010. The Resource Program shows that most of BPA’s (including Idaho municipal and cooperative customers) incremental energy needs for the next several years can be achieved by meeting the conservation targets in the Council’s Sixth Power Plan and relying on short- and mid-term market purchases. BPA will update the Resource Program periodically as load forecasts, the Council’s Power Plan, and customer requirements and resource opportunities evolve.

BPA establishes targets for energy efficiency for the region based on the integrated regional plan of the Council’s Sixth Power Plan. As a requirement of the BPA contract, the power rate for utilities includes an allocation for conservation that will be paid back to the utility upon completion of approved energy efficiency measures to help meet the target.
Failure to implement the measures will result in forfeiture of that conservation allocation from the individual utility to BPA.

Although historically the Idaho municipal and cooperative utilities have been able to rely on BPA for all power needs, the new BPA contracts, effective October 1, 2011, will “cap” the amount of federal power available to all utilities. Each utility will be faced with acquiring resource to meet any future load growth. These resources may be developed or acquired independently or jointly with other utilities, including BPA (tier two power purchase). Each utility will follow its own City Council or board approved process for evaluating resources and determining the best power resource acquisition. These processes are public processes and involve consideration of factors related to load forecasting, power availability/variability, costs, and transmission availability.

FORECAST ELECTRICAL DEMAND IN IDAHO

The forecast annual average electrical demand for the state of Idaho for investor-owned utilities, municipalities, and cooperatives is shown in Table 8 and Figure 19 below. The data in the table was provided directly by each utility, co-op, or municipality.

Table 8 – Forecast Annual Average Load (aMW)

<table>
<thead>
<tr>
<th>Year</th>
<th>Idaho Power</th>
<th>Municipalities</th>
<th>Co-Ops</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>1,676</td>
<td>480</td>
<td>125</td>
<td>228</td>
</tr>
<tr>
<td>2014</td>
<td>1,698</td>
<td>487</td>
<td>126</td>
<td>230</td>
</tr>
<tr>
<td>2015</td>
<td>1,715</td>
<td>494</td>
<td>128</td>
<td>233</td>
</tr>
<tr>
<td>2016</td>
<td>1,732</td>
<td>499</td>
<td>129</td>
<td>235</td>
</tr>
<tr>
<td>2017</td>
<td>1,755</td>
<td>504</td>
<td>130</td>
<td>237</td>
</tr>
<tr>
<td>2018</td>
<td>1,774</td>
<td>509</td>
<td>131</td>
<td>240</td>
</tr>
<tr>
<td>2019</td>
<td>1,794</td>
<td>514</td>
<td>133</td>
<td>242</td>
</tr>
<tr>
<td>2020</td>
<td>1,816</td>
<td>519</td>
<td>134</td>
<td>244</td>
</tr>
<tr>
<td>2021</td>
<td>1,842</td>
<td>524</td>
<td>135</td>
<td>247</td>
</tr>
<tr>
<td>2022</td>
<td>1,863</td>
<td>529</td>
<td>137</td>
<td>249</td>
</tr>
<tr>
<td>2023</td>
<td>1,883</td>
<td>534</td>
<td>138</td>
<td>252</td>
</tr>
<tr>
<td>2024</td>
<td>1,898</td>
<td>539</td>
<td>139</td>
<td>254</td>
</tr>
<tr>
<td>2025</td>
<td>1,914</td>
<td>544</td>
<td>141</td>
<td>257</td>
</tr>
<tr>
<td>2026</td>
<td>1,932</td>
<td>549</td>
<td>142</td>
<td>259</td>
</tr>
<tr>
<td>2027</td>
<td>1,952</td>
<td>554</td>
<td>144</td>
<td>262</td>
</tr>
<tr>
<td>2028</td>
<td>1,967</td>
<td>560</td>
<td>145</td>
<td>265</td>
</tr>
<tr>
<td>2029</td>
<td>1,987</td>
<td>565</td>
<td>147</td>
<td>267</td>
</tr>
<tr>
<td>2030</td>
<td>2,015</td>
<td>570</td>
<td>148</td>
<td>270</td>
</tr>
<tr>
<td>2031</td>
<td>2,035</td>
<td>576</td>
<td>150</td>
<td>273</td>
</tr>
<tr>
<td>2032</td>
<td>2,053</td>
<td>581</td>
<td>151</td>
<td>275</td>
</tr>
</tbody>
</table>

Annual Average Growth Rate
1.18%  0.15%  1.11%  1.10%  1.10%  1.01%
Table 9 and Figure 20 show the forecast peak summer load for investor-owned utilities, municipalities, and cooperatives that are typically driven by irrigation and air conditioning use. The data in the table was provided directly by each utility, co-op, or municipality.

Table 9 – Forecast Summer Peak Load (MW)

<table>
<thead>
<tr>
<th>Year</th>
<th>Idaho Power</th>
<th>Rocky Mountain</th>
<th>Avista</th>
<th>Municipalities</th>
<th>Co-Ops</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>3,041</td>
<td>756</td>
<td>553</td>
<td>196</td>
<td>366</td>
<td>4,912</td>
</tr>
<tr>
<td>2014</td>
<td>3,095</td>
<td>765</td>
<td>561</td>
<td>199</td>
<td>371</td>
<td>4,990</td>
</tr>
<tr>
<td>2015</td>
<td>3,142</td>
<td>774</td>
<td>569</td>
<td>201</td>
<td>376</td>
<td>5,061</td>
</tr>
<tr>
<td>2016</td>
<td>3,181</td>
<td>780</td>
<td>578</td>
<td>204</td>
<td>380</td>
<td>5,123</td>
</tr>
<tr>
<td>2017</td>
<td>3,230</td>
<td>787</td>
<td>585</td>
<td>206</td>
<td>385</td>
<td>5,193</td>
</tr>
<tr>
<td>2018</td>
<td>3,278</td>
<td>792</td>
<td>590</td>
<td>209</td>
<td>390</td>
<td>5,261</td>
</tr>
<tr>
<td>2019</td>
<td>3,327</td>
<td>798</td>
<td>598</td>
<td>212</td>
<td>396</td>
<td>5,330</td>
</tr>
<tr>
<td>2020</td>
<td>3,380</td>
<td>802</td>
<td>605</td>
<td>215</td>
<td>401</td>
<td>5,402</td>
</tr>
<tr>
<td>2021</td>
<td>3,434</td>
<td>805</td>
<td>614</td>
<td>217</td>
<td>406</td>
<td>5,476</td>
</tr>
<tr>
<td>2022</td>
<td>3,482</td>
<td>810</td>
<td>622</td>
<td>220</td>
<td>411</td>
<td>5,545</td>
</tr>
<tr>
<td>2023</td>
<td>3,529</td>
<td>813</td>
<td>631</td>
<td>223</td>
<td>416</td>
<td>5,612</td>
</tr>
<tr>
<td>2024</td>
<td>3,574</td>
<td>816</td>
<td>639</td>
<td>226</td>
<td>422</td>
<td>5,677</td>
</tr>
<tr>
<td>2025</td>
<td>3,615</td>
<td>818</td>
<td>647</td>
<td>229</td>
<td>427</td>
<td>5,736</td>
</tr>
<tr>
<td>2026</td>
<td>3,658</td>
<td>819</td>
<td>655</td>
<td>232</td>
<td>433</td>
<td>5,797</td>
</tr>
<tr>
<td>2027</td>
<td>3,708</td>
<td>821</td>
<td>664</td>
<td>235</td>
<td>439</td>
<td>5,867</td>
</tr>
<tr>
<td>2028</td>
<td>3,754</td>
<td>824</td>
<td>673</td>
<td>238</td>
<td>444</td>
<td>5,933</td>
</tr>
<tr>
<td>2029</td>
<td>3,800</td>
<td>826</td>
<td>682</td>
<td>241</td>
<td>450</td>
<td>5,999</td>
</tr>
<tr>
<td>2030</td>
<td>3,857</td>
<td>828</td>
<td>691</td>
<td>244</td>
<td>456</td>
<td>6,077</td>
</tr>
<tr>
<td>2031</td>
<td>3,907</td>
<td>835</td>
<td>700</td>
<td>247</td>
<td>462</td>
<td>6,152</td>
</tr>
<tr>
<td>2032</td>
<td>3,955</td>
<td>830</td>
<td>710</td>
<td>251</td>
<td>468</td>
<td>6,212</td>
</tr>
</tbody>
</table>

Annual Average Growth Rate 1.58% 0.51% 1.50% 1.46% 1.46% 1.39%
CONCLUSION

As stated in the introduction of this report, baseload resources contribute significantly to the reliable operation of the electrical system. While the focus of the Baseload Task Force is on these resources, the task force felt it was also important to understand the difference between baseload resources, peaking resources, renewable resources, and how they influence the operation of the electrical system.

In addition, many public policy issues currently exist that will ultimately influence the electric utility industry. At the federal level, these issues include mandated renewable energy development through legislation, and climate change and the reduction of carbon emissions which would primarily impact the operation of coal-fired power plants. The state of Idaho has already seen the impact of federal legislation, through PURPA, in the substantial development of wind resources throughout southern Idaho.

In Idaho, where there has been little interest in developing a renewable portfolio standard, the primary focus shifts to water related issues. Because of the amount of hydroelectric generation in the state, water is an important commodity to utilities and a major factor in being able to continue to provide low-cost electricity to customers. Water is also vitally important to the agricultural industry which has historically been the cornerstone of the
State's economy. Resolution of these issues and finding an optimized and balanced solution should be a priority.

While this report highlights some of the key issues currently facing the electric utility industry, a substantial amount of additional information can be found in the integrated resource plans of each of the three regulated Idaho utilities. Each of the State's IOUs are required to update these long-range resource plans every two years in order to account for current economic conditions and regulatory requirements that will have an impact on the cost and reliability of electrical service to Idaho consumers.
ISEA Baseload Task Force

Chairman:
Mark Stokes     Idaho Power Company

Members:
Gregory Duvall  PacifiCorp
Steve Enyeart   Bonneville Power Administration
Douglas Hall    Idaho National Laboratory
Jeff King       Northwest Power and Conservation Council
Jack Lance      Idaho National Laboratory
Dan Kunz        U.S. Geothermal
Marv Lewallen   Clearwater Paper Corporation
Randy Lobb      Idaho Public Utilities Commission
Joe Perkowski  Idaho National Laboratory
Michael Reed    Idaho National Laboratory
Jim Smith       Monsanto
Steve Weiss     Northwest Energy Coalition

Baseload Task Force Members Biographies

Chairman

M. MARK STOKES, B.S., MBA, P.E., is the Director of Water and Resource Planning at Idaho Power Company. Mark has over 21 years of experience at Idaho Power Company. The Water and Resource Planning department’s primary responsibilities include resource planning, load forecasting, water and weather forecasting, cloud seeding, river engineering and stream flow gaging.

Mark is a graduate of the University of Idaho with a Bachelor of Science Degree in Civil Engineering. He also holds a Masters Degree in Business Administration from Northwest Nazarene University and is a registered Professional Engineer in the state of Idaho. Mark and his wife of 21 years have three children and live in Meridian, Idaho.

Members

STEPHEN H. ENYEART, P.E., is currently Senior Electrical Engineer in Customer Service Engineering of the Bonneville Power Administration(BPA). As such he coordinates generation (wind) interconnection projects at BPA, assisting in studies, plans of service, cost estimates and
construction activities. He has spent 10 years working on wind generation interconnection technical requirements, new standards, studies and construction requirements.

Mr. Enyeart is a Registered Professional Engineer in the State of Oregon, received a B.S.E.E. degree from Portland State University in 1973, and is a member of IEEE. He holds over 36 years experience in the utility industry and industrial electrical engineering. His major experience areas are in EHV and HV substation design, transmission and distribution system planning, EHV relay systems design, and dispersed generation protection. Past positions held include: Senior Electrical Engineer, Pacific Engineering Corporation, Portland, Oregon (1989-2000); Chas. T. Main Incorporated, Portland, Oregon (1980-1987); and Bonneville Power Administration, Portland, Oregon (1973-1980).

Member of the BPA Cross-Agency Management Team for Wind and Renewables. Presenter at several conferences, symposiums and forums on wind interconnection and integrations issues for the BPA grid. Works on Committees to establish policies for operation and control of wind generation; includes work with public on wind generation interconnection requirements, including dynamic VAR requirements, voltage control, impact on power system regulation, generation reserves, automated controls for variable generation limits, and improved forecasting of wind generation.

DOUGLAS HALL is the program manager of the Idaho National Laboratory’s Water Energy Program a principal author of the Hydropower Task Force report, the lead author of the Hydropower Chapter of the Renewable Electricity Futures Project report for DOE and a contributing author to the Hydropower Chapter of the International Panel on Climate Change (IPCC) Special Report on the Effect of Renewable Energy on Climate Change Mitigation. He has led a comprehensive assessment of the gross power potential of all natural streams in the 50 states and has served as an expert witness before major city public hearings. Subsequently, he led a study to identify feasible potential hydropower sites on U.S. natural streams and estimate the developable power potential at these sites assuming a damless small hydropower development model. He led an assessment of the gross power potential of all natural streams in Brazil. Results of the assessments have been incorporated into GIS applications on the Internet developed under his direction. The applications allow users to select sites of interest and view their attributes in the context of topography, hydrography, existing transportation and power infrastructure, cities and populated places, and land controlled by seven federal agencies. He is currently leading an INL research team in assessing the power potential of U.S. non-powered dams and constructed waterways and identifying locations for new pumped storage hydroelectric plants.

Oregon. Jeff’s responsibilities include assessing the commercial availability, cost, performance, 
environmental and other characteristics of electric power generating resource options. Jeff also 
maintains planning data regarding Pacific Northwest electric power generating facilities, and 
analyses issues pertaining to generating resource development and operation. This information 
is used by the Council for preparing its Northwest Power Plan and by utilities and others for 
developing electric power plans and policies.

Jeff previously worked as a staff engineer for Battelle Pacific Northwest Laboratories 
and as a test engineer for the Naval Reactors program. Jeff holds a Bachelor of Science in 
Mechanical Engineering from the University of Washington and studied Regional Planning at 
the University of Pennsylvania.

JOHN J. “Jack” LANCE, Director of Applied Engineering at the Idaho National Laboratory.
Mr. Lance has 35 years of experience in the commercial nuclear power industry across a broad 
spectrum of manufacturers, utilities, service providers and research and development 
organizations. His experience includes engineering management at Yankee Atomic Electric 
Company, extensive experience on large, complex nuclear and fossil technology programs for 
the Electric Power Research Institute (EPRI) and a 20-year association with the ASME Boiler and 
Pressure Vessel Code Committees.

Mr. Lance is the founding director of EPRI's Nuclear Maintenance Applications Center 
and previous manager of the Plant Technology Program. He is recognized for his ability to 
establish collaborative programs with nuclear facilities and industry, both nationally and 
internationally.

DANIEL KUNZ, B.S., MBA, also Chairman of the Geothermal Task Force, is the Founder, 
President and CEO of U.S. Geothermal Inc. Mr. Kunz, of Boise, Idaho, has over 30 years of 
international and domestic experience in engineering, management, accounting, finance and 
operations. Mr. Kunz holds a Masters of Business Administration and a Bachelor of Science in 
Engineering Science.

Mr. Kunz has held key executive positions in Ivanhoe Mines Ltd. (President and 
Director), MK Gold Company (Co-Founder, President, CEO and Director) and 17 years with 
Morrison Knudsen Corporation (laterally as Vice President and Controller).

In 1998 Mr. Kunz led Ivanhoe Mines into Mongolia where, in 2001, he was part of the 
team that discovered Oyu Tolgoi, one of the largest copper-gold mineral deposits in the world. 
The market capitalization value of Ivanhoe Mines was about $200 million when Mr. Kunz joined 
the company in 1997 and was about $4 billion when he retired to devote his full time efforts to 
U.S. Geothermal Inc.

In 1995 Mr. Kunz was named its Distinguished Alumni from the University of Montana 
Tech (formerly the Montana College of Mineral Science and Technology). Mr. Kunz is a director
of the non-profit entity, Mountain States Group of Boise, providing human and rural health services to disadvantaged individuals through programs like the Center, and the Agency for New Americans.

MARV LEWALLEN, B.S., M.S, MBA, P.E., is Clearwater Paper’s Environmental & Energy Director. Mr. Lewallen received a B.S. and M.S. in Nuclear Engineering from Oregon State University and an MBA from the University of Washington. He received his professional engineering license from the State of Oregon in 1980.

Mr. Lewallen has worked in the energy and environmental fields for over 30 years in areas ranging from assessing nuclear and fossil fuel cycles, combined heat & power project development and most recently as supporting Clearwater Paper’s efforts in environmental performance and energy optimization. Prior employers include Battelle Memorial Institute, Portland General Electric, Northwest Natural Gas, Weyerhaeuser and several consulting firms. Marv and his wife Karen live in Spokane.

RANDY LOBB, B.S., P.E., is the Utilities Division Administrator for the Idaho Public Utilities Commission. Randy received a Bachelor of Science degree in Agricultural Engineering from the University of Idaho in 1980 and obtained an Idaho Professional Civil Engineering license in 1985. He worked for the Idaho Department of Water Resources from 1980 through 1987 with specific focus on hydroelectric project development and irrigation system energy efficiency.

In 1987 Mr. Lobb went to work for the Idaho Public Utilities Commission as a Staff Engineer. In 1992 he assumed the role of Engineering Supervisor and by 2000 was promoted to Utilities Division Administrator. Mr. Lobb currently oversees staff review of all cases filed before the Commission with specific expertise in electric resource planning, power supply cost analysis and water system operations. He is a past board member of the Northwest Energy Efficiency Alliance and a past participant in Idaho Power Company’s Integrated Resource Planning Advisory Group, Avista Utility’s Energy Efficiency Advisory Board and PacifiCorp’s Rocky Mountain Area Transmission Study. Mr. Lobb and his wife of 34 years have three children and live in Boise.

JOSEPH C. PERKOWSKI, Ph.D., is the current Manager of Energy Initiatives at the Idaho National Laboratory (INL) located in Idaho Falls, Idaho. Prior to joining INL, he served on Assignment to the National Renewable Energy Laboratory (NREL) as Market Sector Manager, Responsible for the integration of selected technical activity in renewable energy technology with the commercial marketplace.

He worked at the Bechtel Corporation before his NREL assignment as Manager of Advanced Civil Systems Research and Development, and prior to that at United Technologies Corporation (UTC); and the Oxford Development Group, Edmonton, Alberta, Canada. Prior
employment Includes: the position of Senior Research Officer with the Corporate Environmental and Social Affairs Department of Petro-Canada, with responsibilities including the development of internal business policy papers and guidelines regarding environmental impact assessment techniques. He has a Ph.D. from MIT in Civil Engineering/Environmental Systems Management.

At INL currently, Perkowski primarily works with private sector clients (such as large North American utility firms) on a variety of new technology development issues, including innovative nuclear energy system alternatives and carbon sequestration liability assessments.

MICHAEL E. REED, B.S., M.S., is a Senior Process Analyst at the Idaho National Laboratory (INL). His present work includes the analysis and development of hybrid energy systems and life cycle analysis of power, chemical, and liquid fuel production systems. He has held this position since October 2009.

Prior to his work at INL, Michael’s work experience included 12 years associated with the National Energy Technology Laboratory where he was responsible for technical, economic, and environmental analysis of fossil fuel based power and liquid fuel production systems. Michael’s other work experience includes technical customer support and instruction with Aspen Technology, Inc. and most recently at General Motors where he was responsible for worldwide strategic analysis of the electricity supply chain as part of an integrated energy analysis and intelligence group within GM’s Research and Development organization. Michael holds BS and MS degrees in Chemical Engineering from West Virginia University.

STEVEN WEISS, B.A., M.Ed., has worked for the Northwest Energy Coalition (NWEC) for 15 years as a Senior Policy Associate and leads Coalition activities on utility issues before the Oregon Public Utility Commission, Bonneville Power Administration, and the Northwest Power and Conservation Council (NPCC). NWEC is a coalition of approximately 110 environmental, low-income, consumer, and faith-based organizations, utilities and unions formed in 1981 to advocate for a clean and affordable energy future for the Northwest US.

Steve was heavily involved in the successful 1999 Oregon legislative effort to pass an electricity restructuring law and co-authored the final bill. This law established the “Energy Trust of Oregon” funded by a 3% public purpose charge to provide conservation services to the IOUs in Oregon, required utilities to provide “green” options, and provided over $16 million annually for low-income assistance and weatherization.

Steve is the Environmental Representative serving the Western Electricity Coordinating Committee’s (WECC) Scenario Planning Working Group formed to provide input to the West’s transmission planning effort. He has extensive experience as NWEC’s expert witness in numerous rate cases and IRPs and NW Power and Conservation Council proceedings.
Recently he authored *Bright Future*, a study modeling a path for the northwest to reduce its CO₂ emissions to levels needed to avoid global warming, electrify the transportation system, and save endangered salmon in the Snake River system.

Before joining the NWEC, Steve was a Director of Salem Electric, a co-op utility, for 12 years and owned a bicycle shop in Salem. He has a B.A. in physics from U.C. Berkeley, and a Masters Degree in Science Education from Bucknell University in Pennsylvania. Steve is married, has a 21-year old son and two granddaughters.