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Sustainability by combining nuclear, fossil, and renewable energy sources

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A B S T R A C T

The energy industries face two sustainability challenges: the need to avoid climate change and the need to replace traditional crude oil as the basis of our transport system. Radical changes in our energy system will be required to meet these challenges. These challenges may require tight coupling of different energy sources (nuclear, fossil, and renewable) to produce liquid fuels for transportation, match electricity production to electricity demand, and meet other energy needs. This implies a paradigm shift in which different energy sources are integrated together, rather than being considered separate entities that compete. Several examples of combined-energy systems are described. High-temperature nuclear heat may increase worldwide light crude oil resources by an order of magnitude while reducing greenhouse gas releases from the production of liquid fossil fuels. Nuclear–biomass liquid-fuels production systems could potentially meet world needs for liquid transport fuels. Nuclear–hydrogen peak power systems may enable renewable electricity sources to meet much of the world's electric demand by providing electricity when the wind does not blow and the sun does not shine.

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1. Introduction

The two major energy challenges for the world are replacing crude oil and reducing greenhouse gas emissions. The world's supply of light crude oil is limited and most of the remaining oil comes from politically unstable parts of the world. However, oil remains important. For example, in the United States oil provides 39% of the total energy demand. Two-thirds of that oil is used for transportation, the same fraction of oil that is imported.

The other challenge is the increasing concentration of greenhouse gases in the atmosphere, particularly carbon dioxide. Carbon dioxide is the primary greenhouse gas that affects climate. After atmospheric carbon dioxide levels have increased, it takes millennia for these levels to return to normal. Equally important, carbon dioxide levels strongly impact the characteristics of the biosphere and geochemistry because atmospheric carbon dioxide concentrations control the planet's average pH (acid–base concentrations).

The world has three major energy sources: fossil fuels, renewables, and nuclear. Historically, these energy sources have been treated as competing energy resources for which economics and environmental constraints determine which energy source is used. Traditional strategies to address oil shortages or concerns about climate change assume that one energy source replaces another. However, the assumption that these are primarily competing energy sources may be fundamentally incorrect. New constraints and new technologies suggest that in many cases these energy sources must be tightly coupled to meet society's requirements. This paper examines this hypothesis with four examples. Two of the examples represent alternatives to replace the traditional production and refining of crude oil into liquid transport fuels; the other two exemplify possible future nuclear–renewable electrical systems.

2. Liquid-fuels production

Major changes are occurring in liquid-fuels (gasoline, diesel, and jet fuel) production. Because of limited supplies of high-quality crude oil, heavier feedstocks (heavy oil, tar sands, shale oil, and coal) are being increasingly used to produce liquid fuels. However, the production of liquid fuels from these feedstocks results in much larger greenhouse gas emissions per liter of fuel. Consequently, greenhouse gas emissions from the use of liquid fuels are increasing significantly faster than the production of liquid fuels. To understand these changes, a brief description of the current liquid-fuels production systems is provided. Two combined-energy alternative liquid-fuels production options are then described.

Oil production is traditionally measured in oil barrels, the unit of measurement used in this paper. A barrel of oil contains 42 U.S. gallons, or 0.16 m^3. A metric ton of oil contains ~7.3 barrels of crude oil. World oil consumption is about 85 million barrels per day, while the United States consumes about 20 million barrels per day.

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2.1. Traditional liquid-fuels production and futures

The fuel cycle for liquid fuels includes obtaining the feedstocks; conversion of those feedstocks to liquid fuels; transport of the liquid fuels to the user; and burning the liquid fuel in a car, truck, train, ship, or airplane. Each step consumes energy and releases carbon dioxide. Fig. 1 shows the greenhouse gas releases per vehicle mile from a diesel-powered suburban utility vehicle (SUV) for each step in this fuel cycle (Marano and Ciferno, 2001). Carbon dioxide is the primary greenhouse gas. Energy consumption is roughly proportional to greenhouse gas releases. With the production of liquid fuels, the total fuel-cycle energy consumption and carbon dioxide releases to the atmosphere are 130–250% of those of the vehicle consuming the liquid fuel.

The process of extracting high-quality sweet (low-sulfur) crude oil, converting it to diesel fuel, and transporting the diesel fuel-to-the fuel pump consumes relatively little energy and releases relatively small quantities of carbon dioxide. In contrast, if liquid fuels are made from coal, more energy is used and more carbon dioxide is released in the production process than is present in the final fuel. As the stocks of high-grade crude oil are exhausted and liquid fuel is made from lower-grade resources, much more energy will be used and much more carbon dioxide will be released to the atmosphere to make a liter of liquid fuel. Greenhouse gas releases could be doubled per liter of fuel consumed as alternative feedstocks replace light crude oil.

To understand why the production of liquid fuels is so energy intensive, some understanding of the refinery operations (Gary et al., 2007; Self et al., 2007) that convert various feedstocks to liquid fuels is required. Refineries are among the largest industrial facilities on earth and typically consume 15–20% of the energy value of the crude oil. In the United States refineries consume over 7% of the total energy demand. A highly simplified schematic of a refinery is shown in Fig. 2 (left). Three important operations are conducted within large integrated refineries.

The common operation within all refineries is distillation: the primary process used to separate hydrocarbon mixtures into gasoline, diesel, jet fuel, and other products. The first major operation in refineries is the atmospheric distillation column, where the crude oil is heated to ~400 °C, most of the oil is vaporized, and various fractions are condensed at different temperatures to produce different intermediate products that are further processed to produce liquid fuels. The heavy oil components that do not vaporize are heated to ~450 °C and sent to a vacuum distillation column that operates at low pressure and separates the heavy components into various fractions. The liquid leaving the vacuum distillation column is resid. These two distillation operations typically use 35–40% of the energy consumed in a refinery.

Resid is the low-value product from the vacuum distillation column that is effectively a solid at room temperature. It is the component of the crude oil that does not vaporize. If it is further heated to a higher temperature, it will decompose before boiling. Resid contains the solid impurities dissolved in the crude oil. High-grade light crude oils have low resid fractions, whereas heavy crude oils have high resid fractions.

Liquid fuels have a roughly two-hydrogen-to-one-carbon ratio. Resid and heavy feedstocks (heavy oil, oil sands, oil shale, and coal) have lower hydrogen-to-carbon ratios. Two options exist to convert these feedstocks into liquid fuels with the required hydrogen-to-carbon ratio: (1) produce hydrogen and add it to the feedstock or (2) subtract carbon from the feedstock. Both processes are used in modern refineries and coal liquefaction plants.

- *Thermal cracking*. Thermal cracking is a process in which the resid is quickly heated to ~500 °C, exits the heat exchanger, and decomposes into lighter hydrocarbons and petrocoke. Petrocoke is a high-carbon solid residue that is burnt as a fuel.
- *Hydrocracking*. Hydrocracking is the addition of hydrogen to increase the hydrogen-to-carbon ratio and produce a liquid fuel.

Both processes release large quantities of carbon dioxide to the atmosphere. Thermal cracking produces large quantities of carbon dioxide when fuel is burnt to heat the resid and when the by-product petrocoke is burnt for energy. Hydrocracking does not release significant quantities of carbon dioxide. However, hydrogen is typically produced by reacting natural gas or another fossil fuel with water and air to produce hydrogen and carbon dioxide.

2.2. Nuclear–fossil liquid-fuels production

If carbon dioxide releases from liquid-fuels production are to be minimized, liquid fuels should be produced only from high-quality light crude oils. However, the resources of light crude oil are limited. What is required is a technology to create large quantities of

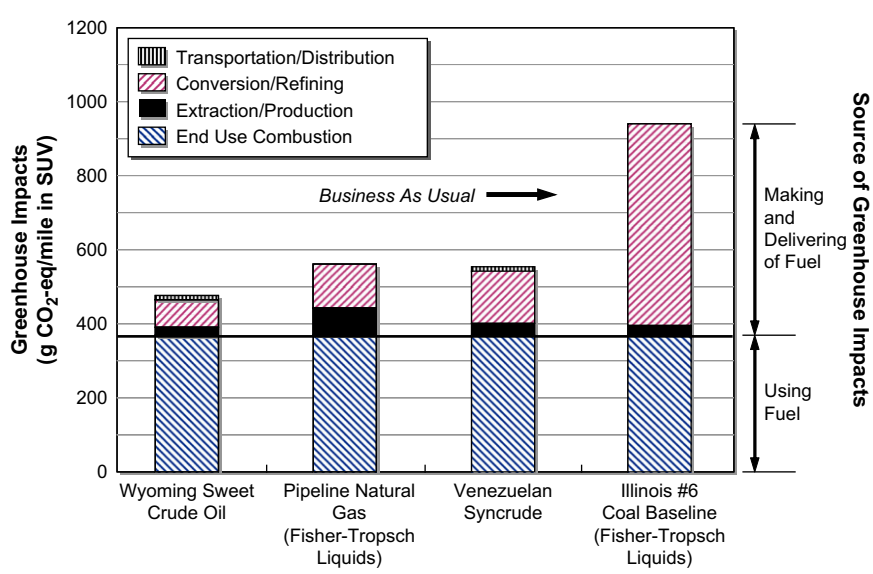

Fig. 1. Greenhouse gas releases per vehicle mile for diesel fuel produced from different sources.

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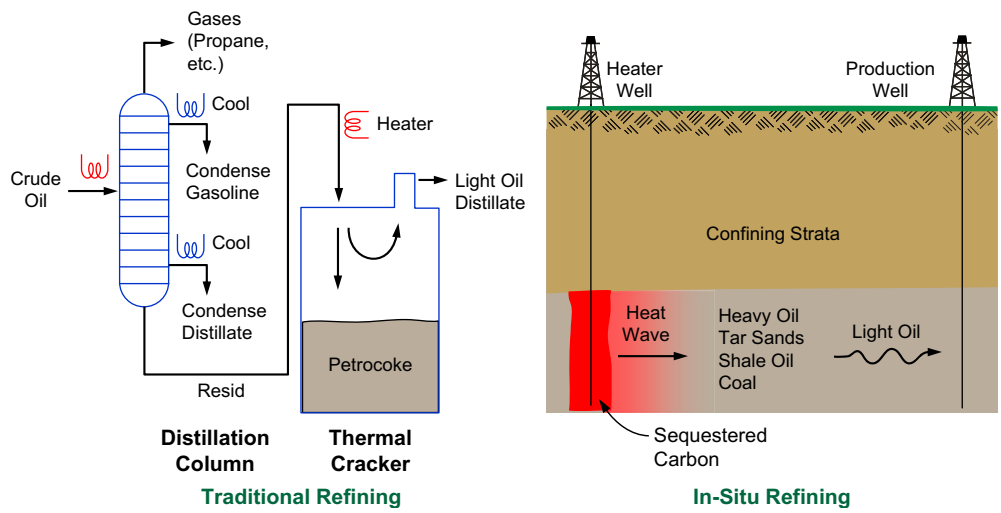

Fig. 2. Distillation and thermal cracking of high-molecular-weight hydrocarbons in a refinery and in an underground hydrocarbon reservoir.

light crude oil without the release of large quantities of greenhouse gases. One option (Forsberg, 2008a) is a nuclear–fossil light-oil production system. Massive underground resources of fossil fuels could be converted into liquid fuels, but many of these resources have been economically unrecoverable with existing technologies. Examples include the following:

- *Old oil fields*. Over half the oil remains in a depleted oil field trapped by capillary forces between grains of sand or within cracks in the rock.
- *Tar sands*. Oil recovery from tar sands has been limited to surface deposits and underground deposits where steam heating can reduce the viscosity of the oil until it flows.
- *Oil shale*. Oil shale is an organic that upon heating is converted to a liquid fuel and a high-carbon residue in the spent oil shale.
- *Soft coal*. Soft coal, if heated, is converted to char and a liquid fuel.

Starting in the 1970s, researchers began to examine methods for underground oil recovery from these fossil deposits. Because of new technological developments, concerns about greenhouse gas emissions, and higher oil prices, these technologies are now progressing from the laboratory to field testing, with initial leasing of properties for commercial production.

Conceptually, the technology is simple (Fig. 2, right side). A fossil deposit is heated to high temperatures. As the temperatures increase, any volatile hydrocarbons will vaporize (be distilled), move as gases toward recovery wells, condense in the cooler zones, and be pumped out of the ground as a liquid or vapor. This distillation process leaves most impurities behind. While capillary forces can hold liquids in cracks in the rock, gases easily permeate most reservoirs. As the temperature further increases, heavier hydrocarbons that are not vaporized will be thermally cracked to produce lighter volatile hydrocarbons that can be recovered, along with a carbon residue that remains in place. In effect, heating the underground fossil-fuel deposit duplicates the distillation and thermal-cracking processes found in a refinery. These processes offer two major advantages:

- *Abundant light crude oil*. Fossil-fuel resources are very large. For example, the United States has the largest oil shale deposits in the world. The midpoint estimate is 800 billion barrels of recoverable oil, or about three times that of Saudi Arabia. At current rates of U.S. crude oil consumption (~20 million barrels per day), there is sufficient oil shale to meet the U.S. liquid-fuel demand for ~100 years. The world resources of oil shale and coal far exceed those of crude oil.
- *Control of carbon dioxide emissions*. Unlike the circumstances in a refinery, the solids from an underground thermal-cracking process (petrocoke, char [from coal], spent oil shale, etc.) remain underground sequestered as carbon. While many questions remain unanswered about large-scale sequestering of carbon as carbon dioxide, we know that carbon sequestered as carbon (coal) works. If the heat is provided by an energy source that does not emit carbon dioxide, the result would be low emissions of carbon dioxide from the entire production process because a high-quality crude oil distillate is produced that requires little added refining to produce transport fuels.

Experimental work and pilot plants have progressed the furthest for the underground recovery of oil from shale. In this application, the leading candidate for underground heating of the geology is electricity. Heating oil shale yields both liquids and gases. Currently it is proposed to burn the gases (one-third of the energy recovered) to provide the electricity that is required. A greenhouse-neutral heating option exists—the use of high-temperature reactors to produce the high-temperature heat (Forsberg, 2006) required to heat oil shale (Fig. 3). The heat is transferred from the reactors to the oil shale using liquid-metal or liquid-salt heat-transport loops.

Nuclear heat provides several potential advantages. The energy requirements for retorting the oil shale are reduced by a factor of 2. Direct use of high-temperature heat avoids the conversion of heat-to-electricity (with all the associated losses) and subsequent use of the electricity to produce heat. Thus, expensive electricity is replaced with lower-cost thermal energy. The products from retorting the oil shale are recovered as products, and none are burnt to produce the heat required to operate the process. Carbon dioxide and other air emissions from the production process are avoided. About 12 GW(t) of high-temperature heat would be required to produce a million barrels of oil per day. The required temperatures would be near 700 °C.

The same technology can be potentially applied to old oil fields, oil sand deposits, and coal deposits. In effect, nuclear heat has the potential to create massive quantities of light distillate crude oil that can be converted with little energy and limited carbon dioxide emissions into traditional liquid fuels with sequestration of the carbon from the underground thermal-cracking process as carbon

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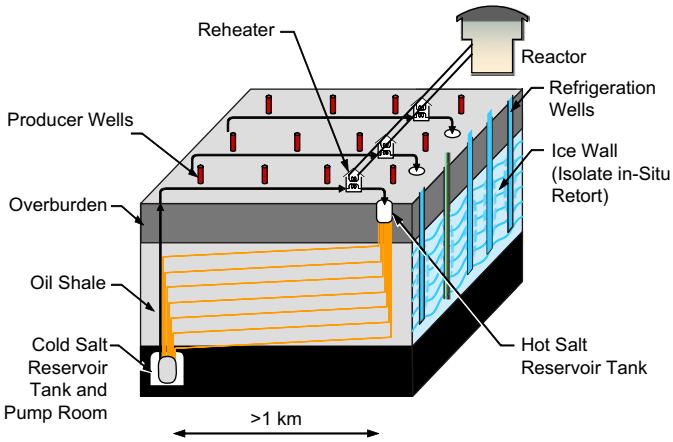

Fig. 3. One configuration for underground heating of oil shale with nuclear heat.

in the original fossil-fuel deposits. There are strong incentives to develop a nuclear–fossil production system to produce high-quality light crude oil in a world where (1) most of the conventional resources of light crude oil are in politically unstable countries and (2) constraints have been imposed on carbon dioxide emissions.

2.3. Nuclear–biomass liquid-fuels production

There are major worldwide initiatives to produce liquid fuels from biomass. Liquid fuels from biomass are greenhouse neutral. Biomass is produced by sunlight, carbon dioxide from the atmosphere, and water. The carbon dioxide from burning biomass fuels recycles the carbon dioxide back to the atmosphere. No net increase in atmospheric carbon dioxide levels occurs with biomass fuels. However, the production of liquid fuels from biomass is currently limited.

Available data indicate that U.S. biomass resources are about typical of the world as a whole; thus, U.S. biomass data will be used herein in understanding the liquid-fuels potential of different biomass feedstocks in terms of liquid-fuels production. The United States (Perlack et al., 2005) could produce about 1.3 billion dry tons of biomass feedstock per year (Table 1) for conversion to liquid fuels without major cost or availability impacts on the production of food or fiber. Except for the grains, most of the biomass resources are cellulosic biomass that cannot be used as food for humans.

In the United States, the largest biomass resources are crop residues with corn stover (corn stocks and corn cobs) being the primary crop residue. However, the forms of biomass are highly diverse which implies that no single technology will be used to produce liquid fuels from biomass feedstocks. Even in urban areas, significant biomass resources exist (refuse, manufacturing wastes, etc.). The energy value (Forsberg, 2007a) of the 1.3 billion tons of dry biomass per year that is available in the United States depends upon the form in which it is used.

- *Burnt biomass*. The energy content of the biomass, if burnt, would be equal to burning 9.8 million barrels of diesel fuel per day; however, additional energy would be required to grow, collect, and transport the biomass-to-furnaces.
- *Fuel ethanol*. If the biomass were converted to fuel ethanol, the energy value of the ethanol would be equal to about 4.7 million barrels of diesel fuel per day. This scenario assumes that some of the biomass is converted into ethanol and that the remainder of the biomass provides the energy for the biomass-to-ethanol conversion processes. The energy value of the product ethanol is only half that of the original biomass. Like the conversion of heavy oils and coal to liquid fuels (Fig. 1), biomass requires significant energy inputs for production of high-quality liquid fuels.
- *Diesel fuel*. If all of the carbon in the biomass were converted to diesel fuel, 12.4 million barrels of diesel fuel could be produced per day. This assumes that nonbiomass energy sources provide the needed energy to operate the biomass-to-fuel plants and to produce the hydrogen needed for the conversion process. Because of the nonbiomass energy and hydrogen inputs into the biomass-to-fuels plant, the energy value of this diesel fuel exceeds the energy value of the original biomass. The quantity of available diesel fuel would be approximately equal to the transport fuel demand of the United States.

Table 1
Sustainable annual biomass availability for liquid-fuel production in the United States

Agriculture		Forest residues	
Source	Millions of dry tons	Source	Millions of dry tons
Grains to biofuels	87	Manufacturing residue	145
Crop residues	428	Logging debris	64
Perennial crops	377	Fuel reduction treatments	60
Process residues	106	Fuel wood	52
		Urban wood waste	47
Total agriculture	998	Total forest	368

For the United States, liquid fuels from biomass could potentially meet the nation's need for liquid transport fuels, but only if the biomass is used as a feedstock and not as the energy source to operate the biomass-to-liquid-fuels conversion plants. The same principle is applicable worldwide. When used to provide this energy, nuclear energy becomes the enabling technology to convert biomass from an auxiliary source of liquid transport fuels into the primary source of liquid transport fuels in a transportation system with no significant greenhouse gas emissions.

The use of biotechnology to increase the biomass yields of plants for fuels is at an early stage of development. Much work is under way to develop plants with (1) higher biomass yields and (2) selected biomass constituents. Over a period of decades, dramatic increases in biomass production may be possible with plants optimized for fuel production. For example, the corn yield per acre in the United States has increased by a factor of 6 over an 80-year period (U.S. Department of Agriculture, 2003). Longer-term options include nontraditional biomass plants such as algae and kelp that could be grown in locations that are unsuitable for traditional biomass and that potentially require much less land (Farrell et al., 2008).

The nuclear–biomass liquid-fuels option (Forsberg, 2007a) is not a single option but rather three options that could be implemented sequentially as technology is developed. Each option requires more sophisticated technology, produces more liquid fuels per unit of biomass, and requires more energy from the nuclear component of such a system.

2.3.1. Ethanol from starch

Today fuel ethanol in the United States is primarily made from starch with corn being the primary feedstock. Corn kernels contain carbohydrates (starch) and proteins. In the corn-to-ethanol process, enzymes convert the carbohydrates to sugar, which is then fermented to produce ethanol. About two-thirds of the corn kernel is starch that becomes ethanol. The nonfermentable components, which consist primarily of proteins and the by-products of fermentation, become animal food or are converted to other useful

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products. Because of the value of the protein as an animal food, these by-products are not burnt to produce energy to operate the plant. In most cases, natural gas is used to provide this energy.

The non-solar-energy input to grow the corn and convert it to ethanol is typically about 70–80% of the energy value of the ethanol (Hill et al., 2006). Most of that energy is supplied by burning fossil fuels. About one-half of that energy input is in the form of low-temperature, low-pressure (150-psi) steam (McAloon et al., 2000) used within the ethanol plant.

Because ethanol plants require low-temperature (180 °C) steam, the steam from the nuclear reactor would first go through high-pressure turbines to produce electricity and then be sent to the ethanol plant. In the ethanol plant, the steam would be condensed and warm water would be returned to the nuclear power plant. Almost all of the heat would come from condensing the steam. Modern steam systems would allow more than a mile of separation between the reactor and the ethanol plant; thus, the ethanol plants would be located beyond any security perimeters.

The cost of such steam (Forsberg et al., 2007a) can be determined from the price of electricity assuming that the utility wants the same income from selling steam that it would obtain from converting the steam to electricity and selling that electricity. For a representative electricity price of $53.89/MW h(e), the corresponding steam price would be $10.67/MW h(steam), or $3.13 per million Btu. The price for steam is about half the price of natural gas in the United States. The cost of heat is low because the ethanol plant requires low-temperature steam, not the more valuable high-temperature steam.

A large ethanol plant producing 100 million gallons of ethanol per year requires about 80 MW(t) of steam, the equivalent of 4.73 million liters of ethanol per year per megawatt (thermal) of steam. Ethanol plants would require 19.9 GW(t) of low-temperature steam to produce ethanol with the energy equivalent of a million barrels of diesel fuel per day. Because of the favorable economics, several nuclear utilities are considering sale of steam to ethanol producers. However, the available feedstocks of starch are limited because of competing uses. Thus, the total quantity of liquid fuels that can be produced from starch is limited.

2.3.2. Ethanol from cellulose

Most of the world's biomass is cellulose, and most of the world's feedstocks that could be converted to liquid fuels are cellulosic feedstocks (Table 1). Consequently, it is expected that the next-generation biomass-to-liquid-fuels plants will convert cellulosic biomass into ethanol. Pilot-plant facilities are operating. Current plans for conversion of cellulosic biomass-to-ethanol involve separation of the cellulosic components from lignin—the other major component of biomass. Enzymes convert the cellulosic feedstocks to sugars, which are fermented to produce alcohol, while the lignin that cannot be converted to ethanol is burnt for energy.

To maximize liquid-fuel production per unit of biomass, the lignin must also be converted into liquid fuels rather than burnt as boiler fuel. This can be done by using nuclear energy, rather than burning lignin, to provide the energy (primarily steam) for ethanol production and by commercializing methods to convert the available lignin-to-liquid fuels. Several processes to convert this lignin-to-hydrocarbon fuels are under development (Ragausk et al., 2006; U.S. Department of Energy, 2007a; Montague, 2003). Most of these processes require limited quantities of hydrogen for hydrotreating, a product that can be produced by nuclear reactors.

If lignin is converted to liquid fuel and if steam from nuclear plants replaces the lignin that was to be burnt as a fuel, the energy content of the liquid fuels per unit of biomass feedstock can potentially be increased by 50% and about half the U.S. demand for liquid transport fuels could be met. Because the primary nuclear energy input is in the form of low-temperature steam (something that nuclear power plants are very good at producing at low costs), the economics are potentially competitive worldwide.

There are limitations. The cellulosic-to-ethanol technology is in the pilot-plant stage of development; however, large resources are being provided by governments and venture-fund organizations to commercialize the technology. The commercialization of the lignin-to-fuel technology is behind the cellulosic-to-ethanol technology. Last, there will be practical limitations on the use of nuclear energy for liquid-fuels production. The weight and volume of biomass increase shipping expenses, and not all biomasses will be within economic shipping distances of existing or future nuclear power plants.

2.3.3. Biomass-to-hydrocarbon fuel

To maximize the energy value of the liquid fuel per unit of biomass, the final liquid fuel should be a hydrocarbon. Chemical processes such as Fischer–Tropsch can convert biomass into hydrocarbons such as diesel fuel. The energy value (Ragausk et al., 2006; Shinnar and Citro, 2006; Agrawal et al., 2007) of these liquid fuels per unit of biomass input is 3–4 times greater than that achieved by using biological processes to produce liquid fuels and biomass as the energy source for the conversion plants. This is a consequence of two factors. All of the carbon is converted to fuel. No biomass is burned to provide energy. No biomass is consumed in a fermentation process that converts cellulose to ethanol and carbon dioxide. Second, the biomass is fully converted into a hydrocarbon [$(CH_2)_n$] rather than into ethanol. Hydrocarbons have a higher energy value per carbon atom.

This option requires significant external energy input in the forms of hydrogen, heat, and electricity. Recent analysis (Ragausk et al., 2006) has provided estimated quantities of hydrogen required for conversion of biomass-to-diesel fuel. About 0.25 kg of hydrogen is required per liter of diesel fuel (0.95 kg/gal) produced. This is the longer-term nuclear–biomass option, in which the economics are strongly dependent upon nuclear–hydrogen production costs.

3. Peak electricity production

3.1. The challenge

Electricity demand varies daily, weekly, and seasonally. Today fossil fuels are primarily used to match electricity production with fluctuating electricity demand. These fossil fuels are used because (1) they are inexpensive to store (coal piles, oil tanks, and underground natural-gas storage) and (2) the technologies for conversion of fossil fuels to electricity have relatively low-capital-costs. The production of intermediate- and peak-load electricity is a major use of fossil fuels.

The use of fossil fuels to meet variable electrical demands may be limited in the future because of concerns about climate change. While carbon dioxide from fossil power plants may be sequestered underground, carbon dioxide sequestration systems are likely to be uneconomic for the production of intermediate and peak electricity because of high capital costs. Recent assessments (Massachusetts Institute of Technology, 2007) indicate that sequestration may increase bus-bar electrical costs by up to 40% for base-load fossil power production systems. While such systems will likely be competitive in much of the world as central electric power plants that operate at constant power levels, these systems are likely to be uneconomic for peak power production in which the power-generating equipment is used for limited periods of time each year.

Renewable forms of electricity (wind and solar) compound the challenge. The output of these energy sources is highly variable on a day-to-day basis and thus requires large peak electricity production capacity as backup power. Much of the world also

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experiences very large seasonal variations in renewable electricity output. In some parts of the world, such as the southwestern United States, the peak seasonal demands for electricity match potential renewable electricity generation. For example, the air-conditioning load is greatest when the sun is the hottest. In other parts of the world, the seasonal variations in output of renewable forms of electricity do not match the customer demands for electricity. This implies the need for seasonal energy storage.

Renewable electricity is the great uncertainty in the future of electricity production. Wind is competitive in some markets. Solar cells are currently too expensive for large-scale unsubsidized production of electricity. However, no fundamental reasons have been identified why they should be intrinsically expensive given that the material quantities required per unit of power output are very small. Proposals (Zweibel et al., 2008) have been developed for national solar systems to meet U.S. energy needs. While only time will ultimately determine if photovoltaics and other renewable electric systems will become highly competitive, there is the real potential that they could become a low-cost source of electricity. However, their ability to make a major contribution to the world electricity demand depends upon deploying technologies that produce backup power when the sun does not shine and the wind does not blow.

Each of the existing major nonfossil methods to produce peak electricity has major limitations:

- *Hydropower*. Hydroelectricity is used for peak power production. However, the use of hydropower depends upon large differences in elevation that exist in only some parts of the world. One variant of hydroelectricity is pumped storage, in which water is pumped uphill during times of low electrical demand and goes through the turbines at times of high electrical demand. In some parts of the world, these systems can meet daily requirements for peak electricity. Nevertheless, they are incapable of meeting the variations in seasonal electrical demands because the energy storage capacity in the form of water in reservoirs at higher elevations is limited.
- *Compressed air energy system (CAES)*. CAES uses compressed air as the storage media. When excess low-cost power is available, air is compressed and stored in underground caverns. When there is a need for peak electricity, the compressed air is fed to a combustion gas turbine to produce electricity. In a gas turbine, 40–50% of the energy produced by the turbine is used to compress incoming air; thus, the gas-turbine electricity output is increased by a factor of 2 by using compressed air from storage caverns rather than compressing the air as needed. Several such systems are in operation, and the coupling of such systems to solar electricity has been proposed (Zweibel et al., 2008). CAES can operate in a nonfossil mode by sending the compressed air through the turbines without burning fuel. However, the energy content of compressed air is low, making it very expensive to use CAES for seasonal storage of electricity.
- *Nuclear*. Traditional nuclear power plants can be used for peak power production; however, these are capital-intensive power systems. Partial-load operation implies high cost electricity.

These considerations lead to the conclusion that in a carbon dioxide–constrained world, one of the great electricity challenges is finding low-cost methods to meet variable electrical demands. A definite need exists to find alternatives to the use of fossil fuels in this role today, but the capital-intensive, low-operating-cost characteristics of nuclear and renewable electricity make these energy sources poor options for peak power production. Two nuclear–hydrogen options to address this challenge are described.

3.2. Hydrogen intermediate and peak electricity system (HIPES)

HIPES (Forsberg, 2007b) is an advanced system for peak power production with the potential capability to store energy on a daily, weekly, and seasonal basis. HIPES consists of three major components (Fig. 4).

- *Hydrogen production*. Hydrogen is produced from water, with the by-product production of oxygen. The hydrogen and oxygen can be produced by (1) dedicated nuclear plants or (2) use of electricity at times of low electrical demand.
- *Hydrogen and oxygen storages*. Underground storage facilities are used for the low-cost storage of hydrogen and oxygen on a daily, weekly, or seasonal basis.
- *Hydrogen-to-electricity conversion*. Fuel cells, steam turbines, or other technologies are used to convert the hydrogen and oxygen to electricity. The use of the oxygen with the hydrogen distinguishes this technology from other methods used to produce peak electric power.

The economics of HIPES are based on (1) minimization of the cost of hydrogen production by producing hydrogen at the maximum rate possible from capital-intensive facilities or using low-cost electricity at times of low electricity demand; (2) low-cost bulk hydrogen and oxygen storages; (3) low-capital-cost, high-efficiency conversion of hydrogen and oxygen to electricity; and (4) the large price differential between peak and base-load electricity.

In many markets the price of peak electricity is 3–4 times that of base-load electricity. When using electricity from the electrical grid for the production of hydrogen and oxygen, HIPES can deliver about 1 kW h of peak electricity for every 2 kW h of electricity inputted into the system. The differential in electric prices is sufficient to cover this cost of converting base-load electricity into peak electricity.

3.2.1. Peak electricity production

The characteristic of all methods of peak and intermediate electricity production is that the equipment is operated for limited periods of time ranging from a few hundred hours to several thousand hours per year. For favorable economics, the equipment to convert the fuel-to-electricity must have low-capital-costs. Two technologies (fuel cells and steam turbines) have been identified for conversion of hydrogen and oxygen to electricity at higher efficiencies and lower capital costs than those available with existing fossil-fuel methods (such as combined-cycle plants) for peak power production. The steam turbine option (Fig. 5) is described herein.

Hydrogen, oxygen, and water are fed directly to a burner to produce high-pressure, very high-temperature steam. Because the combustion temperature of a pure hydrogen–oxygen flame is far beyond that acceptable for current materials of construction, water is added to lower the peak temperatures. The technology is that of a low-performance rocket engine. The resultant steam is fed directly to a very high-temperature turbine that drives an electric generator. Through the use of advancing gas-turbine technology with actively cooled blades, it is expected that peak steam temperatures at the inlet of the first turbines can approach 1500 °C. The projected heat-to-electricity efficiency for advanced turbines approaches ~70%, starting with compressed oxygen and hydrogen from the storage facilities.

The technology is based on ongoing development of an advanced natural-gas electric plant that uses oxygen rather than air (Anderson et al., 2004). Combustors with outputs of ~20 MW(t) are being tested. With a feed of natural gas and oxygen, a mixture of steam and carbon dioxide is created. After it passes through the turbine to the condenser, the steam is condensed and the carbon dioxide is available for (1) injection into oil fields to increase the

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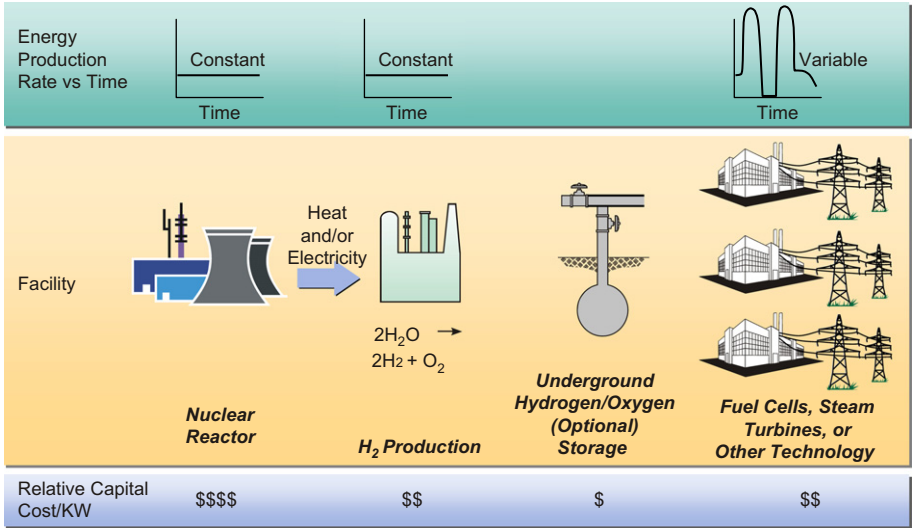

Fig. 4. Hydrogen intermediate and peak electrical system.

recovery of oil and/or (2) sequestration. The higher heat-to-electricity efficiency and the production of a clean carbon dioxide gas stream for long-term sequestration of the carbon dioxide greenhouse gases has created strong incentives to develop oxy-fuel combustors for burning of fossil fuels.

The capital costs (Forsberg, 2007b) are significantly less than those for existing methods to convert fossil fuels to electricity. The preferred method today for peak power production is the natural-gas-fired combined-cycle plant with a high-temperature gas turbine producing electricity and the hot gas-turbine exhaust being sent to a steam boiler with the steam used to produce additional electricity. As is the case for traditional combined-cycle plants, the HIPES turbine remains but the need to compress air as an oxidizer is eliminated as well as the massive gas flow of nitrogen (80% of air) through the system. Equally important, the expensive high-surface-area boiler in the combined-cycle plant is also eliminated. These changes simultaneously increase efficiency (55–70%) and lower the capital costs. This new option is still in an early stage of development.

3.2.2. Hydrogen and oxygen storages

The central challenge in replacing fossil fuels for variable electricity production is the need for a method to store energy.

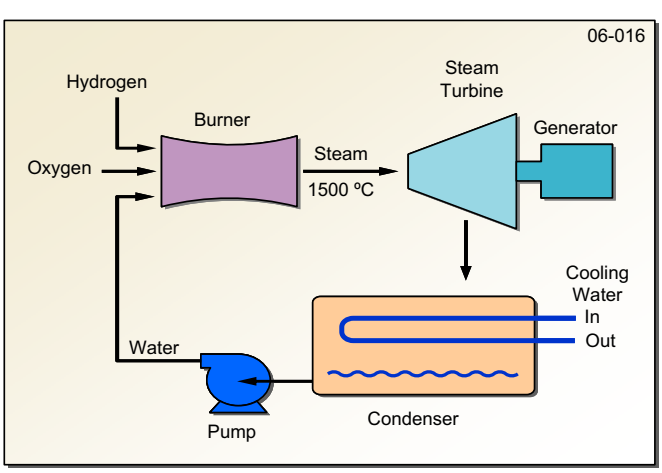

Fig. 5. Oxygen–hydrogen–water steam cycle.

Unlike electricity, hydrogen can be stored inexpensively (Forsberg, 2005) for days, weeks, or months in large underground facilities with the same technology used to store natural gas. In the United States, approximately 400 underground storage facilities store at high-pressure a third of a year's production of natural gas in the fall before the winter heating season.

This storage method is the enabling technology to match hydrogen production to demand. However, the required technology has massive economics of scale. Hydrogen storage on a small scale is 1–2 orders of magnitude more expensive than on a large scale. The characteristics of centralized storage imply economic penalties for decentralized hydrogen production systems that must then use collector pipelines to move hydrogen to centralized storage.

A limited number of such hydrogen storage facilities now exist in Europe and the United States. Equally important, measurements of helium concentrations in different geologies from radioactive decay and the long-term existence of natural-gas deposits provide evidence that many geologies have the low gas permeability required for hydrogen storage. Although studies on oxygen storage have been conducted, this technology has not yet been demonstrated.

At the current time, hydrogen is the only nonfossil energy source for which the technology exists to store energy on a scale sufficiently large to cover seasonal variations in electricity demand. This is because hydrogen storage has both the compressed-gas storage energy as in CAES and the much larger chemical energy associated with the hydrogen. The high energy density drastically reduces the gas storage volumes and thus the storage costs.

3.2.3. Hydrogen and oxygen productions

There are many methods to produce hydrogen and oxygen for HIPES. However, production and transportation economics will favor centralized hydrogen production and favor nuclear–hydrogen production in much of the world. This is a system characteristic independent of the specific hydrogen production technology that is chosen.

- *Production economics*. Hydrogen production is a chemical process with chemical process characteristics and cost-capacity scaling factors (between 0.6 and 0.7) that strongly favor large plants (Forsberg, 2008b). Today the largest hydrogen consumers are refineries and ammonia (fertilizer) plants that typically use natural-gas-to-produce hydrogen. The largest

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refinery natural-gas-to-hydrogen plant has a hydrogen output that would require three 1000-MW(e) nuclear plants using electrolysis to match production.

- *Transportation*. Hydrogen is expensive to transport (Summers, 2003; U.S. Department of Energy, 2007b), with large economics of scale. The transport costs are several times higher than that of natural gas because of the low molecular weight, and hence low density of hydrogen (Bossel and Eliasson, 2003). With hydrogen production costs between $1 and $3/kg, transportation costs can become the dominant cost of delivered hydrogen. A kilogram of hydrogen has about the same energy during combustion as a gallon of gasoline. This has several implications.
  - *Centralized versus decentralized production*. It is relatively economic to move hydrogen (like natural gas) from centralized facilities to distribute users down the pressure gradient—but not to move it in the reverse direction. This combination of factors (Forsberg, 2008b; Bossel and Eliasson, 2003) makes it expensive to move hydrogen up the pressure gradient from decentralized production sources to central storage and creates a major economic barrier to coupling decentralized hydrogen production systems (such as some types of solar hydrogen systems) with the bulk storage systems required by HIPES.
  - *Production technology*. The high hydrogen transport costs will likely determine preferred hydrogen production technologies for much of the world. Wind may be the preferred technology where there are high wind speeds. Solar energy may become a competitive option where there are sunny skies. For fossil fuels, in a carbon dioxide-constrained world, it will be competitive option where carbon dioxide by-product of hydrogen production can be sequestered underground. However, only some parts of the world have geologies suitable for carbon dioxide sequestration (Massachusetts Institute of Technology, 2007; U.S. Department of Energy, 2007c) and thus would be suitable for hydrogen production using fossil fuel. Nuclear energy does not have these geographical constraints and thus may become the primary long-term method of hydrogen production because it avoids the high costs of long-distance hydrogen transport.

HIPES requires oxygen. This favors nuclear and renewable hydrogen production systems that simultaneously produce oxygen as a by-product of hydrogen production (Forsberg, 2008b). The alternative source of oxygen is oxygen separation from air with an energy cost of ~230 kW h/ton and an economic cost of ~$20/ton. That is a credit of $0.176/kg H_2 for methods that coproduce oxygen relative to costs for hydrogen produced from fossil fuels—a process that produces only hydrogen. Economics and transport safety (Forsberg et al., 2007b) factors both support oxygen production close to the storage facilities.

Hydrogen and oxygen for HIPES may be produced by electrolysis with electricity from the electrical grid. However, there are economic incentives for production at nuclear plant sites even if the hydrogen production technology is electrolysis. The various production systems have large requirements for motive power (compressors) and heat that can be directly provided by the nuclear plant. Co-siting also avoids electricity transmission losses.

3.3. Nuclear-combustion combined-cycle (NCCC) systems

A second peak electricity option is an NCCC power plant (Forsberg and Conklin, 2007) that uses heat from a high-temperature nuclear reactor and hydrogen to meet base- and peak-load electrical demands (Fig. 6). For base-load electricity production, air is first compressed; then flows through a heat exchanger, where it is heated to between 700 and 900 °C; and finally exits through a high-temperature turbine to produce electricity. The heat, via an intermediate heat-transport loop, is provided by a high-temperature reactor. The hot exhaust gases from the Brayton-cycle turbine are then fed to a heat recovery steam generator that provides steam to a steam turbine for added electrical power production.

To meet peak electrical demand, after the nuclear heating of the compressed air, hydrogen is injected into the hot air and burnt to increase power levels. This process raises the peak inlet temperatures to both the gas turbine and the steam turbine with corresponding increases in electricity output by up to a factor of four. In this mode of operation, the peak gas-turbine inlet temperature is ~1300 °C—about the same temperature and operating conditions as those of a standard utility natural-gas-fired combined-cycle gas turbine that exhausts its heat to a bottoming Rankine steam cycle.

The nuclear heat raises the temperature of the incoming air above the auto-ignition temperature of the fuel—the temperature at which the fuel will spontaneously burn; thus, the fuel-to-air ratio does not need to be controlled to ensure flame stability and plant operation. Consequently, the combined-cycle plant can operate at any power levels between base-load nuclear and the maximum peak power output. The response time to changes in power demand is much faster in an NCCC plant than in a plant that uses traditional fossil-fueled combustion turbines. This capability for rapid changes in power production is a result of the difference between operation of a conventional combustion turbine and that of an NCCC plant.

- *Traditional Brayton power cycle*. In a traditional combustion turbine, the fuel-to-air ratio must be controlled to ensure flame

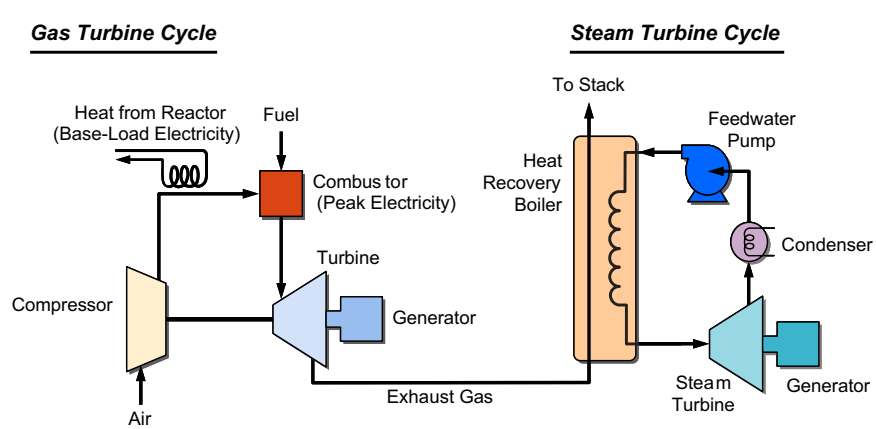

Fig. 6. Nuclear-combustion combined-cycle electric plant.

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stability. To increase the power demand, the airflow and fuel injection rate are increased simultaneously. As more fuel is added, the extra-power is first used to increase the airflow. Consequently, a significant lag time exists between the signal for more power and the delivery of that power.

- *NCCC power cycle*. With nuclear base-load heat, the compressor operates at a constant speed with a constant airflow through the system. When additional electricity is required, fuel is injected into the system. The time between fuel injection into the burner and an increase in power level is determined by the flight time between the fuel injectors and the turbine—a fraction of a second. The air compressor does not change speed or require more energy.

The nuclear preheating avoids the use of expensive fuels to heat air to >700 °C. An NCCC plant would use the same hydrogen production and storage systems as HIPES, providing the option for production of hydrogen by electrolysis at periods of time with low electricity demand. With such a system, the reactor would operate continuously at base-load conditions but the station electricity output to the electricity grid would be from zero to the maximum peak capacity of the plant.

3.4. Peak power challenges

The variable electric power output of most electrical grids is achieved by varying the power output of low-capital-cost, premium-fueled fossil power plants. If there are constraints on the use of fossil fuels, economically meeting variable electrical demand becomes one of the grand challenges for future electrical girds. HIPES and NCCC systems are potential solutions to the challenge of producing peak electricity and are also enabling technologies for the large-scale use of renewable electricity production options such as solar and wind in a nuclear–renewable electricity system. Without a method to effectively store electricity, the contributions of renewable electricity will be limited.

4. Conclusions

The traditional paradigm is that nuclear, fossil, and renewable energy sources are competitors. Today we face two sustainable energy challenges: the need to avoid climate change and the need to replace traditional crude oil as the basis of our transport system. To address these challenges, radical changes in our energy system will be required. This requires rethinking the roles of different energy sources and considering energy systems that tightly couple nuclear, fossil, and renewable energy sources to create nuclear–fossil systems and nuclear–renewable systems.

The pathway to such a future will likely be initiated in the production of liquid fuels. Nuclear–biomass and nuclear–fossil futures involve nuclear plants providing heat—a product for which the nuclear economics in many cases are economically competitive today and where the initial nuclear–biomass liquid-fuel options require no new technology. In the longer term, nuclear energy is potentially the enabling technology for the large-scale use of renewable electricity because nuclear energy may be able to provide peak electricity when the sun does not shine or the wind does not blow.

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