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Approaching Zero

POWER & ENERGY

As long as we burn fossil fuels, we will have carbon emissions to contend with. What are the most promising ways to keep them at a minimum?

By Tim Lieuwen, George Richards, and Justin Weber

Establishing clean and sustainable energy systems is one of the preeminent issues of our time. This is due to two mega-issues: global warming and energy security. On the one hand, the global warming issue has led to significant discussions about reductions of carbon dioxide emissions. However, concerns about energy security are driving us to consider domestic fuel resources. This naturally leads to coal—the U.S. has 25 percent of the world’s reserves of that resource (more than any other country in the world) and a supply that could meet our current energy demands for over 200 years. Indeed, U.S. coal reserves have a larger energy content than what is available from the world’s known recoverable oil.

The pressure of meeting environmental and energy security concerns while also satisfying growing demand require us to increase, diversify, and optimize the use of energy sources. It is clear, however, that there is no one “silver bullet.”

Our future energy portfolio will consist of a diverse mix of fuel sources and energy conversion approaches.

This diversification has already begun. Over the last decade, the use of energy derived from sources such as sunlight and wind has grown significantly. Even with continued growth, however, many projections indicate that a combination of alternative and conventional energy sources will be required to meet expanding global energy demand and that combustion-based energy conversion systems will continue to be the predominant approach.



Integrated gasification combined-cycle power plants, like this one in Tampa, gasify the coal before combustion.



This coal gasification test facility at Freiberg,

Germany, is used to optimize the fuel conveying and feeding systems, as well as to investigate how a wide variety of fuels behave in the gasification process.



A natural gas flame burns bright blue in an atmosphere composed of oxygen and carbon dioxide. The combustion products are simply CO₂ and water.

According to data from the Energy Information Administration, combustion devices relying on coal, petroleum, natural gas, or bio-derived fuels currently power more than 75 percent of the U.S. electric power production, manufacturing, and processing capacity, and essentially all aircraft, automobile, and civilian marine propulsion. Those numbers speak to the magnitude of the challenge facing us.

To address the competing challenges of providing low-cost, reliable energy while managing environmental impacts and utilizing domestic resources, interest in fuel-flexible combustion-based energy systems that can manage CO₂ emission has grown dramatically. The desire to reduce CO₂ emissions and increase diversity in fuel sources will dramatically change future system architectures and design paradigms. It will also introduce a variety of new, fundamental research problems, as well as practical issues associated with overall system reliability, cost, and complexity. But some of the basic approaches for achieving those goals utilizing combustion-energy devices are now evident.

There are three basic approaches for combustion devices in a carbon-constrained world. The first two apply to fossil fuels: one can either remove the carbon before combustion or remove it afterwards. In either case, the carbon must then be pumped into storage in geologic formations such as depleted oil and gas reservoirs, porous rock formations, or unminable coal seams. This approach essentially puts the carbon back underground where it originated, and is referred to as CO₂ sequestration. The third approach is to combust a biologically derived fuel. Biofuels remove as much CO₂ from the air (via photosynthesis) as they release when consumed, making the net carbon emissions nearly zero. (Accounting for harvesting, transportation, and other associated activities can give biofuels a slightly positive carbon emission.)

The United States has massive amounts of CO₂ storage capacity in various underground locations, and in

different geologic formations. Moreover, an important near-term application of such sequestration technology is enhanced oil recovery, in which CO₂ can be used to stimulate the production of oil wells. CO₂-enhanced oil recovery has been practiced for more than thirty years in western Texas, providing a valuable experience base from which new projects can benefit. As another example, Canada's EnCana in Saskatchewan uses CO₂ generated from a North Dakota coal gasification plant to enhance oil production; the CO₂ is transported more than 200 miles north via pipeline to the oil fields.

Removing the carbon from a solid fuel, such as coal or biomass, prior to combustion requires gasifying it. Gasifiers are essentially large pressure cookers that heat the fuel in the absence of oxygen. At a sufficient temperature, the fuel decomposes into synthesis gas, or syngas, which is a blend of hydrogen and carbon monoxide, both of which are fuels, as well as other diluents. The specifics of the syngas composition, such as H₂-to-CO ratio, depend upon the feedstock and gasification approach.

In order to produce fuel richer in hydrogen, the CO can be reacted with steam in a water-gas shift reactor, which shifts the mixture to a high-H₂ and CO₂ mixture. The CO₂ can be removed, and the H₂ mixture combusted in a combined-cycle power plant, similar to modern plants which utilize natural gas.



Synthesis gas made from coal is cooled in this chamber by the injection of water. Solidified clinker particles can then be removed and the clean gas sent to a combustor.

There are a number of benefits and challenges associated with this approach, known as an integrated gasification combined-cycle plant. As could be expected, cost is a significant consideration. According to a National Energy Technology Laboratory study, the cost of installing an IGCC plant without carbon capture can be larger than the cost of a conventional pulverized coal plant, although the IGCC offers other benefits such as efficiency or emissions reductions. However, with capture technology, the IGCC plant is estimated to have a lower installed cost than a pulverized coal plant outfitted with flue gas CO₂ scrubbers.

The efficiency of an IGCC plant with CO₂ capture is reduced by losses associated with gasification and water-gas shifting. Carbon capture itself reduces the relative plant efficiency, due to CO₂ compression and other losses. This implies that, in order to capture the carbon, more fuel must be burned and CO₂ generated. The U.S. DOE and E.U. have several major programs in place to address these efficiency penalties, including advanced fuel gas cleaning and CO₂ separation technology.

Using pure hydrogen as a fuel is complicated because designs for low NO_x pollutant emissions generally require premixed operation. In a premixed system, fuel and air are mixed upstream of the combustion chamber, and this introduces a variety of operational challenges for any fuel, but especially for hydrogen, which burns much faster than conventional fuels. Because the mixture can burn before it reaches the combustion chamber, there is a danger of autoignition, similar to knock in an automotive engine. In addition, flashback—where the flame

propagates upstream—can occur. In either instance, high temperature gases entering regions not designed for the heat can damage parts. Premixed systems are also prone to “combustion instabilities,” which result in large amplitude acoustic oscillations that can reduce part life.

Optimizing these systems often involves trade-offs among emissions, power production, efficiency, pulsation levels, and other performance demands. The balance is so delicate that even changing the composition of the fuel gas can degrade performance.

That’s a problem, since depending upon the source of coal and the gasification technology, the composition of the syngas can vary significantly. For instance, the hydrogen levels of syngas at current IGCC installations range from 10 to 60 percent. Existing IGCC installations utilize older, non-premixed technology and can handle the varying syngas compositions without too much difficulty. However, the variability in syngas composition will be problematic for premixed operation, the preferred mode for future systems. A system designed to operate reliably with one syngas, say, with low hydrogen levels, may need to be redesigned or may require additional measures (such as steam injection) to operate satisfactorily with a higher hydrogen-content fuel.

The alternative to precombustion capture approaches, which generally lead to high hydrogen combustion, is to capture the carbon after combustion. There are various post-combustion carbon capture concepts, including those based on amine solvents, membranes, and condensation processes. In these processes, the combustion system is largely the same as at present, but the flue gas is treated to separate most of the CO₂. The separation is costly using known techniques, and consumes significant energy. Active research programs in many nations are investigating methods to reduce the cost and energy penalty associated with flue-gas scrubbing.

An alternative to flue-gas scrubbing is oxy-fuel combustion. In this approach, the combustion process typically involves burning fuel in pure oxygen rather than air, in order to avoid the large volumes of nitrogen that would otherwise need to be handled in the cleanup process.

To prevent flame temperatures from exceeding material limits, diluents such as steam or CO₂ are required to replace the nitrogen. This approach enables the CO₂/steam exhaust stream to be separated into concentrated CO₂ and water by a simple condensation process.

The oxy-fuel technique can be applied to pulverized coal boilers, and a number of pilot-scale tests and demonstration projects are already in operation. For solid fuels such as coal or biomass, research programs are currently investigating how changes in the oxygen and diluent level affect the combustion process, as well as heat transfer to the boiler surfaces. An interesting possibility—unique to oxy-fuel—is the potential to tailor the oxygen/diluent levels (and flame temperature) to improve combustion with different solid fuels, potentially increasing fuel flexibility.



This oxy-fuel system manufactured by California-based Clean Energy Systems is ready for start-up. The injector (top) mixes fuel, oxygen, and diluent into the combustion chamber of the 200 MW thermal machine.

Several other power cycles utilizing oxy-fuel combustion have been proposed. These either consist of slight modifications of existing gas turbine combined cycles, integration with gasification processes for syngas combustion, or completely new concepts such as the Graz cycle. For turbine power cycles, the aerodynamic design of the gas turbine must be modified. For example, the thermodynamic properties of CO_2 relative to air cause substantial differences in how it responds to compression in a gas turbine.

For instance, adiabatically compressing 70 °F air with an 80 percent efficient compressor from 1 atm to 15 atm increases its temperature to 823 °F. By contrast, the same compression process for CO₂ increases its temperature to 546 °F. Similarly, the turbine expansion process also results in a much higher temperature drop for air than CO₂ for the same pressure drop. This implies that materials, coatings, and blade designs would need to be reconfigured.

The combustor design in the turbine will share features with conventional gas-fired burners, but using carbon dioxide or water diluent raises combustion opportunities and challenges. In addition to autoignition, flashback, and pulsations, a fourth critical operability issue is “blowout,” where the flame becomes detached from the location where it is anchored and is physically “blown out” of the combustor. Carbon dioxide diluted flames have slower chemical kinetics than methane-air flames; as such, flame stability is more problematic as they are easier to blow off. That means designing systems which are resistant to blow-off yet also capable of operating over a range of power settings, various fuels, and so on is a design challenge. However, for the same reasons, the autoignition and flashback issues are likely far less problematic than in conventional dry low-NO_x gas turbines.

Oxy-fuel power systems also necessitate a new perspective on emissions. Combustor effluents will be presumably sequestered, and thus, their interactions with the terrestrial atmosphere are not relevant. The system’s emissions have other interesting qualities. For example, without design changes, CO emissions of carbon dioxide-diluted systems are much higher than in fuels burned in air, due to higher equilibrium levels and slower chemistry. This is, in essence, a loss in efficiency, and results in increased fuel costs for the same power output.

For similar reasons, exhaust oxygen emissions are important, not only because of the cost and power consumption associated with generating the gas, but also because the O₂ and CO gas composition cannot exceed a maximum threshold if the exhaust is intended to be sent through a pipeline for storage.

Combusting biomass is a third approach to achieve low net carbon emissions. Biomass fuel is a term that covers many varieties of organically derived materials, from agricultural and paper mill waste to plants harvested as energy crops. Biofuels can be combusted either as a synthesis gas derived from gasification of the source feedstock, or as liquid fuels created through industrial processes.

A key challenge with biofuels is simple energy density: A large power plant requires a very significant fuel supply, which would require feedstock transportation over a very large radius. Transportation costs can quickly make such options non-economical. For these reasons, biomass utilization favors a small power plant configuration that can, however, give up the usual economic and performance advantages of larger scales.

Recently, significant interest has emerged in algae as a biomass supply. Some species of algae grow at phenomenal rates, providing a new option for biomass supply. Algae is also attractive because it can be grown in areas unsuited for conventional food crops, and some species produce hydrocarbon oils that may be recovered directly for energy production. It has been proposed that algae production might be accelerated by growth in the flue gas of conventional power plants, due to the elevated CO₂ levels. Ongoing studies are aimed at defining the potential of these technologies as well as evaluating methods to refine the algae biomass and oils.



The 4 GW Drax Power Station in North Yorkshire, England, is one of the largest biomass co-firing facilities in the world. Here the biomass is being processed prior to combustion.

One way to reduce the supply limitations of pure biomass fueling is to mix biomass and fossil fuels such as coal in both combustion and gasification applications. By using a mixture of these fuels, the power or chemical plant economics can be scaled with confidence around the stable supply of coal, while also including a renewable component at variable levels, depending on biomass availability. Direct co-firing of coal and biomass is already practiced in multiple power plants around the world.

Aside from simple co-firing, the addition of carbon capture and sequestration in a plant using biomass can lead to negative CO₂ emissions. This approach is especially attractive to power plant operation because the benefits of biomass addition can be realized immediately, while the carbon capture technology is being developed and added later.

A similar situation exists for coal-biomass mixtures used in liquid transportation fuel production. Liquid fuels, synthetic natural gas, and other chemicals can all be produced from solid fuel gasification by various synthesis gas processing techniques.

Co-gasification of coal mixed with biomass does introduce some new development issues. While there is significant experience with pure biomass gasification, most pure-biomass gasifiers are relatively small, and operate at atmospheric pressures. In contrast, most coal gasifiers are built to capture the scale and economic advantages of large, pressurized gasifiers. Injection of biomass into a pressurized gasifier is complicated by the nature of biomass, which is usually not brittle like coal and is thus difficult to grind into particles that are readily fed through coal feeding systems. The greater reactivity of biomass means that it may not require the same level of size reduction as coal, potentially saving some grinding energy, but pneumatic conveying may be incompatible with the larger and often irregular biomass particles.

To make biomass more compatible with co-gasification, methods of pretreatment, from drying to pyrolysis, are being considered. One method being looked at is torrefaction, which typically involves heating the biomass for less than 30 minutes at around 250 °C. At those low temperatures, most of the fuel heating value is retained, but the energy density is increased, and the product biomass is brittle enough to grind like coal. The process is similar to what happens when a green coffee bean is roasted—it becomes brittle enough to grind, but retains much of the original mass.

While renewable energy sources are expected to take on a greater generating burden in coming decades, they do present some challenges. The variable nature of wind, for instance, requires that back-up power be ready to meet demand when the wind stops blowing. One way to meet that is through energy storage, in the form of pumped water storage hydropower or through compressed air. Batteries may also take on an increased role.

But depending on the size of the needed storage, economics, efficiency, and other project specifics, energy storage may not be preferred. Instead, variable wind output may be balanced by load-following with power plants combusting some fuel. The Netherlands, for instance, has a goal this year of 9 percent electricity generation from wind energy, but no energy storage is currently used. Instead, power plants have been operating to meet aggressive requirements to follow the load. Significant “turndown” of a fossil power plant can be required to allow wind energy to displace the baseload output.

This introduces new demands on the combustor performance, which must maintain emissions and stable combustion over a wide range of heat output. Likewise, boiler and turbine material lifetime can be adversely affected by wide variations in temperatures and power output, increasing stresses that some plants were not designed for. In some cases, implementation of advanced control methods has allowed older fossil power plants to better follow the load. In other instances, such as in South Korea, specifically designed fossil power plants are being used to follow the load.

Continued development of advanced combustion methods, materials, and process controls might be expected to increase the potential to follow the load. But the relative contributions of load-following and energy storage is expected to depend on the specific combination of renewable power and fossil fuel backup. Whatever the exact level of load-following achieved, it is helpful to recognize that the combination of renewable generation and fossil represents a net reduction in CO₂ emissions.

These are challenging problems, but many of the best minds are hard at work to address them. Major programs from the U.S. Department of Energy, the European Union, China, India, and other countries are under way, in addition to internal programs at many of the largest energy and petrochemical companies in the world. There will be many exciting solutions as we grapple with the competing problems of growing our economies, reducing our environmental impacts, and increasing our energy security.

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