The Electricity Journal 34 (2021) 107042

Contents lists available at ScienceDirect

The Electricity Journal

journal homepage: www.elsevier.com/locate/tej

Addressing the low-carbon million-gigawatt-hour energy storage challenge

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ARTICLE INFO

Keywords:
Heat storage
Biofuels
Hydrogen

ABSTRACT

The energy system of the United States requires several million gigawatt hours of energy storage to meet variable demand for energy driven by (1) weather (heating and cooling), (2) social patterns (daily and weekday/weekend) of work, play and sleep, (3) weather-dependent energy production (wind and solar) and (4) industrial requirements. In a low-carbon world, four storage options can meet this massive requirement at affordable costs: nuclear fuels, heat storage, hydrocarbon liquids made from biomass, and hydrogen. Because of the different energy sector characteristics (electrical supply, transportation, commercial, and industrial), each of these options must be developed. Capital costs associated with electricity storage at this scale using, for example, batteries and hydroelectric technologies are measured in hundreds of trillions of dollars for the United States alone and thus are not viable.

1. Introduction

Fossil fuels are remarkable. They are (1) inexpensive, (2) economic to store and (3) economic to transport globally. The storage challenge is what makes getting off fossil fuels so difficult. Wind and solar photovoltaic, unlike traditional energy sources, have no storage reserves. Some numbers tell the story (Fig. 1). We use a 100 quads of energy per year in the U.S. with about 6 weeks of storage in the system—more in winter and less in summer. This storage addresses daily to seasonal changes in energy demand while providing assured energy in the face of hurricanes, earthquakes, and multi-week weather events. Without stored energy, the energy system has no resilience. Six weeks of storage is 3.4 million GWhs; that is, the U.S. storage requirements are measured in millions of gigawatt-hours.

To understand the scale, consider options to provide a million gigawatt hours of storage for the electric sector. If the capital cost goal of battery systems at $200/kWh is achieved, the investment cost is $200 trillion—about 8 times the U.S. GNP. Today the U.S. Energy Information Agency (U.S. Energy Information Agency, August, 2021) reports installed costs of utility-scale battery systems at $589/kWh. Equally important, the decelerating cost trends with time (Fig. 2) suggest that battery costs will level off near $500/kWh as the cost of raw materials make up a larger fraction of the total costs. While large-scale battery installations have been growing rapidly, the scale is small—about 0.5 GWh of added storage capacity per year. Today 99% of U.S. electricity storage is hydroelectric pumped storage—553 GWh (DOE 2021). If we use hydro pumped storage, we would need to expand the total U.S. pumped storage capacity by a factor of 1800 for a million gigawatt hours.

Recent studies (Sepulveda, 2021) have evaluated what is required of storage to have a major beneficial economic effect on the price of electricity in a low-carbon electricity system. Electricity storage capital capacity costs must be < $20/kWh to reduce electricity costs by more the 10%–expensive storage is of little value to electrical customer. Electricity storage technologies are too expensive and or geographically limited to meet the storage challenge. As energy sources migrate away from fossil fuels, the requirements for and costs of energy storage drive the energy system design.

The U.S. energy system is based on fossil fuels that provide energy and energy storage. If one adds significant quantities of instantaneously harvested wind and solar, energy storage must be added to match production with demand. If there is a small amount of wind or solar, these generators simply reduce the consumption of natural gas or coal. However, if the harvesting capacity begins to approach the total demand for electricity, production will sometimes exceeds demand and the excess wind or solar power must be curtailed or stored. That is now occurring in locations from Germany to California.

Large-scale wind and solar change the market. Fig. 3 shows the impact on electricity production in California if half the electricity is from wind (green) and solar (gold). The incremental production costs of wind and solar are near zero. In a free market the wholesale price of electricity drops to zero at times of excess production and thus the revenue drops to zero. It creates massive economic incentives to add storage to boost revenue. This is both a daily and a weekly phenomenon;

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https://doi.org/10.1016/j.tej.2021.107042
Received 5 October 2021; Accepted 10 October 2021

there are many more hours of zero price electricity on the weekend with an incentive to store energy on the weekends for use during the weekdays. In addition, there is about a factor of two in the seasonal output of solar at the mid-latitudes (Mulder, 2014) implying a massive seasonal impact.

In systems with large wind or solar input, the costs of storage drives the cost of electricity. The U.S. Energy Information Agency (February, 2021) has estimated the levelized cost of electricity for solar ($31.30/MWh), on-shore wind ($31.45/MWh) and offshore wind ($115.04/MWh) in good locations. The levelized cost of storage using batteries is $121.86/MWh—about four times higher than the cost of making electricity. Because of the night-day cycle and cloud cover, solar systems operate only about 30% of the time. In any system with significant solar or wind this implies that most of the electricity will go through storage before going to the customer. Therefore, the cost of storage, not the cost of electricity production from wind and solar, is the primary cost of electricity to the customer. This assumes daily storage of electricity where the battery is used each day. If weekly storage of electricity, the cost of storage increases by a factor of 7 (7 days in the week) because the storage device is used only one seventh the time. More than 99% of existing electricity storage (U.S. Department of Energy January, 2021) is hydroelectric pumped storage. Most existing electricity storage is pumped hydro with estimated costs near $150/MWh (Akhil, 2013) but these costs are highly site dependent—unlike manufactured storage systems such as batteries. These systems have extremely long lifetimes relative to batteries.

The high cost of low-carbon energy storage systems is why today most storage is in the form of natural gas, oil and coal in the residential, commercial, industrial, and transportation sectors. Storage costs for fossil fuels are an order of magnitude less.

If the goal is a low-carbon energy system, the challenge requires rethinking the entire energy system in the context of energy storage—not just the electricity sector where the high costs of storage limit the use of electricity to decarbonize the economy. It starts with the observation that, in the United States, there are three major ways we deliver energy to the customer: electricity, liquid hydrocarbon fuels and gaseous fuels. We have those three delivery methods because of their respective unique characteristics that meet particular needs of society including energy storage.

- *Electricity*. It is extraordinary in its versatility and the ability to economically meet the energy needs of small devices—from hair dryers to laptops to lights to motors. It is also the most expensive form of energy to produce, store and transport. The technological requirements are demanding—must continuously control voltage

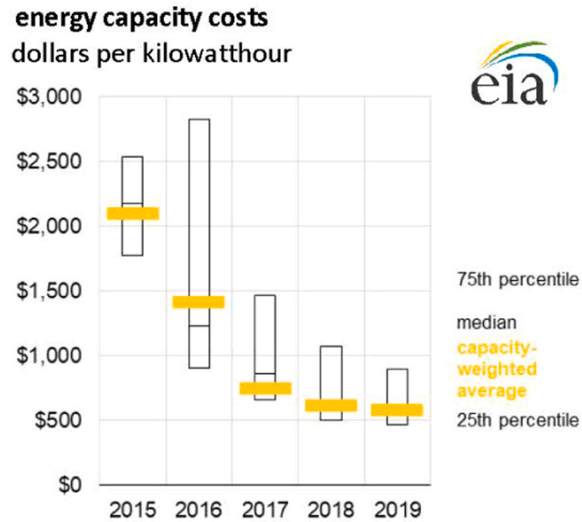

Fig. 2. Total Installed Battery Costs for Large-scale Systems in the United States (U.S. Energy Information Agency, August, 2021).

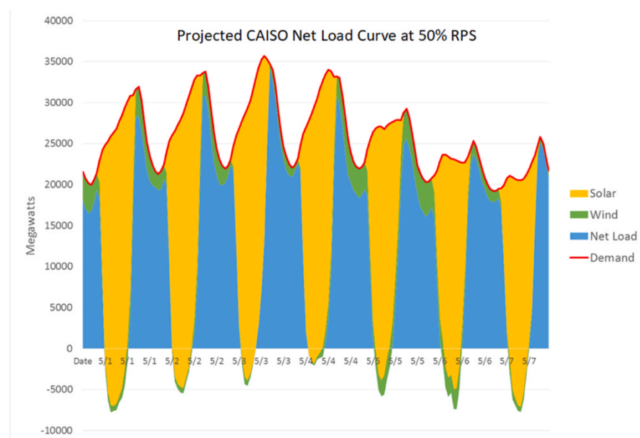

Fig. 3. Projected Electricity Production (California Energy Storage Alliance, 2021) in California with 50% from Wind (green) and Solar (gold).

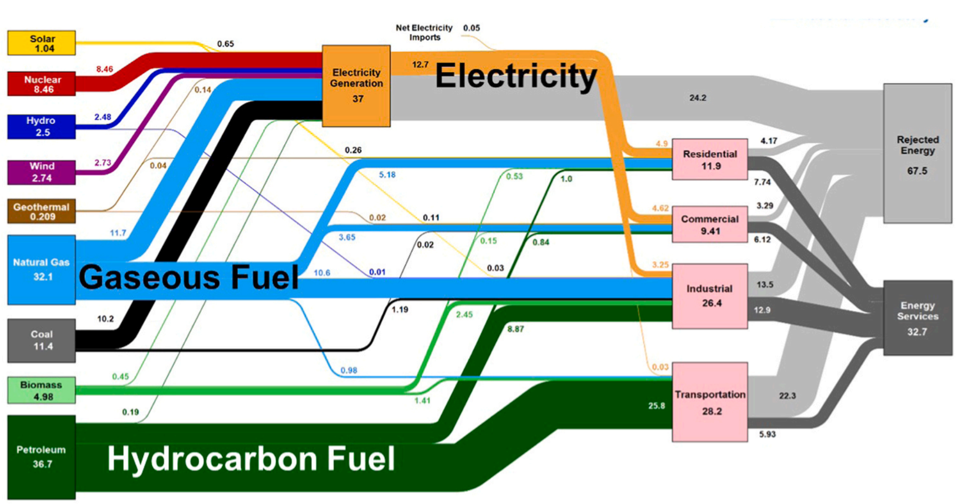

Fig. 1. U.S. Energy Flow Diagram (2019) with a Total Energy Consumption of 100.2 Quads (Lawrence Livermore National Laboratory, 2020).

(electrical pressure) and frequency or the grid will collapse. We have never found an economic method to store large quantities of electricity; thus, we store the fuels (uranium in nuclear reactor cores, coal, oil, natural gas, water behind dams, etc.) at the power plants that are used to produce electricity.

- *Gaseous fuels*. The first well-documented use of gaseous fuel was for town lighting that occurred in 1807 in London and rapidly expanded to major cities around the world. It was soon used for cooking in homes and other purposes. The gas was town gas—a mixture of hydrogen and carbon monoxide made from gasification of coal with gas storage facilities built into these systems. Natural gas did not fully replace town gas until the 1950s in the United States and the 1970s in Great Britain. Natural gas system has massive underground storage facilities that decouple steady-state production from highly variable demand. We have the option of a second gaseous fuel transition to hydrogen that can use the same storage system.
- *Liquid hydrocarbon fuels*. In the early development of the car, there were debates about the power source including electricity from batteries and various liquids stored in tanks. The oil industry produced kerosene for lighting and had a waste product—gasoline. Gasoline won out-partly because it was easy to store a great deal of energy as a liquid in a tank. We have the option to replace oil with hydrocarbon biofuels where biomass is converted into liquid hydrocarbons at biorefineries with massive external inputs of heat and hydrogen at the refinery. The same storage systems would be used.

There is a fourth energy medium that is inexpensive to store: heat. Heat storage has not been historically used on a large scale because of the availability of storable fossil fuels, but it may become an important storage form in a low-carbon economy.

We examine herein the four energy carriers in the context of energy storage. This includes the production of non-fossil hydrocarbon and gaseous fuels where the storage and handling characteristics motivate their manufacture and use.

2. Options to address the storage challenge

The characteristics of the three energy carriers are shown in Table 1. Historically, electricity has been produced using fossil fuels, uranium, wind, solar and hydro. Today hydrocarbon and gaseous fuels are thought of as sources, since they have accumulated over geological time periods—but that is only strictly true if the hydrocarbon is oil and the gaseous fuel is natural gas. Hydrocarbon fuels can be made from biomass. If the gaseous fuel is hydrogen, the starting material may be (1) natural gas that is converted into hydrogen by steam methane reforming with sequestering the carbon dioxide, (2) electrolysis of water with heat and hydrogen provided by a nuclear reactor or (3) some other process. If we are to discontinue exploitation of fossil fuels, the historical mindset that liquid and gaseous fuels are oil and natural gas must be broken; this requires us to mitigate the loss of their inherent energy storage function.

Table 1
Energy Carriers and Their Characteristics.

Attribute	Fuel Type Hydrocarbon Liquid (Oil)	Gaseous Fuel (Natural Gas)	Electricity
Energy Density	High	Low	Low
Storage Cost	Very Low	Low	High
Transport Cost	Very Low	Low	High
Transport Capacity	Pipeline 10 s GWs	Pipeline 10 s GWs	Power Line GWs
Versatility	Medium	Low	High
Continuous Delivery	No	Yes	Yes
Power for Small Applications	No	No	Yes
Replacement	Nuclear Biofuels	Hydrogen	Electricity with Heat Storage

2.1. Electricity

Electricity is expensive to store. Instead, the fuels to make electricity are stockpiled: coal, natural gas, oil, uranium and water behind dams. The largest fraction of the stored energy in the electricity sector is in the form of nuclear fuel in reactors. Nuclear reactors refuel every 18–24 months implying an average sufficient-fuel-in-core for 9–12 months. That translates into several million gigawatt hours of stored energy that addresses daily to seasonal storage challenges. As discussed below, fossil fuel storage inventories are one (natural gas) to three months (coal). The only other significant low-carbon storage in the electricity sector is water behind hydroelectric dams that depends upon seasonal weather patterns and is geographically limited.

Fig. 4 shows the cost breakdown for delivered electricity in the U.S. About 40% of the cost is associated with transmission and distribution; the balance is in the production of electricity. While oil and natural gas are distributed across the country, electricity production and transmission is regional with a few small exceptions. Historically the big long-distance transmission systems have been in countries such as Sweden, Brazil, and Russia that moved electricity from remote low-cost hydroelectric sites to urban centers. More recently China has built long-distance transmission lines to move hydropower and some wind energy long distances.

The cost structure of delivered electricity has major implications in the viability of electrification of the economy. Consider the heating market where gaseous fuels are the primary energy source—particularly in cold climates. The building heating challenge exceeds the cooling challenge. If room temperature is 70°F, a cold day may be − 20°F for a temperature difference of 90°F between inside and outside temperatures. In contrast a hot day of 115°F implies that the difference between inside and outside temperature is only 45°F. Heating in colder climates could increase total electricity demand (kWh) by 50%; however, the peak demand for electricity would more than double (Sepulveda, 2021). The added distribution and transmission capacity implies massive

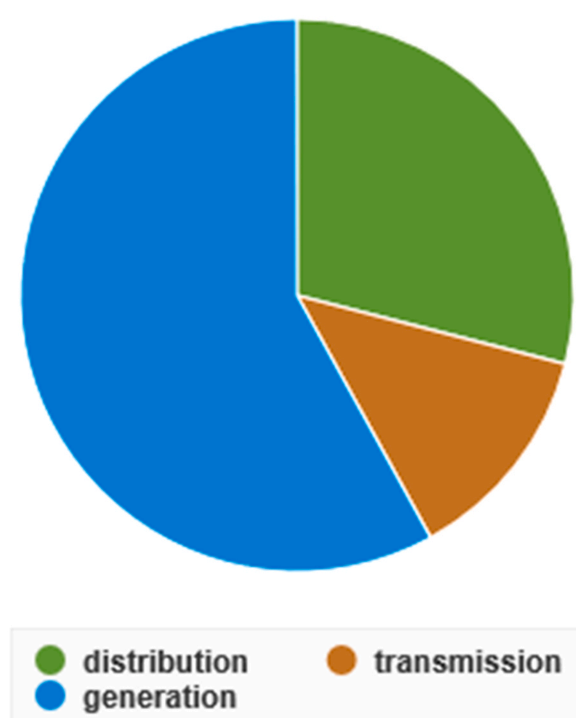

Fig. 4. Cost Breakdown of Delivered Electricity to the Customer in the United States in 2019 (U.S. Energy Information Agency, 2021a).

increases in electricity costs for everyone to meet this peak demand for less than 100 h per year. That high cost is because storage is in the form of fuels at the power plant. As discussed later, with oil and natural gas heating the storage is either near the customer or on the customer site in the form of home heating oil or LPG tanks.

It is the combination of the high cost of the electricity transmission/distribution and electricity storage that limits electrification of much of the economy. Any major energy demand that imposes large peak electricity demands makes electricity expensive and that demand an unlikely candidate for electrification in a low-carbon world.

2.2. Hydrocarbon fuels

The defining feature of hydrocarbon fuels ($(CH_2)_xH_2$) is the high energy density per unit volume or mass compared to any other chemical system that makes energy storage very inexpensive. That is for several reasons. First, the H-C-H bond incorporates hydrogen in high density chemical form. The average atomic weight of that three unit structure is 4.7 versus the next lightest element lithium with an atomic weight of 7. Second, the oxygen for combustion comes from the atmosphere. It is not required to transport oxygen to where the combustion occurs. In contrast, a lithium battery contains the lithium and oxygen—plus a massive amount of other materials to avoid having the fuel and oxidizer accidently combust inside a sealed package and creating a fire. The power densities of batteries have limits based on chemistry and safety that are far below hydrocarbon fuels. If fossil fuels did not exist, diesel and jet fuel would have been discovered and manufactured for their remarkable capabilities of high energy density and safety in handling. There are severe economic penalties going from hydrocarbon fuels to batteries or other energy storage systems in aircraft or heavy trucks where an added kilogram of fuel implies one less kilogram of cargo.

Oil and any replacement hydrocarbon is cheap to store—and large quantities are stored to assure no energy shortages and meet variable demand. The U.S. historically has consumed about 20 million barrels per day (EIA, September, 2021). There was however a significant decrease in 2020 due to the pandemic. The U.S. government National Petroleum Reserve has a capacity of 714 million barrels of oil—a 35 day supply. Commercial crude oil inventories are typically about 400 million barrels—a 20 day operating reserve. Total oil and petroleum product inventories are typically near 1900 million barrels implying slightly more than a 90 day supply. Any replacement for hydrocarbon fuels needs to provide the similar resilience for normal variations in demand (daily to seasonal) and unexpected events.

Table 2
U.S. Daily Consumption of Oil Products (EIA, 2021b).

Product	Annual Consumption (millions of barrels per day)
Finished motor gasoline[a]	8.034
Distillate fuel oil (diesel fuel and heating oil)[a]	3.776
Hydrocarbon gas liquids (HGLs)	3.197
Kerosene-type jet fuel	1.078
Still gas	0.611
Asphalt and road oil	0.342
Petrochemical feedstocks	0.286
Petroleum coke	0.260
Residual fuel oil	0.217
Miscellaneous products and other liquids[b]	0.152
Lubricants	0.100
Special napthas	0.045
Aviation gasoline	0.011
Kerosene	0.008
Waxes	0.004
Total petroleum products	18.120

[a] Includes fuel ethanol in gasoline and biodiesel in distillate fuels.
[b] Includes other liquids not included in the table.

Going forward, can we substitute electricity or gaseous fuels for liquid hydrocarbons and if so, what are the limits? Table 2 shows the current uses of oil in the United States. Gasoline is the largest fraction of the oil market—about 8 million barrels per day are consumed primarily by light vehicles. It is a diverse set of uses from chemical feedstocks where there are no substitutes, to jet aircraft where the substitutes such as liquid hydrogen are very expensive to light-duty vehicles (cars and light trucks) with several options. With heavy trucks and aircraft the operating costs including fuel dominate. The primary cost of automobiles is in the vehicle thus increases in vehicle costs present major challenges for lower-income families—a major challenge if political decisions are made to favor all-electric vehicles.

It is assumed by many that the light-vehicle fleet can be electrified—but there are major constraints. The light-duty vehicle fuel options (Green et al., 2019) include replacement of fossil-fuel gasoline with biofuels or hydrogen, hybrid vehicles, plug-in hybrid vehicles and all-electric vehicles. Hybrid vehicles burn some type of fuel and have batteries on-board. When the vehicle slows down or goes down the hill, the battery is charged. When the vehicle goes a short distance, the vehicle accelerates or goes up the hill, the battery provides power. The battery enables the engine to operate in its most efficient modes most of the time. It has been estimated that hybrids could reduce gasoline consumption by up to 30%. Plug-in hybrid vehicles have a heavier battery package that enables the vehicle to go on shorter trips without using the motor and recharging by plugging into the electrical grid. A combustible fuel is used on longer trips. Because plug-in vehicles are duel-fuel vehicles, the owner can chose to operate using fuel or electricity depending upon the relative price of fuel or electricity. All-electric vehicles have large battery packages to enable longer distances and significantly higher costs partly driven by the costs of raw materials in the batteries.

Electric vehicles must be recharged from the electricity grid. A recent study (Bedir et al., 2018) examined likely times when these vehicles will be recharged in California (Fig. 5) and found most recharging will be done in the early evening shortly after the sun sets—the time of peak daily electricity demand. This is caused by work schedules and single car families that want assured car availability. There is a second effect of all-electric vehicles in northern climates. With internal combustion engines, heat for the passenger compartment is provided by the engine—waste heat at no cost. With all-electric vehicles heat is provided by batteries that increases peak vehicle electricity demand at times of peak winter electricity demand. From the perspective of the electricity grid, an all-electric vehicle implies massive grid and power plant capacity expansion to meet a peak demand and major increases in electricity prices. There are proposals to require time-of-day electricity prices and

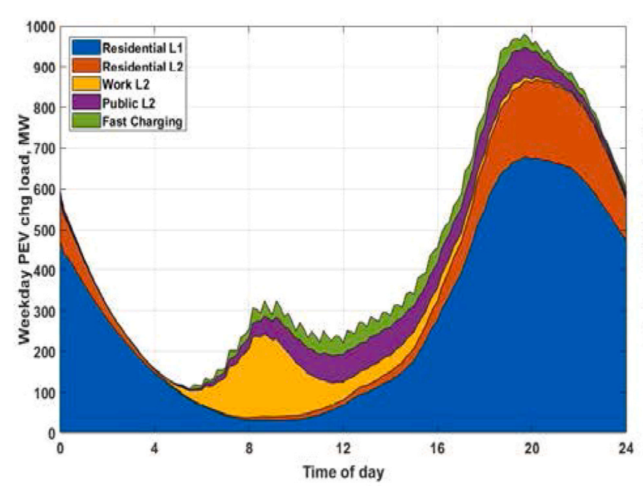

Fig. 5. Projected California plug-in electric vehicle electricity demand 2017–2025 vs time of day.

other mechanisms to change recharging times; but all of these options require changes in human behavior with most of the burden falling on single-vehicle families with lower incomes while reducing the advantages of cars—transportation on demand.

From the perspective of the electricity grid, there is a radical difference between all-electric vehicles and plug-in hybrid electric vehicles that have (1) batteries and (2) engines that could be fueled using biofuels, hydrogen and other storable fuels. With a plug-in hybrid vehicle, there is assured transportation if the battery is not charged. The owner of such a vehicle would prefer to recharge when electricity prices are at a minimum and is willing for the utility to control times of recharging. Plug-in hybrids have the potential to be recharged at times of lower electricity demand resulting in greater utilization of the transmission/distribution system (Fig. 3) and thus lowering the cost of electricity. As a consequence, plug-in hybrids with hydrocarbon fuel storage have the potential to reduce the average price of electricity, reduce investment in the electricity system, create a more robust energy system and save the customer money. Such assessments indicate that reducing hydrocarbon fuel consumption by a third using electricity may be achievable at reasonable cost but full replacement of liquid fuels will be very expensive and difficult because of the storage function of hydrocarbon fuels.

2.3. *Gaseous fuels (and coal)*

The third energy sector are the gaseous fuels. The history of gaseous fuels is about delivering hydrogen in different forms from town gas ($CO+H_2$) to natural gas (CH_4) to potentially hydrogen (H_2). There are major initiatives in Great Britain to initiate this second transition—probably because the town gas to natural gas transition came late to Great Britain and thus a memory of this transition. Gaseous fuels are easy and inexpensive to store in underground formations and easy to transport in pipelines with capacities measured in tens of gigawatts—an order of magnitude larger than the transmission capability of a large power line. Typically about 3 trillion cubic feet of natural gas is in storage with large seasonal variations (American Gas Association, 2016). Annual consumption is about 30 trillion cubic feet so a 35 day supply of gaseous fuels are in storage. In the U.S. there are about 400 storage facilities in thirty states. This is the working gas inventory—there is an additional buffer gas in the storage facilities kept there to simplify operations. This inventory excludes gas stored in pipelines and customer facilities. This storage capacity exists because gas wells, processing facilities and pipelines cost more than gas storage and thus economic incentives to operate at maximum capacity and variable demand with storage. Natural gas is sent via pipeline to storage facilities near the final customer year-round. Local storage is used to meet peak demand including peak winter demand that is many times the capacity of the long-distance pipelines.

In northern climates gaseous fuels are used for heating—a capability that is difficult to economically replace with electricity but easily achieved by hydrocarbon fuels. Meeting peak heating demand is relatively easy because of two features of gaseous fuel. First, storage is inexpensive (Hauch et al., 2020) enabling local storage to meet peak demand. The capital costs for gaseous and liquid fuels storage facilities is below one Euro per kWh ($1.17 per Euro) excluding power conversion costs. Second, as the pressure in the pipeline goes down from greater demand, the gas flow accelerates. The intrinsic system characteristics enable economically meeting wide variations in demand.

In the context of switching from natural gas to hydrogen as the gaseous fuel, it is noted that the U.S consumes about 10 million tons of hydrogen per year to produce fertilizer, refine oil and for other purposes. This industrial demand has resulted in a pipeline system along the Gulf coast of the United States and a significant experience base in hydrogen transport and storage. In a low-carbon world, massive added quantities of hydrogen would likely be used to replace coal in the production of steel and upgrading of biofuels to hydrocarbon fuels (Forsberg, 2009). In all of these applications hydrogen is used because of its chemical properties; that is, there is no substitute. As a consequence, there will be a massive increase in hydrogen production whether or not it is used as a gaseous fuel (He et al., 2021).

In the United States coal and natural gas compete in the electricity market with natural gas replacing coal because of (1) its low cost, (2) the ability of natural gas plants to quickly vary power output in markets with large-scale use of wind and solar and (3) opposition to the burning of coal. In 2020, the U.S. utilities burned 436.5 million short tons of coal with a stored inventory of 132.7 million tons at the power plants- − 110 day inventory at power plants. That stored inventory addresses hourly to seasonal variations in demand—plus weather and risks of shutdown of coal mining or rail transport for any reason.

3. Electricity production with heat storage

In a low-carbon system, the electricity production options are nuclear, wind, solar photovoltaic (PV), concentrated solar power (CSP), hydro, geothermal and fossil fuels with carbon capture and sequestration (CCS). Nuclear power plants can be built anywhere and operate most economically with constant output. Wind, PV, CSP and hydro output depend upon the local weather and climate. Wind, PV and CSP output are non-dispatchable. Geothermal and fossil fuels with CCS depend upon local geology. Only some parts of the world have geothermal resources and fossil fuels with CCS require the appropriate geology for sequestration of the carbon dioxide.

There is a four part storage challenge. Replacing fossil fuels, unless replaced with low-carbon hydrocarbon liquids or gaseous fuels, removes energy storage from the electricity system. Adding wind and solar provides no storage and dramatically increases the incentives for storage because production does not match demand. Nuclear energy has massive storage but the economics favor base-load operations. Last, any significant electric heating load or addition of all-electric vehicles will increase peak demand.

In the electricity grid, heat storage is the low-cost energy storage option because it uses cheap materials. Heat storage in electricity systems is not new. In the 1930 s in Berlin, the first large steam accumulators were being coupled to a coal plant to provide heat storage that enabled variable steam to the turbine to rapidly vary electricity output while the coal plant operated at base load (Forsberg, 2019). Heat storage has not been widely deployed because today fossil fuels provide a low-cost storage option.

Fig. 6 shows heat storage coupled into a system to produce variable electricity to the grid. This is the system design of current CSP systems (Bauer et al., 2021) and the system design proposed for multiple advanced nuclear reactors (Natrium, 2021; Moltex Energy, 2021) to enable heat-generating technologies to match electricity demand (Forsberg, 2021; Forsberg et al., 2020). The heat generating system (nuclear, CSP, etc.) operates at maximum capacity at all times. Cold nitrate salt or oil from storage tanks is heated and sent to hot storage tanks. When electricity prices are high, heat is sent from heat storage to the turbines to produce electricity. The peak electric generating capacity may be several times the peak generating capacity of the nuclear or CSP system without storage. When electricity prices are low, all heat from the nuclear or CSP plants goes to storage. At times of very low electricity prices (Fig. 3), electricity from the grid (such as from PV systems) is converted into stored heat with resistance heaters coupled to the heat storage system. If heat storage is depleted, hydrocarbon or gaseous fuels are used to enable assured peak electricity production by providing the extra heat that would have come from the heat storage system. The same system is used for cogeneration of electricity and heat for industry.

Existing CSP heat storage systems store several gigawatt hours of heat in nitrate salts at capital costs of $25/kWh of heat that translates into $60–70/kWh of electricity after accounting for the efficiency of converting heat to electricity (Electric Power Research Institute, 2010). Advanced heat storage systems may lower heat storage capital costs to $10/kWh of electricity. This is in contrast to batteries with current

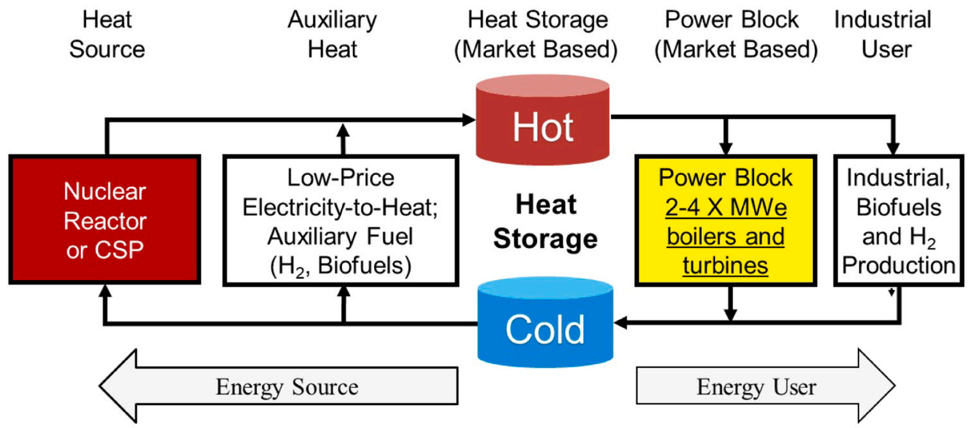

Fig. 6. CSP system with large-scale heat storage.

capital costs in excess of $500/kWh with goals to reach $200/kWh of electricity. The capital cost of storage is only part of the total costs. The other cost is providing assured generating capacity (kilowatts) to meet peak electricity demand. If one buys a kilowatt of solar PV or wind capacity, a kilowatt of capacity is needed from the storage system to provide electricity at times of low wind or solar conditions. An additional kilowatt of gas turbine capacity is required to back-up the battery for assured generating capacity if multiday cloudy weather or low-wind days. In Fig. 6 (right), every kW of generating capacity is available to meet peak demand by providing a low-cost combustion heater that backs heat storage—there are not multiple generators required to deliver one assured kW of capacity.

Energy losses from storage are small for heat generated by a nuclear or CSP system that goes through storage to the power block—a percent or two. In contrast, if low-price electricity is bought from the grid and converted to heat and then back to electricity, the round-trip efficiency is near 40%. The conversion of electricity to heat is near 100%; but, the conversion of heat back to electricity is typically near 40 + %. The electricity to storage to electricity efficiency is 78% for pumped hydro facilities and 81% for batteries (U.S. Energy Information Agency, February 2021b). Batteries convert electricity to chemical storage and back to electricity. Hydroelectric plants convert electricity to stored water at high elevations and back to electricity. There are significant losses whenever converting one energy form to another.

Advanced heat storage systems are being developed to lower heat storage costs to $2–4/kWh of heat. In a 2-tank nitrate heat storage system, 40–50% of the cost is in the nitrate salt and 40–50% of the cost is in the insulated tanks [Electric Power Research Institute, June 2010]. To drastically lower the costs, one can't use nitrate salts as the heat storage material or expensive salt storage tanks. Fig. 7 shows the Crushed Rock Ultra-large Heat Storage (CRUSH) system that is designed to address this challenge (Aljefri, 2021; Forsberg, 2021). It is in the early stages of development and may show the ultimate limits in low-cost heat storage.

The heat storage material is crushed rock—the lowest cost heat storage medium. Nitrate salt is only used for heat transfer—not heat storage. Heat is added to the crushed rock by spraying the hot heat-transfer fluid (oil or nitrate salt) over the crushed rock section by section as shown in Fig. 7 (upper right and lower left). The fluid drains through the crushed rock to the catch pan below the crushed rock. The cold heat transfer fluid is collected by the bottom collection pan to be reheated. If the nitrate salt or heat transfer oil is not fully cooled by the time it reaches the collection pan (Fig. 7, lower right), the warm fluid is

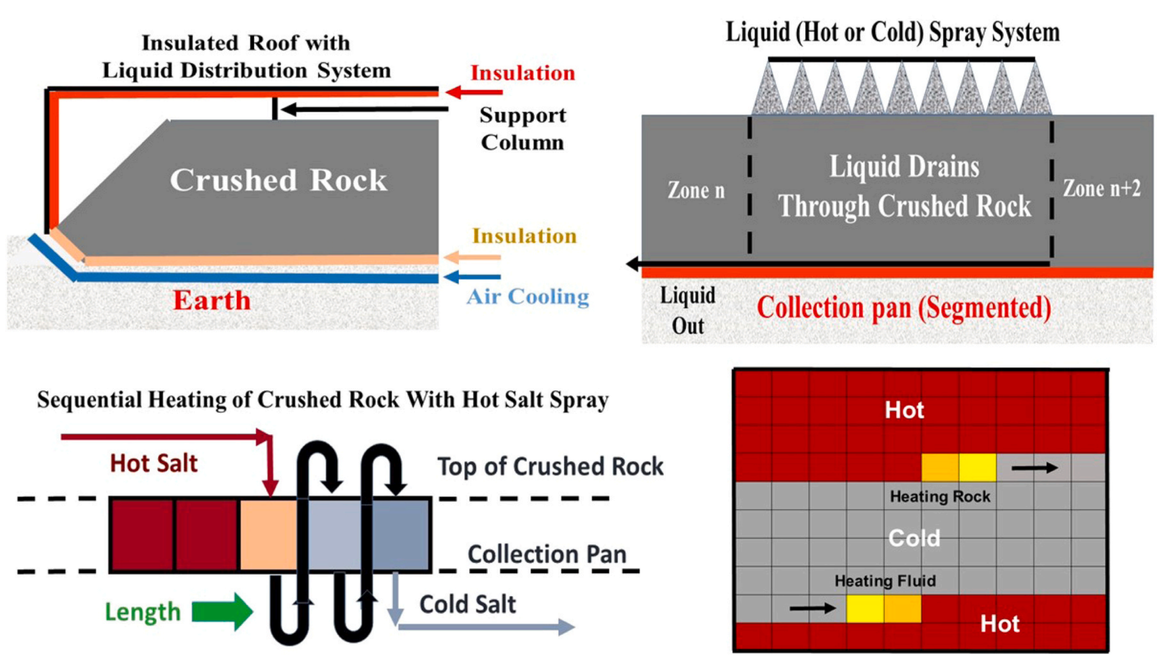

Fig. 7. Crushed Rock Ultra-large Stored Heat (CRUSH) System.

pumped onto the top of the next section of crushed rock to preheat the crushed rock. To recover the heat, cold fluid is poured on top of hot rock and is heated as it flows the drain pans. Sequential sections of rock are heated with hot oil or nitrate salt. There is a rock heating wave followed by a second wave to recover heat. When either wave reaches the end of the structure, it starts over at the other end. Lower-temperature CSP systems and light-water reactors would use heat transfer oil to move heat to the crushed rock and from the crushed rock to the power cycle. Higher-temperature CSP, reactor systems and electricity-to-heat systems would use nitrate salts for heat transfer. Inert gas fills the void space between rocks. A wave of hot oil or hot salt heats the crushed rock from left to right.

Expensive tanks are replaced by a low-cost insulated structure similar to an aircraft hangar with no forces on the side walls. Tanks are expensive because they have to resist hydraulic forces. The crushed rock is 20 + meters deep with sloping sides to allow rock expansion and contraction. A 100-GWh heat storage system with dimensions of 250 m on a side would have capabilities similar to the Tennessee Valley Authority Raccoon Mountain pumped storage facility that can produce 1600 MW of electricity for 22 h. Very-low-cost heat storage is not possible on the scale of a single gigawatt-hour nitrate storage tank because there is too much container surface (steel, insulation and support structure) per unit of stored heat. The building cost goes up as the square of the system dimensions while the heat storage capacity goes up as the cube of the dimensions. Large capacity systems are required to minimize costs.

The scale of low-cost heat storage with 10 s of gigawatt hours of storage may change CSP deployment (Forsberg, 2021). Large-scale heat storage also implies the power block (steam cycle, turbine generator, and transmission grid) is much larger with economics of scale. However, this scale is far beyond any CSP ground-based solar farm or solar tower. This requires many CSP farms sending hot nitrate salt via pipeline to heat storage and the central power block (Fig. 8).

There is another class of large-scale crushed rock storage that is closer to commercial development. Siemens is developing a gigawatt-hour hot-rock system (Siemens Gamma, 2021) where at times of low electricity prices air is heated and blown through the crushed rock to heat it. At times of high electricity prices, cold air is blown through the hot rock and the resultant hot air is sent to a steam boiler to produce electricity. The peak crushed-rock temperature is about 650 °C. There is an operating pilot plant. The development challenges are less because air does not react with many rock types. However, the capital costs per unit of stored heat are expected to be higher because (1) need large air heat exchangers versus liquid nitrate heat exchangers and (2) system size is limited by air pressure drops.

4. Gaseous fuels production

The second energy sector is gaseous fuels where hydrogen is the likely replacement for natural gas. The ultimate hydrogen market could be 20–40% of total energy because of three markets: hydrogen for chemical applications from fertilizer to steel production, replacement for natural gas and large-scale production of biofuels as discussed below. In this sector we have the existing low-cost storage technology; thus, the question is how to produce hydrogen at a low cost. There are multiple production options.

The near-term lowest-cost hydrogen production option is steam methane reforming of natural gas followed by CCS (Muradov, 2017; Shell, 2021; Carter and Hickman, June, 2021). This is a low-cost option if low-cost natural gas and good carbon dioxide sequestration sites. The relatively low cost is because of the process chemistry where steam plus natural gas yields hydrogen plus carbon dioxide. Fossil power plant CCS is expensive because of the high cost of separating the carbon dioxide from the stack gas. Carbon dioxide is typically about 10% of the stack gas. In steam methane reforming most of the carbon dioxide exits the process as nearly pure carbon dioxide—little or no cost for carbon capture. Carbon dioxide sequestration underground is inexpensive (Smith et al., 2021). Heat is also required in the process and the combustion of natural gas does produce a dilute carbon dioxide. However, there are variants of the process where the carbon dioxide released to the atmosphere is below 1%. If the heat is provided by nuclear reactors, there are no carbon dioxide releases (Yan and Hino, 2011).

The second set of options uses low-temperature electrolysis or high temperature electrolysis (HTE). Low-temperature electrolysis is electrolysis of water—a process that has been commercial for over a century. High-temperature electrolysis is steam electrolysis that requires electricity and steam. It is significantly more efficient (James et. al. 2016; O'Brien et al., 2010; O'Brien, 2012; Hauch et al., 2020], is expected to have lower capital costs and couples well to nuclear plants that can produce steam and electricity. HTE is in the early stage of commercial deployment. A defining characteristic of all electrolysis processes is the high capital costs—both for the electrolytic cells and associated power supply systems and hydrogen handling systems. Low-cost hydrogen is only possible with high capacity factors as shown in Fig. 9. One consequence is that solar hydrogen is very expensive because of the low capacity factors of solar systems. Nuclear plants have capacity factors of about 90% versus wind near 41% and solar near 30%.

The near-term nuclear hydrogen production option with HTE is co-production of hydrogen and peak electricity (Fig. 10). Hydrogen is produced most of the year to minimize hydrogen production. Electricity is produced 5–15% of the year when electricity prices are high rather than hydrogen. This maximizes revenue. The economic penalty incurred by lower hydrogen plant capacity factors is relatively small if electricity is diverted to the grid for a limited number of hours per year. This feature can help meet the occasional peak summer or winter electricity loads. The nuclear plant replaces the gas turbine for peak electricity production. The first demonstration of this system is planned for a nuclear plant in Minnesota.

The second nuclear hydrogen production option is the nuclear hydrogen gigafactory (Fig. 11). First build a modular nuclear reactor

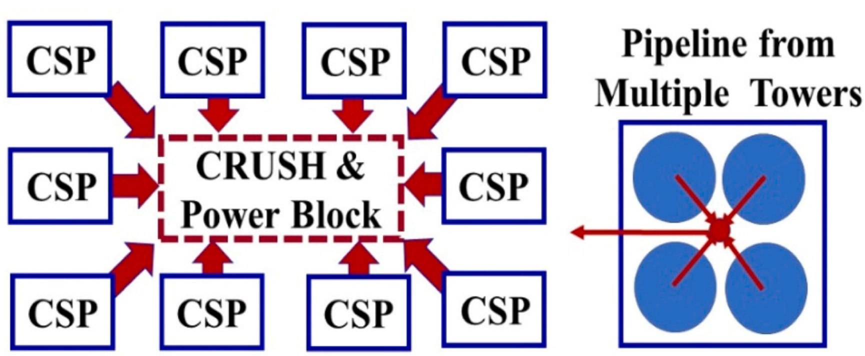

Fig. 8. Multiple CSP Farms Feeding Common CRUSH and Central Power Block System.

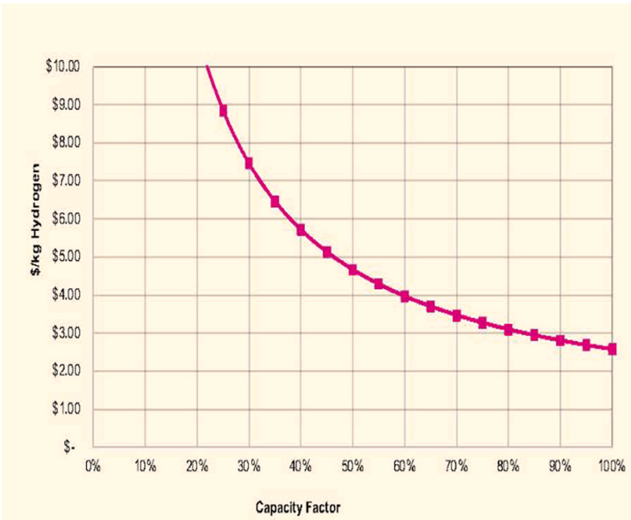

Fig. 9. Illustrative Cost of Hydrogen Vs Capacity Factor (Courtesy of LucidCatalyst (2020)).

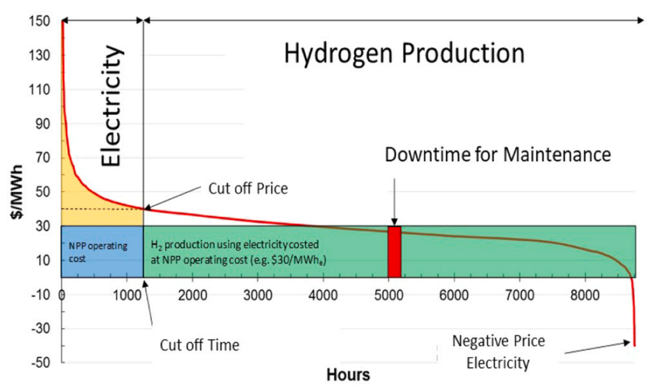

Fig. 10. Coproduction of Nuclear Hydrogen and Electricity (Boardman et al., August, 2019).

Fig. 11. Hydrogen Gigafactory with Factory in Back, Reactor Field in the Middle and Hydrogen Plant in the Front (Courtesy of LucidCatalyst (2020)).

fabrication plant that produces reactors to be sited next to the factory with the hydrogen plant. Second with shipyard cranes that can lift several thousand tons, move reactors from factory to nuclear plant site by crane. Third, if the reactor needs refurbishing, transport it back into the factory. This approach changes building nuclear reactors from a construction-site-based model into a manufacturing-based model where the site hydrogen production capacity grows over 10 years and thereafter the factory produces replacement reactors. Factory fabrication (LucidCatalyst, 2020) can dramatically lower the cost of nuclear power plants—in addition to improved economics of operation of multiple reactors at a single site and economics of scale for the hydrogen production plant. A single plant would have 36 nuclear reactors of 600 MWt each for a total site production rate of 2 million tons of hydrogen per year.

The gigafactory is possible because of the difference between transporting and storing energy as hydrogen versus electricity. A very large power line can transmit a few gigawatts of energy with significant energy loses in transmission. A single hydrogen pipeline can transport many tens of gigawatts and can be coupled to low-cost underground hydrogen storage facilities to match steady-state production with variable demand on an hourly to seasonal basis. The ability to cheaply transport and store massive quantities of hydrogen makes a gigafactory viable. It is the similar combination of low-cost oil pipelines and oil storage that made possible today's large integrated oil refineries that are similar in scale in terms of energy output to proposed hydrogen gigafactories.

There are three longer-term hydrogen production options. The first is direct pyrolysis of natural gas into hydrogen and carbon that is buried. The energy cost of this process is about one seventh that of electrolysis—however the process is early in the development cycle (Upham et al., 2017). The second set of options are nuclear thermochemical processes that convert heat and water into hydrogen and oxygen (Yan and Hino, 2011). This process has the potential to have significantly lower costs than electrolysis. It is at the early pilot plant stage of development. Last, there is the option of coupling solar with very large-scale heat storage (Forsberg September 2021) that would enable the hydrogen plant to operate at higher capacity factors.

5. Hydrocarbon fuels production

Liquid hydrocarbons are cheap to store; thus, the question is not storage but whether one can replace oil in the production of hydrocarbon fuels. Recent studies and workshops (Forsberg et al., September, 2021; Forsberg et al., December, 2021) have asked the question: Can we economically (1) replace crude oil with low-carbon biomass, (2) modify oil refineries to be biorefineries that produce drop-in hydrocarbon replacements for gasoline, diesel, jet fuel, and chemical feedstocks, (3) sequester carbon from the atmosphere and (4) keep everything else essentially unchanged?

There are two strategies to convert biomass into liquid hydrocarbon fuels. The traditional process to provide biofuels is shown in Eq. 1 where biomass plus oxygen yields biofuels plus carbon dioxide. The carbon in the biomass serves two functions: (1) a source of carbon for the hydrocarbon fuel and (2) an energy source for the conversion process.

$$\text{Biomass} + \text{Oxygen} \rightarrow \text{Hydrocarbon Fuels} + \text{Carbon Dioxide} \tag{1}$$

$$CH_{1.44}\,O_{0.66} + O_2 \rightarrow (CH_2)_xH_2 + CO_2$$

The second strategy is to convert biomass plus massive quantities of heat and hydrogen into hydrocarbon fuels and water. The hydrogen is used to remove the oxygen found in biomass and to provide the added hydrogen to produce a hydrocarbon fuel. Biomass is the carbon source in the production of gasoline, diesel and jet fuel. Nuclear energy provides the external energy source to produce heat for the biorefinery. Hydrogen may be produced using nuclear energy, steam methane reforming of natural gas with CCS or other sources. These energy inputs will be 10–20% of the total energy consumption of the U.S. and the world. For an economically viable system, massive steady-state heat and hydrogen inputs at large biorefineries are required that match the requirements of the biorefinery.

$$\text{Biomass} + \text{Hydrogen} + \text{Nuclear Heat} \rightarrow \text{Hydrocarbon Fuels} + \text{Water} \tag{2}$$

$$CH_{1.44}\,O_{0.66} + H_2 + \text{Heat} \rightarrow (CH_2)_xH_2 + H_2O$$

Using external heat and hydrogen inputs makes it possible to replace all oil with biofuels using available biomass supplies. First, external heat and hydrogen more than doubles the quantities of hydrocarbon fuels per ton of biomass feedstock. This reduces the land requirements for biomass production by more than a factor of two. Second, external heat and hydrogen enable use of biomass feedstocks that are poor energy, food, and fiber sources but excellent sources of carbon for production of biofuels. The external heat and hydrogen is the enabling technology so that there is sufficient biomass to provide the necessary carbon to replace oil without major increases in the costs of food and fiber—the other uses of biomass. The initial estimates are that the United States may be able to produce ultimately up to 3 billion tons of biomass annually on a sustainable basis when biomass is considered as a carbon source, not as an energy source. This is more than sufficient to replace oil.

The system is shown in Fig. 12. Low-density biomass is sent to local depots where it is converted into storable, stable, energy-dense forms suitable for long-distance transport to the biorefinery. At the biorefinery the biomass is converted into hydrocarbon fuels and chemical feedstocks with massive inputs of nuclear heat and hydrogen. The liquid transport fuels are burnt releasing carbon dioxide to the atmosphere and that carbon dioxide grows new biomass—thus there is a circular carbon dioxide cycle. Another option at the biorefinery is to produce variable quantities of hydrocarbon fuels and carbon dioxide that can be sequestered underground. If this is done, it results in negative carbon emissions; that is, reducing the carbon dioxide content of the atmosphere.

Large biorefineries, equivalent to a 250,000 barrel per day oil refinery, are required to minimize costs and enable variable production of gasoline, diesel, jet fuel and other products with time. Low-density biomass can't be economically shipped long distances; thus, local depots are required to convert biomass into storable, economically-shippable intermediate commodities. In this context, cellulose is the primary form of biomass on earth. To replace oil requires that the primary feedstock be cellulosic feedstocks—there are insufficient supplies of other types of biomass. Most cellulosic feedstocks have low densities and thus the need for local depots to produce a shippable intermediate commodity. Today's biofuels industry is based on sugar, starch and other forms of biomass. These forms of biomass are dense and shippable but in limited supply.

There are three depot options with three different intermediate commodities. The depot choice depends upon the type of biomass available and local logistics capabilities. First, biomass may be densified and shipped as dry pellets. Second, biomass may be fed to anaerobic digester that produces a methane/carbon-dioxide gas mixture that is shipped via pipeline to the refinery—plus a digestate that is returned to the soil. Third and last, there is flash heating of biomass that produces pyrolysis oil and biochar. Thus we have three distinct intermediate commodities emanating from the depots: 1) dry pelleted biomass, 2) biogas (methane and carbon dioxide) and 3) pyrolysis liquid.

For biofuel production we only want carbon and hydrogen—not the other elements in biomass including nitrogen, potassium and phosphorus, etc. The depots and the refinery enable recycle of nutrients in digestate and biochar back to farms and forests to improve long-term soil productivity. This approach contrasts sharply with the dominant current model of food and fiber production as well as the burning of biomass that does not recycle nutrients back to the soil. The nuclear biofuels system combined with depots may help enable long-term sustainable agriculture and forestry.

At the biorefinery the intermediate biomass commodities are processed into a biocrude oil by direct hydrogenation of biomass or by the Fischer Tropsch process. This biocrude is then converted into hydrocarbon products by traditional refinery processes. These processes are variants of existing, large-scale processes used to convert natural gas and coal into oil. These processes require massive quantities of hydrogen and concentrated heat sources (Eq. 2). The nuclear reactors providing the massive heat inputs to the biorefineries must be collocated with the biorefineries. The refinery can produce carbon dioxide for sequestration when excess low-price biomass is available or during times of low liquid-fuel prices. This option provides variable negative carbon emissions while stabilizing the price of liquid fuels and biomass caused by variable production of biomass or changing markets for liquid fuels over time.

The cost of biomass would expect to increase as the demand increases. Thus, there is a price curve for nuclear biofuels but that curve is not well defined. We do not know the price point that determines the relative amounts of electricity, hydrocarbon fuels and gaseous fuels for the most economic energy system. Separate from these considerations, the economics of biofuels is dependent upon whether the government pays for sequestered carbon dioxide or sequestered carbon in the soil. This can be a significant revenue stream for such systems.

6. Conclusions

The central feature of the global energy system is the need to provide variable quantities of energy on a daily to seasonal basis; that, in turn, requires massive quantities of energy storage. For the U.S., Europe and China, energy storage is required at the scale of millions of gigawatt hours. Today most of that energy storage is in the form of carbon (coal), hydrocarbon liquid fuels (oil), gaseous fuels (natural gas) and nuclear fuels. The cost of storage in these systems is extremely low.

The capital costs of replacing the storage capabilities of hydrocarbon liquid fuels and gaseous fuels are so high that these energy carriers are unlikely to be replaced. Instead, hydrocarbon fuels made from biomass will replace oil and hydrogen made from multiple sources will replace natural gas. Electricity, hydrocarbon liquid fuels and gaseous fuels are

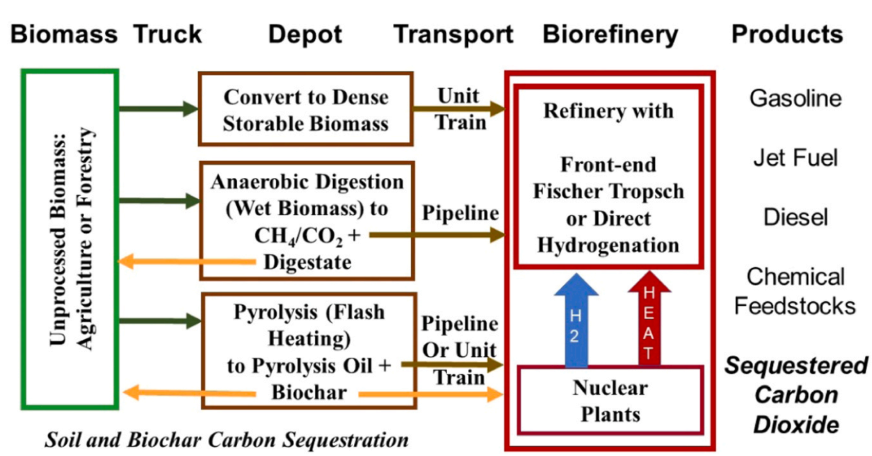

Fig. 12. Nuclear Biomass to Biofuels System.

partly interchangeable; thus, partial substitution is possible but energy storage costs place severe constraints on full-scale substitution. Because it is expensive and difficult to replace the storage and other functions of these energy carriers, we should expect a future that includes all three energy carriers.

It is the electric sector where innovations in storage are required. That will likely imply heat storage because of the low cost of heat storage materials relative to electric storage systems such as batteries and pumped hydro storage with its geographical limitations. The role of electricity storage (batteries, pumped hydro, etc.) will be limited because the energy storage costs are one to two orders of magnitude greater than storing heat, nuclear fuel, hydrocarbons and gaseous fuels.

Declaration of Competing Interest

None.

Acknowledgments

This work was supported by the Shanghai Institute of Applied Physics (SINAP) of the Chinese Academy of Sciences and U.S. Department of Energy.

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