Hybrid baseload nuclear power for variable electricity and fuels

BY CHARLES FORSBERG

Wider use of nuclear heat could address both the intermittency of renewable energy and the high cost of domestic liquid fuels.

THE WORLD FACES two energy challenges. The first is the release of carbon dioxide to the atmosphere from the burning of fossil fuels, with the potential for large changes in climate and in the acidity of water and soil. This threatens food supplies, because as climate changes, agriculture must move to less productive soils. Also, humanity's infrastructure—designed for specific climate and sea-level conditions—would have to be rebuilt.

The second challenge is dependence on Persian Gulf oil and gas. The four largest oil companies are the national firms of Iran, Saudi Arabia, Qatar, and Iraq, with their respective combined oil and gas reserves of 320, 300, 180, and 140 billion barrels (gas reserves are included here in barrels-of-oil-equivalent, in terms of energy content). For comparison, ExxonMobil, the largest Western oil company, has reserves of 15 billion equivalent barrels of oil. Oil prices arise from political decisions, and oil dependence can be a cause of war.

Nuclear energy is used today for baseload electricity production because its operating costs are low, even though its capital costs are high. Electricity, however, meets only 40 percent of energy demand in the United States, and only two-thirds of that electricity is baseload. The traditional vision of nuclear energy implies meeting perhaps a quarter of the nation's energy demand (the upper limit of baseload, as currently reckoned). A broader vision of nuclear energy is required in order to match the world's need for electricity and fuels.

Nuclear power plants have been coupled to a variety of systems to meet demands for industrial heat—a practice that will grow with time—but the greater challenge is to produce variable electricity, which is added to baseload electricity as needed to meet changes in demand. Variable electricity is now produced by the burning of fossil fuels, and the need for it is expected to grow with the addition of wind and solar systems, since their output is too intermittent to satisfy demand.

There could be a different path forward: the use of baseload nuclear plants to meet variable electricity demand. Electricity would be sold at times of high demand and correspondingly high prices, and nuclear heat would be used for other purposes at times of low demand and low prices. Because of the size of the electricity sector, the only application large enough to use these quantities of heat is in the fuels production sector. Because the largest renewables challenge[1] is to provide backup electricity when the wind doesn't blow and the sun doesn't shine, the economical production of variable electricity with nuclear power could enable the large-scale use of renewables.

The examples below propose three nuclear hybrid energy futures and the challenges that must be overcome in order for them to be deployed.

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CALIFORNIA ELECTRICITY STORAGE REQUIREMENTS AS PERCENTAGE OF TOTAL ELECTRICITY GENERATED

	Hourly	Weekly
Nuclear	7	4
Wind	45	25
Solar	50	17

Gigawatt-year energy storage

Today, variable electricity is produced by burning stored coal, oil, and natural gas. One nonfossil option is to store energy at times of low electricity demand in order to meet peak demand later.[2]

Estimates of the electricity storage requirements for California are given below under three idealized futures, in which all electricity is generated by nuclear, wind, or solar power plants. In each case, the plants over one year generate the kilowatt-hours consumed by California over one year; the plants operate at their highest respective outputs to minimize electricity production costs; electricity is stored when production exceeds demand and is provided to customers when demand exceeds production; and there are no losses or inefficiencies in the electricity storage systems.

In the nuclear future, all electricity is from nuclear plants with steady-state output at all times. In the solar future, all electricity is from solar thermal trough systems in the California desert, following the National Renewables Energy Laboratory (NREL) solar performance model and Cal-

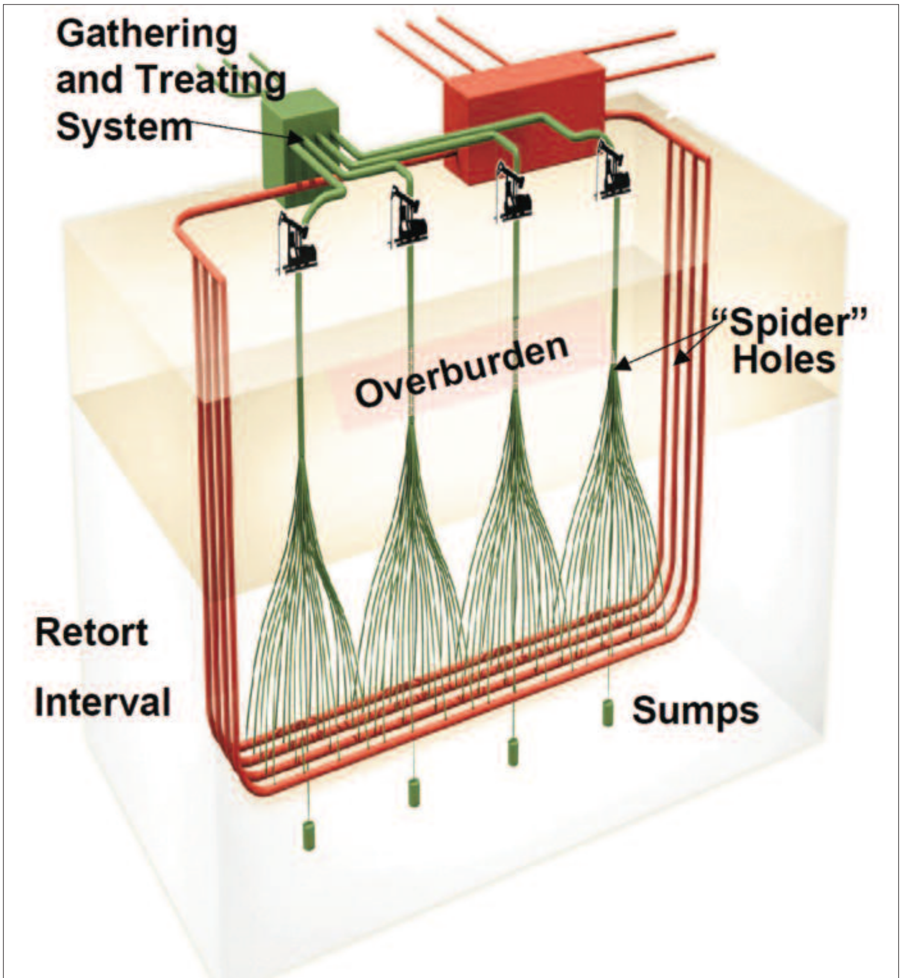

Fig. 1. Conceptual diagram of nuclear-geothermal energy storage system

ifornia solar data. In the wind future, all electricity is from wind systems, following California wind data and NREL's wind farm performance model.

The results (see table on page 33) are shown as the percentage of total generated electricity that must go into storage when production exceeds demand to meet peak demand later.

The hourly storage requirement is based on production and demand analysis for every hour in a year from recorded California demand, and data for solar and wind energy source potential within the state. For example, in the all-solar case, it is assumed that the total output of solar plants operating year-round at full capacity produce the total kilowatt-hours required to meet yearly electricity demand, but production does not match demand most of the time. Half of those kilowatt hours go to storage to provide electricity when demand exceeds the output of solar plants. In contrast, only 7 percent of the generation goes to storage if nuclear energy provides all the electricity. For an equivalent amount of electricity, therefore, the all-solar future (and the all-wind future) would require more storage capacity than the all-nuclear future.

The nuclear advantage is a consequence of two factors. First, two-thirds of electricity meets baseload demand, for which nuclear is already used because of the steady output of power reactors. Second, if nuclear power coupled to storage is used to meet variable demand, the steady output of reactors can supply most of the remaining third of the electricity that is consumed. In effect, this means that there would be a "new" baseload that comprises nearly all of the system's needed electricity.

The weekly storage requirements assume that the electricity demand is constant each week, and the storage system must address variations in electricity demand between different weeks of the year. About half of the storage requirements are seasonal; that is, methods to store energy are needed in the spring and fall for the summer and winter electricity demands. This is a function of latitude, with greater storage requirements at higher latitudes.

If renewables are to be economical, they must be less expensive than nuclear systems to cover the larger storage requirements, or some nonfossil method must be found to produce economical variable electricity. For the continental United States, an all-nuclear electrical system would have about the same storage requirements everywhere, whereas storage requirements for all renewable systems are dependent on location, with some of their lowest storage requirements in California. As shown in the table, however, storage for renewables in California as a whole would need to be much larger than storage for nuclear.

While there are many technologies (including batteries, hybrid plug-in electric vehicles, and pumped storage) to address short-term storage needs, no technologies exist to address weekly and seasonal energy storage needs—half of the energy storage market. One option to be explored is geothermal heat storage (see Fig. 1).

In this system, at times of low electricity demand, a reactor heats a cube of rock a kilometer underground, creating an artificial geothermal heat source for intermediate and peak electricity production. The heat transfer fluid is pressurized hot or cold water. This is based on two commercial technologies: (1) the heating of underground heavy oil deposits to lower the viscosity of the oil and thus enable it to be pumped, and (2) traditional geothermal electricity production.

Seasonal heat storage is primarily applicable to large nuclear systems. It is not possible to insulate rock a kilometer underground. Heat losses, however, vary by the square of the storage system size, while heat storage capacity varies by the cube of the system size. The larger the storage capacity of the system, the smaller the fraction of stored heat that is lost. For systems able to receive about 0.1 gigawatt-years (GWy) of heat, the losses are only a few percent of the stored heat. The technology works only on a large scale, implying its coupling with nuclear plants or some types of large solar-thermal plants. A gigawatt-year of heat storage could be achieved with a rock cube 400 meters on a side.

An economic analysis has been performed for a possible future New England electricity grid based on today's hourly electrical demand. Based on the assumptions used, the low-cost economic system would contain 10 GWe of baseload nuclear plants producing electricity, roughly 6 GWe of baseload nuclear plants producing electricity and heat for the storage system (with geothermal intermediate-load electricity production from the stored heat), and natural gas peaking units. The capital cost of a nuclear geothermal system is higher than that of equivalent natural gas turbines, making those turbines preferred for peak power production; these units would operate only a few hundred hours per year, where fuel costs are low.

Nuclear/shale oil

A second approach to the production of variable electricity with baseload nuclear power could be through service to an industrial market that can economically absorb gigawatts of heat at times of low electricity demand. Most industrial processes

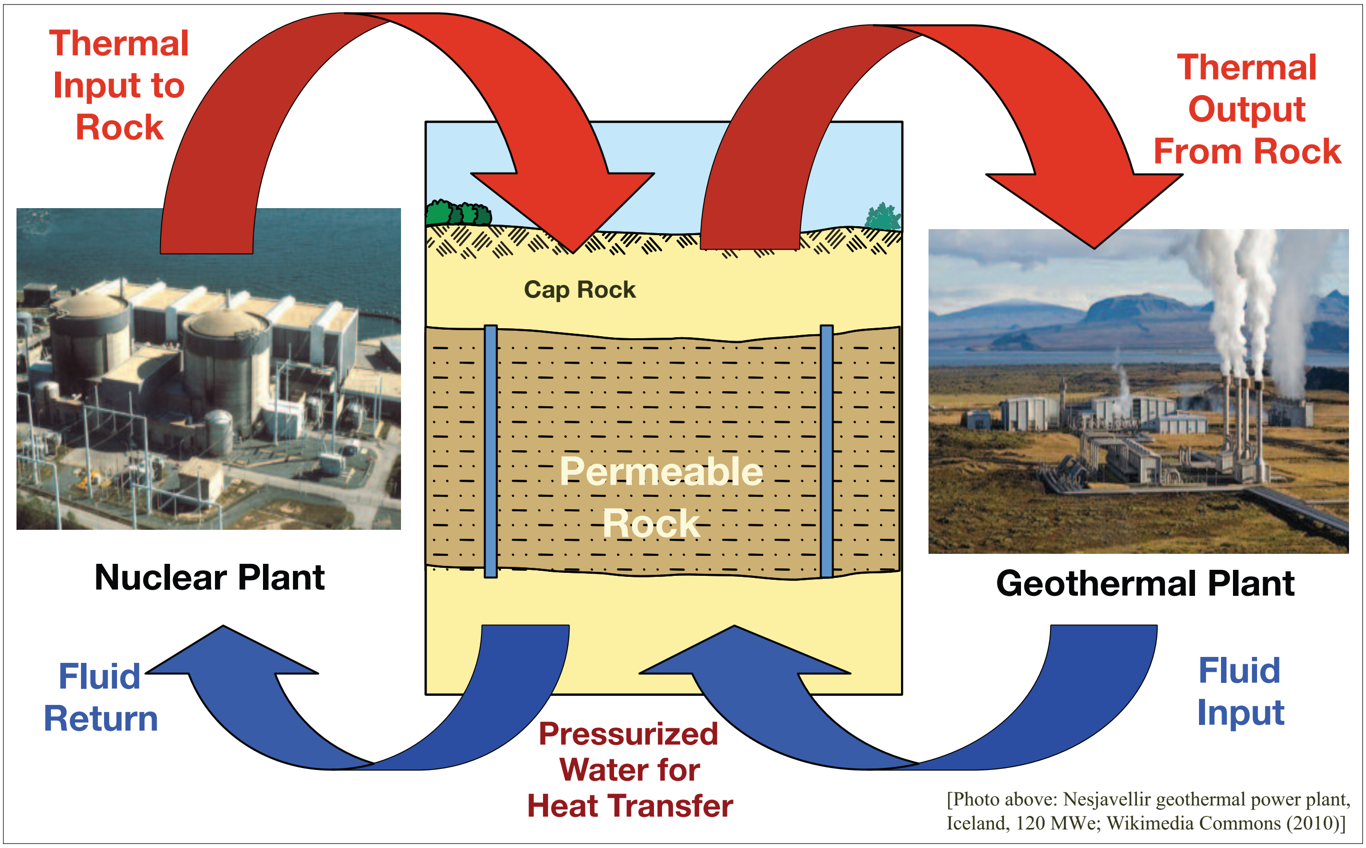

Fig. 2. Heating system for shale oil recovery

are uneconomic if operated at part load, but one such process has been found: the production of shale oil.[3]

The United States has about 60 percent of the global reserves of oil shale in the world, resources that exceed the oil reserves of the Middle East. Many of these shale deposits can produce more than a million barrels of oil per acre. The development of this resource would free the United States from dependence on foreign oil.

What oil shale contains is not petroleum, but kerogen, which upon slow heating is converted to a high-quality light oil, various light gases, and a carbon char. The shale must be heated to roughly 370 °C for this conversion to occur. It can be heated *in situ* with electrical heaters, natural gas, or steam lines (see Fig. 2). The carbon char remains underground. The energy required to convert and extract the products is about one-fourth as great as the energy content of the products, so there are major incentives to use nuclear heat to avoid burning much of the products and to reduce greenhouse gas emissions.

Because of the large quantities of oil shale per acre, in the lifetime of a single 600-MWt high-temperature reactor, the longest distance to a well head for heat injection would be less than two miles. The United States imports about 10 million barrels of oil per day. About 330 modular reactors with a total thermal output of 200 GW could produce sufficient shale oil to replace oil imports. The total heat output from these smaller high-temperature reactors would be about equal to two-thirds of the heat output from the light-water reactors now operating in the United States.

Unlike other industrial processes, shale heating is slow, requiring months to years because of the low thermal conductivity of the rock. Because of this, heat can be added to the rock at a variable rate with low economic penalties. This characteristic enables the use of baseload nuclear power for simultaneous shale oil recovery and variable peak electricity production. This is economically attractive, because electricity can be sold at premium prices when the demand is high, and shale can be heated when the price of electricity is low. The oil-bearing shales are mainly located in Colorado, Utah, and Wyoming, so the reactors' electricity would be sold to customers in the Western electrical grid. Options exist to use light-water reactors for shale oil heating.

The coupling of nuclear shale oil production with variable electricity production could dramatically lower greenhouse gas releases by replacing fossil electrical plants that provide variable electricity. Consider a system in which the nuclear plant produces 3 GWy of heat on average, one-third to heat shale and the rest for variable electricity, and the efficiency of producing electricity from nuclear and fossil plants is equal.

The 1 GWy of nuclear heat produces 4 GWy of shale oil and gas. The 2 GWy of heat devoted to variable electricity production avoids the burning of 2 GWy of fossil fuels to produce that electricity. The credit for the avoidance of greenhouse gases from fossil power plants that would have produced the variable electricity can be applied to the shale oil, which means that the total net greenhouse gas releases per liter of gasoline from shale oil that is burned would be half that of liquid fuels from other fossil sources. Nuclear shale oil may thus enable economical nuclear production of variable electricity that in turn could enable the larger-scale use of renewables because of the presence of a lower-cost source of variable electricity.

Nuclear/wind/hydrogen

A third method of producing variable electricity with baseload nuclear power would involve serving an industrial market that can economically absorb excess electricity at times of low electricity demand.[4] A nuclear/wind/hydrogen system may have that capability.

Today, wind and solar electricity, with few exceptions, are uneconomical without subsidies, but the production costs are going down. This leads to the following question: If the production cost of renewable electricity continues to decrease, is it possible for renewable electricity to become an economical large-scale source of energy? Low electricity production costs do not mean low-cost electricity for the customer, unless that electricity is generated when the customer needs electricity. Unfortunately, wind energy production cannot be relied upon to

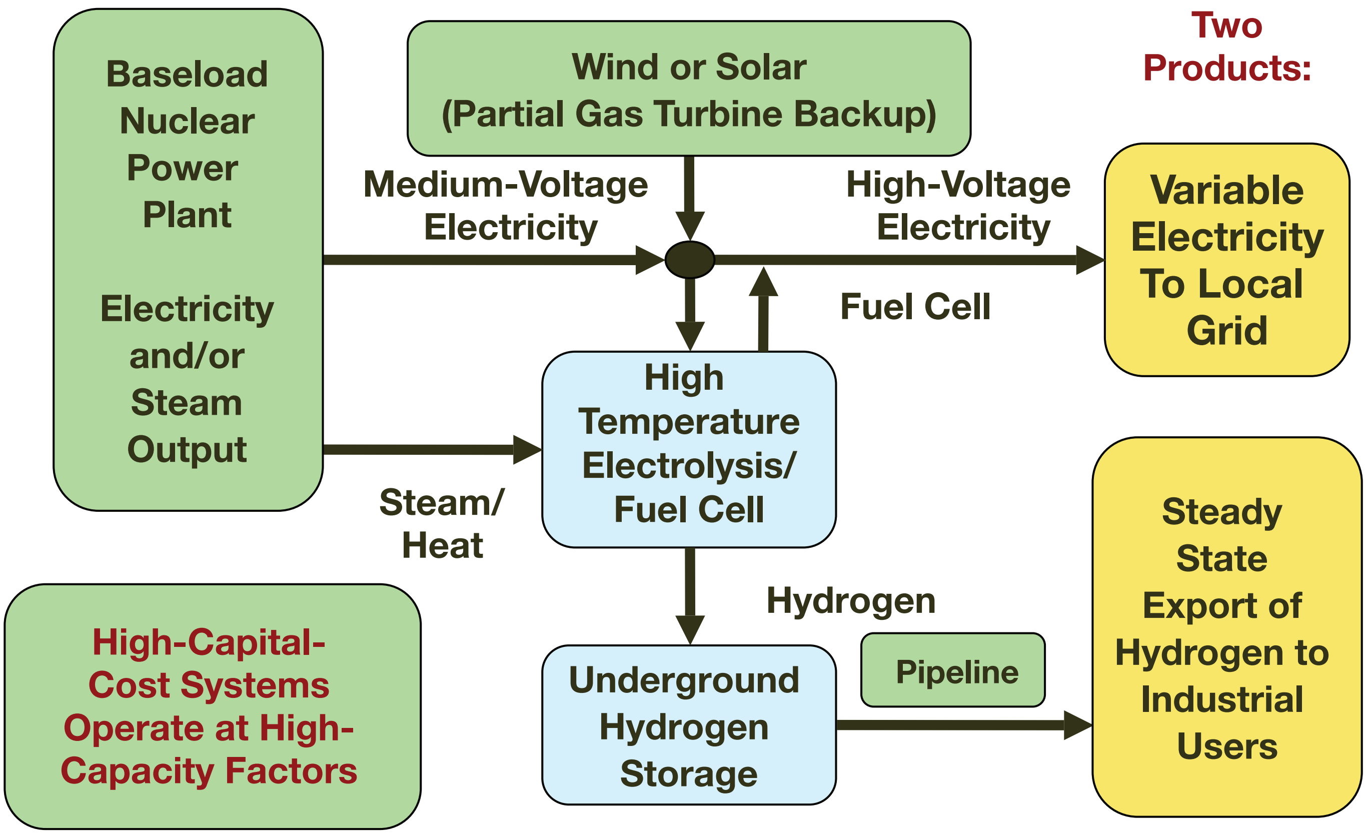

Fig. 3. Electricity-hydrogen system design

match customer demand either during the day or seasonally.

A system that may enable large-scale economical use of renewables for electricity production is shown in Fig. 3. A case study was done on a nuclear/wind/hydrogen/natural gas system to provide the total electricity demand for the Midwest electrical grid and hydrogen for the Chicago and Alberta refinery markets. The Midwest electrical grid covers parts of the north central United States and south central Canada and has a baseload demand of 39.5 GWe, an average electricity demand of 61.8 GWe, and a peak demand of 96.5 GWe.

The economics are favorable assuming significant reductions in wind turbine costs, successful commercialization of high-temperature electrolyzers for hydrogen production that can also operate in reverse as fuel cells to produce electricity, and higher-priced natural gas. Economics require that the capital-intensive low-operating-cost system components (nuclear plants, wind farms, and hydrogen pipelines) operate at near or full capacity, while lower-capital-cost components (hydrogen storage, natural gas turbines, and electrolyzers) operate at part load.

The key components include the following:

■ *Nuclear power plants*—There would be 40 GWe of baseload power reactors. The equivalent of an additional 2.5 GWe of baseload nuclear plants would produce a variable mixture of heat and electricity, with the heat used for high-temperature electrolysis of water.

■ *Wind power plants*—The system would contain 50 GWe of wind capacity, with an annual capacity factor of 35.3 percent.

■ *Natural gas turbines*—There would be 25.5 GWe of gas turbines to meet part of the electricity demands at times when there is not enough wind power. The wind turbines are also backed up in part by fuel cells.

■ *High-temperature electrolysis (HTE)/fuel cells (FC)*—HTE is the steam electrolysis of water, a process that is more efficient than traditional electrolysis because heat used to make steam partly replaces electricity. The heat would be provided from nuclear reactors that produce variable outputs of electricity and steam. A 1000-MWe nuclear reactor produces 2857 MWt of heat, which, when combined with 15 438 MWe of electricity (nuclear and wind), will produce 120.81 kg of hydrogen per second. The HTE system can be operated in reverse, as FCs, with hydrogen producing electricity at times of high demand.

■ *Hydrogen pipelines and storage*—Two 36-inch 1000-km pipelines would move the hydrogen to markets. Hydrogen would be stored underground through the same low-cost technology that is already being used for the storage of natural gas. The storage would allow the expensive long-distance pipelines to operate at full capacity, independent of the variable rate of hydrogen production.

If electrolyzers were free, they would already be used to produce hydrogen for industrial markets when electricity prices are low, but this is not the case. A reversible HTE/FC system, however, could be economical because of the characteristics of electricity demand that effectively lower the capital cost of electrolysis.

Hydrogen is more expensive than natural gas; traditionally, in fact, it is made from natural gas. Thus, one would assume that all peak electricity demands are met by gas turbines, but many gas turbines operate only a few hundred hours per year to meet peak electricity demands. For them, most of the cost is capital cost, not the cost of the natural gas.

For an HTE/FC system, there exists the option of hydrogen production when there is excess electricity, and operation in reverse (using hydrogen to produce electricity) at times of high demand. This would replace low-capacity-factor gas turbines. Hydrogen is a more expensive fuel, but the savings in gas turbine capital costs make HTE/FC the preferred option and would help pay for a major fraction of the capital cost of the HTE/FC plants. Because the cost of an HTE plant and an HTE/FC plant are nearly identical, the capital cost of electrolysis is effectively reduced, and the potential for an economical hybrid system is created.

For this set of assumptions, the economic optimization resulted in about 60 percent of the electricity produced by nuclear energy. About 5.5 GWy of wind electricity is used to produce 1.3 million tons of hydrogen per year. The HTE system, used as FCs, produces only 0.5 percent of the total electricity because of the inefficiencies of converting electricity to hydrogen (and back to electricity) that make hydrogen an expensive fuel for electricity production. In this mode, however, the FCs make up a quarter of the grid's non-wind capacity to produce electricity at times of high demand and low wind conditions.

Wind produces 26 percent of the electricity, and combined-cycle natural gas plants produce 11 percent. The system has low carbon dioxide emissions relative to traditional wind systems because natural gas backup is minimized when the wind doesn't blow. About 4 percent of the electricity goes into hydrogen production, primarily for commercial sales.

Beyond nuclear baseload

The challenges of climate change and oil dependence demand that we think beyond nuclear baseload electricity, which is partly an accident of history. We had a new nuclear technology to produce heat, and the technology to use that heat to produce electricity had already been developed for fossil-fired plants. It was the marriage of these two technologies that created the nuclear power plant as we know it.

Compare this to the development of the jet engine. It is a great technology but would have gone nowhere without the parallel development of the swept-wing aircraft that took advantage of the jet engine's unique capabilities to propel aircraft. In the context of moving nuclear energy beyond baseload electricity, we are in the position of the developers of the jet engine: Coupling technologies must be developed in order for new applications to be added.

For the three examples herein, the coupling technologies are (1) gigawatt geothermal heat storage, (2) variable steam heating of oil shale, and (3) high-temperature electrolysis/fuel cycle systems. In each case, the initial assessments indicate the potential for economical commercial systems, but it will take serious development efforts to determine whether each technology is as promising as it appears.

Since the 1970s, it has been the stated policy of the United States to reduce oil dependence, but oil dependence has grown, resulting in nearly continuous military and political intervention in the Middle East to maintain access to oil. More recently, the United States and most other countries have set goals to reduce greenhouse gas emissions, but global carbon dioxide emissions are increasing. These failures require a rethinking of energy strategies.

A part of that failure is thinking separately about fossil fuels, nuclear, and renewables. Government institutions and private companies are organized along energy sources. Hybrid energy systems that combine energy sources (such as nuclear and oil shale, or nuclear, wind, and hydrogen) have the potential to break the energy gridlock, but changes in technology, institutions, and regulation would be required.

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