Nuclear Renewable Oil Shale Hybrid Energy Systems: Configuration, Performance, and Development Pathways

by

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B.S. Physics, B.S. Mechanical Engineering
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Abstract

Nuclear Renewable Oil Shale Systems (NROSS) are a class of large Hybrid Energy Systems in which nuclear reactors provide the primary energy used to produce shale oil from kerogen deposits and also provide flexible, dispatchable electricity to the grid. Kerogen is solid organic matter trapped in sedimentary shale, and the formations of kerogen oil shale in the western United States are the largest and densest hydrocarbon resource on the planet. When heated above 300°C, kerogen decomposes into oil, gas, and char. NROSS couples electricity and transportation fuel production in a single operation, reduces lifecycle carbon emissions from the fuel produced, improves economics for the nuclear plant, and enables a major shift toward a very-low-carbon electricity grid.

The nuclear reactor driving an NROSS system would operate steadily at full power, providing steam for shale heating in closed steam lines when the price of electricity is low and electricity to the grid when the price of electricity is high. Because oil shale has low thermal conductivity, heat input to the shale can be cycled as needed without disrupting the steady increase in average temperature. The target average shale temperature of 350°C would be reached over 2 years using two heating stages in the baseline configuration driven by light water reactors. First stage heating brings the shale to an intermediate temperature, assumed to be 210°C in this study. The second heating stage isolates the steam delivery line from the reactor and uses electricity, purchased when prices are low, to increase steam temperature and bring the shale to 350°C. This capacity to absorb low price electricity mitigates the tendency for electricity prices to collapse to zero, or potentially negative values, during periods of peak wind and solar output.

The analysis herein shows that liquid fuels produced by a baseline NROSS would have the lowest life cycle greenhouse gas impact of any presently available fossil liquid fuels and that operation as part of an NROSS complex would increase reactor revenues by 41% over a stand-alone baseload reactor. The flexible, dispatchable electricity provided by NROSS could also enable the transition to a very-low-carbon grid in which renewables are widely deployed and the NROSS provides variable output to balance their uncontrolled output to meet demand.

Fully deployed, NROSS could require tens or hundreds of reactors. Large fleet operations and local mass production of the necessary hardware could bring about substantial reductions in system cost as development proceeds, potentially offering a pathway to jumpstart and maximize the realization of the mass production cost savings envisioned for small modular reactors. The development pathway to achieve large scale NROSS deployment will be complicated, however, requiring involvement from many government agencies, a demonstration system, and a complex commercialization effort with partnered nuclear vendors, utilities, and petroleum system developers.

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Title: Research Scientist

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And finally, I want to thank the Department of Nuclear Science and Engineering here at MIT for believing in me and giving me an opportunity of lifetimes to study nuclear engineering with the very best.

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Part 1: Background

1. Introduction

Humanity will face many serious challenges connected with the supply and use of energy in the 21st century. These challenges will take on many forms: technical, environmental, economic, geological, political, and organizational.

The greatest of these challenges is the need to minimize the impacts of global climate change, and adapt to the changes that cannot be prevented. The average surface temperature of the earth has increased by 0.8°C over the last century [1], and study of our climate has revealed overwhelming evidence that the release of carbon dioxide from human activities has caused the majority of this increase [1]. It is likely that the earth would continue warming throughout this century even if all carbon dioxide emissions were to cease immediately, but it is certain that the earth will warm even more if emissions continue [2]. This increase in global average surface temperature is already impacting our environment and economy, and could have disastrous consequences if we do not minimize the human contribution to this warming and adapt to those changes [2]. Minimizing the human contribution to global climate change requires many significant changes to our economy and use of technology. The primary requirement is the elimination of carbon dioxide emissions from our energy and transportation technologies.

Study of the current state of the energy sector in the United States clearly shows that if a substantial reduction in carbon emissions is needed, there are two places to work to accomplish it: the electric power sector and the transportation sector [3, 4, 5]. Figure 1.1 shows flows of energy in the United States economy in 2013. Fossil fuels remain our largest source of primary energy, and the two largest "blocks" of energy conversion and use are electricity generation and transportation. Figure 1.2 shows that these "blocks" are, in the same order, also our nation's largest sources of greenhouse gas (GHG) emissions.

Research efforts currently or recently underway have already provided a sobering picture of the context of this challenge. Google, Inc. [3] and the State of California [6] have been pursuing urgent investigations of options for low-carbon energy supply out of a desire to tackle big problems, satisfy a perceived moral mandate of carbon neutrality, and plan for the implementation of California's Renewable Portfolio Standard [7]. Google has cancelled a major internal R&D effort named "RE<C", however, after internal investigations showed that replacing all current coal generation with renewables would not only not be sufficient to prevent major impacts from climate change, but it also wouldn't be economically feasible with today's systems and technology [3]. The California Council on Science and Technology reaches a similar conclusion, stating that "to reduce emissions by 80% [relative to 1990; the state's 2050 goal]… we had to draw on technology that was not currently available at scale" [6]. Big new very-low-carbon energy technologies are unambiguously required to meet this challenge.

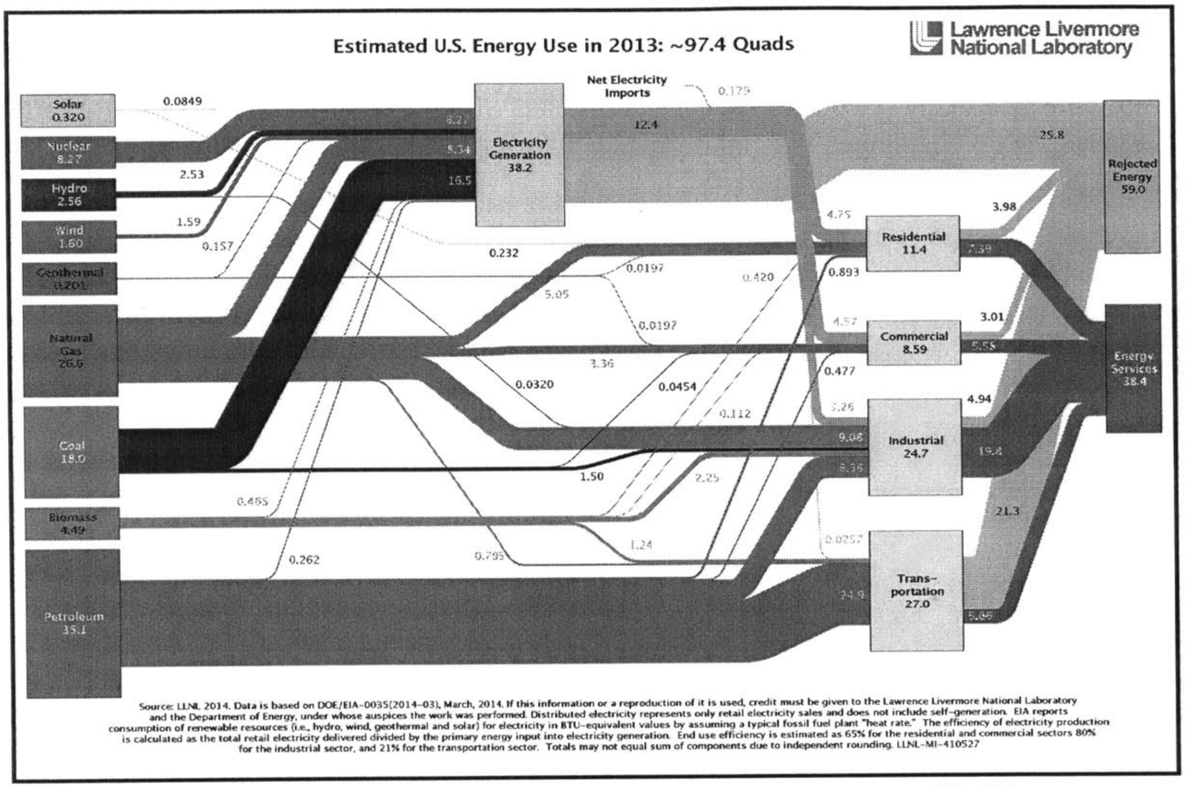

Figure 1.1. Flowchart of 2013 United States energy use (Ref 5)

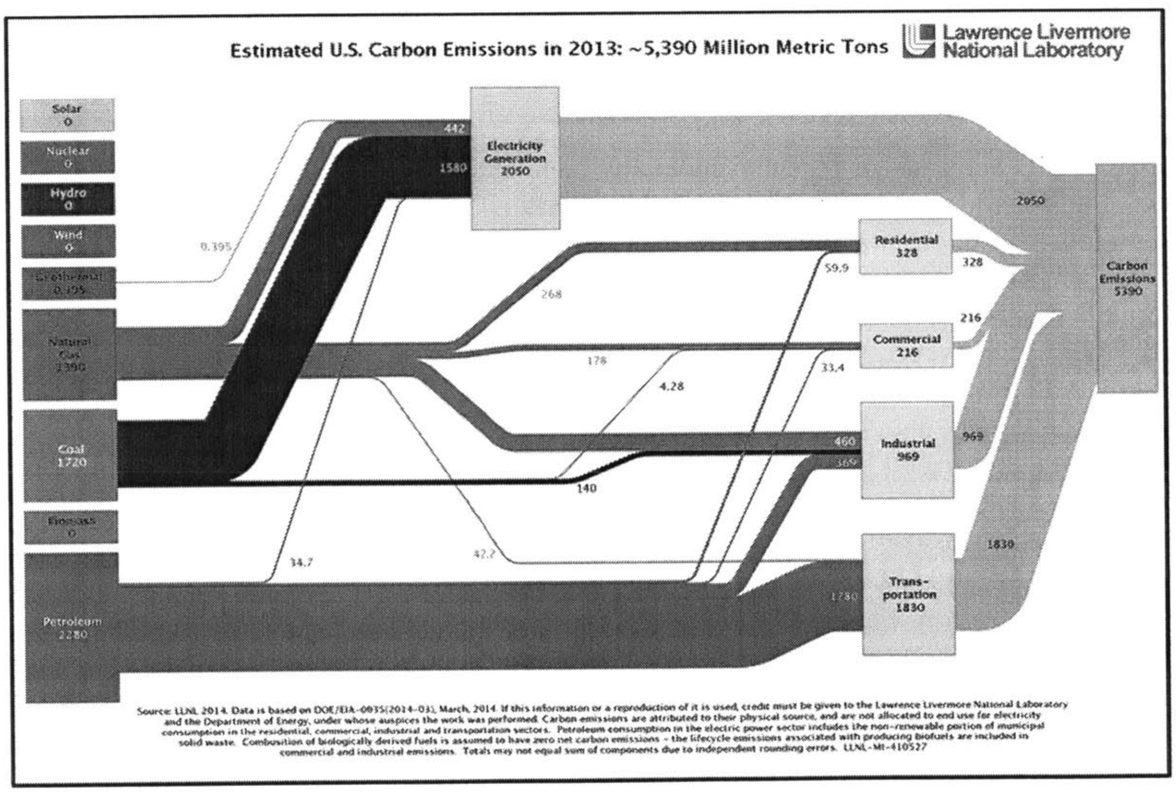

Figure 2. Flowchart of 2013 United States carbon emissions (Ref 5)

The second great energy challenge of the 21st century is the changing supply of hydrocarbons. Hydrocarbons are essential for many purposes; the overwhelming majority are used to produce liquid transportation fuels, as was shown in Figure 1. Our only economically significant sources of hydrocarbons are fossil resources. The distribution and nature of fossil hydrocarbon resources is changing rapidly as global demand increases and traditional reserves of natural gas and crude oil are depleted. Recent technology developments have already changed the landscape of fossil resources, making bitumen sands and shale gas resources not only accessible and economically viable, but plentiful. These resources, however, will also be depleted, and much work remains before substantially more sustainable hydrocarbon production methods, independent of fossil resources, are ready for deployment.

A complex patchwork of electricity distribution organizations and regulatory systems in the United States complicates both of these challenges. Regulation of the electric power sector in the United States requires action in multiple branches of the federal government and in up to 50 states, ensuring that any structural changes will be bureaucratically and legally complex. Deployment of advanced new energy technologies is also often affected by these complexities.

The United States has a very large amount of an unconventional hydrocarbon resource called kerogen. Kerogen deposits in the western US are called oil shale and represent the largest and most concentrated hydrocarbon resource on earth, larger than all historic crude oil production worldwide. A very large operation would be required to extract, process, and refine this resource. Production of shale oil from oil shale has the potential for severe environmental harm and large GHG emissions using current technologies and strategies; as this thesis will show, however, shale oil also has the potential to have lower lifecycle carbon emissions than any other source of fossil liquid fuels.

Development of Nuclear-Renewable Oil Shale Systems (NROSS) would represent a very large step toward resolving these challenges. NROSS couples electricity and transportation fuel production in a single operation with primary power provided by very-low-carbon nuclear reactors, reducing lifecycle carbon emissions from the fuel produced and improving economics for the nuclear plant. This thesis explores the configuration, performance, and development pathway of such systems.

1.1. Objectives

The work described in this thesis addresses four goals:

1. Describe the general strategic motivation to develop a large energy system to address the challenges of very-low-carbon energy supply and secure hydrocarbon supply and the specific strategic motivation to develop NROSS.
2. Describe the configuration of a Nuclear Renewable Oil Shale System (NROSS) that accomplishes those goals.
3. Analyze a selection of NROSS performance measures, chosen to demonstrate the value and viability of the system concept.
4. Describe the necessary research and development efforts (R&D), institutional partnerships, demonstration systems, and commercialization activities (collectively, a "development pathway") necessary to deploy NROSS.

1.2. Organization

This thesis is organized into three Parts and several Chapters.

Part 1 contains Chapters 1 through 3 and describes the background information necessary to understand the strategic motivations for and configure and analyze NROSS. Chapter 2 provides background information on the impacts of intermittent renewable generation on electric power systems. Chapter 3 describes kerogen resources, primarily in the United States, and describes technical approaches to processing kerogen, primarily in-situ techniques under recent development. A selection of history, literature, and discussion of hybrid energy systems can be found in Appendix A.

Part 2 contains Chapters 4 through 7 and describes the configuration and performance of NROSS. Chapter 4 describes a selection of configuration options; chapters from here on will focus on one particular option, driven by small modular light-water-cooled reactors (SMRs) likely to be available in the near future. Chapter 5 describes large field operations of NROSS. Chapter 6 reports on commercial performance analysis of NROSS. Chapter 7 reports the expected GHG impact of NROSS products.

Part 3 contains Chapters 8 through 10 and describes the NROSS development pathway. Chapter 8 discusses a possible long-term transition to re-use NROSS hardware and infrastructure as a large geological heat storage system. Chapter 9 discusses other development pathway considerations, including the involved organizations, possible business models and system ownership, safety and licensing considerations, and technology transfer to commercialize NROSS. Chapter 10 presents my conclusions and recommendations for near-term future work.

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2. Impacts of Intermittent Renewable Generation

To maintain a secure supply of electricity under any conditions, any grid that uses intermittent renewable generators (IRGs) requires a sufficient supply of flexible, dispatchable generation. A *dispatchable* generator is one whose output can be scheduled with certainty in advance, usually one day in advance in modern electric power systems. A *flexible* generator is one capable of rapid adjustments in real time. *Intermittent renewable generators* are those whose output is not controlled by human operators or designed control systems and is instead controlled primarily or exclusively by the instantaneous availability of that system's input. Solar photovoltaics (PV), wind turbines, and ocean current or ocean wave generators are all IRG. Most implementations of solar thermal power systems would qualify as IRG, as well. Output from wind turbine and PV generators can decrease from full power to zero in a matter of minutes, so flexible dispatchable generators must be able to throttle quickly to make up that lost generation.

Flexible dispatchable generation is currently typically provided by a spinning reserve of gas turbine systems, with most of the turbines kept at low power levels at any given time. Traditional nuclear and coal generators generally cannot change power level fast enough to serve such a role, and grid scale storage is unlikely to be widely and economically available for many years. If a secure supply of very-low-carbon electricity is desired, a new kind of very low carbon, flexible, dispatchable generator is needed.

2.1. Grid Management of IRGs

Several studies have been carried out and are ongoing to understand the impact of expanded use of IRGs on both real electric grid systems and model systems. Figures 2.1 and 2.2 show results from two studies of the grid managed by the California Independent System Operator (CAISO) [1, 2].

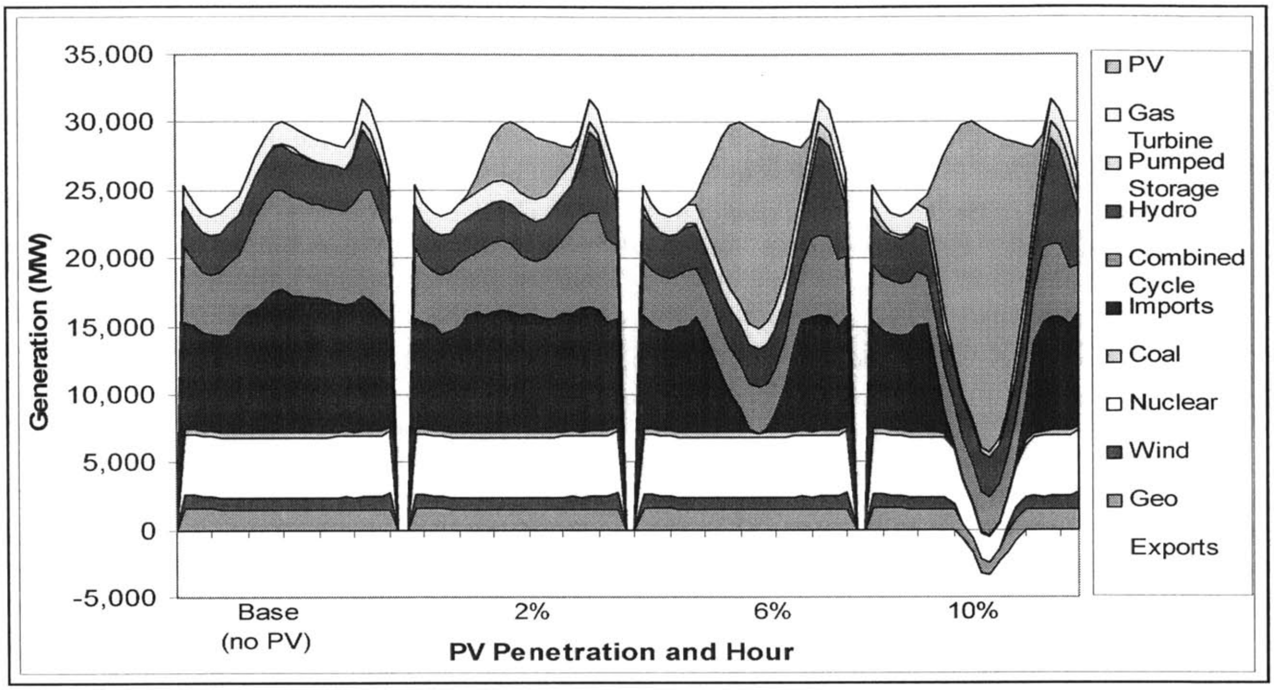

Figure 2.1. Impact of different photovoltaic (PV) electricity production levels on load service in California, typical spring day (Ref 1)

Figure 2.1 shows how other generators might be forced to respond to increases in the total energy delivered by photovoltaic (PV) generators, assuming PV is always dispatched when it is available. Note that "PV Penetration" in this study refers to percent of total electricity delivered over one year, not capacity. This result shows that markets are substantially impacted by as little as 6% PV, with California's normally large imports eliminated. At 10% PV, it is impossible to maintain an appropriate level of spinning reserve capacity without over-generation at midday. In this case, midday prices on the CAISO market will almost certainly be negative, prices in surrounding markets will be very low, and some generators may shut down rather than operate during low demand spring days. There would be no incentive to invest in unsubsidized new generating facilities in such a market. These issues, combined with the very large ramp rates seen as PV generation increases in the morning and decreases in the evening, create a severe grid management challenge.

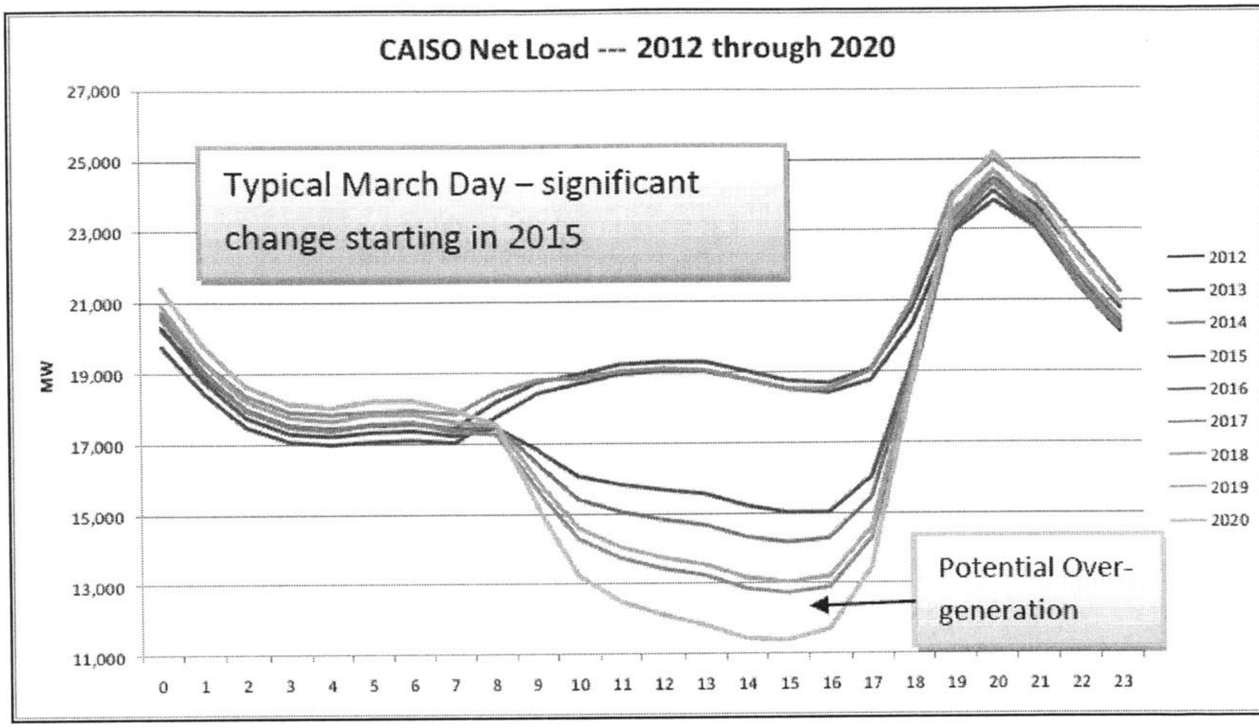

Figure 2.2. Net load (actual load minus IRG supply) with forecast increase in renewable generation (Ref 2)

Figure 2.2 shows a similar result, the CAISO "Duck Curve". CAISO has publicized this figure to raise awareness of the technical challenges caused by growing use of IRG. For reference, California current receives about 0.5% of its total yearly electricity from PV; CAISO projects approximately 2% PV in 2016 (the second year in which a major decline in midday net load is visible in Figure 2.2). This indicates that grid management issues may arise at even lower PV penetration than that suggested by the NREL results shown in Figure 2.1.

The problems to be overcome in IRG development are expressed somewhat differently in a study of IRG market value in Europe. As Hirth states in the 2013 study, "The supply of VRE [variable renewable energy, same as IRG] is variable," and "the output of VRE is uncertain until realization" [3]. This has the ultimate effect of reducing the value of IRG as more intermittent generators are built and simultaneously increasing the value of flexible dispatchable generation. Figure 2.3 from Hirth shows the reduction in wind generation value as market share increases, calculated by the European Electricity Market Model EMMA using real grid and weather data from 2010.

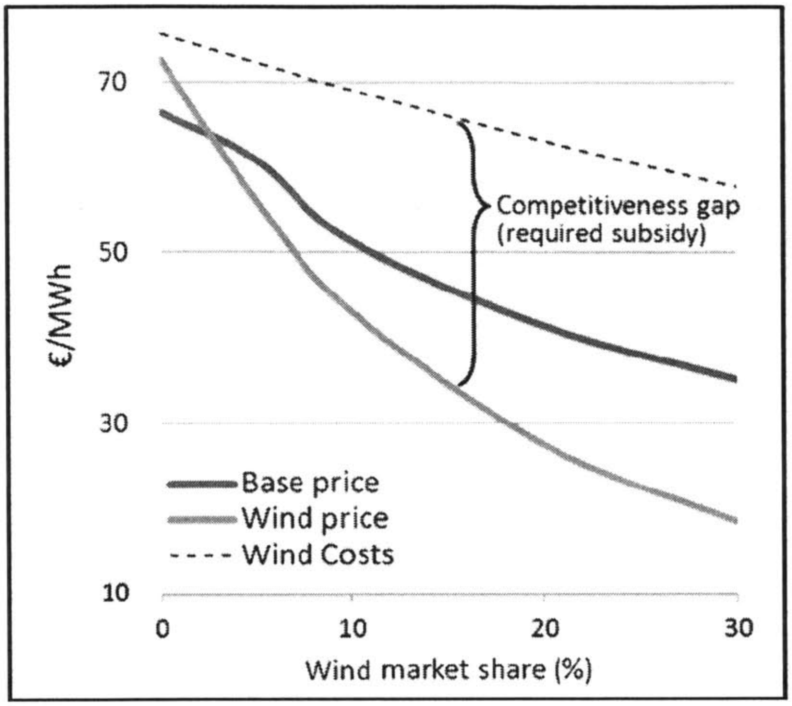

Figure 2.3. Market value of wind electricity generation (Ref. 7)

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3. Oil Shale Resources and Processing Technologies

Kerogen is a solid, insoluble mixture of heavy organic compounds found in sediments and sedimentary rocks. When heated, kerogen decomposes into hydrocarbons. The weight distribution of the products and the rate of decomposition both depend on the temperature and the heating rate, and somewhat less on the pressure at which the heat is applied. Kerogen is different from bitumen, which is soluble in a range of organic solvents and water. Kerogen is present in very low concentrations in many types of dirt and rock.

Oil shale is sedimentary host rock that contains high kerogen content. It is implied, in nearly all discussions of oil shale (including this thesis), that the rock in question is a potentially economically viable source of hydrocarbons. Shale oil is the set of liquids produced by decomposition of the kerogen in oil shale. Gaseous products are significant in many processes for extracting hydrocarbons from oil shale (making up as much as 40% of the energy content of products in some processes), and could be referred to as "shale gas," although this has an unfortunate potential for confusion with the gases trapped within shale formations (in gaseous form) and currently produced by hydraulic fracturing in many parts of the United States.

The density of an oil shale resource is measured in gallons of hydrocarbons per ton of shale. Since this quantity could vary with different processing methods, the reference value provided to describe a particular sample of shale is usually derived from results of the Fischer assay. The Fischer assay is a standardized lab-scale test. From Ref 1,

> *The standardized Fischer assay method consists of heating a 100-gram sample crushed to –8 mesh (2.38-mm mesh) screen in a small aluminum retort to 500°C at a rate of 12°C per minute and held at that temperature for 40 minutes. The distilled vapors of oil, gas, and water are passed through a condenser cooled with ice water into a graduated centrifuge tube. The oil and water are then separated by centrifuging. The quantities reported are the weight percentages of shale oil (and its specific gravity), water, shale residue, and "gas plus loss" by difference.*

The weight percentage of shale oil and its specific gravity are sufficient to report the volume of oil per mass of shale.

This method does have some limitations. The Fischer assay itself includes a specific processing technique, and different processing technologies at different scales (lab, demonstration, commercial) can produce differing qualities and quantities of oil. Process-specific yields, either in gallons per ton of shale or joules of fuel energy per ton of shale are also reported regularly in oil shale literature and process descriptions. The Fischer assay technique also includes no mechanism to measure the distribution of products (mass distribution) in the shale oil or in the produced gases; the distribution of particular products may be important for some operations. Producing more octane, for example, with less of other specific products would result in a product stream that requires much less processing to convert into transportation fuel.

The characterization of the products of particular processes is highly empirical, due to the chemical complexity of kerogen and potential variations in composition even within the same formation. It is therefore very difficult to predict the detailed properties of the products of a process before demonstration and testing.

3.1. Distribution of US Resources

The U.S. has the largest and most concentrated oil shale formations in the world. This resource contains more oil than has been produced globally since the start of the oil industry. U.S. oil shale resources are estimated to be equivalent to about 2 trillion barrels of oil—similar to in size to global coal reserves if they were converted to oil [2, 3].

Economically significant oil shale resources are found in three areas: the Piceance Creek Basin of western Colorado, the Uinta Basin of eastern and southeastern Utah, and the Green River Basin of Wyoming. Collectively, the geology host to oil shale in this entire area is referred to as the "Green River Formation."

The oil shale of the Piceance Creek Basin is the densest of the three areas, but is also the deepest underground and the thickest in vertical extent of the oil shale itself. This formation by itself contains the equivalent of over 800 million barrels of oil in an area no larger than 60 miles across in any direction [1]. A cross section of a particular north-south segment of the Piceance Basin formation is shown in Figure 3.1.

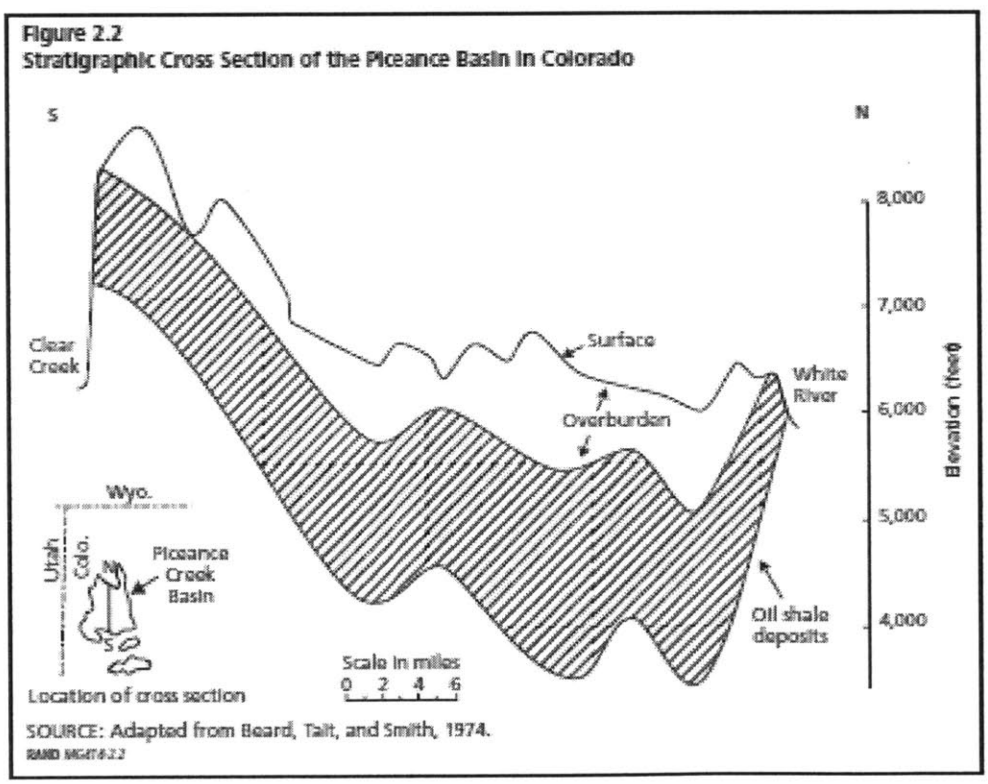

Figure 3.1. Cross section of oil shale deposits in Piceance Creek Basin (Ref 1)

Given the concentrated resource base, a large-scale nuclear oil shale production complex could include over 200 reactors each with an output of 500 to 1000 MWt (small modular reactors) in an array where reactors are separated by kilometers. The spacing would be determined by the need for heat underground. The highest-density oil shale in the U.S. is located in low-population areas of Utah, Wyoming, and Colorado, shown in Figure 4.

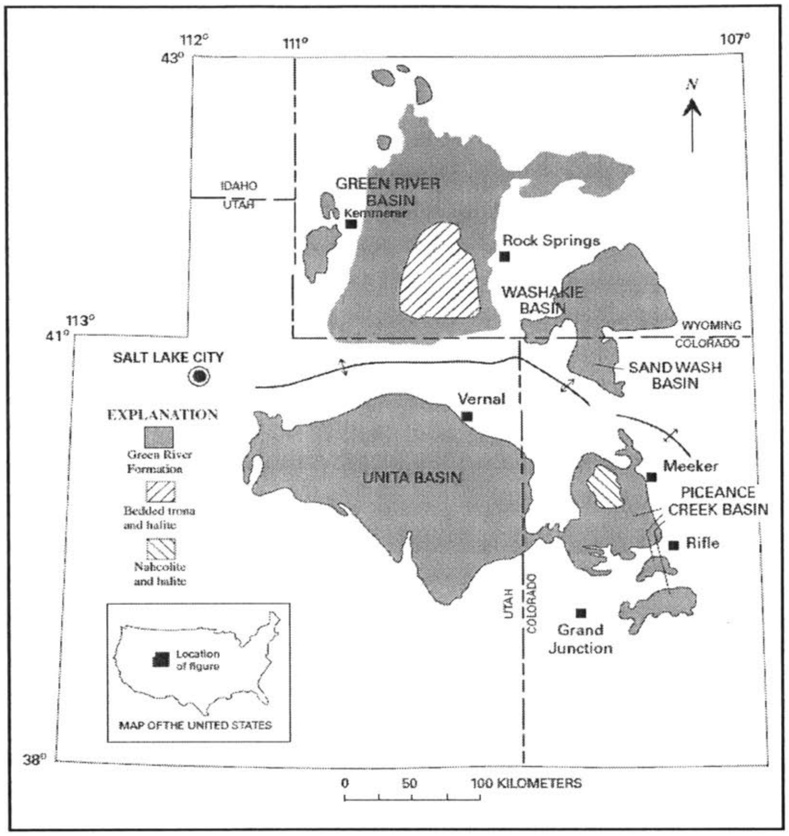

Figure 3.2. Location of Green River Formation oil shale resources in the western United States (Ref 1)

3.2. Kerogen Processing Technologies

All kerogen processing currently carried utilizes surface retorts. These typically heat crushed shale in a cylindrical vessel near ambient pressure to about 500°C. The shale must be mined and crushed separately before processing. Some surface retorts generate most or all of the heat needed for steady-state operation from combustion of the heaviest solid components of the decomposed products of kerogen, called char. Retorts of this type would require very little external power, and some are actually net generators of power. However, the most common types of host rock for kerogen begin decomposing into calcium compounds and carbon dioxide (CO2) above 400°C, which increases their CO2 emissions to levels far above any conventional refinery. Surface retorts must also sequester mine tailings, fine residual shale, and other potential contaminants.

Several major oil exploration corporations, national labs, and some smaller organizations have developed a range of in-situ oil shale processing and extraction technologies. Although some of these technologies have seen multiple decades of development, none of them have been demonstrated on a commercial scale.

3.2.1 Shell In-situ Conversion Process

One of the most mature system concepts is the Shell In-situ Conversion Process (ICP) [4, 5]. This system would employ electric resistance heating, with heaters in an array of vertical drilled wells, to heat the kerogen-bearing shale layer. Hydrocarbons are extracted by a set of separate, conventional drilled wells. Small-scale kerogen processing experiments and technology trials have contributed to the development of Shell ICP and resulted in greatly improved understanding of the kinetics of kerogen decomposition and the influence of temperature and pressure on the decomposition process. Shell ICP was the subject of a thorough life-cycle assessment of energy use and greenhouse gas (GHG) emissions by Brandt [6], which provided a valuable public literature reference of the baseline Shell ICP system design. Most other proprietary technologies have not had studies of this detail made publicly available. Shell ICP was under active development from 1981 to 2013, when Shell announced that they were divesting their leases in Colorado and ending their experimental field work there [7].

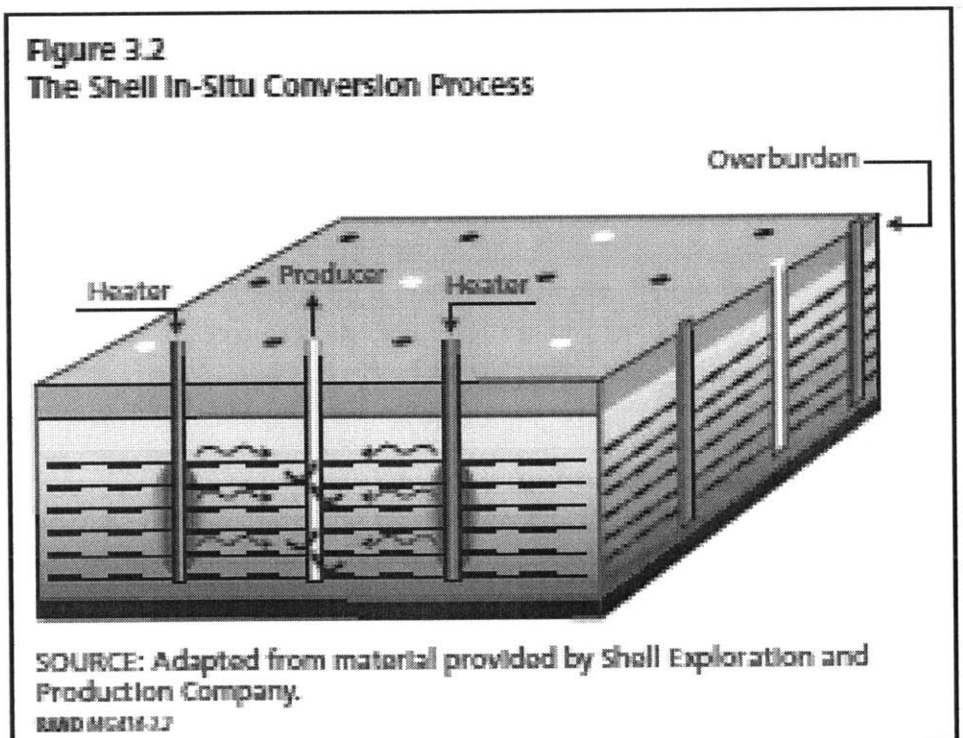

Figure 3.3. Illustration of the Shell In-situ Conversion Process (Ref 4)

3.2.2. Exxon Electrofrac

Exxon is currently developing an in-situ processing technology called ElectroFrac [8]. In this system, the kerogen-bearing shale layer would be hydraulically fractured and the fractures filled with electrically conductive fluid. Electrodes would be connected with the fractures through rows of vertical drilled wells to form a resistance heating system. Hydrocarbons would again be collected by a separate set of conventional drilled wells. ElectroFrac has been under development since the 1990s.

3.2.3. Chevron CRUSH

The Chevron CRUSH process was under development, in a collaboration with Los Alamos National Lab, from 2006 to 2012 [9]. This process also called for hydraulically fracturing the kerogen-bearing shale layer, then propelling heated carbon dioxide through the layer to heat the kerogen. The layer had to be substantially broken, beyond the fracturing caused by normal hydraulic fracturing techniques, to allow for sufficient CO_2 flow, and use of explosives and other propellants to further break up the shale was investigated. The CO_2 was circulated through vertical wells and heated at the surface. Fracturing and breaking of new production zones would proceed directly from previous zones, with any organic residues remaining in the depleted zone combusted to preheat the next zone.

3.2.4. American Shale Oil Corporation

The American Shale Oil Corporation (AMSO) and its predecessors have held a lease for testing, adjacent to the Shell lease, since 2007. AMSO is currently developing a process that involves heat delivery via gas combustion in horizontal wells through a particularly deep Colorado shale layer [9]. This process is intended to set up oil/vapor convection currents in fractures in the shale layer. A previous concept considered by AMSO would have used steam to heat the horizontal wells in a manner similar to the closed line heat transfer subsystem under study herein [9].

3.2.5. Red Leaf Resources

An important characteristic of underground heating is that it is a slow process. Slow heating results in high quality oil, whereas fast heating results in lower-quality oil of much lower value. Historically all surface retorting strategies have involved fast heating of shale oil in small surface retorts. A new processing technology under development by Red Leaf Resources since 2005 may alleviate both the problems of slow underground heating and lower quality products from fast retorts with a radically different retorting strategy. The process is currently in the pilot plant stage of development in Utah [3, 4].

This process is neither a true in-situ process nor a traditional surface retort. Red Leaf uses a capsule just below grade, lined with clay and gravel, as their retort, with an arrangement of mild carbon steel pipes circulating hot natural gas or fuel gas exhaust to heat crushed shale. The capsule is completely enclosed after being filled with mined crushed shale. Oil and gases are collected at drains on the bottom, sides, and top of the capsule. The current design calls for a final average shale temperature of 370°C after 210 days of heating. A capsule with heating pipes is illustrated in Figure 3.4.

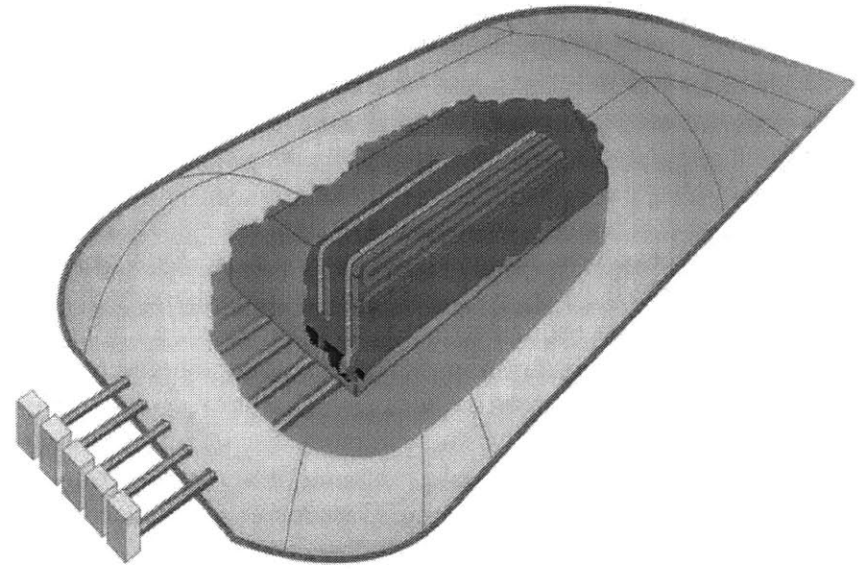

Figure 3.4. Illustration of a Red Leaf clay-lined surface retorting capsule (from Ref. 10)

3.3. Recent Integration Studies

Forsberg [12] proposed three particular large-scale hybrid energy systems: underground thermal energy storage (UTES), high-temperature steam electrolysis (HTSE) for hydrogen and oxygen production, and extraction of kerogen oil shale. The goal of these large-scale systems is high capacity factors, full utilization of capital-intensive renewable and nuclear primary energy sources, and flexible generation of electricity in balance with grid demand. This goal, combined with the inherent intermittency of wind and solar photovoltaic (PV) generators, implies an important system requirement: some component of the system must be able to accept varying heat and/or electricity with minimal performance losses or economic penalties. This requirement is echoed in the fourth of the common features Forsberg identifies in these systems:

> *(1)high-capital-cost low-operating-cost nuclear and renewable energy systems operate at full load, (2) solar and wind send electricity directly to the grid,(3) the steam from the nuclear plants can be sent either to turbines for electricity production or users of electricity and steam, and (4) hybrid energy systems can accept variable steam and electricity inputs with only small economic penalties.* [12]

A series of studies of integration of nuclear heat and power for oil shale processing began in 2006 with strategic studies and concept proposals by Forsberg [12]. Robertson performed process modeling studies at INL on integration of a high-temperature gas-cooled reactor (HTGR), under development as part of the NGNP program, into both in-situ and ex-situ oil shale operations [13, 14]. Integration studies continued with the work of Forsberg [15, 16], and later Curtis and Forsberg [17, 18, 19], at MIT. These continuing studies presented other reactor options for coupling, including current light water reactors and near-future small modular reactors; showed the revenue benefits for the coupled system of electricity sales into a deregulated electricity market; and indicated the potential to reduce GHG emissions of the coupled nuclear oil shale system below the emissions of current average gasoline and diesel production [19].

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Part 2: Configuration and Performance

4. System Configuration

NROSS couples a nuclear reactor plant with a petroleum processing system that includes a heat delivery subsystem to heat oil shale in the ground. The nuclear reactor operates steadily at full power; this power is accordingly directed to electricity production and/or to the heat delivery subsystem, depending on the present operating mode.

4.1. Baseline Reactor

The baseline NROSS reactor is a small modular integral pressurized water reactor (SMR), assumed to have properties and performance similar to those of the designs proposed by NuScale, B&W mPower, Holtec, or Westinghouse. Reasons for this selection include:

1. *Minimal technological risk.* LWR technology is the only reactor technology currently developed to commercial levels. It is not currently certain that any advanced reactor technologies will be commercially available before 2030, while deployment of large commercial NROSS by that time should be technically achievable.
2. *Transportability.* The oil shale formations in the United States extend over a large, rough, sparsely populated area. A large development would require an array of nuclear plants separated by kilometers [1]. Even with localized mass production of reactors and major components, a smaller transportable reactor is likely to be easier to install where needed.
3. *Timing.* SMRs are targeted for commercial operation by 2025 under a DoE cost-sharing program [2]. With a vigorous development effort, NROSS technical design should be complete and ready for a technology demonstration by then.
4. *Output temperature.* LWRs can output steam at a maximum of about 320°C, below the 350°C necessary for kerogen decomposition to hydrocarbons over a 2 year heating cycle. Although this initially seems like a major liability, use of a second higher-temperature heating stage powered by electricity purchased from the grid during periods of very low prices actually enhances the grid balancing capabilities of NROSS.

4.2. Heat Delivery Subsystem

The baseline heating system uses closed steam lines running from the nuclear plant into the ground and through the oil shale formation. The steam lines connect to the secondary loop of the reactor using a heat exchanger, and both the reactor secondary loop and the steam delivery loop have bypasses to isolate the reactor from the steam delivery subsystem. Although the reactor secondary loop and steam delivery loop could share a condenser system, the system is likely much easier to license if the secondary loop and steam delivery loop each have their own physically isolated condensers and recirculation pumps.

The complete system has a single energy input, thermal power from the nuclear reactor, and two energy outputs: electricity, and hydrocarbons recovered from the decomposed kerogen. We can also model the nuclear plant as a smaller single-input, two-output system, with the outputs in that case being electricity and steam. Figure 4.1 illustrates baseline NROSS energy flows.

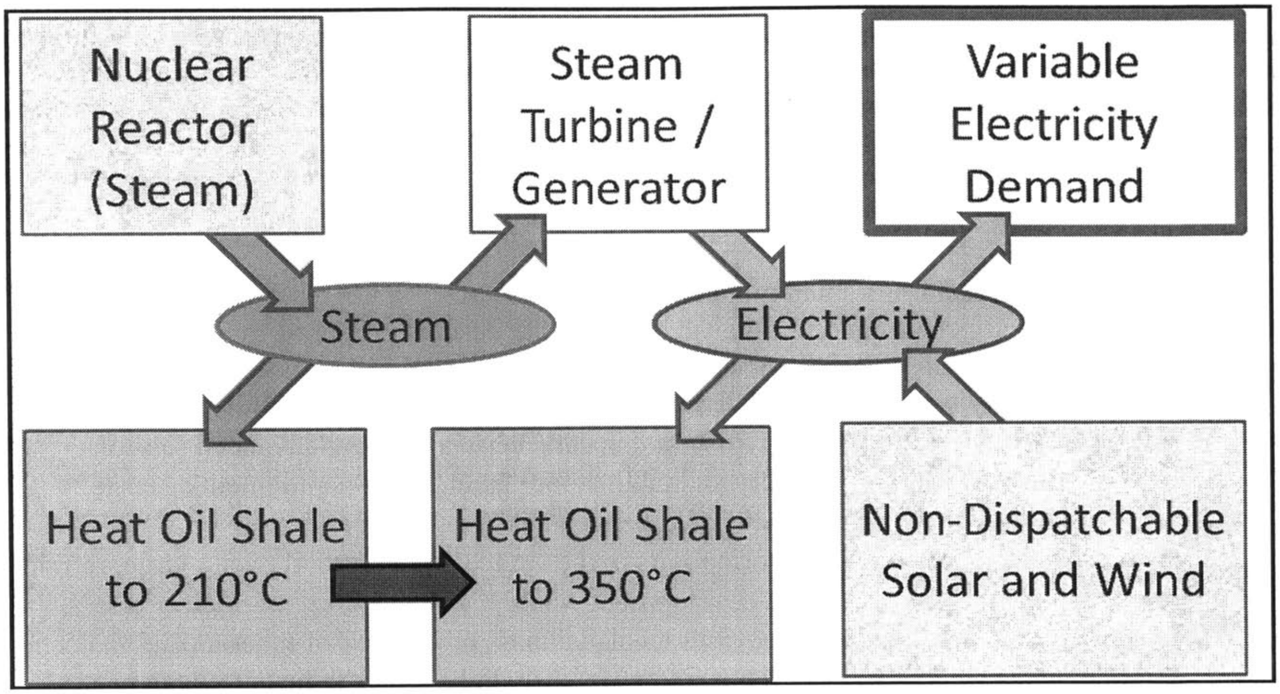

Figure 4.1. Energy flow diagram of baseline NROSS

The baseline system uses a 2 year heating schedule for each oil shale production zone. The first year is lower-temperature heating from the reactor, with a conservative target average shale temperature of 210°C at the end of that year. The second year is higher-temperature heating, in which the purchased low-price electricity powers electric heaters in the steam loop to further increase temperature, with a final target average shale temperature of 350°C. Figure 4.2 illustrates the stages of operation of a baseline oil shale production zone.

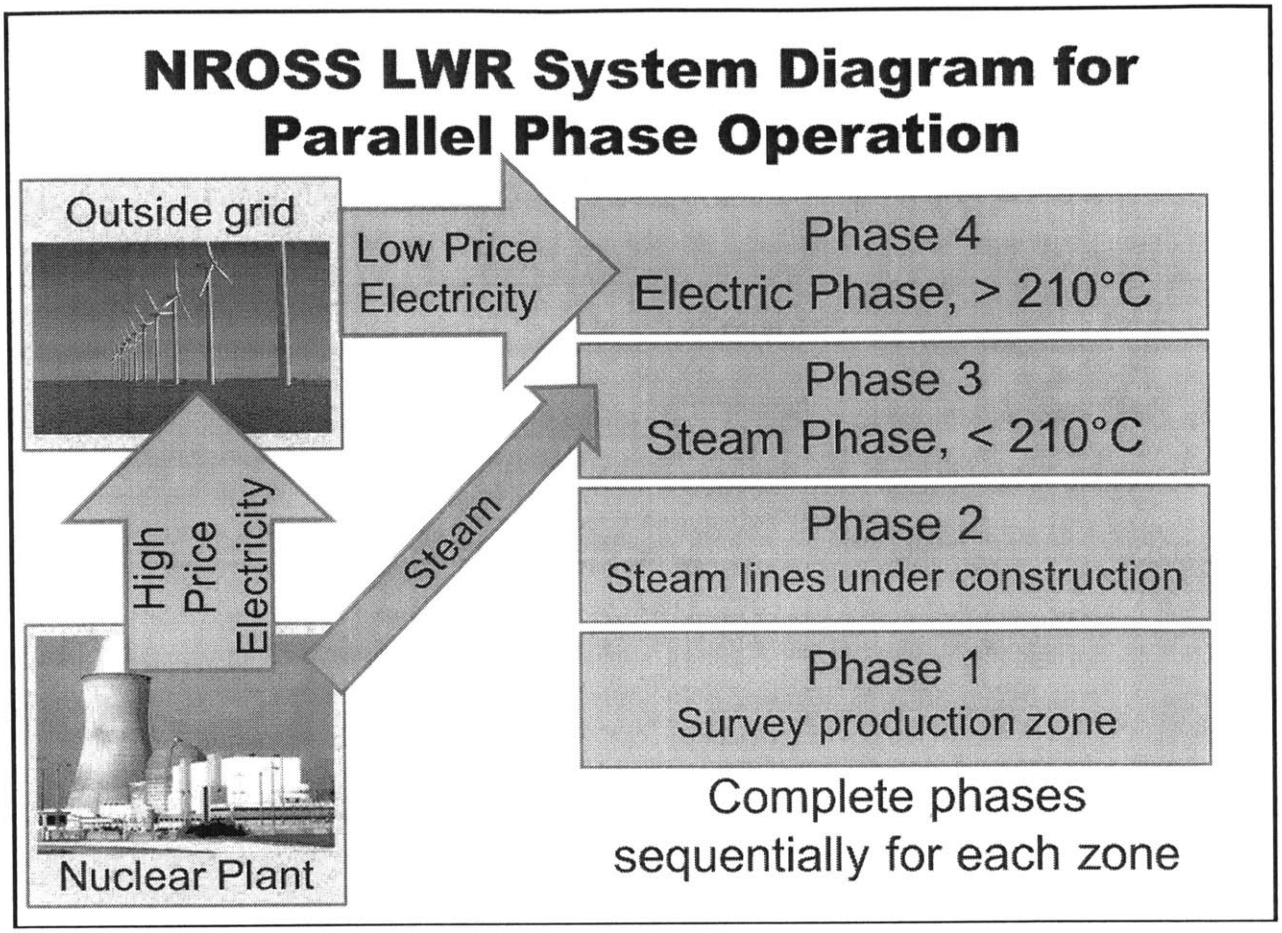

Figure 4.2. Illustration of parallel implementation of two required heating phases of each production zone

4.2. Features of a Production Zone

In the baseline NROSS configuration, each Production Zone will be supplied with hot steam from the attendant reactor for 1 year, then supplied with hot steam circulated in the same closed pipe system and evaporated using an electric boiler. The steam condenses as it heats the oil shale and is continuously recirculated during both heating stages.

Each Production Zone will have many separate pipes carrying steam through the oil shale formation. This is necessary because each pipe will have a "zone of influence," the volume of rock that can be heated to the target temperature of 350°C within 2 years by heat from that pipe, with a radius of only a couple meters. Limited study of heat transfer in this system suggests that pipe spacing of 3m to 4m would be suitable.

The generic Production Zone will have a rectangular cross section and surface footprint. Heat delivery pipes enter one side of the rectangular cross section, descend to the oil shale, run horizontally through the shale, then return vertically to the surface. The baseline configuration places a condenser and recirculation pump at the surface on the return lines. The pressurized water is directed through either a heat exchanger from the reactor plant or an electric boiler, depending on the current heating stage, or through a safety bypass line anytime the reactor or electric boiler are unavailable. Following discussions will assume that one of the heat sources is available at all times. A side view of a Production Zone is shown in Figure 4.3 with dimensions representative of a Production Zone located in the central part of the Piceance Basin Formation of Colorado for reference.

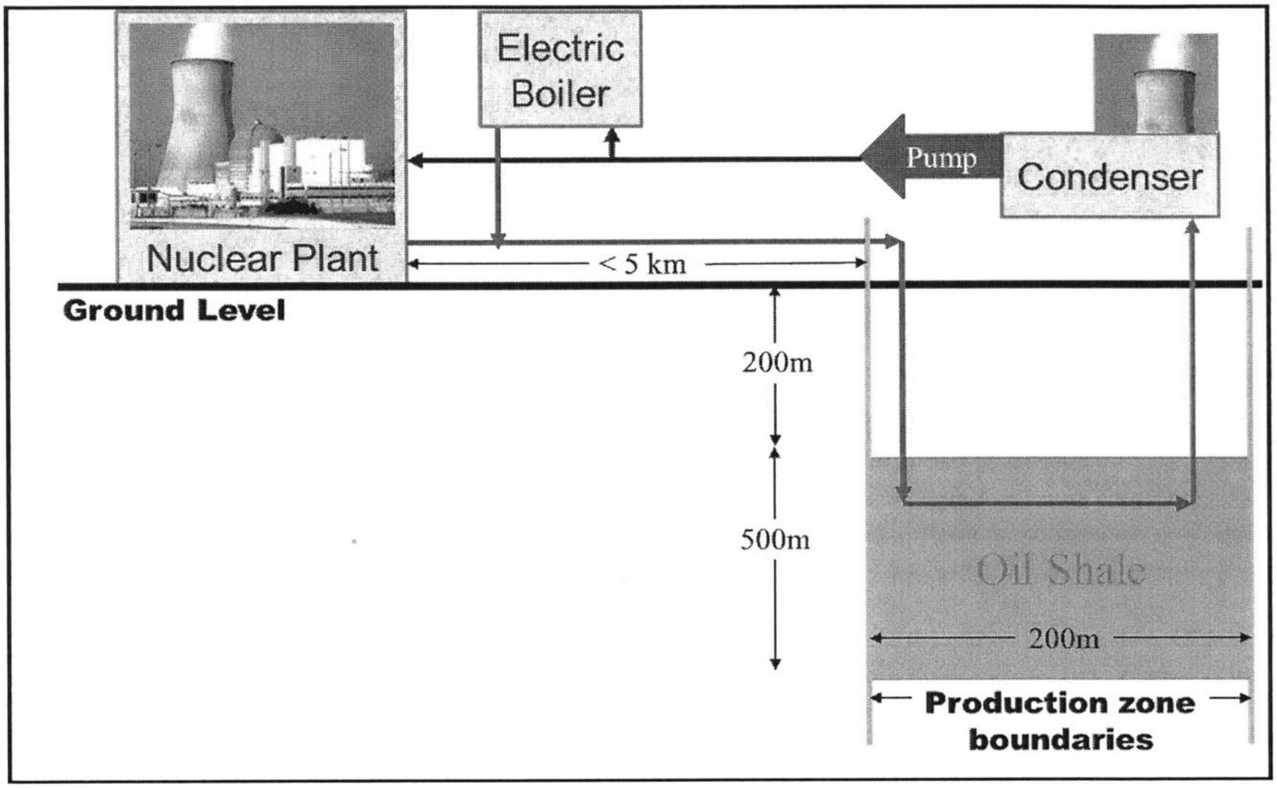

Figure 4.3. Side view of a Production Zone

The heating time of 2 years is selected for two reasons. First, several small scale experiments in support of other in-situ oil shale production concepts have characterized samples of oil shale heated over that duration to final temperatures ranging from 300°C to 400°C and have shown that a distribution of hydrocarbons suitable for sale as oil can be generated. See Chapter 3, references 4 and 5 for descriptions of some of these experiments. The distribution of products of kerogen decomposition can vary as a function of the original kerogen composition and temperature, and the temperature inherently varies with time in an in-situ system. The second reason to specify a 2 year heating time for the purposes of this work is to match the time specified for Shell ICP, enabling us to make use of parameters of their design and the lifecycle assessment by Brandt with better accuracy and applicability.

The optimal size of Production Zones may change over time as the relative values of electricity, heat, and/or hydrocarbons change. If the relative value of electricity increases, the reactor will spend more time producing electricity, so the average annual heat output and the optimal Production Zone size will decrease. It will be necessary to estimate the expected annual heat output about 2 years in advance of heating a particular Production Zone to allow for delineation, survey, and drilling and construction of an appropriate size zone.

4.3. Determining Production Zone Size

The geometric configuration of oil shale underlying any particular plot of land and the density pattern of that shale (recalling that the density of oil shale is most commonly reported in gallons of product per ton of shale) will be unique. Each Production Zone will therefore have to be uniquely surveyed and have boundaries established that encompass a suitable total volume of oil shale.

The optimal volume of oil shale within Production Zones may additionally change over time as the relative values of electricity, heat, and/or hydrocarbons change. The nuclear reactor is an asset with a lifetime of at least 60 years. Each Production Zone that the reactor serves should be sized appropriately for the desired heating duration, the quantity of heat the reactor is likely to output during the first half of that duration, and the appropriate corresponding volume of shale that can be heated to the target temperature (350°C) by that quantity of heat. With the heating duration of 2 years set, and with the quantity of heat the reactor will output each year known, the cross section of the Production Zone should be set to encompass a volume of shale that can be fully heated by the available quantity of heat.

4.3. Service Region

A Service Region consists of a number of contiguous Production Zones that will be processed over the lifetime of one or more attendant reactors and are located close enough to the reactor plant to be readily accessible by insulated steam lines with minimal heat losses. Transmission distances up to 5 kilometers are assumed to have suitably low losses.

The simplest possible Service Region would be a rectangle of Production Zones surrounding a single reactor. If the reactor is assumed to have a lifetime of 60 years, the Service Region would contain 60 Production Zones. Two Production Zones would be heated at any one time: the first would be in 1st stage heating using heat delivered by the reactor, and the second would be in 2nd stage heating using electric heat.

It is likely to be desirable to located several reactor modules in a single plant (this is explicitly called for in the designs of the NuScale plant, for example). Correspondingly, the Service Region would have a number of Production Zones equal to the reactor-years of operation anticipated from the attendant multi-module plant. The baseline Service Region is assumed to be served by a single reactor with a 60 year lifetime.

4.4. Alternate Petroleum System

The Red Leaf Resources process, described in Chapter 3, presents the most promising alternative currently known. It employs single-use retorts formed by a clay-lined excavated volume (Fig. 4.4) with dimensions greater than 300 meters filled with crushed oil shale. Closed heating pipes run through the crushed shale. Because of the high permeability of the crushed shale, convective gas flow creates a relatively uniform temperature throughout the retort volume. This offers much greater control of temperature and the rate of temperature increase during heating. This design feature implies that less closed heating piping would be required to offer better heat transfer than underground retorting. The improved control of the heating process may dramatically increase opportunities for process optimization as operational experience is accumulated (opportunities for and implications of future process optimization are briefly discussed in Chapters 5 and 7). As a surface system, installation of heating pipes is much simpler and much cheaper in the Red Leaf capsule retort than in in-situ systems. The drilling of large numbers of heating pipes is likely to be a significant cost driver in in-situ systems.

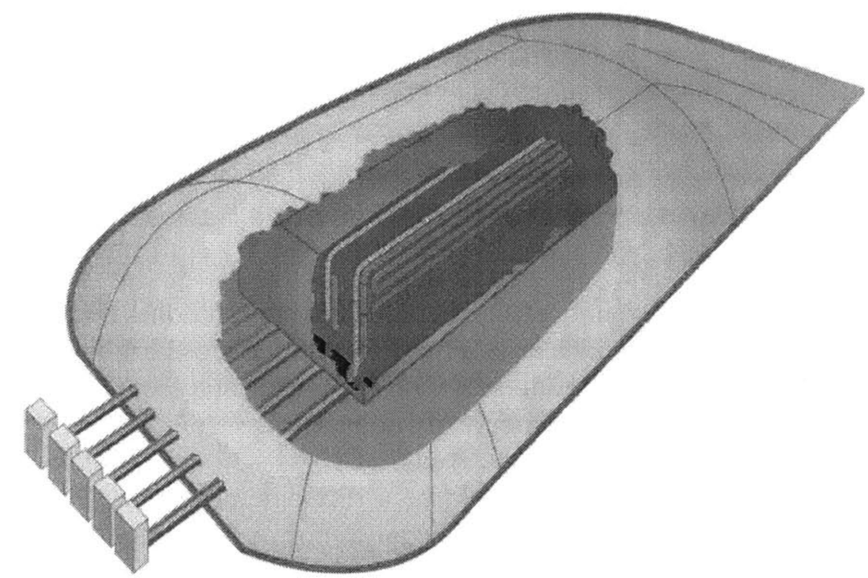

Figure 4.4. Illustration of a Red Leaf clay-lined surface retorting capsule (from Ref. 4)

Red Leaf designs its system for a baseline heating schedule of 210 days with a target final average shale temperature of 370°C. If coupled with LWR steam heating, this target temperature would require two heating stages, just like the NROSS baseline configuration. The current heating system employs natural gas burners that drive hot exhaust through the heating pipes at slightly elevated pressure. Conversion to steam heating would require some design changes, but those changes would be manageable and would likely improve some aspects of the heating system design (reducing necessary heating fluid volume within the capsule, for example, due to the substantially greater heat capacity of water and the excellent heat transfer achieved in two-phase steam-water systems).

4.5. Future Reactor Options

A variety of advanced reactor design are under development at universities, companies, and national laboratories around the world. In recent years in the United States, there has been particular interest in the high-temperature helium cooled reactor under development through the Next Generation Nuclear Plant (NGNP) program and the Fluoride-Salt-Cooled High-Temperature Reactor (FHR), also known as the Advanced High Temperature Reactor (AHTR). The US Department of Energy and several international organizations also have a long history of interest in sodium-cooled fast-neutron-spectrum reactors (SFRs). All of these reactors are potentially suitable primary energy suppliers for future NROSS developments.

For NROSS analysis purposes, reactors with peak coolant temperatures above 400°C and single-output power conversion systems that are compatible with the steam heat delivery loop can all be analyzed together, at this early stage of development, as High Temperature Reactors (HTR). Figure 4.5 illustrates energy flows in an NROSS system powered by a HTR.

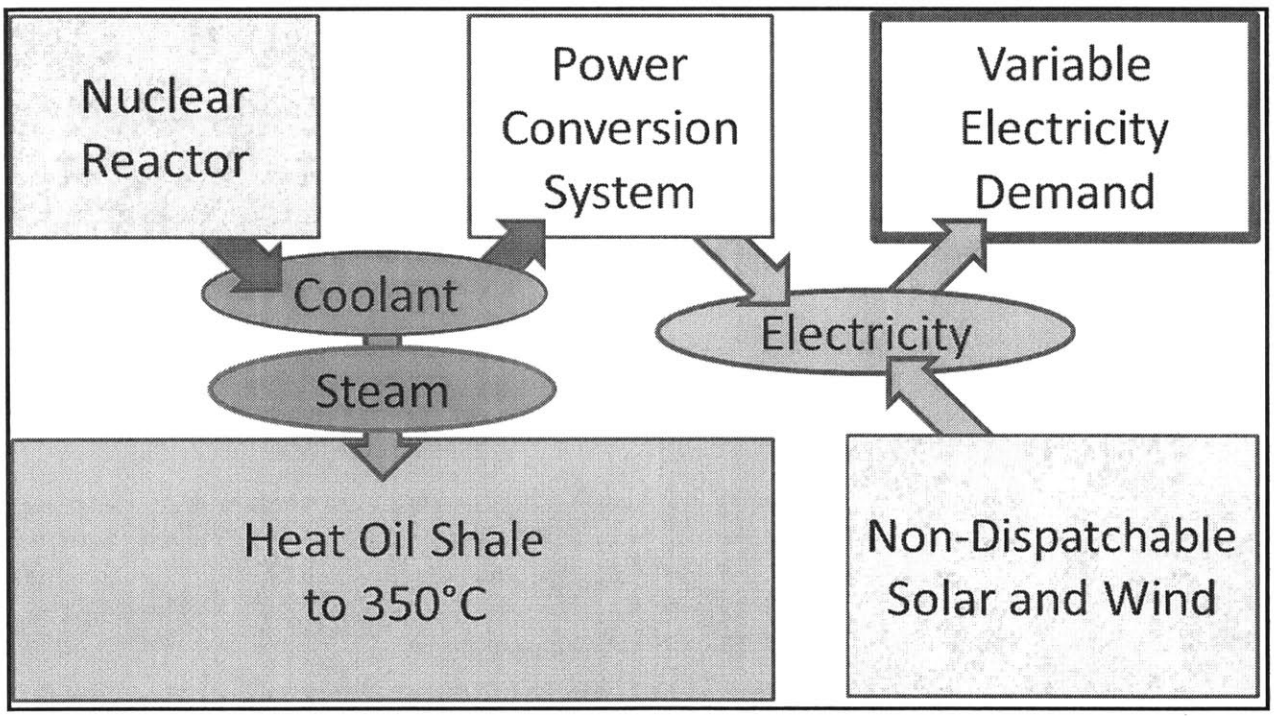

Figure 4.5. Energy flow diagram of HTR-NROSS

Certain advanced reactor designs have multi-stage or multi-output power conversion systems that would require more detailed consideration. The FHR is an example of such a design [5, 6]. The FHR delivers heat to a Nuclear Air-Brayton Combined Cycle (NACC) through salt-to-air heat exchangers. The air-Brayton portion of the power conversion system may include supplemental fuel injection (natural gas or hydrogen) or a Firebrick Resistance-Heated Energy Storage System (FIRES) for increased peak power output [6]. Exhaust from the air stream heats a steam generator, which may direct steam either to a bottoming cycle steam turbine for additional electricity production or to a process heat delivery system. Energy flows in an FHR-NROSS system are illustrated in Figure 4.6.

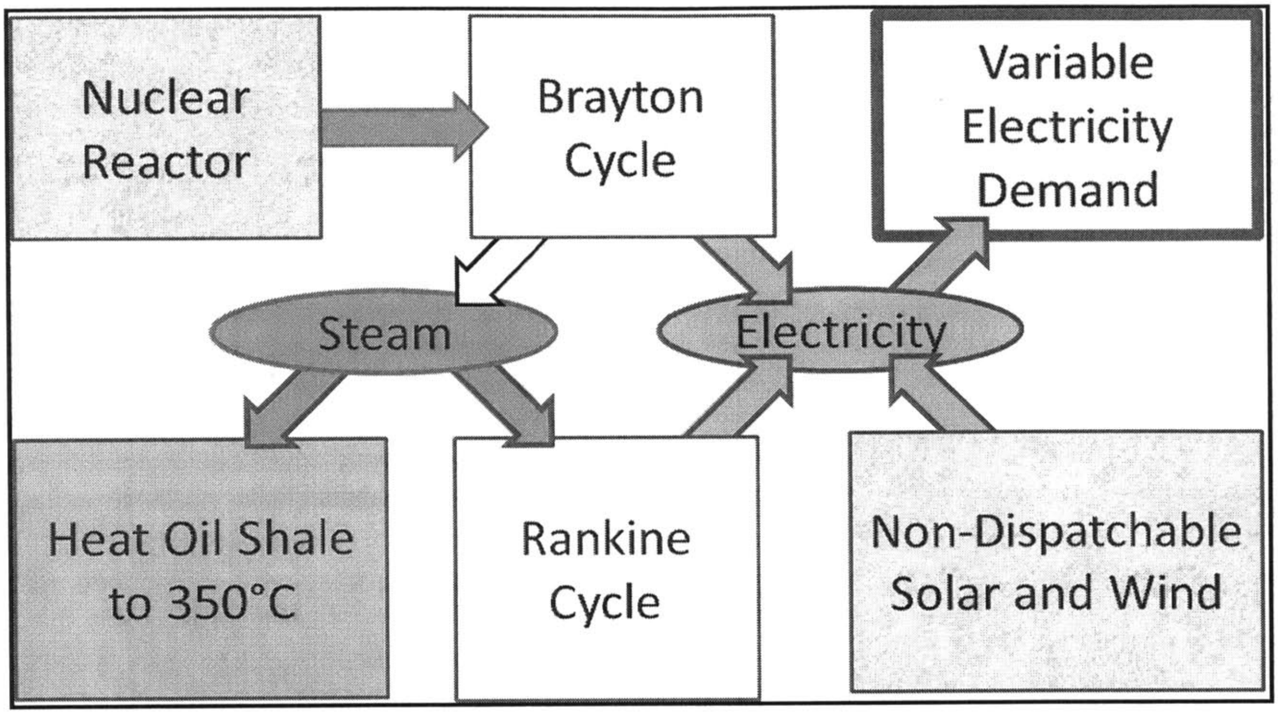

Figure 4.6. Energy flow diagram of FHR-NROSS

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5. Cost Saving Opportunities in Large Field Operations

Studies to date [1, 2, 3] have identified a wide range of cost saving opportunities that are likely to arise in the large field operations of a large NROSS development. The cost saving opportunities are categorized and described in the following sections. All of these represent opportunities for further study and analysis.

5.1. Capital Cost Savings

The first category of cost saving opportunities would reduce the average overnight capital cost per reactor in the NROSS development. Quantification of the expected reduction in cost relative to stand-alone plants or Nth-of-a-kind baseload electricity generation plants is beyond the scope of this thesis. I recommend using relative overnight capital cost per reactor and relative completed cost per reactor as the figures of merit for quantifying capital cost savings, using the best available estimates of Nth-of-a-kind baseload electricity reactor cost for comparison.

<u>Sequential construction of 10s to 100s of reactors.</u> A large NROSS development of very dense oil shale, such as that found in the Piceance Basin Formation of western Colorado, could involve deployment of 200 or more reactor modules in an area less than 30 miles in each direction. Although the points at which investment in a central module factory is justified and at which Nth-of-a-kind capital cost levels are achieved is still a hotly debated topic, both of these points are quite certain to have been reached by the time N = 100. Such a large development would therefore favor construction of a module factory near the development area for final assembly of modules and fabrication of large components. This development strategy has already been proposed for SMRs in other contexts, but it remains unclear if the market for baseload electricity generators in North America is sufficient to justify investment in module factories.

<u>Short transportation distance for finished modules</u>. Modules would only need to be moved a short distance to their plant site if the module factory is adjacent to the NROSS development area. Module transportation might occur purely on internal routes, which could be purpose built for heavy transportation and would be free of public traffic. However, the terrain of the major US oil shale areas is rough, rocky, and in some areas mountainous. It is currently unclear if the cost savings from short distances and purpose-built transport routes would offset the increased cost of transport over rough terrain.

<u>Favorable learning curve for module assembly</u>. Final assembly of all modules installed in a large NROSS development could be carried out in a single local plant, which would assure maximum learning and efficiency from sequential module assembly. Whatever number of reactors is necessary to arrive at Nth-of-a-kind capital cost for conventional baseload reactor modules, the number necessary to arrive at Nth-of-a-kind capital cost for NROSS modules is either equal or less.

Shared infrastructure. The option exists to develop shared infrastructure and support facilities for many modules or many multi-module plants within a large NROSS development. Possible shared infrastructure and support items include:

- Radioactive waste processing
- Spent nuclear fuel storage
- Heavy lift equipment (possibly in the form of a rail-mounted system that can be moved to the module or plant currently being installed or under maintenance or refueling)
- Offices for administration
- Maintenance workspaces and equipment
- Spare parts storage
- External electricity connections

A more substantial departure from traditional reactor operations could be realized by sharing safety systems such as backup electric generators, emergency response equipment, or control facilities. Backup electric generators could represent a particularly interesting option for sharing between reactors, as generators can serve their safety functions just as effectively whether they are directly adjacent to the reactor or hundreds of meters away. Separating the backup generator from the reactor might actually increase overall safety by providing a larger physical boundary between the reactor and generator, reducing the impact an accident could have on the generator, and providing additional redundant power supply options for each reactor. Designing the overall facility for safe operation with a more complicated backup power supply would require much more complicated analysis, but the possibilities for simultaneously increasing overall safety and decreasing facility cost justify additional investigation.

5.2. Operations and Security Cost Savings

The second category of cost saving opportunities would reduce the average operating costs of the reactors in the NROSS development. Quantification of the expected reduction in cost relative to baseload electricity generation plants is again beyond the scope of this thesis. I recommend using average relative fixed operating cost in $ / kW – day of availability and average relative variable operating cost $ / kW-hour of energy delivered as the figures of merit for quantifying operating cost savings, again using the best available estimates of Nth-of-a-kind baseload electricity reactor cost for comparison.

Shared staff. The opportunity to serve a very large number of reactors within the NROSS development with the same staff would reduce the necessary staff per reactor compared with a conventional plant. This has important implications in many areas of operations, from administration to outage services.

Shared training facilities. The large number of NROSS reactors could share a quite small number of training facilities, including reactor simulators, and smaller number of instructors. Training facilities would also be certain to have near maximum utilization with very little downtime.

Maintenance learning curve. A large NROSS development could include dedicated mock-up facilities for maintenance operations and centralized coordination of maintenance schedules to ensure full utilization of a full-time maintenance crew. Many functions only required during outages in conventional plants might be provided by full-time staff in the NROSS development. A particularly promising option would be to employ a small set of full-time refueling and outage maintenance teams that rotate from one reactor to another on a centrally planned refueling and maintenance schedule. These teams would likely learn to work at a level of efficiency never before seen in civilian nuclear power operations.

Security. One of the most significant potential differences in operations for an array of reactors is the security strategy. Protecting a large area from intrusion and interference is very different from protecting a single facility. Monitoring the entire area directly with security personnel would represent a resource-intensive endeavor.

However, although the details are classified, experience with U.S. Air Force missile bases suggests that this is not necessary to maintain an appropriate level of security. Electronic sensors and video surveillance can monitor a secure perimeter, and a security force can respond to unusual or unauthorized activity from a central staging location. The Piceance Creek Basin oil shale formation of Colorado underlies a land area smaller in extent than the Air Force missile bases protected using this strategy. Figure 5.1 shows the area of that formation next to the area of Warren Air Force Base (AFB) in Wyoming, Nebraska, and Colorado.

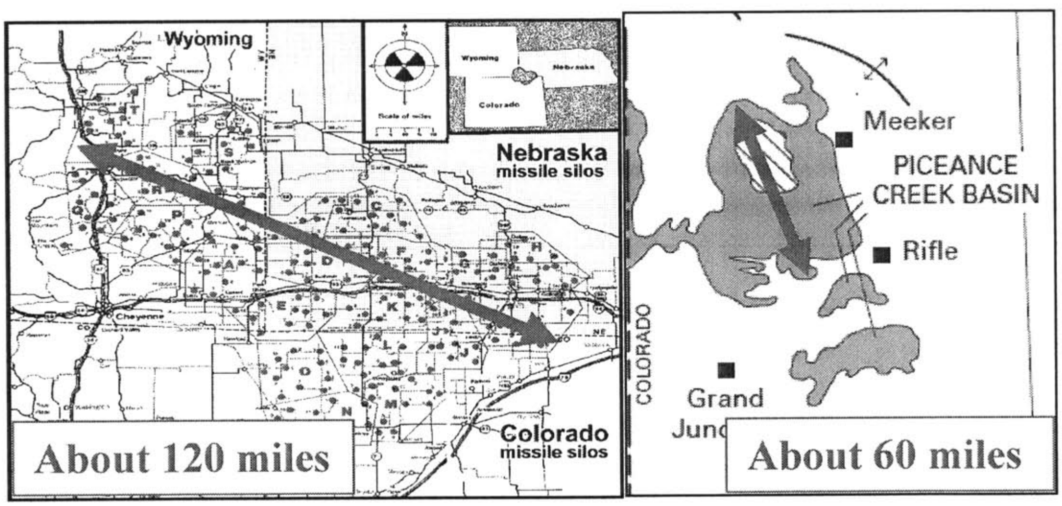

Figure 5.1. Area comparison between Piceance Creek Basin oil shale formation and Warren AFB (Warren AFB map from Ref 1)

It is highly likely that suitable monitoring, access prevention, and response techniques could be developed without requiring any disclosure of specific military techniques. Knowing the overall strategy, and knowing that it has a long history of high effectiveness, offers a clear starting point for developing the detailed techniques of potentially a lower-cost reactor array security strategy.

In this context, there is a coupling between maintenance activities and security. Missile security is partly based on heavy concrete structures that are sealed. The security force increases during maintenance. The same strategy may be applicable for NROSS. The existence of many reactors in a small zone creates options such as massive concrete access panels that provide physical security but can be easily removed with heavy cranes. Portable (truck or rail) heavy lift cranes for maintenance is not viable for single reactors but is viable for a fleet of reactors in a small zone.

5.3. Institutional Structure and Availability of Capital

Arrays of reactors imply different institutional structures—including long-term contracts with reactor vendors that could extend over decades. There is some experience of this type in the nuclear industry in France, Russia, and Japan. There is abundant experience in other U.S. industries, such as the airline industry.

The scale of operations is much larger than traditional nuclear enterprises, but within the scale of operations of the large oil and gas companies. Companies such as Shell®, Exxon®, and BP® have assets and revenues measured in hundreds of billions of dollars. Single projects often cost 10 to 20 billion dollars with a history of joint efforts on larger projects.

The scale of the resources and the involvement of the supermajor petroleum corporations combine to create a market opportunity quite different from most nuclear ventures. To illustrate the difference, Tables 5.1 and 5.2 show the yearly revenues of the largest international petroleum corporations and US nuclear utilities, respectively. Table 5.3 shows the typical completed cost of recent nuclear build projects.

Table 5.1. Reported Revenue of Top 4 Petroleum "Supermajors," 2012 [2]

Name	Reported Revenue (Billion USD)
Royal Dutch Shell	$484.5
ExxonMobil	$452.9
BP plc	$386.5
Chevron Corporation	$245.6

Table 5.2. Reported Revenue of Top 4 United States Nuclear Holding, Utility, and Operating Companies, 2013 [3]

Name	Reported Revenue (Billion USD)
Exelon	$23.5
Duke Energy	$19.6
Southern Company	$16.5
FirstEnergy	$15.3

Table 5.3. Reported Cost of Selected Nuclear Build Projects in the United States in 2007 dollars [4]

Name	Operation Start	Cost
Seabrook	1990	$12.9B
Votgle 1 & 2	1989	$19.1B
McGuire 1 & 2	1984	$4.0B
Diablo Canyon	1986	$11.6B

These tables illustrate, at least partially, why new nuclear build projects are rare and considered highly financially risky. A utility holding corporation with $15B in yearly revenue takes on a substantial risk if it dedicates $4B (or substantially more) in capital to a single construction project. However, the petroleum supermajors are 10 to 30 times larger than US nuclear utilities and each one routinely takes on many multi-billion dollar development projects at once around the world. The problem of availability of capital, one of the prime motivators of the development of SMRs, is either substantially reduced or eliminated if the oil shale development project is underwritten by a petroleum supermajor.

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6. Commercial Performance

The core of the commercial case for development of NROSS is the finding that integration in NROSS substantially increases the revenue derived from the power output of the reactor. This result is shown below for two separate models of system operation across a range of market conditions.

6.1. Revenue

NROSS presents a novel economic situation for a nuclear system. This system has at least two economically useful outputs, although which outputs are considered will differ depending on what system boundary is considered.

6.1.1. Electricity Prices

Electricity prices in deregulated electricity markets can change several times per hour according to real-time system demand and availability of generators and transmission capacity. Electricity prices can change by over 100% at essentially any time in a system with large amounts of intermittent renewable generation (IRG) or severely constrained transmission resources. Examples of this are shown in Figure 6.1. Figure 6.2 shows the number of hours per year that electricity could be purchased in real time at various prices in California between July 2011 and June 2012. This distribution of real time dispatch (RTD) prices is used in some form in all results presented in this chapter. Some features of this distribution are given in Table 6.1.

Table 6.1. Features of the RTD electricity price distribution for California from Reference 1

Mean price	$30.41 /MWh
Highest observed price	$1000 /MWh
Lowest observed price	-$32.56 /MWh
Frequency of negative prices	348 hours, 4%
Standard deviation	$43.37 /MWh

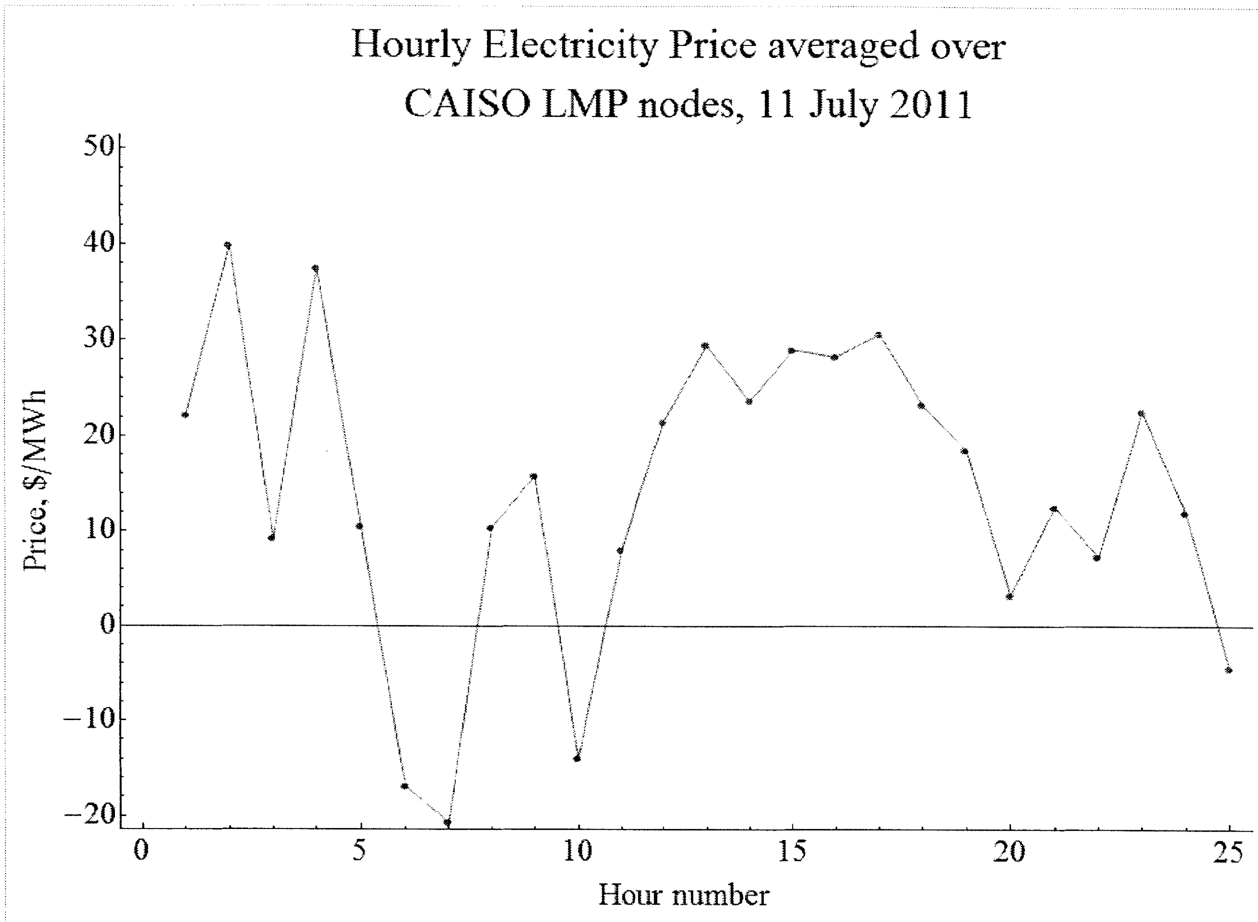

Figure 6.1. Real time dispatch (RTD) prices, averaged by hour and averaged over the locational marginal pricing (LMP) hubs of California, for 11 July 2011 (Data from Ref. 1)

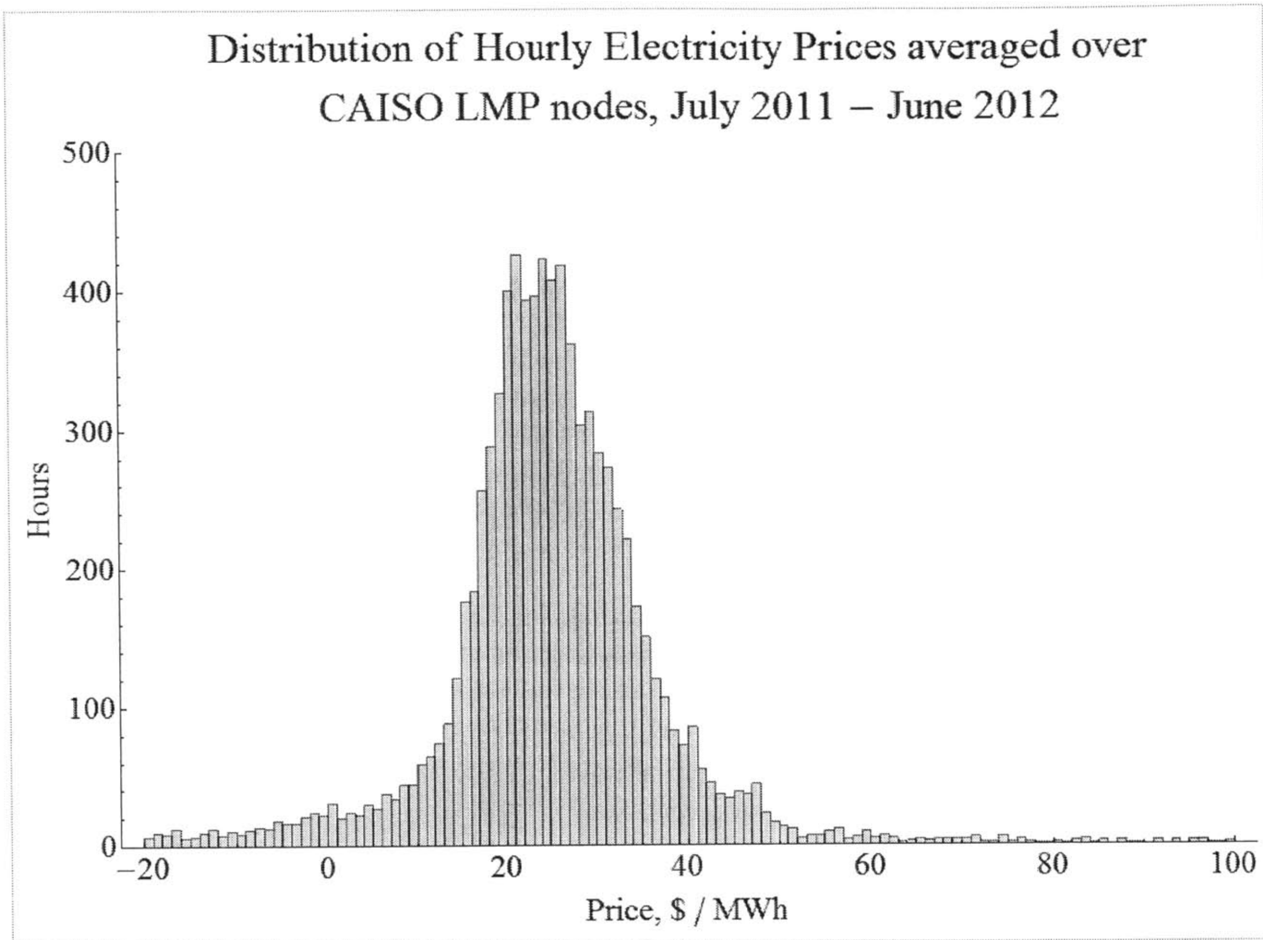

Figure 6.2. Distribution of RTD electricity prices averaged by hour and averaged over the LMP hubs of California (Data from Ref 1)

Oil or gas prices also vary, but over much longer timescales, with changes greater than about 10% over a month being rare. Further, hydrocarbons are much cheaper to store than electricity, and liquid fuels are not technically constrained to precisely match supply and demand at all times as electric systems are. Hydrocarbon prices can therefore be considered approximately constant for the purposes of daily or weekly operations.

Ownership structure will play a role in optimization of revenue. A single owner of the entire NROSS complex may find that shale heating is nearly always favored during periods of high oil prices, for example, while divided ownership with a long-term contract between the nuclear plant and petroleum system operator (PSO) may favor much more frequent electricity sales. The ownership structure and contract terms may set a wide range of other constraints that govern plant operations.

Regardless of system ownership, because electricity prices vary more rapidly than hydrocarbon or heating fuel prices, electricity price will be the most important variable in dynamic system operation. All electricity price data used in these analyses are taken from Reference 1. Various parameters are derived from values in Reference 2.

6.1.2. The Steam Vendor revenue model

In this analysis, the nuclear plant owner is considered an economically distinct entity from the oil shale PSO. These may both be distinct from the land owner, and possibly from other specialized subcontractors; the land owner's status will not be relevant to this model, however.

The goal of this model is to calculate revenue for the nuclear plant owner during a steady-state year. Revenue may be derived from two outputs: electricity to the grid or steam heat to the petroleum system. Revenue is calculated hour-by-hour using the CAISO electricity price data set presented in Figure 7.2, with the assumption that transmission infrastructure exists to connect NROSS to the CAISO grid. California represents the largest electricity market in the western half of the US and is a leading state in policies designed to promote development of IRG, so it is a natural fit as a customer for the electricity produced by NROSS. It is assumed that the plant only outputs one product at a time, switching between discrete operating modes defined as follows:

- Mode 1: Sell steam heat to the PSO. To calculate value, it is assumed that the heat displaces natural gas, which could otherwise have been used to provide heat input, and is sold at the price of natural gas price unit heat.
- Mode 2: Sell electricity to the California grid.

Unless otherwise stated, the reactor has a thermal power of 507 MWt and electric output of 169 MWe, implying a conversion efficiency of 33%.

Mode 1 revenue in any particular hour of Mode 1 operation would be calculated by:

$$R_{EH1SV} = H * P_{NG} \tag{6.1}$$

where:
R_{EH1SV} = Expected hourly revenue in Mode 1 of the Steam Vendor model
H = Heating power in MWt
P_{NG} = Natural gas in \$ /MWh

Mode 2 revenue would be similarly calculated by:

$$R_{EH2} = E\ P_E \tag{6.2}$$

where:
R_{EH2} = Expected hourly revenue in Mode 2
E = Electricity output in MWe = $0.33H$
P_E = Price of electricity in \$ /MWh

The electricity price at which the plant would switch operating modes is labelled the "critical electricity price" (E_{CPSV}). E_{CPSV} is calculated by:

$$E_{CPSV} = \frac{H\,P_{NG}}{E} = 3P_{NG} \tag{6.3}$$

Equations 6.1 and 6.2 can be interpreted to express "Expected Hourly Revenue" as a function of electricity price for a set of assumed parameters (reactor thermal power, conversion efficiency, and natural gas price). Figure 6.3 shows a plot of expected hourly revenue in each operating mode.

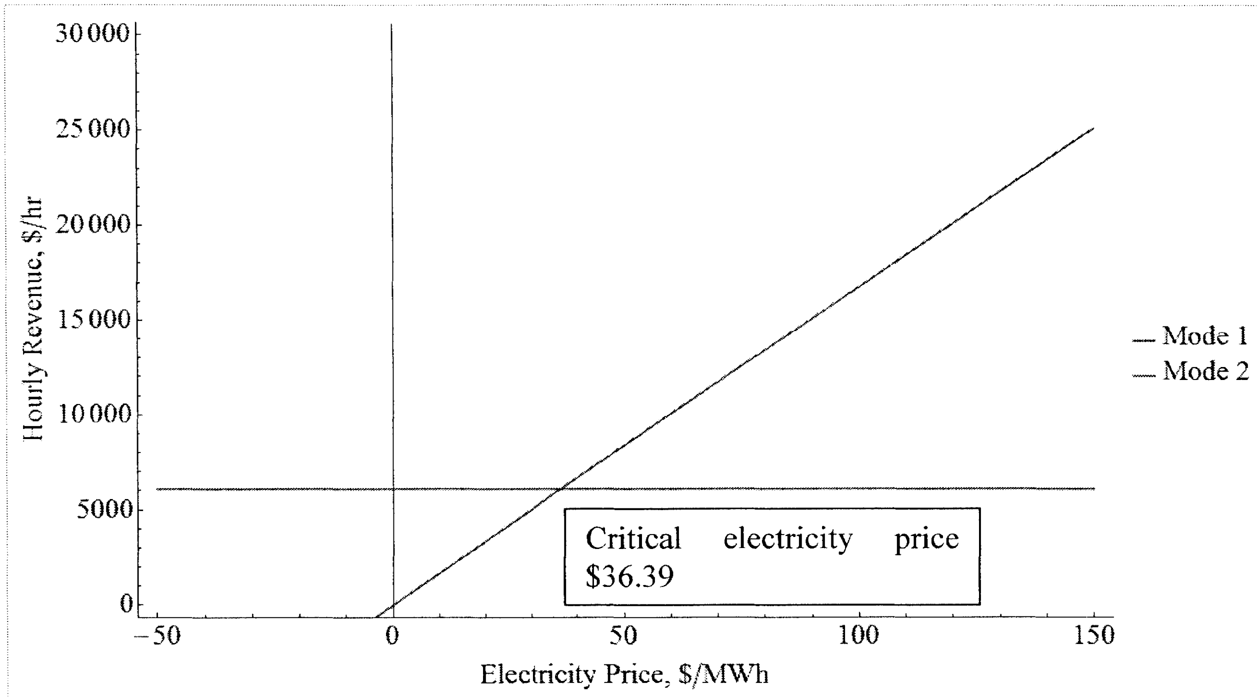

Figure 6.3. Expected Hourly Revenue of the Steam Vendor operating modes as a function of electricity price (507 MWt reactor, 33% efficiency, Natural Gas price $12.01 /MWh)

Some additional assumptions in the Steam Vendor model:

- The plant may switch operating mode instantaneously at the end of each hour of operation.
- The reactor operates at all times in both operating modes at full rated power.
- The steam turbine system used in Mode 2 to produce electricity has a conversion efficiency of 33%, a value typical of Rankine steam cycles operating at the conditions on the secondary side of a pressurized water reactor.
- The PSO buys power as necessary for second stage oil shale heating. In this model, purchases of heating power by the PSO are not relevant to reactor owner revenue. Further, it doesn't actually matter what fuel or energy source the PSO uses for second stage heating.
- Natural gas is the cheapest alternative heat source available. Therefore, if the price of reactor heat is lower than the price of a unit of natural gas heat, purchase of heat from the reactor is favored. Therefore, there is no need to explicitly model competition between the reactor owner and other potential heat suppliers.

- The price of natural gas is not connected to the price of electricity. A single natural gas price is assumed to apply at all times during each revenue analysis calculation. The baseline price of $12.01 / MWh was an actual Henry Hub price observed during June of 2013.
- The cost of additional hardware necessary for heat delivery is assumed to be small and is not included in revenue calculations or comparisons.

Figure 6.4 illustrates the energy flows in the Steam Vendor revenue model. Note the two energy flow paths: red for Mode 1 operation (steam heat sales) and green for Mode 2 operation (electricity sales). Also note that heat inputs from other potential heat sources for second stage heating are not included in this figure. Figure 6.5 shows the results of the Steam Vendor revenue calculation, superimposed on the distribution of electricity prices in the CAISO market from reference 1 with assumed reactor power, assumed natural gas price, and calculated critical electricity price indicated. The "Sell Electricity" percentage indicates the percentage of time the NROSS systems spent selling electricity in Mode 2.

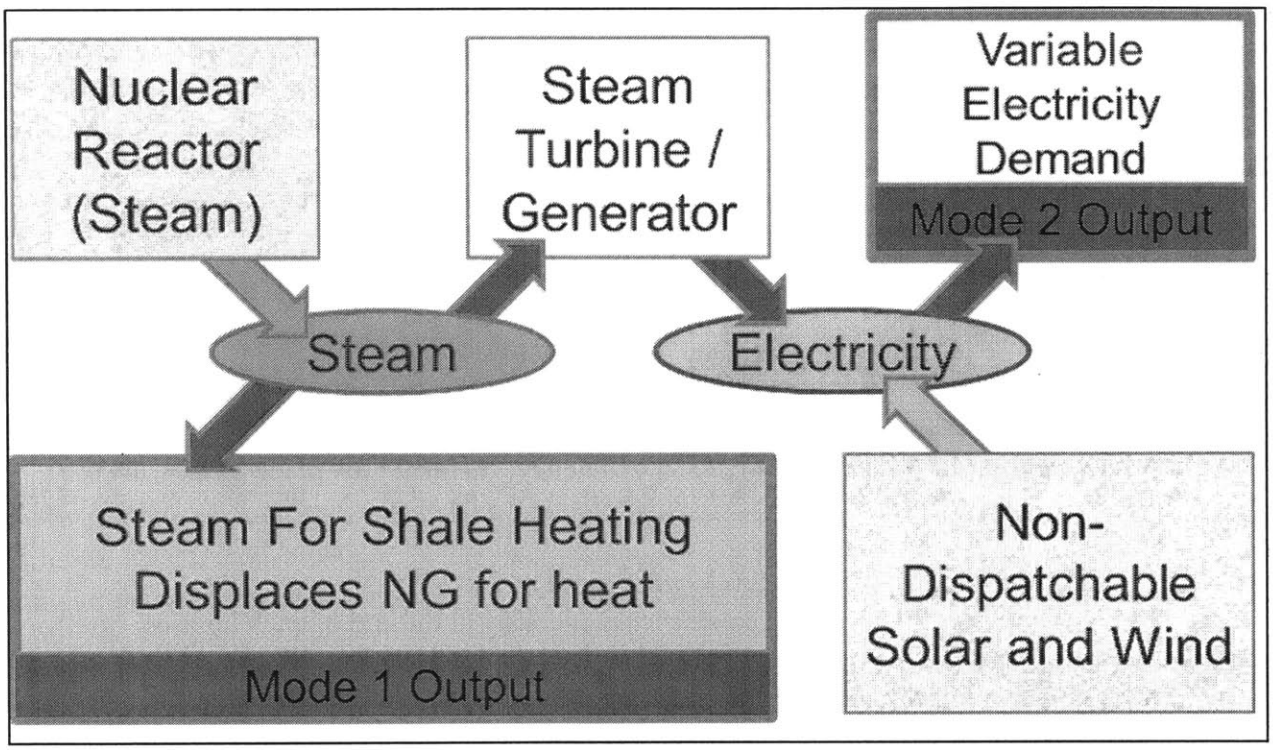

Figure 6.4. Energy flows in the assumed operating modes in the Steam Vendor revenue model

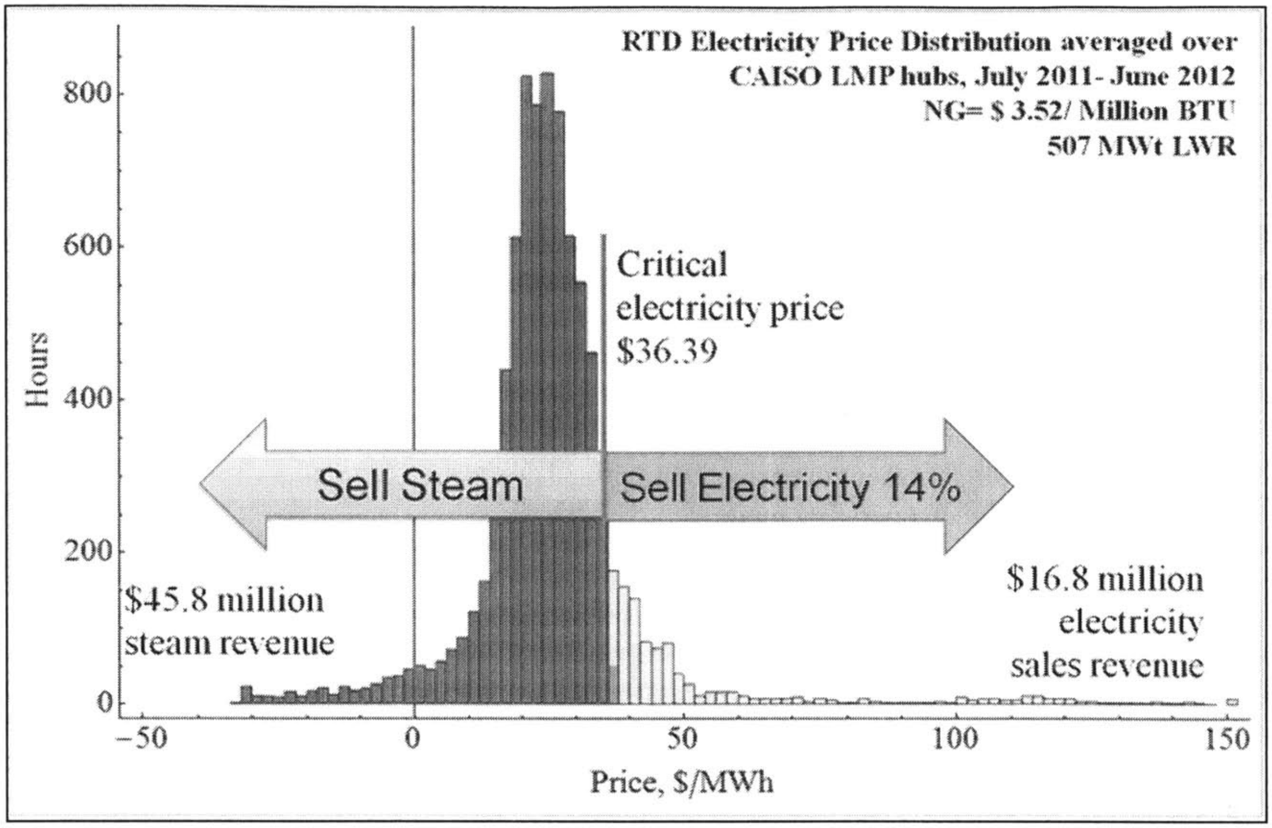

Figure 6.5. Results of Steam Vendor revenue analysis, displayed over CAISO price distribution

The primary use proposed for SMRs in the United States is base load electricity production. Base load electricity sales revenue therefore provides a base case for economic comparison. A reactor with the parameters assumed in this analysis (507 MWt, 169 MWe) would have had revenue of $44.5 million if it sold power onto the California grid during the same year analyzed in the Steam Vendor revenue calculation. Total NROSS revenue for the year shown in Figure 6.5 was $62.7 million, which represents an increase of 41% over baseload revenue.

The reader should note that natural gas prices were historically low in the United States in 2013, and that most in-situ oil shale systems currently under active development actually call for much more costly electric heat input over the entire heating schedule. Also note the disproportionate value of electricity. Although only 14% of the hours in the analysis year are spent producing electricity for outside sale, that electricity represents 27% of plant revenue. Heat was sold to the PSO anytime electricity prices were low or negative.

Three major trends are likely to affect the economics of NROSS over the next two decades (the time period in which NROSS deployment should occur): increasing natural gas price (the likely competition in low-cost heat for the next decade), increasing average price of electricity, and increasing variance in the distribution of electricity prices as more IRG comes online. It is therefore important to investigate the sensitivity of the results above to changes in natural gas price, average electricity price, and electricity price distribution variance.

6.1.3. Steam Vendor sensitivity calculations

Natural gas price. The Steam Vendor model may be used to calculate expected revenue for any assumed value of natural gas price. Changes in natural gas price will change the following quantities:

- Critical electricity price (E_{CP})
- The value of each unit of Mode 1 heat sales (set to 90% of the assumed natural gas price)
- The fraction of time spent in each operating mode (which is a function of E_{CP})
- Revenue from each operating mode
- Total revenue

The distribution of electricity prices is not changed in this sensitivity calculation. This is likely not realistic; a change in natural gas prices would likely change electricity prices, as well. Baseload plant revenue is still used for comparison with the total NROSS nuclear plant revenue in this calculation. The results of this calculation, fraction of time spent in Mode 2 (electricity production) and revenue advantage of the NROSS nuclear plant (defined in Eq. 6.4), are shown in Figures 6.6 and 6.7.

$$Revenue\ advantage = \frac{Plant\ revenue - baseload\ electric\ plant\ revenue}{baseload\ electric\ plant\ revenue} \qquad (6.4)$$

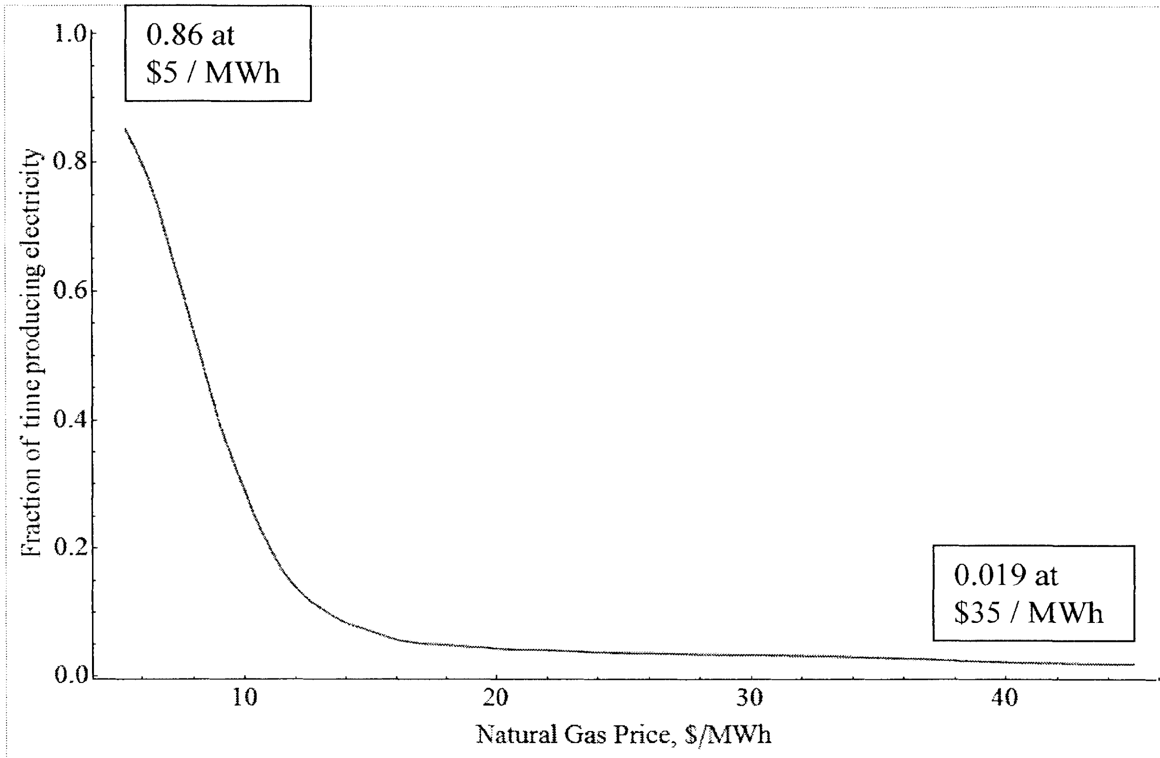

Figure 6.6. Fraction of time in Mode 2 (electricity production) as a function of natural gas price

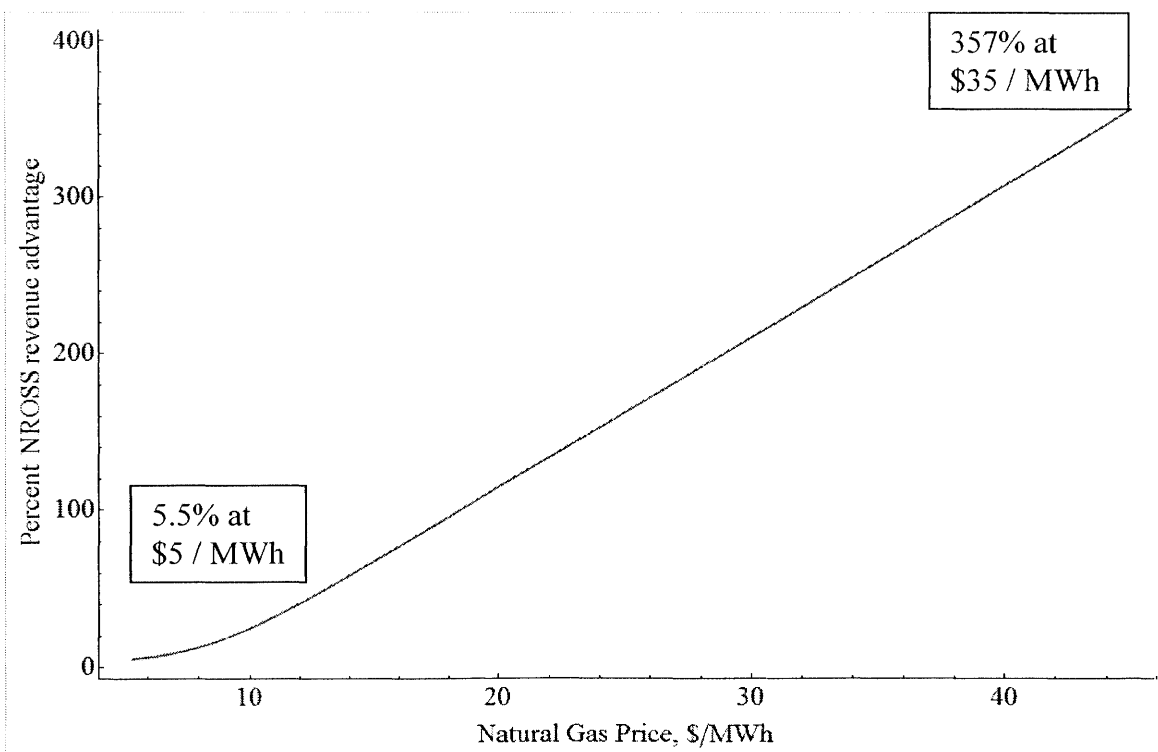

Figure 6.7. NROSS nuclear plant revenue advantage as a function of natural gas price

Natural gas prices across this entire range have been observed in the last 10 years. The lowest price of that period was $1.95 /MMBTU, or $6.65 /MWh, in April 2012; the highest was $13.42 /MMBTU, or $45.79 /MWh, in October 2005. Similarly high prices were seen in December 2005 and June 2008. Prices in 2014 alone varied from $6.00 /MMBTU (Feb) to $3.78 /MMBTU (October). All natural gas price data from Reference 3.

The results are clear: the plant will spend less time selling electricity, and earn more revenue, as natural gas prices increase.

Average electricity price. To investigate sensitivity to changes in average electricity price, we must modify the electricity price distribution. Analysis of deregulated electricity markets is an underdeveloped area of energy economics literature; no concise methodology exists to change a single parameter in a deregulated electricity market as is desired in this calculation. Therefore, I have employed the following method in this sensitivity analysis:

1. Calculate the average electricity price in the original CAISO dataset ($30.41 /MWh)
2. Calculate the difference between the original average price and the postulated average price for sensitivity calculation
3. Add that difference in average price to every (load, price) datapoint in the original CAISO dataset.
4. Run the Steam Vendor analysis on this new price distribution.

It is desirable to preserve the dynamics of the market expressed in the original dataset, since those dynamics would be difficult or impossible to separately reproduce. Each electric power system in the United States, and each deregulated electricity market, are unique, so it is difficult to define a "representative" market for model building purposes and would, even if possible, be of uncertain value.

The results of this calculation, fraction of time spent in Mode 2 and revenue advantage of the NROSS nuclear plant, are shown in Figures 6.8 and 6.9.

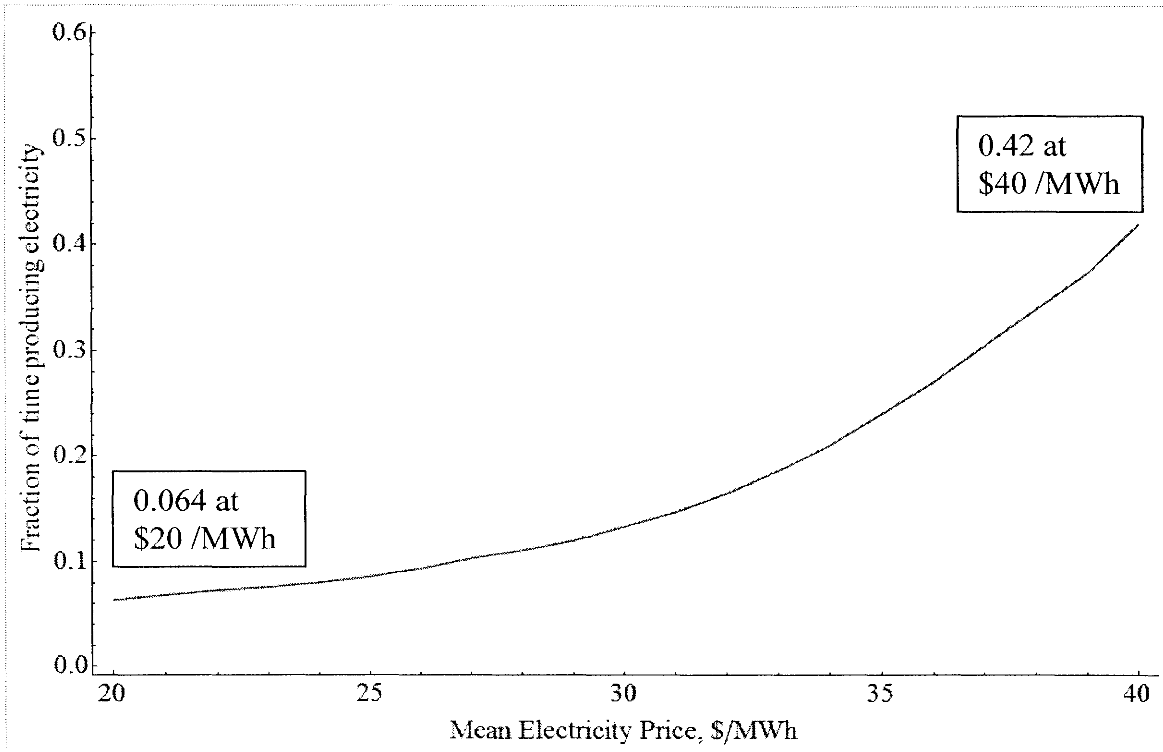

Figure 6.8. Fraction of time in Mode 2 (electricity production) as a function of average electricity price

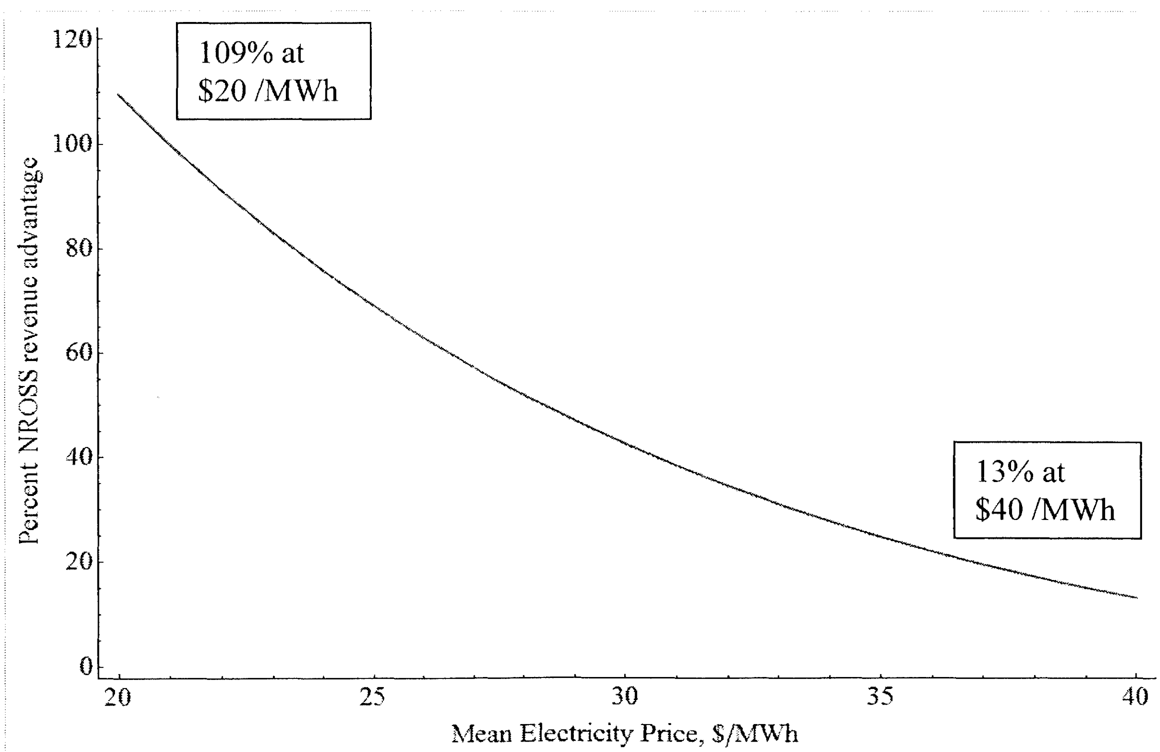

Figure 6.9. NROSS nuclear plant revenue advantage as a function of average electricity price

Electricity price variance. As discussed in Chapter ZZ, it is likely that the variance of electricity prices in many markets will increase as usage of IRG increases. This will be the result of depressed prices during periods of high renewable resource availability and increased prices at other times. I have employed the following model to change electricity price variance while preserving, as much as possible, the dynamics of the CAISO market.

The load profile of the original dataset will be preserved. At various values of a "Variation parameter" P_V between 0 and 1, the price distribution will be reconstructed with electricity prices at each (load, price) datapoint changed by

$$\Delta P_{E_i} = 2\, P_V \,\langle price\rangle \frac{(load_i - \langle load\rangle)}{\langle load\rangle} \tag{6.5}$$

where <brackets> indicate the mean for that quantity in the dataset and subscript $_i$ indicates a quantity calculated for a particular datapoint.

This change in price will modify the load-price structure of the dataset. Using this method, standard deviation of the price distribution varies from \$43.37/MWh at $P_V = 0$ and \$46.82/MWh at $P_V = 1$. Figure 6.10 shows a scatterplot of the original load-price dataset and the reconstructed dataset with $P_V = 0.5$.

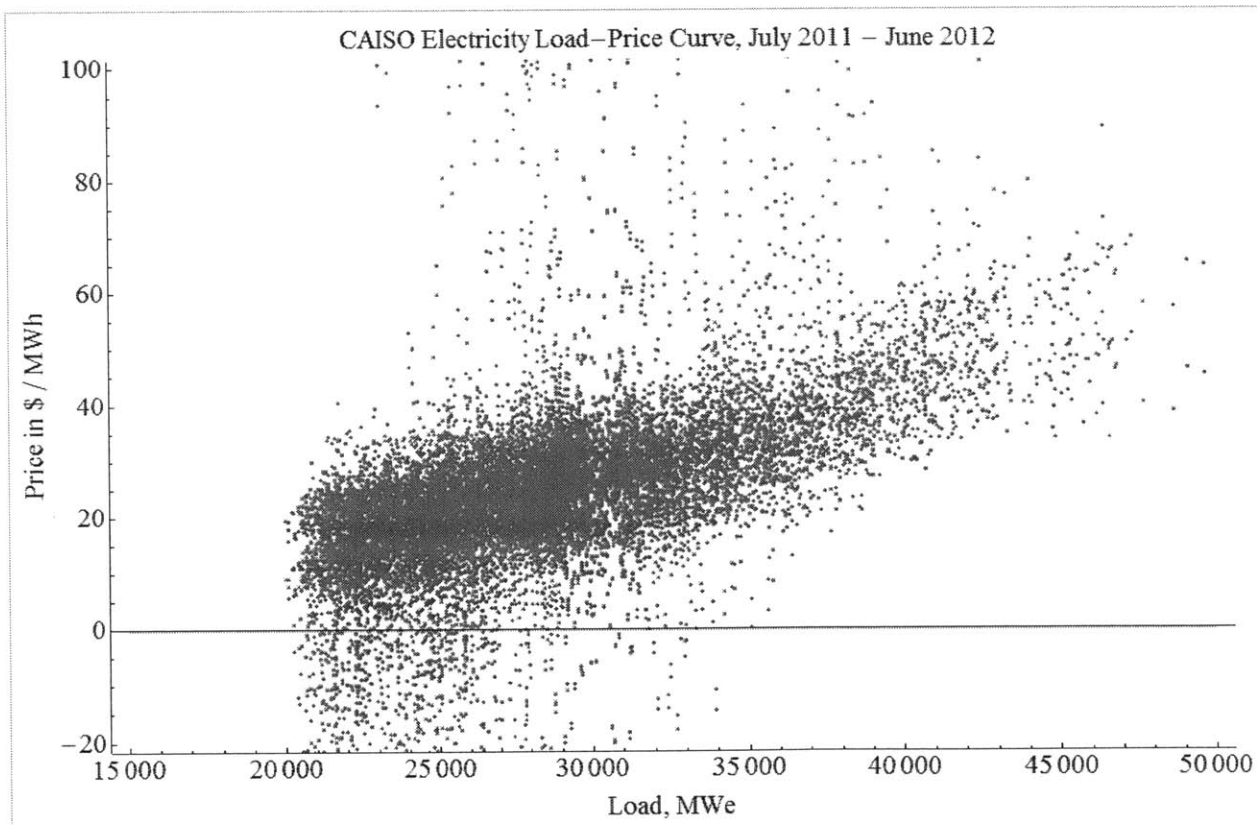

Figure 6.10. Scatterplots of the original CAISO load-price dataset (blue) and the modified set with PV = 0.5 (purple)

Figure 6.11 shows standard deviation of the set as a function of Pv. As expected, this plot shows quadratic behavior.

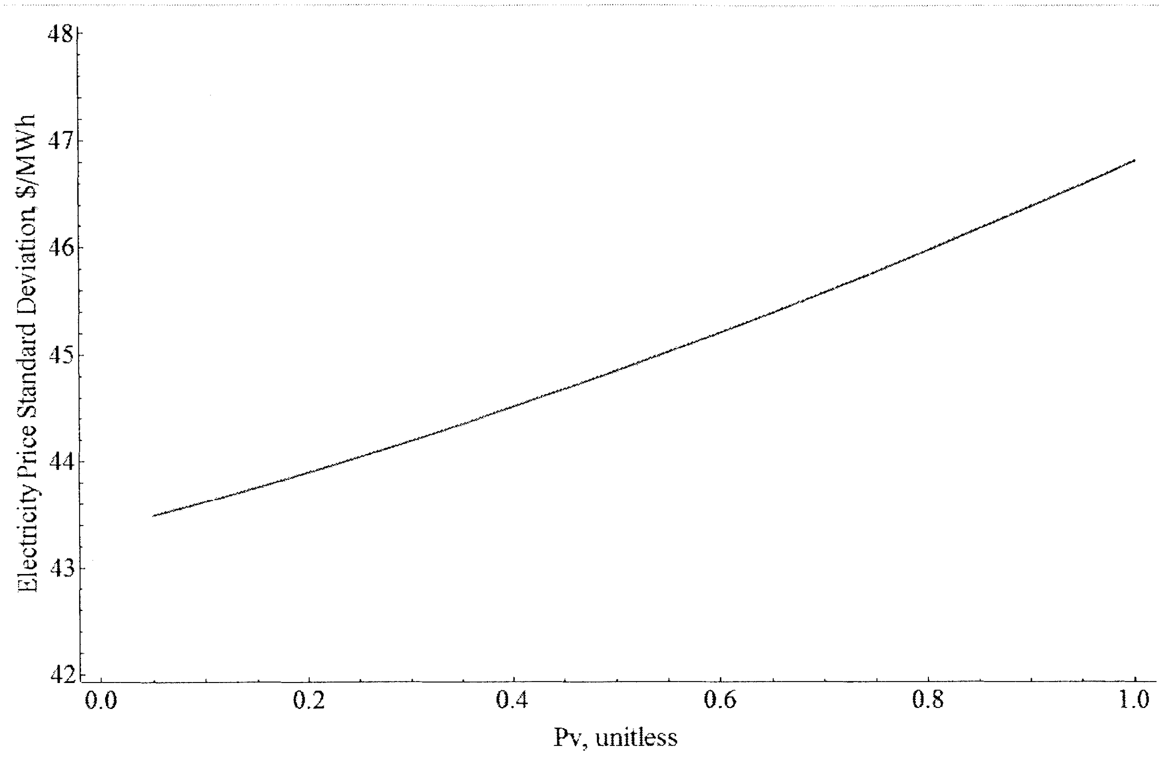

Figure 6.11. Standard deviations of modified load-price sets as a function of Pv.

The results of this sensitivity calculation, fraction of time spent in Mode 2 (electricity production) and relative revenue of the NROSS nuclear plant, are shown in Figures 6.12 and 6.13.

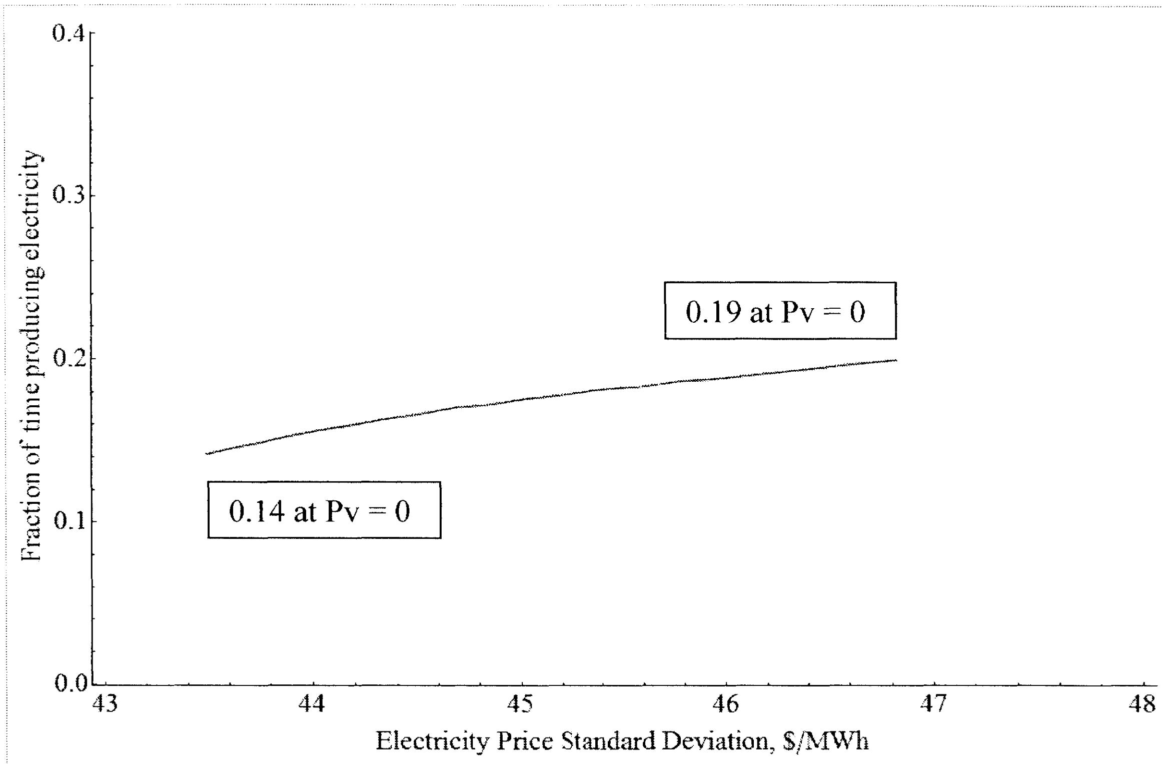

Figure 6.12. Fraction of time in Mode 2 (electricity production) as a function of electricity price standard deviation

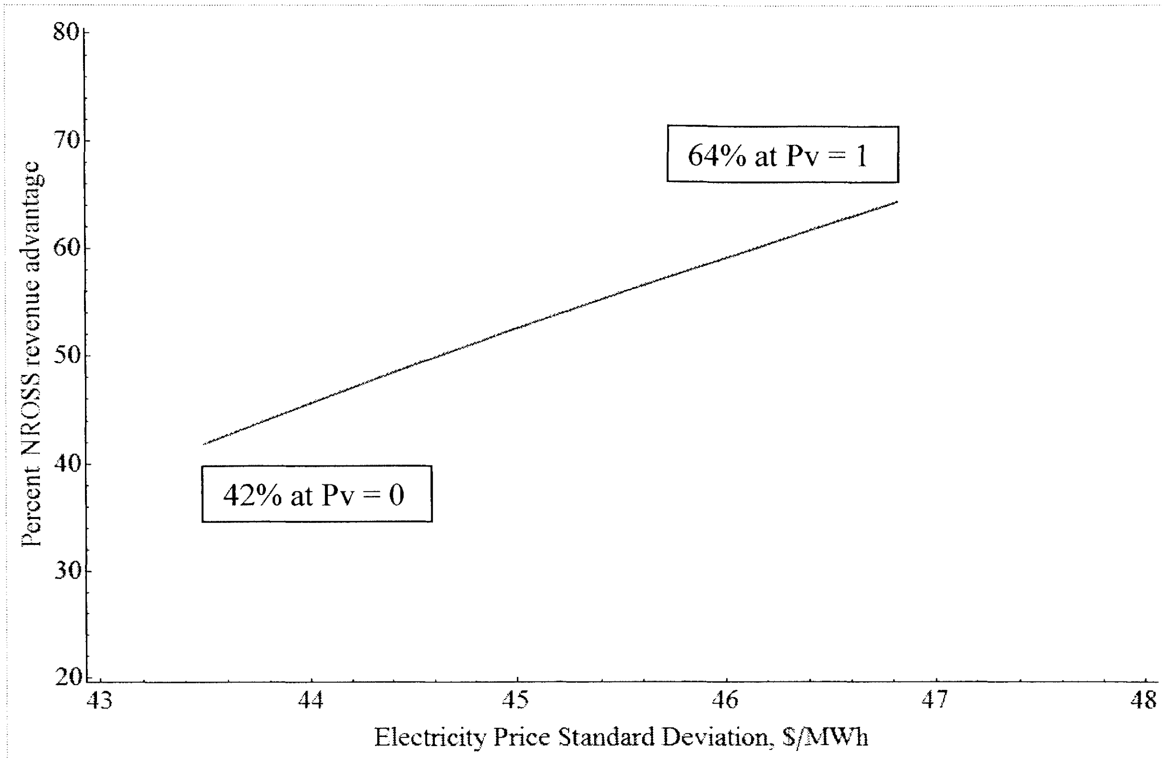

Figure 6.13. NROSS nuclear plant revenue advantage as a function of electricity price standard deviation

NROSS revenue and time spent producing electricity will slightly increase as electricity price variations increase.

All of these variations are likely to occur simultaneously. As an example of one possible future, Figure 6.14 shows NROSS revenue results in a future with natural gas price 2x higher than a typical 2013 level, average electricity price increased by 50%, and electricity price deviation increased by 2$/MWh (corresponding to $P_V = 0.65$). We can see that in this future, NROSS reactor plant revenue is 72% higher than revenue from an equivalent baseload plant.

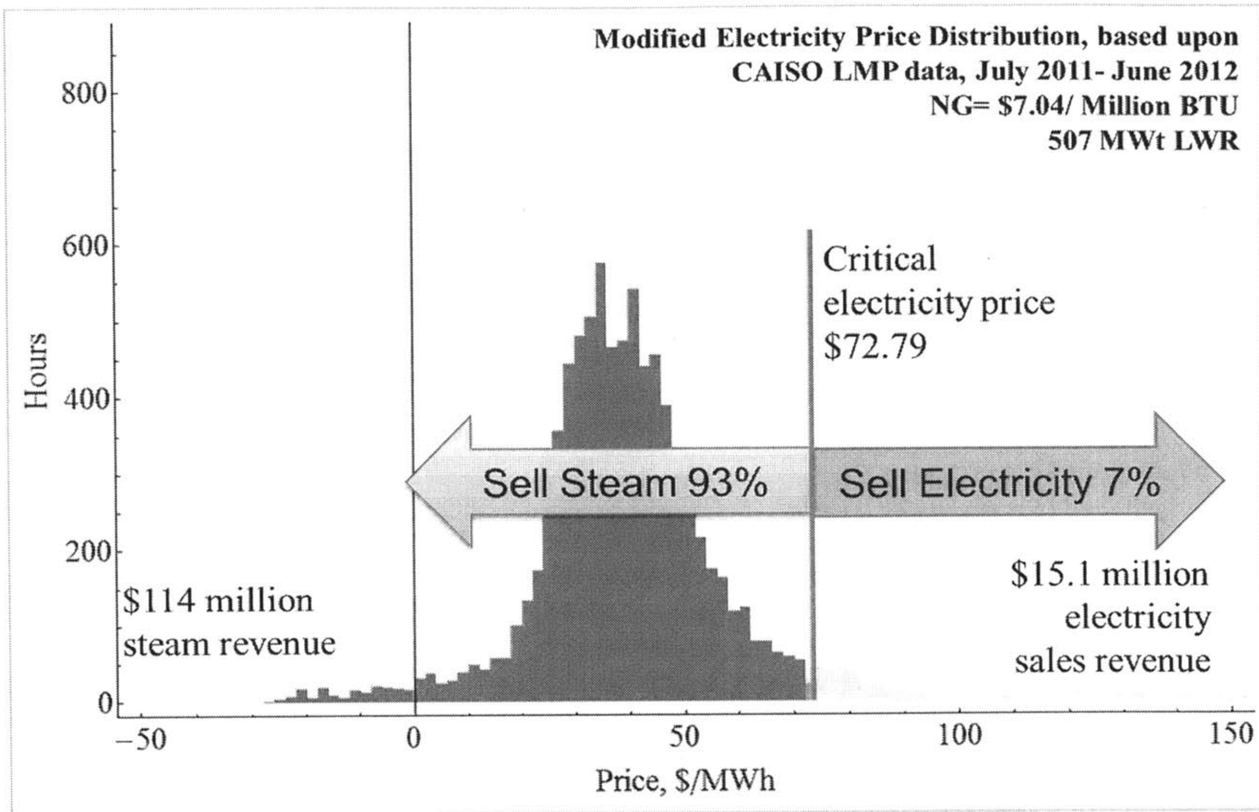

Figure 6.14. A revenue calculation for a possible future with increased natural gas price and higher and more varied electricity prices

6.1.4. The Single Owner revenue model

The other revenue model explored assumed that all revenue from the NROSS operation is collected by a single organization (presumably, the single owner of the entire operation).

The goal of this model is to calculate revenue for this single organization during a steady-state year. Revenue may be derived from two outputs: electricity to the grid or sales of oil derived from heated oil shale. Revenue is again calculated hour-by-hour using the CAISO electricity price data set presented in Figure 6.2, with the assumption that transmission infrastructure exists to connect NROSS to the CAISO grid. It is assumed that the plant only outputs heat to one product stream at a time, switching between discrete operating modes defined as follows:

- Mode 1: Heat the oil shale. Here, the value of each unit of heat is required for comparison with the potential electricity sales revenue. For each hour in Mode 1, the system is credited revenue equivalent to the quantity of oil produced by the quantity of heat input during that hour from second state electric heat minus the cost of purchased electricity.
- Mode 2: Sell electricity to the California grid.

Mode 1 revenue in any particular hour of Mode 1 operation would be calculated by:

$$R_{EH1SO} = B(P_O + P_G) - H\,P_E \tag{6.6}$$

where:
R_{EH1SO} = Expected hourly revenue in Mode 1 of the Single Owner model
B = Barrels of oil produced per hour of heat input
P_O = Price of oil (\$/bbl)
P_G = Price of gases produced per barrel of oil (expressed in \$/bbl)

Mode 2 revenue would be similarly calculated by:

$$E_{CPSO} = \frac{B(P_O + P_G) - H\,P_E}{E} \tag{6.7}$$

Figure 6.15 illustrates energy flows in the Single Owner model. The red arrows again indicate the energy flows of Mode 1 operation; green arrows indicate the energy flows of Mode 2 operation.

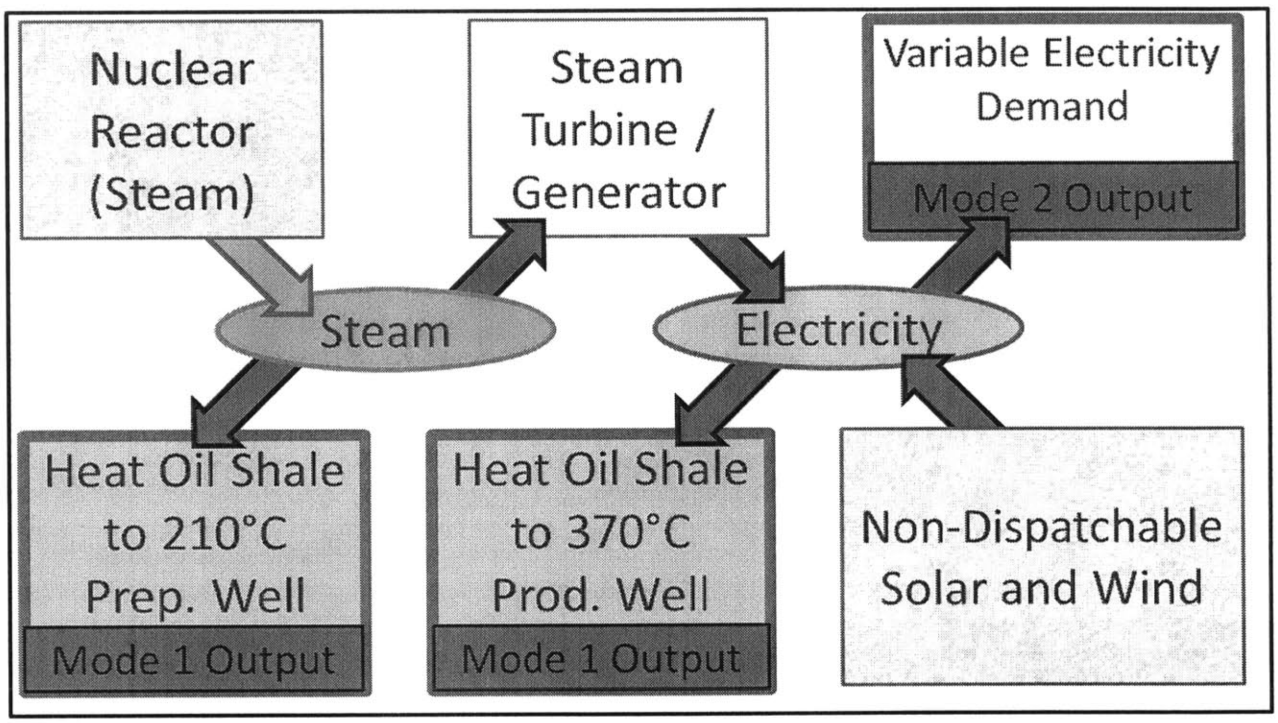

Figure 6.15. Energy flows in the assumed operating modes in the Single Owner revenue model

Some additional assumptions in the Single Owner model:

- The plant may switch operating mode instantaneously at the end of each hour of operation.
- The reactor operates at all times in both operating modes at full rated power.

- The steam turbine system used in Mode 2 to produce electricity has a conversion efficiency of 33%, a value typical of Rankine steam cycles operating at the conditions on the secondary side of a pressurized water reactor.
- First stage lower-temperature heating and second-stage higher temperature heating each input half of the quantity of total energy used to produce each unit of oil from heated kerogen. Steam heat is provided to a first stage Production Zone, and electric heat is provided to a second stage Production Zone, at the same rate.
- The system is at steady state.

With oil at $100 per barrel (a typical price for 2012 and 2013), oil production is favored during 97% of operating hours. This result is shown in Figure 6.16.

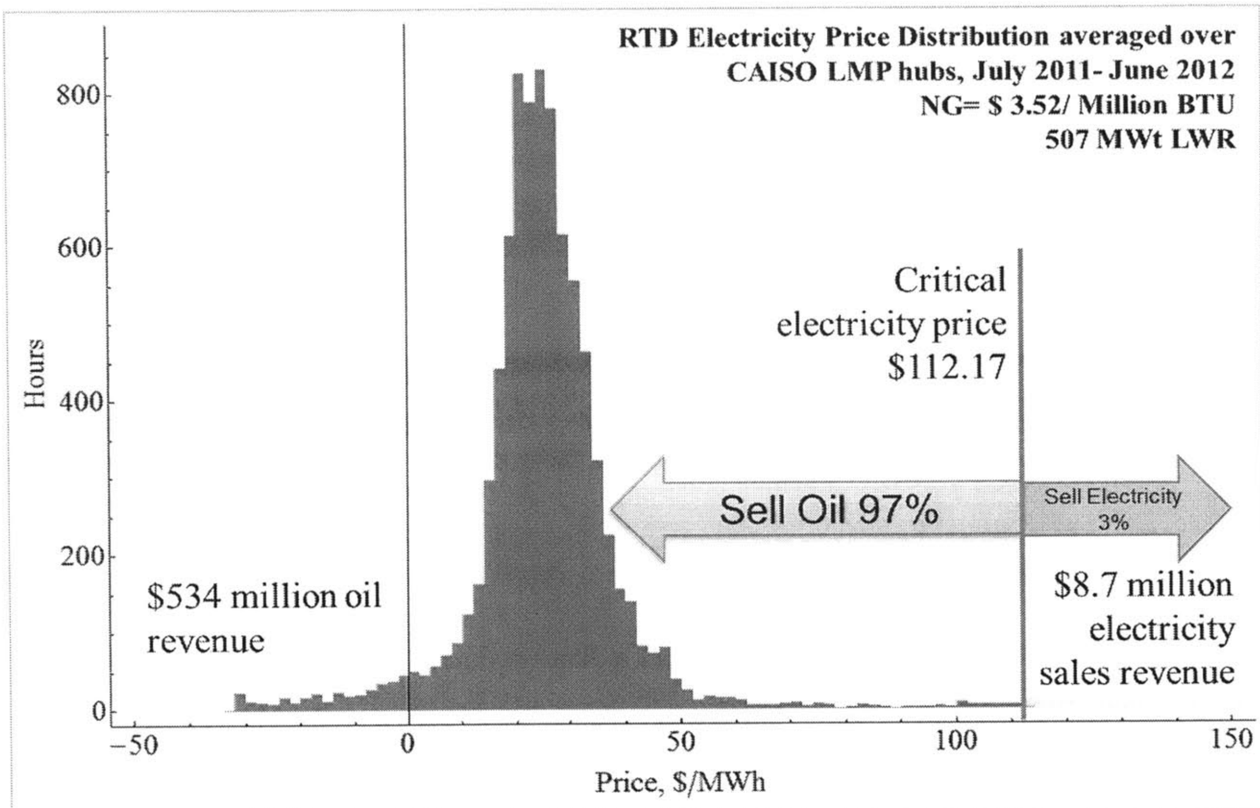

Figure 6.16. Results of Single Owner revenue analysis, displayed over CAISO price distribution

This facility earns 1,019% more revenue than a standalone baseload reactor. This is a somewhat less meaningful comparison than the comparison in the Steam Vendor model, however, because the single owner now has to pay for the drilling, hardware, and infrastructure of the entire petroleum system in addition to the nuclear plant.

This model also highlights an operational difficulty in this system: the single owner or PSO must predict oil prices up to 2 years in advance to know what the value of their present heat input is.

This is exceedingly difficult. Our efforts at publicly predicting the value of energy commodities have a long history of very low accuracy and very low ability to predict market shocks.

For this model, I have only analyzed sensitivity to oil price. The results of this sensitivity calculation, fraction of time spent in Mode 2 and revenue of the NROSS system, are shown in Figures 6.17 and 6.18.

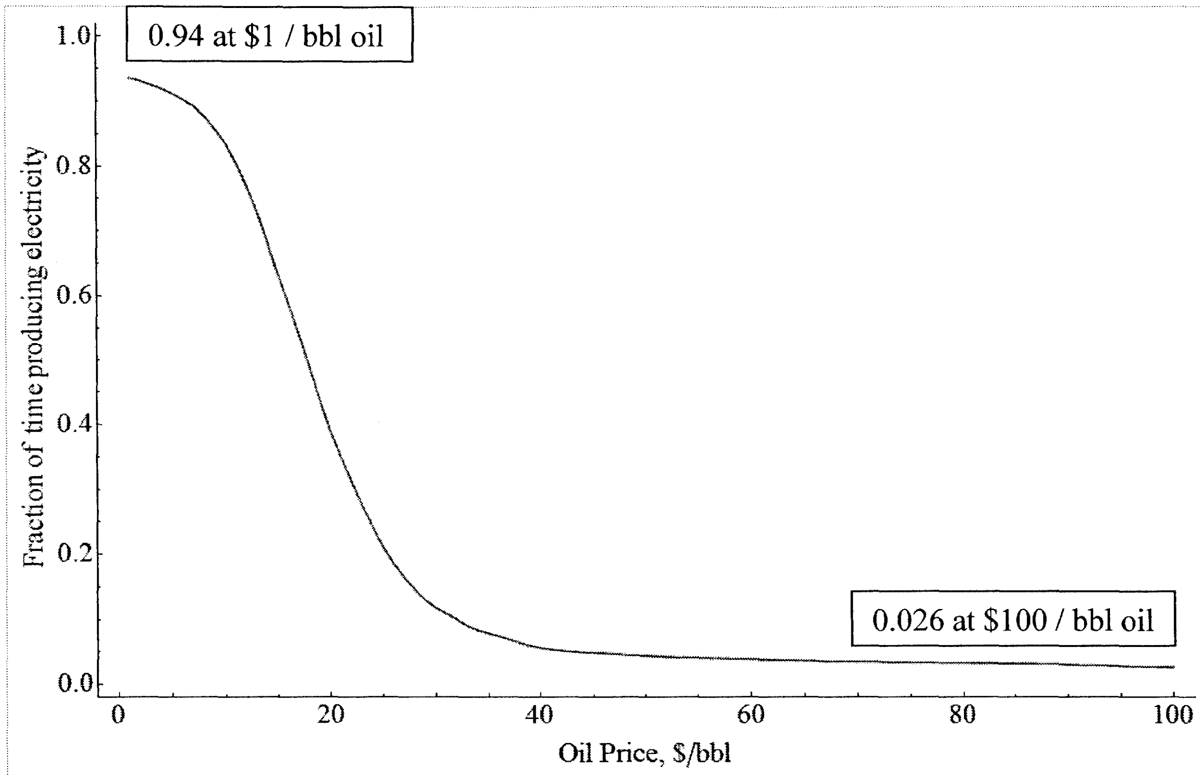

Figure 6.17. Fraction of time in Mode 2 (electricity production) as a function of oil price for a single owner NROSS system

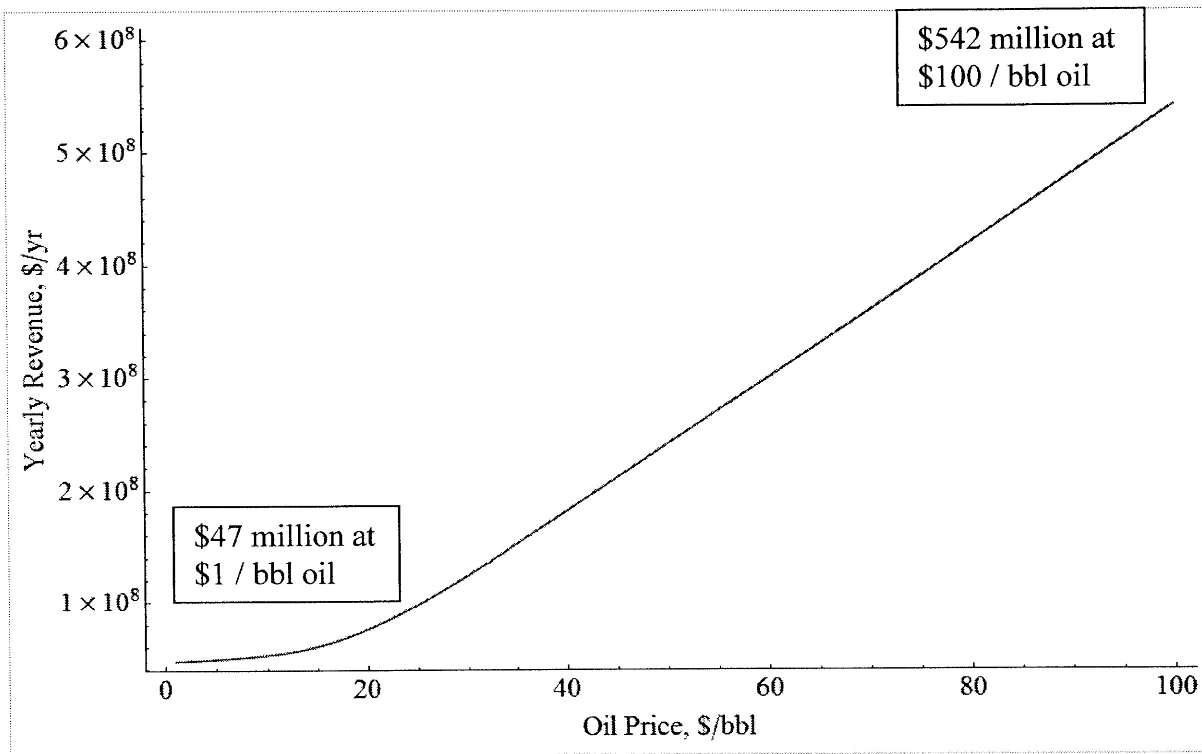

Figure 6.18. Single owner NROSS revenue as a function of oil price

Unsurprisingly, NROSS would produce much more electricity, and make less revenue, as oil prices decrease. Total revenue is dominated by oil sales throughout this price range, and operating time is dominated by shale heating until oil price is below $40/bbl. At $100 per barrel, the facility produces 24.3 million barrels of oil per year. At $50 /bbl, this is nearly unchanged at 23.9 million bbl/yr. At $20, the facility produces 15.3 million bbl/yr.

6.2. System Costs

All factors contributing to NROSS system cost are highly uncertain at this time. No SMRs have been manufactured, and only very small amounts of shale oil from kerogen oil shale formations have been produced in the United States. Many wells of the type required to deliver heat to and recover oil from in-situ oil shale formations have been constructed, but cost data is generally not shared in public literature. The history of nuclear reactor costs includes many examples of projects going over budget by widely varying amounts, and there is a strong desire to "change the game" on reactor costs and create a new trend in the future that looks very different than the trend in the past. It is therefore unclear how much weight to place on the historical reactor cost trend. Finally, as was discussed in Chapter 5, there may be many opportunities in an NROSS operation to change reactor construction and operating costs (hopefully to lower them) in ways that have not been implemented or observed in any available nuclear industry experience. Even the cost factors that can be quantified with some confidence (costs of physical consumables like steel and concrete, for example, or costs of construction and oilfield labor) should be treated with uncertainty, since

NROSS systems are not likely to be constructed before 2025. It is therefore beyond the scope of this thesis to attempt to quantify the capital or operating costs of an NROSS system.

However, there are some comparative arguments that can be made to understand some elements of system cost. These are detailed below.

6.2.1. Relative cost of heat

The baseline configuration of the Shell In-Situ Conversion Process (ICP) system calls for electric heating throughout the entire 2 year heating process [2]. Based on the data used in this analysis, an average unit of electric heat used in that system would cost \$30.43 /MWh. A unit of NROSS heat would match the cost of natural gas heat at \$12.01 /MWh. An NROSS nuclear plant can simultaneously supply heat at lower cost than was anticipated for Shell ICP and achieve a revenue advantage over an equivalent baseload plant.

6.2.2. Reactor operating costs

Increasing reactor operating cost has been a challenge to many currently operating nuclear plants in recent years. It is hoped that small modular reactors will have lower operating costs through efficiency measures like reduced staff, shorter outages, and longer design lifetimes. It is unclear at this time to what extend those reductions in operating cost will be realized in actual SMRs. However, NROSS offers many additional opportunities to reduce reactor operating costs through shared staff, services, and infrastructure over a potentially very large development area with a large number of identical reactors. The realization of even a small subset of these additional opportunities will make NROSS reactors cheaper to operate than typical SMRs and significantly cheaper than traditional large reactors.

Chapter 6 REFERENCES

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2. A. BRANDT, "Converting Oil Shale to Liquid Fuels: Energy Inputs and Greenhouse Gas Emissions of the Shell in Situ Conversion Process," *Environ. Sci. Technol.* **42**, p7489–7495, (2008)
3. US EIA, "Natural Gas – Henry Hub Natural Gas Spot Price," retrieved on 6 January 2015 from http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm (2014)

7. Carbon Emissions

As discussed in Chapter 1, there is an urgent global need to develop very-low-carbon energy supplies. The supply of liquid fuels for transportation is both a particularly important sector, as one of our largest sources of carbon emissions, and one of the most difficult to convert to very-low-carbon energy supplies. Hydrocarbon fuels currently have an unparalleled competitive advantage in the combination of energy density, ease of conversion, and low cost of storage, and it will be some time before they can be completely replaced. Fossil resources currently supply the overwhelming majority of our liquid hydrocarbon fuels. We therefore have strong motivations to seek less carbon intensive technologies for processing and use of fossil liquid fuels.

More immediately, implementation of regulatory carbon emission limits could pose major challenges for producers of unconventional hydrocarbon resources like oil shale. All kerogen shale oil production options under consideration at this time would result in higher lifecycle carbon emissions in their fuel products than conventional crude refining (CCR). Considering that CCR occupies an overwhelming majority of market share in worldwide liquid fuel production, it would be easy to set a regulatory limit that allows continued CCR, and continued use of resources and processes with similar lifecycle emissions, but bans any new resources or processes with significantly higher emissions.

The US Environmental Protection Agency (EPA) announced their intent to regulate carbon dioxide (CO2) emissions from US refineries in 2010 as a result of a court settlement with several state governments on the agency's legal authority to regulate CO2 emissions [1]. That settlement also referred to new regulations on CO2 emissions from new stationary electricity generators, which were proposed in 2013 and should be implemented as a final rule by summer 2015 [2, 3]. EPA is also developing a rule for CO2 emissions from *existing* stationary electricity generators, known as the Clean Power Plan [4], which is currently under revision [3]. Development of a similar pair of rules for hydrocarbon refineries is likely to be among the agency's major priorities once these two rules are completed, and such rules would likely severely limit the options for oil shale development. If oil shale resources will be developed on a large scale, there is an urgent need to minimize carbon emissions in the processing technology and reduce the risk of regulatory problems. As we will see below, baseline NROSS would reduce the emissions of shale oil fuel production from kerogen below the average emissions of CCR fuels and, therefore, below any likely regulatory limit on CO2.

While concerns about climate change may severely restrict the use of fossil fuels, some use of fossil fuels will likely continue even in the very long term. In that case, the question is what source of fossil fuels has the lowest greenhouse footprint? Whatever that source, it could become the preferred long term source of fossil fuels.

7.1. Baseline NROSS Emissions Estimation

In this estimation of carbon emissions from a NROSS process for liquid fuel production, I made extensive use of parameters and results from the life cycle analysis (LCA) of the Shell In-situ

Conversion Process (ICP) by Brandt [5] to describe the petroleum system. Using Brandt's material and energy inputs, we assumed that, for each unit of fuel produced:

- Construction and material inputs were unchanged.
- The quantity of energy input was unchanged.
- Half of the heating power input per unit fuel produced was provided by electricity from the Colorado grid, assumed to consist of
  - 23% typical natural gas generators
  - 59% typical coal generators
  - Remainder zero-carbon hydro and renewables
- The other half of the heating power input per unit fuel produced was assumed to come from nuclear generators, with each unit of input heat emitting one third of the typical carbon from nuclear electricity generation to account for direct steam heat delivery
- Half of the total available nuclear heat is used to heat shale; the other half of the nuclear heat generated electricity for the grid. Note that this is an assumption, not a result of any calculations performed in Chapter 6.
- The carbon intensity of "typical" generators of each type was established from US EIA voluntary emissions reporting data and US EPA carbon inventories [7, 8]

In this calculation, emissions are calculated per unit of refined fuel delivered (RFD). It is important (and somewhat counterintuitive) that emissions include combustion of the fuel during end-use, despite this choice in normalization basis. Lifecycle emissions are calculated as follows:

$$Lifecycle\ Emissions\left[\frac{g_{Ceq}}{MJ_f}\right] = \frac{\sum(Input_i * EF_i) + EU}{MJ_f} \tag{7.1}$$

where:

g_{Ceq} = Grams of carbon equivalent; this carbon is assumed to take the form of CO2; global warming potential (GWP) factors are used to convert other greenhouse gasses (GHG) into an equivalent CO2 basis

MJ_f = Megajoules (MJ) of thermal energy at lower heating value (LHV) embodied in refined fuel delivered (RFD)

$Input_i$ = A material or energy input necessary to some step in the production or transportation of each unit of RFD. Generally expressed in mass per MJ_f or energy per MJ_f.

EF_i = Emissions factor for the present input. This expresses the GHGs released by the present input in terms of CO2 equivalent.

EU = End use emissions in grams of carbon equivalent.

In all factors used in the following analysis, the source had already rendered their inputs, emissions factors, and end use factor into the appropriate g_{Ceq} basis or the directly compatible basis, grams of CO2 equivalent, so my calculations did not require direct use of GWP factors or consideration of GHGs other than CO2 (since the inventory of other GHGs, generally representing a small fraction of the total mass inventory of emissions, was already expressed in C or CO2 equivalent). Also note that this calculation method does not require consideration of the efficiency of the end-use machine or system, and does not directly consider the useful work ultimately extracted from the fuel. This is the primary methodological reason for use of the RFD basis.

Figure 1 shows several of the energy input factors from Brandt's life cycle assessment used in this analysis. Table 1 shows numerical results of this analysis, labelled "Baseline NROSS". Figure 2 shows the same results graphically. Note the use of grams of carbon equivalent, g_{ceq}, instead of the more common grams of CO2 equivalent. This follows the convention set in the LCA by Brandt and in Equation 7.1.

TABLE 1. Primary Energy Inputs and Outputs per Tonne of Shale Processed (MJ/tonne) and Energy Ratios[a]

		energy per tonne of shale produced (MJ/tonne)			
		low case		high case	
	type of energy input (I or E)[b]	input	output	input	output
	Production Site Inputs				
1. Preliminary operations	E	1		1	
2. Drilling	E	7		12	
3. Miscellaneous	E	34		34	
4. Pumping	E	2		4	
5. Freeze wall, purchased electricity	E	37		159	
6. Freeze wall, generated electricity	I	35			
7. Retorting, purchased electricity	E			570	
8. Retorting, generated electricity	I	1154		784	
9. Remediation, purchased electricity	E			74	
10. Remediation, generated electricity	I	39			
	Production Site Output				
11. Synthetic crude oil			2632		2543
	Offsite Inputs				
12. Crude transport, electricity	E	2	13		
13. Refining, external energy input	E	56	83		
14. Refining, internal energy input	I	157	230		
15. Refined product transport	E	16	16		
	Net Output Offsite				
16. Refined fuel delivered, RFD			2475		2333

Figure 7.1. Energy intensity factors from Shell ICP LCA (Ref 5)

Table 7.1. Baseline NROSS emissions estimation results and related data

Emissions type or source	Emissions (g_{ceq} / MJ)	Energy type
Nuclear power plants[3]	4.4	Electricity
Natural gas generators[3]	30.5	Electricity
Coal generators[3]	75.3	Electricity
Colorado grid	51.8	Electricity
Shell ICP[1]	45.45	Fuel
Present bitumen sands	28.3	Fuel
Future bitumen sands[2]	29.5	Fuel
Baseline NROSS	**28.9**	**Fuel**
LWR NROSS on a very-low-carbon grid	**25.0**	**Fuel**
Conventional production of gasoline	25.3	Fuel

Note 1: To provide for an equal-terms comparison, calculated total emissions for Shell ICP have been recalculated with more recent emissions data and the present generation mix in Colorado.

Note 2: The quality of bitumen sands resources is already significantly declining, and continued production will require increasing energy and hydrogen inputs to upgrade the product to a quality suitable for conventional refining [6].

Note 3: Emissions of typical generators are calculated using an average over 2011 data and average over all United States generators of that type [7, 8].

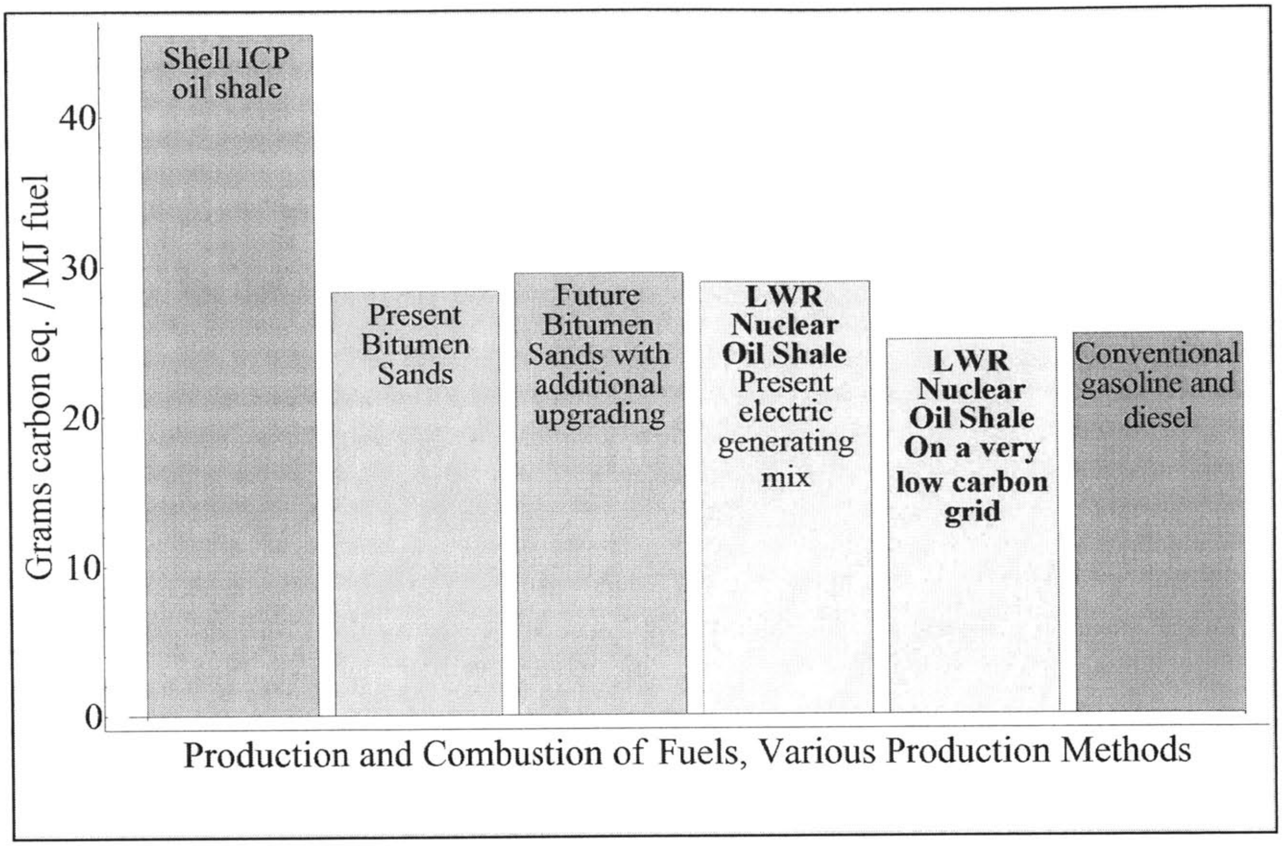

Figure 7.2. Lifecycle "well-to-wheels" emissions of transportation fuel from various production methods

A baseline NROSS, according to these results, can be expected to emit 36% less carbon per unit of fuel product than Shell ICP using Colorado's current electricity generating mix. A nuclear oil shale system connected to the present Colorado grid would emit 15% more carbon than CCR per unit of fuel, but as the transition to a low carbon grid proceeds, nuclear oil shale emissions decline to a level slightly below conventional gasoline production.

7.2. Factors of Interest in NROSS Emissions Estimation

This multi-function facility has some factors in its emissions character not typical either of electricity generators or of fuel refineries.

7.2.1. Electricity Replacement

Direct reduction in greenhouse gas emissions from grid electricity production, due to the nuclear plant outputting electricity during half of its operating hours, is credited to each unit of fuel produced for the case of NROSS operating on a grid very similar to the present one.

In the basis of units of fuel produced, this effect appears quite small, reducing carbon by 0.17 g_{Ceq} per MJ of grid electricity, per MJ of fuel produced. It is important to note that a 1 MJ of fuel is not a large quantity, however. One "barrel of oil equivalent" (BOE) contains 6,110 MJ.

For a large NROSS development, this effect would actually provide compounding benefits, simultaneously reducing the average emissions of the grid electricity used in second stage heating. The result of this effect is shown in the case "LWR NROSS on a Very-low-carbon grid".

7.2.2. Bounding Cases

The results labelled "Baseline NROSS" in Table 1 and Figure 2 can be considered an upper bound analysis, where the development of nuclear reactors in Colorado has been assumed to have a minimal effect on grid carbon intensity other than the direct effect of the electricity produced by the reactor that provides first stage heat for the present unit of fuel.
This feedback would reduce grid carbon emissions by 0.96 g_{ceq} per MJ of electricity per reactor in operation, assuming nuclear power directly replaced coal power on the Colorado grid (which would essentially be the case in the short term, early in the development of NROSS).

In the longer term, the development of 50 SMRs for nuclear oil shale systems could essentially eliminate grid carbon emissions in Colorado. This asymptotic bounding case, assuming the development of a nearly zero carbon grid in Colorado due to large scale NROSS deployment, would have a carbon intensity of only 25.0 g_{ceq} per MJ of fuel produced.

Such a development represents less than a quarter of the potential market for heat and power for oil shale systems in Colorado. However, such a development would be large enough to have many other impacts on grid management and renewable development that are currently difficult to predict and will require electric grid simulation to understand.

7.2.3. Product quality

Not all crude oil is equal. The shale oil produced by in-situ methods is a high-quality crude oil relative to the global crude oil supply with lower refining requirements and lower greenhouse gas emissions at the refinery. The average quality of crude oil (worldwide) is decreasing with more production of heavy oil and oil from tar sands, as suggested by the bitumen sands emissions indicated in Table 1 and Figure 2. NROSS underground operations involve cracking kerogen, vaporizing the oil, and condensing it. In effect, many of the refinery operations that normally produce large GHG emissions are being conducted underground with the carbon residues left underground (sequestered). Furthermore, the quality of the products of the processes can be controlled by varying temperature, pressure, stress state, and other factors during decomposition [9, 10].

Study of product quality during ongoing operations, and the capacity to vary the conditions of decomposition underground, could lead to substantial process optimization once a demonstration facility is available. It is likely that the energy inputs required for kerogen processing and the amount of labor and material needed for the heating and extraction wells (which contribute to total CO_2 emissions) can be significantly reduced as operation proceeds. The properties and kinetics of kerogen oil shale have substantial uncertainty and variation between rock zones, and predictive models cannot fully optimize the design details of the heating systems or the production process without access to operational data. This approach, empirical optimization during operation, is rarely allowed in nuclear power operations, but it is standard practice for petroleum system operators.

7.3. Carbon Offset Policies

Who gets the electricity grid greenhouse gas reduction credits? NROSS enables a near-zero-carbon electricity grid by providing a reliable dispatchable source of electricity and being a consumer of electricity when renewables produce more electricity than the electricity market can absorb. It eliminates near-zero electricity prices that would make renewables uneconomic [11, 12]. The question is who gets credit for the reductions in greenhouse gas releases—the wind turbine or NROSS that enabled larger-scale deployment of wind turbines?

In this context State of California [13] and Google [14] studies have identified that the major challenge for a zero-carbon grid is the need for non-fossil backup power at times of low wind or solar conditions. Long-term non-fossil options include pumped storage, batteries, hydrogen, and other storage devices—each with severe limitations. NROSS serves the same function for a zero-carbon grid and simultaneously produces high-value fuel.

NROSS will be displacing fossil-fueled generators that currently provide flexible, dispatchable electricity on the western US grid. The EPA regulation on carbon dioxide emissions from stationary electricity generators, the Clean Power Plan (CPP) [4], may incentivize exactly this kind of substitution once implemented. Under the United States Clean Air Act [15], states must each develop their own program for implementing regulations such as the CPP. If western states implement a properly formatted carbon offset policy as part of their implementation of CPP, NROSS systems developed in those states will get credit for replacing fossil-fueled dispatchable generators. This would reduce the effective emissions of the liquid fuel produced by NROSS systems, potentially bringing effective emissions below the actual emissions of end-use combustion. Policies of this type may be suitable in other nations with oil shale resources, including China, Estonia, Australia, and Jordan.

7.4. Future NROSS

Later generation NROSS systems may adopt high-temperature reactors as their primary power source once such reactors become available. Work is already underway to adapt a range of high-temperature reactor designs for delivery of heat to a range of chemical and fuel production processes. As one example, there is an option to develop the United States Next Generation Nuclear Plant (NGNP), a helium cooled reactor, for multiple stages of process heat delivery. The highest temperature heat could be used for hydrogen production, with exhaust from this process providing the relatively lower temperature heat needed for kerogen processing. The hydrogen could then be used for either (or both) upgrading of the heaviest hydrocarbons produced in the shale oil stream or peak electricity production in on-site hydrogen turbines. If absorbing grid electricity at times of high renewable output proves valuable, the hydrogen production facility could be oversized to absorb additional electricity when available for even more hydrogen production. The operation and economics of such a complex system would require demonstration in the first-of-a-kind facility.

7.5. Other Oil Shale Processing Technologies

Many approaches to oil shale extraction and processing have been proposed in recent decades. LCA has been used to estimate the emissions from many of them over the last 10 years. A set of recent estimates is shown in Figure 7.3. For reference, CCR has lifecycle emissions that range from 86.6 g_{CO2eq} / MJ_f to 92.8 g_{CO2eq} / MJ_f. The reader should note the change in units from grams of carbon equivalent (used in Brandt's LCA and the estimation performed above) to grams of carbon dioxide equivalent (used in the figure below).

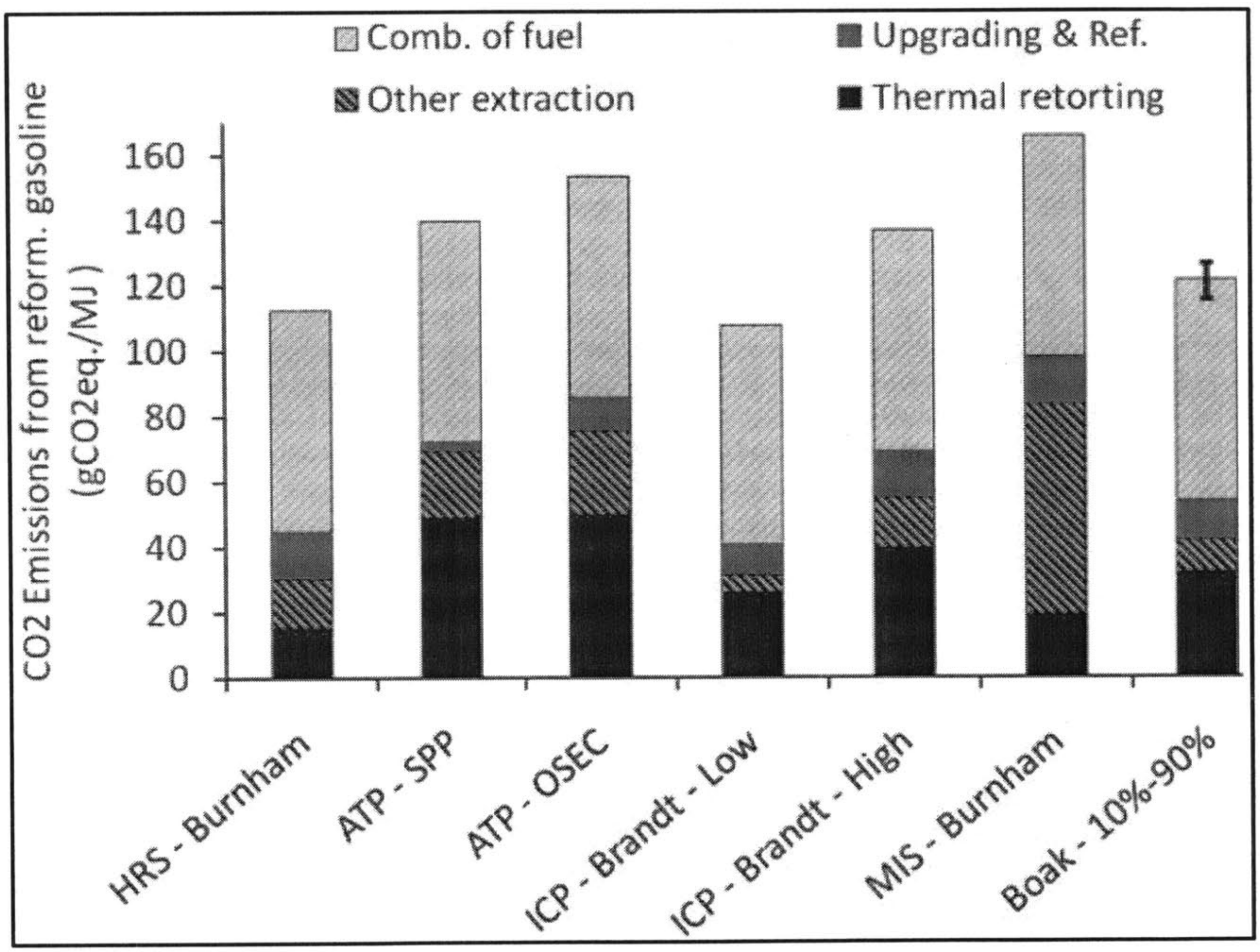

Figure 7.3. A set of oil shale emissions estimates presented in 2010 [16]

We can see that all of these technologies would have higher emissions than CCR. Large scale adoption of any conventional oil shale processing technology would continue the trend in recent years toward higher emissions in the fuel production process. It is quite reasonable to consider essentially all fuel production methods with emissions higher than the average emissions of CCR to be at risk of regulatory restrictions or penalties once new rules on CO2 emissions from refineries are implemented. Large scale adoption of NROSS, however, would reverse the trend and eliminate this risk.

7.5.1. Disclaimer on LCA calculations

The reader should note that there are a very large array of factors that might not match exactly when comparing different emissions estimates. Different data inputs, different system scopes, different component calculation methods, and different energy conversion assumptions could all lead to different ultimate results. Authors agree that all oil shale processing methods studied to date will have greater lifecycle emissions than current conventional crude refining, as shown in Figure 3, and the results of my estimation here fall within the range of emissions estimates proposed by several authors investigating oil shale processing technologies [16].

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Part 3: Development Pathway

8. NROSS Development Pathway

Three top level elements are essential to development of Nuclear Renewable Oil Shale Systems (NROSS). These are: (1) sustained R&D funding for a core technical team, (2) the support of a major petroleum development company, and (3) the support of a small modular reactor (SMR) vendor. This team would then ahve to navigate an array of significant challenges to succeed at large scale NROSS development.

8.1.Contracts and Organizations

NROSS development can only succeed with long-term commitment of a very large amount of capital from all players involved. The reactors will have operational lifetimes of at least 60 years, with a minimum of 10 years required to develop efficient steady-state reactor manufacturing capability and efficient oil shale field operations. Withdrawl of either of the top-level organizations, the petroleum developer or the SMR vendor, would be extremely disruptive to the project and would significantly set back many of the efficiency benefits of the large operation. All of the organizations involved would have to be committed to operations for many decades. There are several reasons this will be difficult.

<u>Electricity market evolution.</u> Restructured electricity markets are less than 30 years old. Every nuclear power plant currently operating in the United States was built in a traditional cost-of-service regulated power system, and all five currently under construction are also in areas with traditional regulation. More than half of operating reactors are now found in restructured markets. Restructured electricity markets continue to change their regulations and market mechanisms from year to year, and are certain to have evolved in very significant ways we cannot currently predict by the end of operations at a major NROSS development. An agile team will be required throughout the development to monitor electricity markets and respond to changes, ensuring that the project continues to provide significant power system benefits and maximize electricity sales revenue.

<u>Oil market evolution.</u> As of this writing, we have just witnessed a plunge in oil prices of over 50% in six months. Both the supply and demand of oil continue to evolve in unexpected ways, and significant uncertainty in future market conditions must be included in the lifecycle economic assessment of NROSS development. We can be quite confident that disruptive changes in the technology of oil extraction and use will arise over the life of a major NROSS development.

<u>Involved organizations.</u> Many organizations will be involved in a large NROSS development. The project will be regulated by several organizations at both the state and federal level and will have a large range of major stakeholders in technology development, construction, and operations. A short list includes:

- Federal regulation of environmental impact by the Environmental Protection Agency (EPA).
- Federal regulation of nuclear power operations by the Nuclear Regulatory Commission (NRC).

- Federal technology development support by the Department of Energy (DOE).
- Federal land use agreements by the Bureau of Land Management (BLM)
- State regulation of environmental impact by the relevant state environmental quality organization (such as the Colorado Department of Public Health and Environment, CDPHE)
- Potential gas and oil pipline development, federally regulated by the Department of Transportation (DoT) and Federal Energy Regulatory Commission (FERC) respectively
- Electricity transmission infrastructure development, possibly by Public Service Company of Colorado or Rocky Mountain Power in Utah.
- Many engineering, procurement, and construction (EPC) companies
- Many other state and local government organizations

8.2. Environmental and Land Use Impacts

Although they are very different from the impacts of mining and surface processing, in-situ oil shale processing also has the potential for major environmental impacts. The greatest among them is likely the possibility of groundwater contamination by petroleum products in the ground.

<u>Groundwater contamination.</u> The team designing the Shell In-situ Conversion System (ICP) took this possibility very seriously, and sought to resolve it through inclusion of a freeze wall in their system configuration [1, 2]. ICP would include a set of wells drilled outside the grid of heater wells that would circulate refrigerant at -40°C, freezing a cylinder of rock around each well. These wells would be positioned far enough from the heater wells to minimize heat flux and close enough to each other that their frozen regions merge to form a solid, impermeable frozen wall around the production zone that would prevent any fluid migration in or out. The preparation of the production zone would include pumping out all mobile liquid water (the water accessible in open connected voids in the rock), and remediation would involve flushing the zone with water to remove as much remaining hydrocarbon residue as possible.

The American Shale Oil Corporation (AMSO) takes a very different approach to managing the possibility of groundwater contamination. They seek to process a much deeper shale layer, below the water table and protected from groundwater by extremely lower permeability rock layers [3].

Red Leaf Resources is pursuing yet another strategy, with plans to contain all products of kerogen processing in sealed capsule retorts [4]. Testing during construction of the capsule should verify that it is not permeable to water or hydrocarbons.

<u>Water usage.</u> All heavy industrial operations require significant quantities of water, and any operations involving mining or pumping oil will require yet more. Water is tightly controlled in the western United States, which tend to have low annual rainfall and rely heavily on their rivers for water supply. The organizations that manage water rights have significant political, industrial, and agricultural importance in Colorado, Utah, and Wyoming.

<u>Land Use and Availability.</u> In Colorado, Utah, and Wyoming, 75% of the land overlying significant oil shale formations is controlled by the Bureau of Land Management (BLM) [5]. Land

has been made available only in limited amounts for research and development. A major NROSS development would require an affirmative decision by BLM to release a large contiguous segment of that land for use.

8.3. Nuclear Licensing and Certification

No commercial nuclear reactor has ever delivered heat off-site or to any use other than electricity generation in the United States. Development of a system to certify plant designs and regulate operations of a reactor that delivers heat to another facility is an essential step in the deployment of NROSS and in a wide range of other possible advanced reactor developments. The development of a system to certify and regulate process-heat reactors would represent a major step forward for a range of other projects seeking to develop Nuclear Hybrid Energy Systems (NHES), as well. Development of the necessary analytical methods and best practices of design for certification and regulation of process-heat reactors can and should begin immediately.

The framework to regulate process-heat reactors must not be application specific. The level of effort and investment likely to be needed to develop the principles and tools for safety analysis of NROSS, then certify and regulate an actual system, is likely to be very large. The AP1000 had exactly the same function as any Generation II pressurized water reactor (PWR) and many of the same major features (physical form of the fuel, coolant, operating temperatures and pressures, system configuration), yet its design certification effort cost over $100 million to complete [6]. The early stage regulation of NROSS, through deployment of the first reactors, may very well be a billion dollar regulatory project. For all of that investment to be of no use to process-heat reactor technologies that might follow, and to have to be made again each time we seek to bring a process-heat reactor or application to market, would be a tragic waste that would ensure that nuclear reactor technology never lives up to its full potential. Fortunately, development of the regulatory framework for process-heat reactors gives us an opportunity to break out of traditional design-specific regulatory procedures and begin generalizing *some* of our methods for regulatory safety analysis and design certification without the need to overhaul all of our thinking about thermal limits, fuel forms, coolants, and radiation protection (since the reactor core of first generation NROSS would still be a PWR).

8.4. Timeline

A core technical R&D team, consisting of experts in geology, petroleum systems, nuclear systems, mechanical systems, and controls should be assembled as soon as possible. This team should spend two years completing a range of additional investigations with a focus on system licensing and heat delivery subsystem selection. These investigations provide the basis to complete a full NROSS conceptual design, which is in turn used as the basis for planning and detailed design of an NROSS demonstration system.

An example NROSS development timeline (presumed to begin soon):

- <u>Year 0</u>: A core technical R&D team is assembled.
- <u>Year 2</u>: Investigations of the technical basis for NROSS development are complete.

    - Generic issues in SMR licensing are resolved. Design certification for at least one SMR begins.
- Year 4: A full NROSS conceptual design is developed.
    - Small scale experiments to validate design and performance features begin.
- Year 5: An envelope of suitable oil shale resources and demonstration sites is identified.
    - At least one SMR design is certified and available for commercial use.
- Year 6: Full scale planning for an NROSS demonstration project is underway.
    - The small scale experimental campaign has produced significant results.
- Year 7: The demonstration project is funded as a public-private partnership. Construction of the NROSS demonstration project begins.
- Year 9: The first test Production Zone is ready, and operation using a non-nuclear heat substitute begins.
- Year 11: Operation of the first test Production Zone is complete.
    - Results are analyzed over the following year to inform design of the second test zone.
    - The first Production Zone is spent and ready for investigation of the most promising re-use option.
- Year 12: Construction of the second test Production Zone begins.
- Year 13: The nuclear plant and second test Production Zone are complete and ready for commissioning.
- Year 14: The nuclear plant is commissioned and begins operating the second Production Zone.
    - The plant does not switch operating modes or output electricity during this first trial year of operation.
    - Construction begins on the third Production Zone.
- Year 15: First stage heating of the second Production Zone is complete.
    - The nuclear plant couples to the third Production Zone and begins full capacity operation with mixed electricity output and heat delivery.
- Year 16: The nuclear plant performs its second handoff to couple to the fourth Production Zone.
    - Full capacity operation continues.
    - All essential NROSS functions have been demonstrated.
    - Oil from the second Production Zone has been sold.
    - The second Production Zone is now spent and ready for re-use.
    - A large NROSS development area is delineated and made available.
    - The SMR vendor begins construction of a module assembly factory.
    - Contracts are signed between the developers of of the large NROSS complex(es).
- Year 17: Infrastructure construction on the NROSS development area is underway.
- Year 18: The module assembly factory is completed.
    - The public-private partnership to operate the demonstration facility is extended; the facility will be used to jointly test design improvements in NROSS Production Zones.
- Year 19: Assembly of the first reactor module is carried out.
    - Construction begins on the first commercial Production Zone.
    - Several commercial Service Areas are delineated and undergo preliminary surveys.
- Year 20: The first fully commercial NROSS reactor is installed.

- Year 21: Full commercial NROSS operations begin with commissioning of the first reactor and first stage heating of the first Production Zone.
- Year 22: The second commercial NROSS reactor is installed and begins operation.
- Year 30: Many commercial NROSS reactors are operating on many Service Areas.
  - The module factory has returned a profit to investors and served as a worldwide model for factory production of nuclear reactors.
  - SMR production rate is now significantly greater than 1 per year.
  - SMR factories have been completed in other developed countries, and SMRs are being sold to new nuclear programs in many developing countries. A competitive worldwide market for modular reactors is emerging.
  - A 4^{th} generation advanced reactor design is certified and available to provide a major NROSS upgrade.
- Year 32: All additional reactors added to the NROSS complex are 4^{th} generation advanced high-temperature reactors.
  - Regulations in the United States now place severe restrictions on carbon emissions from all industry and most types of both public and private infrastructure.
- Year ???: The western United States shuts down its last fossil-fuel-fired power plants. The transition to a very-low-carbon electricity system is complete.
- Year 50: Many non-fossil options for hydrocarbon production are now technically mature, and demand for fossil resources is declining.
  - Demand for hydrocarbons as liquid fuels is also declining as other options for transportation and mobile energy supply mature.
- Year 61: The earliest NROSS reactors receive their life extension to 80 years.
- Year 81: The earliest NROSS reactors are decommissioned.
- Year 100: Most NROSS reactors are decommissioned.
  - Human civilization transitions completely off of fossil resources as NROSS operation draws to a close.

The research necessary in years 0 through 4, including technical basis research and conceptual design, might be suitable for an integrated research program with several university and national laboratory partners. Promising results might justify a second such program for years 4 through 6. Decision points on the proper level of investment in NROSS research occur at years 4 and 7, and a decision point at year 16 presents an opportunity for potential private developers to determine the proper level of investment in large scale NROSS systems. Other disruptive technologies that enable very-low-carbon energy supply may be available by that time.

There are many places where a realistic timeline might depart from this example. The whole timeline may be delayed, or possibly only parts of it, by low oil prices or the introduction of additional disruptive technologies that expand oil supply. Or, a market for SMRs may promptly emerge once one or more designs are certified and justify deployment of SMR factories independent of the NROSS development. Energy technology may evolve so much in the next 60 years that life extensions for the early reactors are not even considered attractive because new reactors are so much safer or cheaper to operate. Or, advanced Gen IV reactors may never play a major role in energy because a compelling alternative flexible, dispatchable, low carbon generator emerged before we figured out how to certify and license them.

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9. Conclusions

Nuclear Renewable Oil Shale Systems couple electricity and transportation fuel production in a single operation, reduce lifecycle carbon emissions from the fuel produced, improve economics for the nuclear plant, and enable a major shift toward a very-low-carbon electricity grid. The analysis herein has shown that liquid fuels produced by a baseline NROSS would have the lowest life cycle greenhouse gas impact of any presently available fossil liquid fuels and that operation as part of an NROSS complex would increase reactor revenues relative to a stand-alone baseload reactor. The flexible, dispatchable electricity provided by NROSS could also enable the transition to a very-low-carbon grid in which renewables are widely deployed and the NROSS provides variable output to balance their uncontrolled output to meet demand. Large scale deployment of NROSS will be an enormous undertaking, requiring substantial resources and involvement from a large and complex array of organizations, but the effort will reduce carbon emissions from both the electric power and transportation sectors, reduce United States reliance on foreign energy resources, and accelerate our transition to a cleaner, more efficient, and more reliable energy system.

9.1. Continuing Work

In line with the timeline presented in Chapter 8, several major efforts should begin immediately to ensure that the project to deploy an NROSS demonstration system can begin by 2022.

9.1.1. Regulatory Certification

Development of the principles, safety analysis tools, procedures, and strategy for certifying the design of a reactor plant capable of external heat delivery needs to begin immediately. This is a major need that cuts across many research and development efforts, and it could provide an opportunity to gradually begin opening our nuclear regulatory processes to new technologies and new functionality in nuclear energy facilities.

9.1.2. Heat Delivery Subsystem Options

Red Leaf Resources was essentially unknown at the beginning of the research efforts, 2 years ago, that resulted in this thesis. In 2011 at least four different major in-situ oil shale processing systems were in development, each with significant novel features. Interesting and efficient oil shale processing options may remain unexplored. Effort should begin immediately to exhaustively search the space of design options for kerogen heating and hydrocarbon capture and recovery. This design space should be very well understood by the time a NROSS demonstration effort commences.

9.1.3. Electric Power System Simulation

Major research efforts already seek to quantify the impacts of intermittent renewable generation (IRG) on our electric power systems and wholesale markets. Simulation of the western United States power system and interactions between NROSS and regional electricity markets should explore the impacts that NROSS will have at various stages of development in a variety of scenarios (including independent developments in each of the three states with major oil shale resources). A particularly valuable goal is quantification of the limits of the current western US power system to tolerate IRG and the amount that those limits can be increased through NROSS deployment.

9.1.4. Options to re-use heating subsystem infrastructure

The baseline NROSS will require the drilling and construction of significant heating infrastructure for each Production Zone. There are options to reuse this infrastructure. In the short term, during NROSS operation, the heat in currently producing zones may be more valuable if extracted and converted to electricity in a scenario where the relative value of electricity suddenly and significantly increases. The heat in a recently completed zone may be useful for pre-heating a subsequent zone. In the longer term, the heating subsystem may be employed to turn spent Production Zones into geologic thermal energy storage systems for seasonal energy storage. These options, and possibly others, should be investigated for potential to improve energy utilization or increase revenue for NROSS.

9.1.5. General SMR regulatory challenges

If SMR designs are to be certified and commercialized, a set of major general issues must be resolved. NRC must present general requirements for plant staff that are suitable for multi-module plants and emergency planning zone (EPZ) size determination guidelines applicable to small reactors. Some detailed requirements for certification of large light water reactor technology will not apply to certain SMRs. If these issues cannot be resolved and the SMR program is significantly delayed or cancelled, NROSS may have to be reimagined. The resources necessary to demonstrate NROSS will increase if SMRs are not available.

9.1.6. SMR factory economics

The economics of a SMR factory require investigation whether NROSS will be developed or not, but NROSS development offers a compelling mass production scenario to investigate. A SMR factory may be economically viable for a large NROSS development even if it is not viable for mass production of baseload electricity SMRs.

9.1.7. Water use

The water use of NROSS employing various heating subsystem options should be quantified, and design options that minimize water use should be investigated. The water availability situation in Colorado, Utah, and Wyoming, with projections through the life of an NROSS development, should be well understood before commencing an NROSS demonstration project.

9.1.8. System cost

Chapter 5 presented an array of factors that will impact NROSS costs and might significantly reduce cost relative to a business-as-usual scenario. The overall cost of particular realizations of NROSS, the benefits of those cost factors, and the impact of any new factors that might be identified, should be quantified to the greatest extent possible. Early identification of the largest drives of system cost will be particularly valuable in optimizing the economic performance of an eventual large development.

Appendix A. Hybrid Energy Systems Background and Definition

There has been sustained interest in recent years in next-generation energy systems that combine multiple primary energy sources or multiple energy products, termed hybrid energy systems (HES). Historically, two classes of HES have dominated technical analysis and commercial interest: industrial systems that provide both electricity and heat from a single fuel source; and residential systems that combine multiple energy services, such as building climate control and electricity. Such systems have typically been referred to as combined heat and power (CHP) or district heating systems. These are the simplest, and most technically mature, types of HES.

Since the origins of the Next Generation Nuclear Plant program (NGNP), new kinds of large scale hybrid energy system concepts have been studied that would use nuclear reactors as their primary energy source. These large systems often involve renewable energy inputs and chemical production and have been termed nuclear hybrid energy systems (NHES). Several dozen NHES concepts and variants have been proposed and analyzed to date. The potential for coupling to this wide range of HES has been a major argument in favor of continued work on the NGNP [1] and a range of other fourth generation high temperature reactors [refs 2-5]

Due to the wide range of possible systems, and the long and poorly standardized history of hybrid energy systems, proposed definitions and goals of HES vary widely between investigators. The feature common to all of them is use of heat for some purpose besides electricity production, distinguishing HES from single-purpose central station electricity generating plants.

A.1. Recent Literature

Investigators contributing to the NGNP program analyzed a wide range of process heat applications for a high-temperature gas-cooled reactor (HTGR). Among these are ammonia production, gasoline production from methanol, liquid fuel production from coal, hydrogen production via steam methane reforming, oil sands recovery, and both underground and surface oil shale processing [refs 6-12].

A 2013 paper by Verbruggen *et. al.* [13] explicitly discusses the difficulties of defining CHP and cogeneration, the historical terms that have been adopted in European Union (EU) environmental policy, noting that that "Effective communication is based on clear terminology, now missing in CHP's world." Verbruggen *et. al.* define CHP and cogeneration equivalently: "CHP or cogeneration is the recovery and use of all or part of the point source heat exhaust, otherwise being rejected, by a thermal power generation plant." [13]

Garcia *et. al.* published a two part analysis in 2013 of hybrid energy system dynamic performance and system costs [14, 15]. This study used two subsets of hybrid energy systems, termed "traditional" and "advanced."

> *One HES option, termed traditional, produces electricity only and consists of a primary heat generator, a steam turbine generator, a wind farm, and a battery storage. The other HES option, termed advanced, includes not only the components present in the traditional*

> *option but also a chemical plant complex to repurpose excess energy for non-electricity services, such as for the production of chemical goods. In either case, a given HES is connected to the power grid at a point of common coupling.* [14]

Recent work at the Idaho National Laboratory (INL) and National Renewable Energy Laboratory (NREL) seeks to identify and optimize the most promising nuclear hybrid energy systems. Denholm *et. al.* generically analyze the use of thermal energy storage in nuclear power plants to balance intermittent renewable generation [16], illustrating a subset of hybrid energy system options and motivating direct connection of nuclear and intermittent renewable primary energy systems to provide electricity with nearly zero carbon emissions. A 2014 paper by Ruth *et. al.* identifies the major challenges in deployment of such combined nuclear and intermittent renewable energy systems, and in the process, introduces the more specific term *nuclear-renewable hybrid energy system*:

> *This paper explores one opportunity – nuclear-renewable hybrid energy systems. These are defined as integrated facilities comprised of nuclear reactors, renewable energy generation, and industrial processes that can simultaneously address the need for grid flexibility, greenhouse gas emission reductions, and optimal use of investment capital.* [17]

Ruth *et. al.* also note the range of meanings previously applied to *hybrid energy system*, including [17]

- "small, decentralized hybrid energy systems which utilize multiple generation sources, often with storage, to provide electricity to remote populations"
- "Single energy source centralized generation facilities that provide multiple services (e.g., electricity, heating, cooling, water)"
- "Co-generation (or combined heat and power)"
- "generation facilities which use fossil fuels in combination with renewables"

Ruth *et. al.* finally define a *hybrid energy system* as follows.

> *This paper defines a hybrid energy system as a single facility which takes two or more energy resources as inputs and produces two or more products, with at least one being an energy commodity such as electricity or transportation fuel. These systems are comprised of two or more energy-conversion subsystems that are traditionally separate or isolated. ... Our definition of hybrid energy system requires coupling ''behind'' the electrical transmission bus, where all subsystems within the hybrid energy system share the same interconnection so that the grid is exposed to a single, highly dynamic and responsive system.* [17]

As further noted by Ruth *et. al.*, Kieffer *et. al.* propose an alternative term: "Flex Fuel Polygeneration (FFPG) is a new technology that employs multiple energy sources and produces multiple energy carriers to construct optimal energy plant designs." [18]

A.2. Defining Hybrid Energy System

It is noteworthy that many recent advancements in energy systems combine renewable and fossil primary energy inputs (which may or may not fit the definition of HES or FFPG proposed by Ruth *et. al.* or Kieffer *et. al.*). One important type of combined system employs concentrated solar power to replace conventional feedwater pre-heating in conventional Rankine cycle power plants [19, 20]. Analysis by Zhao *et. al.* indicates that both the solar thermal collector and coal boiler in a combined coal-solar system achieve higher conversion efficiency than either would achieve alone [21].

Figure 1 combines the definitions provided by Ruth *et. al.*, Verbruggen *et. al.*, Garcia *et. al.*, and some additional commonly used terms in a taxonomy of hybrid energy systems.

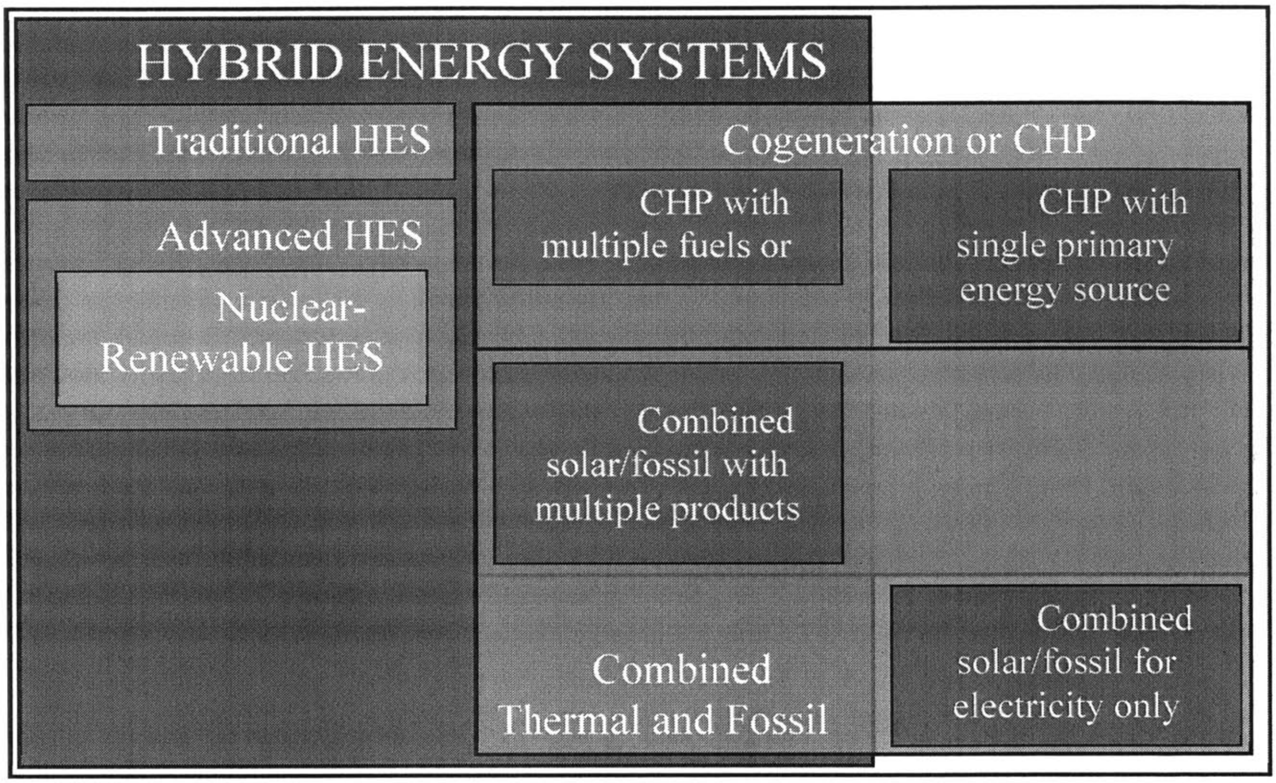

Figure A.1. Illustrative taxonomy of hybrid energy systems and associated terms

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Executive Summary

Nuclear Renewable Oil Shale Systems (NROSS) are a class of large Hybrid Energy Systems (HES) in which nuclear reactors provide the primary energy used to produce shale oil from kerogen deposits and provide flexible, dispatchable, very-low-carbon electricity to the grid. Such systems connect electricity and transportation fuel production in a single complex, reduce lifecycle carbon emissions from the fuel produced, improve economics for the nuclear plant, and enable a major shift toward a very-low-carbon electricity grid.

The western states of Colorado, Utah, and Wyoming, along with Northern Europe, China, Australia, Jordan, and several other countries have abundant resources of a type of solid, insoluble organic matter called kerogen. When heated, kerogen decomposes into hydrocarbons; for this reason, sedimentary shale formations with high kerogen content are called oil shale. This resource has been used for fuel and power production in Estonia and China for several decades. The oil shale formations in the western United States have been thoroughly explored and make up the largest and densest hydrocarbon resource on the planet.

The western U.S. additionally has very large wind resources, and developing them is a major policy priority. Substantial use of intermittent renewable generators (IRGs) leads to low electricity prices at times of high resource availability (such as high wind speed, or peak sunlight at midday), which will either slow the development of renewables or will destabilize markets, complicate system planning, and increase consumer electricity prices. Both of these sets of effects have been both observed and modeled in recent years. Flexible, dispatchable generators are required to provide backup power for IRGs, and the only generators currently available for this role are fossil fueled. A new kind of flexible, dispatchable, very-low-carbon generator is essential for the transition to a very-low-carbon energy sector.

Because oil shale has low thermal conductivity, heat input to shale formations can be cycled as needed without disrupting the steady increase in average temperature and kerogen decomposition rate. The average temperature required for kerogen conversion to liquid fuels is about 350°C when a long heating cycle, greater than 1 year, is used. Light water reactor (LWR) steam in closed loops can heat the kerogen to about 210°C; electrically-heated higher temperature steam can heat the shale to about 350°C in a second heating stage using the same delivery system. This type of slow heating of kerogen, over cycles of 1 year or longer, produces light, high-value hydrocarbons that require less energy input for refining than traditional crude.

The baseline NROSS uses LWRs to provide steam for lower-temperature heating. The system simultaneously buys electricity from the grid for higher-temperature heating when prices are low, as is likely to happen for several hours per day in a system with very high utilization of IRG. The system sells electricity to the grid when the price of electricity is high. This strategy boosts revenue for both the nuclear plant operator and for any IRGs operating on the same grid. The reactor plant powering an NROSS complex would see a revenue increase over an equivalent stand-alone LWR of 41% selling electricity into a wholesale market similar to the one in California in 2011 and 2012. The flexible, dispatchable electricity provided by a large NROSS development could also enable the transition to a very-low-carbon grid in which renewables are widely deployed and the NROSS replaces fossil fueled generators in providing flexible, dispatchable electricity output to match demand.

Liquid fuels produced by a baseline NROSS system will have the lowest lifecycle greenhouse gas (GHG) impact of any presently available fossil fuels. Large scale development of a very-low-carbon electricity system, future process optimization, and possible future adoption of high-temperature reactors could all drive effective carbon emissions down further. If credit is given to NROSS for replacing fossil fueled backup generators for renewables (a form of carbon-offset policy), the effective greenhouse footprint of the liquid fuels would be less than the greenhouse emissions from burning those fuels.

Fully deployed, NROSS could require tens or hundreds of reactors. Large fleet operations and local mass production of the necessary hardware could bring about substantial reductions in system cost as development proceeds, potentially offering a pathway to jumpstart and maximize the realization of the mass production cost savings envisioned for Small Modular Reactors (SMRs). Because a large site with a large array of reactors could be developed as a single large project, many services could be shared, including administration, security, maintenance, refueling outage services, and spent fuel storage. A particularly interesting prospect is the utilization of a full-time refueling outage service crew of permanent employees, servicing one reactor after another in a continuous cycle. The lessons learned and efficiency likely to be developed by such an operation would be unmatched in all prior nuclear operating experience.

NROSS will require a significant development effort in the United States, where kerogen resources have never been developed on a large scale. The regulation of such a system cuts across organizations, including the Nuclear Regulatory Commission, Environmental Protection Agency, Bureau of Land Management, and state regulatory agencies. It involves oil companies and utilities in a complex commercialization effort requiring long-term partnerships. The complexity of the regulatory, business, and institutional challenges will require a demonstration project before commercial scale systems could be deployed. Such a demonstration project would align well with stated political goals of recent US administrations to enable expanded deployment of renewable generators, reduce carbon emissions from both the electric power and transportation sectors, and reduce United States reliance on foreign energy resources. NROSS offers an opportunity to accelerate our transition to a cleaner, more efficient, and more reliable energy system.