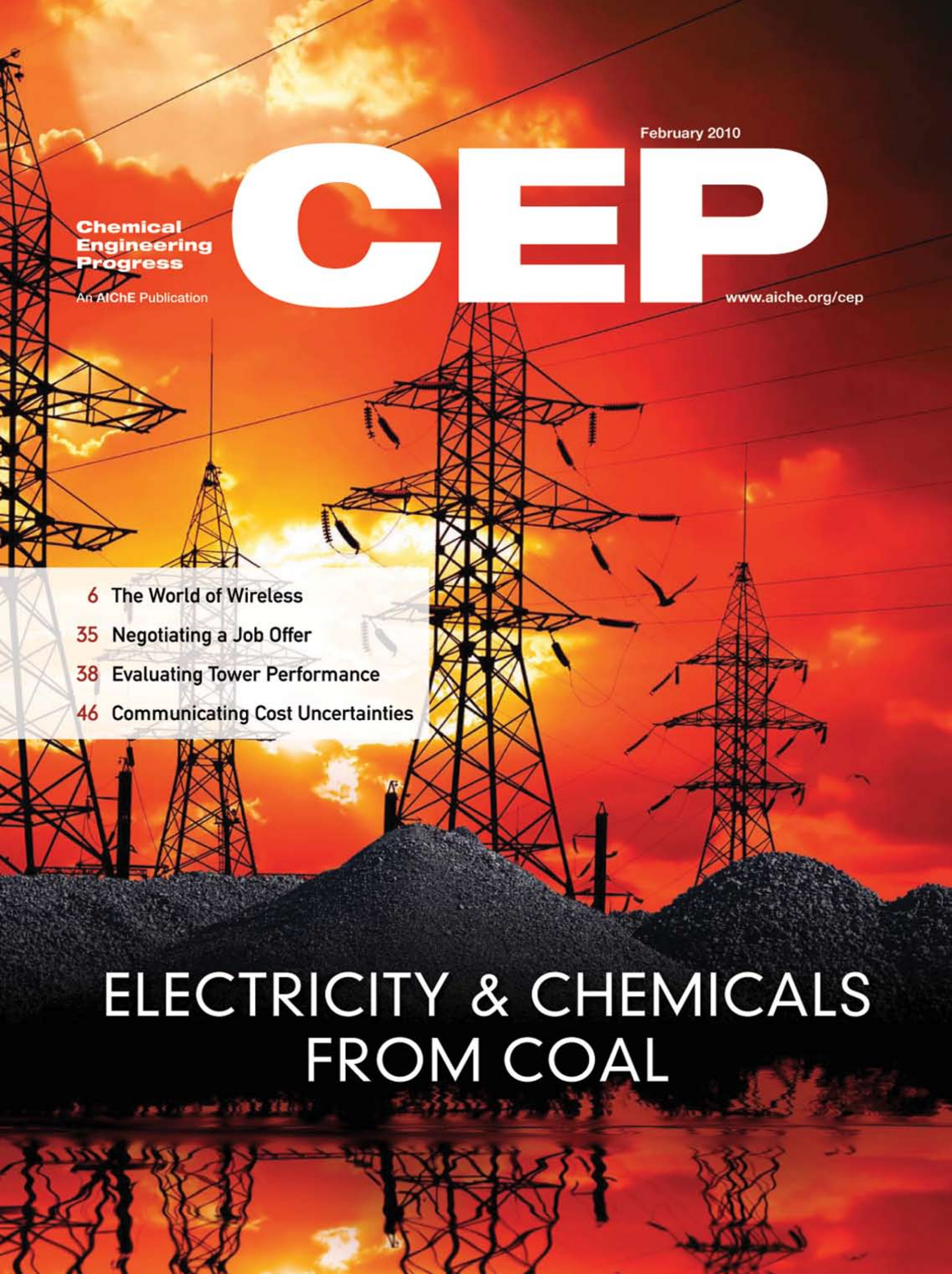

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ELECTRICITY & CHEMICALS FROM COAL

Producing Electricity and Chemicals Simultaneously

Interesting technology ... interesting policy ... difficult economics ... numerous challenges ...

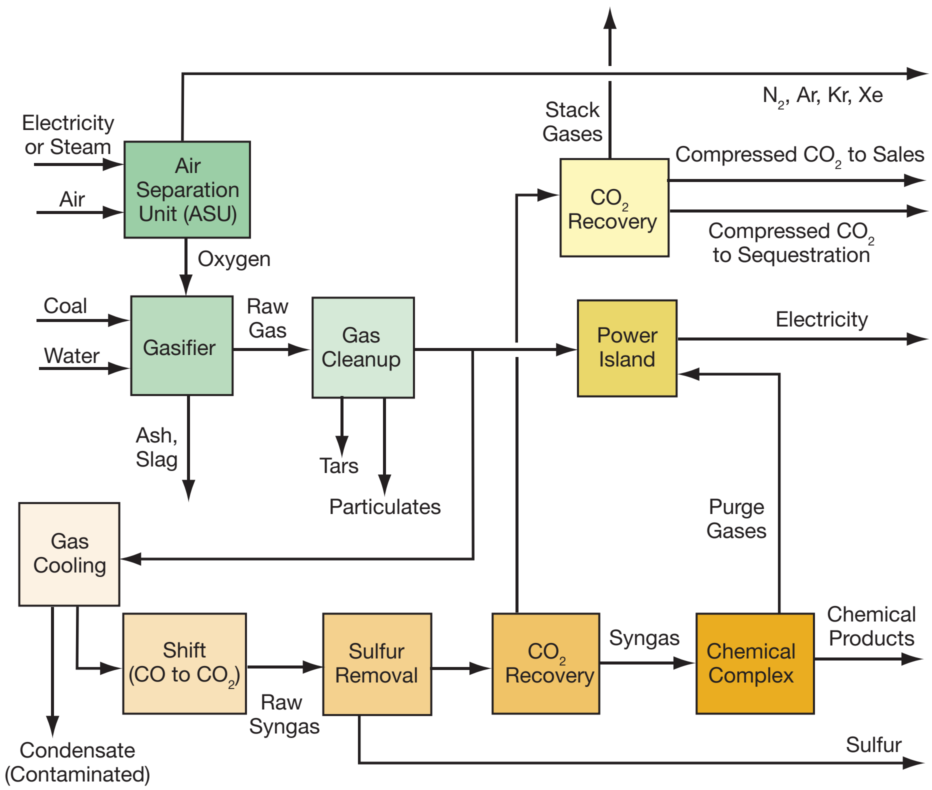
Herbert W. Cooper
Dynalytics Corp.

◀ Eastman Chemical Co. produces organic chemicals via coal gasification at its Kingsport, TN, plant. Photo courtesy of Eastman Chemical Co.

Electricity-generating utilities and chemical manufacturers face two major challenges: The costs of their fuels and feedstocks are rising to unprecedented levels, and they are under increasing regulatory and social pressures to reduce carbon dioxide emissions. A potential solution to both of these issues: gasify widely available low-cost coal, petroleum coke, or biomass, and use the resulting effluent gas stream to simultaneously produce and market electricity through a regulated entity and chemicals through an unregulated entity.

The convergence of several factors, including a desire for energy security, increasing oil and gas prices, and concerns about global warming, has led to increased interest in clean-coal technologies, such as integrated gasification combined cycle (IGCC) — *i.e.*, coal gasification followed by cleanup of the gas produced and its use as a fuel in efficient gas or steam turbine combined cycles to generate electricity. Although IGCC technology continues to evolve *(1)*, the economics of this approach to producing only electricity are, at best, marginal today. And, development of IGCC projects has not been easy in recent years, with approximately one-third not progressing even after significant investment in preliminary activities — a recent survey *(2)* found that 35 projects are in construction or commissioning, seven have been stalled or delayed, and ten have been cancelled.

The synthesis gas leaving the gasifier is similar in composition to the feedstocks used to produce chemicals such as methanol, ammonia, urea, dimethyl ether, and others. Preliminary analyses indicate that if capital costs and certain operating costs are split between electricity and chemical production, there may be substantial economic benefits to using a portion of this gas as a fuel to produce electricity and the remaining gas to produce higher-value chemicals.



▲ **Figure 1.** IGCC technology can turn coal into a synthesis gas that can be used to simultaneously generate electricity and manufacture chemicals.

The basics of IGCC

IGCC involves heating coal (or coke or biomass) to a high temperature in the presence of steam and air (or oxygen), with the amount of oxygen entering the gasifier insufficient for complete combustion. Use of relatively pure (~95–98%) oxygen will produce a synthesis gas with a heating value of approximately 230 Btu per std. ft^3 (Btu/scf); use of air, with its nitrogen burden, will produce a 130-Btu/scf syngas. Typical gasifier conditions are 300–500 psig and 1,400–2,600°F.

Figure 1 is a generalized block diagram of an IGCC process, and Table 1 shows the typical composition of the syngas (or fuel gas) leaving the gasifier. The actual composition of the syngas will depend on the type of coal, the gasification process, and other variables such as the amount of water and oxygen being used.

Although there are significant differences in the flow arrangements (countercurrent, cocurrent, fluidized bed), mechanical construction, and internals of gasifiers, many designs have been developed, and operating availabilities of 90+% have been attained. Among the important process differences are whether the oxygen is provided via compressed air or from an air separation unit (ASU), and whether the coal is fed dry or in a slurry. The common element is that they all use a very-high-temperature process to convert a solid fuel to a gaseous mixture containing large amounts of CO and H_2 mixed with CO_2 (and other compounds), and this mixture is then treated to remove impurities and produce a gaseous fuel suitable for use in combustion turbines.

Importantly, gasifiers are relatively flexible. One supplier has reported the ability to handle coals with a wide range of properties, including sulfur content (0.5–7 wt.%), ash content (<1–40 wt.%), chlorine content (100–2,000 ppmw), and heating value (7,000–17,000 Btu/lb) *(3)*.

Reducing CO_2 emissions: social and political driving forces

Regardless of one's position on global warming, the reality is that governments will impose increasingly stringent requirements aimed at reducing emissions of greenhouse gases (GHGs) — carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydro-

Table 1. Typical composition of a coal gasifier's outlet stream.

	Range, vol.%	Value Used for Economic Analysis, vol.%
Carbon Monoxide (CO)	30–60	43
Hydrogen (H_2)	25–30	26
Water Vapor (H_2O)	2–30	15
Carbon Dioxide (CO_2)	5–15	10
Methane (CH_4)	0–5	2.4
Nitrogen (N_2)	0.5–4	2.2
Hydrogen Sulfide (H_2S)	0.2–1	0.6
Argon (Ar)	0.2–1	0.6
Ammonia (NH_3) + Hydrogen Cyanide (HCN)	0–0.3	0.20
Carbonyl Sulfide (COS)	0–0.1	0.05

fluorocarbons (HFCs), perflourocarbons (PFCs), and sulfur hexafluoride (SF_6).

Numerous approaches to reducing GHG emissions are being discussed at national and local levels throughout the world. In the U.S., for example, the Environmental Protection Agency (EPA) recently issued an "endangerment finding" declaring that greenhouse gases, including CO_2, are dangerous pollutants, and that the EPA has the authority to regulate GHG emissions. It is anticipated that any new regulations would apply to approximately 14,000 large sources that emit at least 25,000 tons of CO_2 per year. This 25,000-ton/yr CO_2 trigger will generally be exceeded by power plants with capacities above about 15 MW.

Regulatory mandates and economic factors are expected to dictate that a substantial fraction of the CO_2 generated by large chemical and power plants be captured from process exhausts and fluegases rather than released to the atmosphere. Regulations are evolving, and are often in conflict — leading to substantial uncertainties as corporations set their global warming agendas, timetables and budgets. Managers of utility and chemical companies will thus need to balance the risks of incurring unnecessary costs against the benefits of taking action earlier rather than waiting until requirements that may involve higher costs are imposed.

Environmental Considerations Other Than CO_2

The environmental performance of a gasifier-based process is generally much better than can be attained with conventional boilers. NOx is not formed in the oxygen-deficient gasifiers; the nitrogen is instead converted to ammonia, which is easily removed. Concentrations of SOx and particulate matter (PM) are typically only 20–50% of those in the exhaust gases from conventional boilers. (Carbon monoxide concentrations may be the same, but will not be higher.)

An IGCC plant uses only 40% of the water needed by a conventional fossil-fuel power plant. This is because only 40% of its electricity is produced by a steam-driven generator, which requires large amounts of water to condense its exhaust, while approximately 60% of its electricity is produced by a gas-turbine-driven generator, which uses only a very small amount of water for cooling lubricating oil, bearings, and the like. In contrast, a conventional power plant produces 100% of its electricity using a steam-turbine-driven generator with a 250% higher capacity.

Liquid water will be produced as condensate during process gas cooling, and will contain various amounts of ammonia, carbon dioxide, sulfuric and sulfurous acids, hydrogen cyanide, and carbonyl sulfide. These require attention, but do not add significantly to the plant's water treatment burden.

Table 2. The electric power and transportation sectors generate roughly three-quarters of all CO_2 emissions *(14)*.

	2008 Emissions, Million m.t./yr	Contribution to Emissions, %
Electric Power	2,359	40.6
Transportation	1,925	33.1
Industrial	966	16.6
Residential	345	5.9
Commercial	217	3.7
Total	5,812	100.0

Reducing CO_2 emissions from power plants

Although CO_2 is produced by a variety of sources, the electric power sector is the largest emitter (Table 2). For this reason (as well as for political and economic reasons), efforts to reduce CO_2 emissions will focus heavily on power plant operations.

The U.S. has large reserves of coal, and about half of the electricity used in the U.S. today is produced from coal. Therefore, much consideration is being given to IGCC plants. They may offer a way to use coal more efficiently and thus produce less CO_2, and they are attractive because they can use widely available low-cost coal, petroleum coke, or biomass.

More than ten years of operating experience has now been accumulated at five coal-fired IGCC plants in the 250–350 MW range* and one 120-MW demonstration plant†. Additional experience is being accumulated at nine newer IGCC power plants now operating throughout the world.

Capture and disposition of CO_2

Many industrial plants practice carbon dioxide capture. The CO_2 is chemically absorbed from process gases and fluegases by solvents such as ammonia, chilled ammonia, methanol, monoethanol or diethanol amine (with additives), and proprietary solutions. The absorbed CO_2 is removed and the solvent regenerated by reducing the pressure and raising the temperature of the solution.

In general, however, these processes are currently not practical for coal-fired power plants, where the fluegas compositions vary, and the concentrations of CO_2 are lower and those of sulfur and oxygen are higher. In addition, because of the large volumes of solvent required to treat power plant fluegases, the energy requirements for regeneration and for pumping the solution back to the high-

* Wabash Power Station, Terre Haute, IN, since 1995; Willem Alexander, Buggenum, The Netherlands, since 1994; Polk Power Station, Tampa, FL, since 1996; Vresova, Czech Republic, since 1996; and Elcogas, Puertollano, Spain, since 1997.
† Cool Water Demonstration Plant, Barstow, CA, since 1984.

pressure absorber are significant. Much research is being devoted to developing other approaches *(4),* such as semi-permeable membranes *(5),* that may be more efficient.

The captured CO_2 may be disposed of in two fundamentally different ways. One is to transport it to oil fields and then inject it underground, where it forces additional oil to the surface. Several enhanced oil recovery (EOR) projects of this nature are underway throughout the world. However, the amount of CO_2 generated by U.S. power plants is enormous — approximately half the volume of natural gas carried by the entire U.S. gas pipeline system, and four times as much by weight. Thus, the transportation requirements for disposing of even a few percent of this are formidable. A somewhat similar approach is to simply store, or sequster, the CO_2 in underground structures; suitable sites for storing 3,500 billion tons of CO_2 have now been identified *(6).*

Table 3. Methanol is an important building block for the manufacture of other chemicals *(9, 11)*.

	Worldwide Demand, Thousand m.t./yr	Percent of Demand
Formaldehyde	17,200	40
Acetic acid	7,300	17
Chloromethanes	5,200	12
Methyl tert-butyl ether (MTBE)	4,700	11
Methyl methacrylate	4,300	10
Methyl amines	3,000	7
Others*	800	2
Total	42,500	100.0

* Primarily dimethyl terephthalate and methyl mercaptan

Chemical production

An alternative approach is to use the gasifier effluent and captured CO_2 as feedstocks to produce other chemicals. Much experience in producing chemicals from gasified coal or coke has been gained at various projects in China, Sasol projects in South Africa, the Dakota Gasification Co.'s Great Plains synfuels plant in Beulah, ND, the Coffeyville Resources nitrogen plant at Coffeyville, KS, and the Eastman Chemical Co.'s chemicals from coal facility in Kingsport, TN. Among other marketable chemicals, these plants produce significant amounts of carbon dioxide, acetic acid, acetic anhydride, ammonia, ammonium sulfate, methanol, methyl acetate, nitrogen and inert gases, and phenol.

Combining electricty generation with chemical production in a coal gasification complex capitalizes on several synergies:

- The composition of the gasifier effluent is similar to that required for producing various marketable chemicals.
- The amount of relatively pure nitrogen and oxygen at approximately 300–400 psig produced by the ASU may be increased at a small incremental cost and used as another feedstock for chemical production.
- The volumes of fluegas produced in IGCC power plants are much smaller than those of conventional steam-boiler power plants because of the much higher pressures used (approximately 465 psia in gasification processes vs. roughly 15 psia in conventional power plants.) This allows the use of smaller equipment and piping.
- The higher pressures in gasification plants provides larger mass-transfer driving forces in pollution control equipment such as scrubbers to capture CO_2 and sulfur compounds.
- High-temperature energy management is an essential part of producing syngas or gaseous fuel economically by coal gasification. Adding a chemical plant provides additional options for integrating the heat sources with lower-temperature heat sinks.
- Construction, startup and operation can be staged so that production may be started and revenues realized from either the electrical plant or the chemical plant while the other is under construction.

Many chemicals can be produced from the process streams and fluegases associated with IGCC thermal power plants. However, considering the production quantities necessary to justify the capital costs, the supporting infrastructure requirements, and the competitive environment, only a few are potentially viable.

Methanol

Methanol is one of the few chemicals that are produced in mega-ton quantities from coal, oil or natural gas and marketed internationally. An initial evaluation of technical and economic factors indicates that producing methanol from coal may, in certain situations, be a promising and logical next step in the U.S. at this time.

Methanol is the simplest alcohol, with a chemical formula of CH_3OH. Its major uses are shown in Table 3.

Fuel and feedstock (which are usually the same material, although they may be different) are the largest components of methanol's production cost. All of the large (>3,000 ton/day) newly announced export-oriented methanol plants are located in the low-gas-cost Middle East, or in China where coal is the most common feedstock.

Methanol is produced in modern plants by the catalytic reaction of CO, CO_2 and H_2 at temperatures of approximately 500°F and pressures of 600–800 psig. The carbon monoxide is produced mainly by steam-methane reforming of natural gas or liquid hydrocarbons, followed by purification. In China and a few other special situations, the carbon monoxide is produced by partial oxidation of coal. Several studies of converting coal to methanol *(7, 8)* indicate that, depending on the coal's carbon content, methanol yields of approximately 20% without recycle of unconverted syngas and 35% with recovery and recycle of unconverted syngas to the reactor inlet can be achieved.

Proven methanol process technology is available via license, primarily from:

- Davy Process Technology (Johnson Matthey)
- Haldor Topsøe
- Lurgi GmbH
- Methanol Casale
- Mitsubishi Gas Chemical.

One possible scenario

Numerous scenarios involving the simultaneous production of electricity and chemicals from coal using IGCC might be developed. The economic analysis presented here is based on an electric power plant that needs to satisfy an average demand of 500 MW and prefers to use a low-sulfur Southern Powder River Basin coal.

The following analysis looks at the financial pros and cons of using half of a gasifier's output to produce and sell methanol and the other half to generate and sell 250 MW, with the electric shortfall being purchased from other generators and resold at cost.

Table 4. Coal properties vary from basin to basin …

	Illinois Basin *(12)*	Powder River Basin* *(13)*
Heating Value (HHV)	11,200 Btu/lb	8,800 Btu/lb
Sulfur	3.2 wt.%	0.32 wt.%
Fixed Carbon	43.4 wt.%	34.50 wt.%
Volatile Matter	35.1 wt.%	32.00 wt.%
Moisture	10.5 wt.%	27.00 wt.%
Ash	11.1 wt.%	5.50 wt.%
Ash Fusion Temperature		
Initial Deformation	2,055°F	2,135°F
Fluid Temperature	2,245°F	2,205°F

* Ash Coal Inc.'s Black Thunder Mine, Southern Powder River Basin, Wright, WY

Table 5. … as well as within an individual basin.

	Illinois Basin Average *(12)*	Standard Deviation
Heating Value (HHV)	11,200 Btu/lb	900 Btu/lb
Sulfur	3.2 wt.%	1.5 wt.%
Fixed Carbon	43.4 wt.%	4.8 wt.%
Volatile Matter	35.1 wt.%	2.9 wt.%
Moisture	10.5 wt.%	3.7 wt.%
Ash	11.1 wt.%	4.0 wt.%
Ash Fusion Temperature		
Initial Deformation	2,055°F	165°F
Fluid Temperature	2,245°F	181°F

Technical basis for the economic evaluation

Coal. As Tables 4 and 5 demonstrate, coal properties vary significantly from basin to basin, as well as from mine to mine within a coal basin and from seam to seam within a mine. Among the most important issues to be resolved when developing a coal-based chemical production facility are establishing the type of coal to be used, the mine from which it comes, and the commercial terms of purchasing and delivering the coal to the plant site.

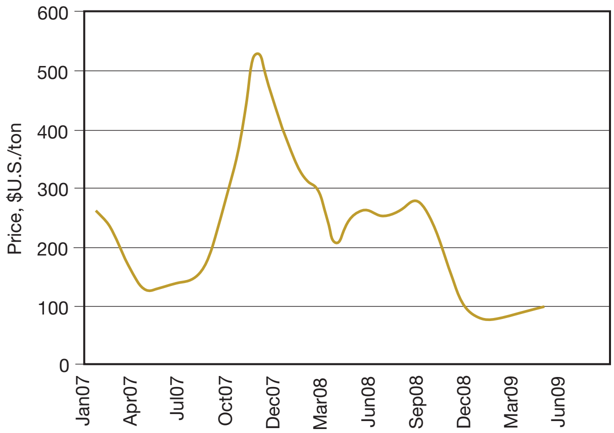
This analysis uses a Southern Powder River Basin coal that has the properties listed in Table 4. The same coal composition is used for both the electricity-plus-methanol and electricity-only alternatives.

Plant performance. The facility includes a conventional gasifier, gas cleanup, and a gas-turbine/steam-turbine system. Table 6 summarizes the production choices that have been made. The values shown are typical, and they have not been optimized for any specific plant, location or business situation. The analysis assumes that carbon capture will be required, and that the CO_2 will be compressed to 2,000 psi and a portion of it is sold for EOR.

Table 6. Representative production data used for the economic analysis (assuming that carbon capture is required).

	Electricity Only	Electricity Plus Methanol
Fuel	PRB Coal	PRB Coal
Electric Capacity (net)	500 MW	250 MW
Net Heat Rate (with carbon capture)	11,800 Btu/kWh	11,800 Btu/kWh
Availability	85%	81%
CO_2 Recovery	90%	90%
Electric Energy Produced (net)	3,723,000 MWh/yr	1,774,000 MWh/yr
CO_2 Sold (at 2,000 psi)	4,918,700 ton/yr	1,440,000 ton/yr
Methanol Produced	—	824,200 ton/yr
Ash Produced	137,300 ton/yr	130,800 ton/yr
Electric Energy Imported	657,000 MWh/yr	2,606,100 MWh/yr

Note: Revenues from sales of inert gases and sulfur products may be noticeable in certain situations, but are not included here.



▲ **Figure 2.** Methanol prices on the U.S. spot market are characterized by significant volatility. Source: *(9).*

Overall approach and simplifying assumptions

This basic economic evaluation does not focus on a particular process, site or financing structure. Rather, it is a simplified assessment of the effects of sales prices of methanol and electricity on the economics of producing electricity only and electricity plus methanol.

Comparisons of this type can be made in many ways. The most common consider:

• net present value (NPV) of the initial investment and the sum of the positive and negative net cash flows, discounted by an appropriate rate

• internal rates of return (IRR) on the total investment or on the equity invested; the IRR is the discount rate that, when applied to the forecasted net cash flows, leads to a sum over the financial life of the project that equals the initial investment.

It is important to understand several subtleties involved in using these (or any other) measures to compare complex financial situations. Among the most serious is that it is almost impossible to accurately establish the discount rate, or opportunity cost of capital, which is a critical input for calculating NPV; normally, a somewhat subjective value is used based on managements' views and experience. In addition, by focusing on absolute values, an NPV analysis will inherently favor large projects over small ones.

The most serious issue related to IRR analysis is that the calculation is based on the reinvestment of all cash flows at the IRR rather than at a discount rate that may be different (and perhaps more-representative of actual market interest rates). This is normally a reasonable assumption for preliminary analysis. Moreover, income from the investment of cash flows, moreover, can be explicitly incorporated if an investment-grade financial evaluation is required. Another issue is that when future cash flows change signs multiple times, there is more than a single IRR that is mathematically correct. In these cases, it is important to try several different initial values or to plot the NPV vs. discount rate to determine the relevant value.

Technical, economic and regulatory risks are inherent in any project. NPV and IRR analyses provide a single value and do not consider ranges. Thus, Monte Carlo simulations, which require assigning (generally subjective) numerical probabilities to various factors, are often used to assess possible outcomes. The level of detail produced, however, is unnecessary for preliminary evaluations, so Monte Carlo techniques have not been applied here.

Because tax aspects of project evaluation are extremely complicated and project-specific, this analysis calculates pre-tax costs of electrical energy generation. A levelized fixed rate of 7.50%/yr for a 20-yr period is used to account for depreciation and a return on equity.

It is assumed that all engineering, procurement and construction (EPC) activities for the power block and the methanol plant are carried out simultaneously, and that they commence in 2010. Operation is assumed to begin in 2015.

Any facility such as this will have a lengthy construction and startup period. Although three to four years might elapse during which funds are being spent without realizing any revenues, to simplify the analysis, instantaneous construction and start of revenue streams are assumed.

All costs have been escalated to be consistent with the 2010 start of EPC activities and 2015 plant startup.

Revenues

Methanol. The U.S. spot-market price of methanol has been subject to much volatility (Figure 2). For example, from early 2007 to mid-2009, spot-market prices in the U.S. varied from $79/ton to $527/ton *(9),* and have most often been significantly below the long-term contract rates.

Since substantial new methanol capacity is coming online and the effects and duration of the global economic recession are unknown, a range of prices from $0 to $500/ton is considered, with an average of $200/ton (escalated to $237/ton in 2015) used as a specific reference point.

It appears that the methanol market is sufficiently competitive to preclude producers from passing carbon taxes on to purchasers.

Carbon dioxide. There is considerable uncertainty about the future value of CO_2, since a new regulatory framework has not yet been implemented. Several oil companies have indicated that a price of $25/ton is near the upper end of the range they would consider for a multiyear contract. Thus, a CO_2 price of $25/ton is used here.

Other products. Revenues from sales of inert gases and sulfur products may be noticeable in certain situations, but are not included in this analysis.

Article continues on next page

Capital expenses

It is likely that funds for this type of major plant will be provided as a package of government grants, debt, and equity. Rather than introduce additional assumptions about the extent and terms for each of these, the economic comparisons are based on 100% equity financing. An allowance for interest during construction has been included in capital expenses.

Power plant. Based on various studies, a unit cost of $6,125/kW is used for the 500-MW electricity-only IGCC option. A unit cost of $10,165/kW is used for the 250-MW portion of the electricity-plus-methanol option, which includes many of the same 500-MW-sized components, such as the gasifiers, coal storage, etc.

Methanol plant. Proprietary information indicates that the current unit cost for a standalone, greenfield gas-feedstock methanol plant is $106,000 per ton/d of methanol capacity. Because certain offsite facilities, the gasifier, and effluent gas-treatment equipment will be shared with the electricity-generation operation, the adjusted incremental unit cost of the remaining methanol plant is estimated to be $83,300 per ton/d of methanol capacity.

Carbon capture and transportation. Carbon dioxide has been recovered and sold for use at sites 300 miles from its origin. The costs of the pipeline system, including recompression stations, are assumed to be $50 million for the electricity-only scenario and $45 million for the electricity-plus-methanol scenarios (which would carry somewhat less CO_2).

Other fixed expenses. Other fixed expenses include capital recovery and a return on investment, fixed operation and maintenance (O&M) expenditures, and insurance. Escalations of 2.50%/yr to 2.75%/yr were applied as appropriate.

Variable expenses

Coal. The current unit cost of Southern Powder River Basin coal is $13.00/ton *(10),* or $0.74 per million Btu (MMBtu), which was escalated to $15.08/ton ($0.86/MMBtu) in 2015. The total battery-limits cost, including $9.00/ton ($0.51/MMBtu) for transportation, is $24.08/ton ($1.37/MMBtu) in 2015.

Carbon taxes. Carbon taxes (or equivalent allowances) are included at a cost of $30/ton of CO_2 ($110/ton of carbon.) There will inevitably be conflicting viewpoints about who should absorb the economic burden. Public Service Commissions have not yet signaled how they will resolve the cost-allocation issues. Therefore, this analysis assumes that:

• a carbon tax will be assessed only on the generation company

• the carbon tax will be based on CO_2 emissions

• Public Service Commissions will allow only the portion of the carbon tax that can be attributed to electricity production to be passed on to consumers by the generation company; this is calculated by multiplying the total carbon tax by the fraction of the total revenues represented by electricity generation.

Other variable expenses. Other major variable expenses include variable O&M, water supply and treatment, and disposal of spent chemicals and catalysts. Escalations of 2.50%/yr to 2.75%/yr were applied as appropriate.

Financial projections

Actual costs and prices will be technology-, project- and site-specific. Nevertheless, the production costs presented in Table 7 are believed to be representative. Internal rates of return for various electricity prices and methanol prices are shown in Figure 3.

The simultaneous production of methanol and electricity is more economically attractive (*i.e.,* it has a higher IRR) than producing only electricity in two situations — if the methanol price is ≥$400/ton and the electricity price is <$170/MWh, and if the methanol price is ≥$500/ton and the electricity price is < $225/MWh. Although these do not appear to be high-probability circumstances in the near future, they are certainly possible if disruptions to the energy supply occur.

Major issues

Fuel/feedstock agreements. It is virtually impossible to finance large capital-intensive projects such as this without first securing long-term fuel-supply and fuel-transportation contracts. This is a manageable issue for coal-fired and petroleum-coke fired plants, but has been insurmountable for two large biomass-based plants that were recently being considered in the U.S.

Sales of products. Within the U.S., the sale and purchase of electricity by utility companies are regulated at the state level, where an agency such as the Dept. of Public Utilities or Public Service Commission (or a similarly named entity) must approve each contract. This includes mechanisms for obtaining electricity competitively within very short timeframes, such as “day-ahead bids.” These systems analyze large amounts of technical data for each participating plant to determine which bids to accept, and hence which power plants will be called on (or dispatched) so that the overall supply mix will have the lowest cost for ratepayers.

It will be difficult (but certainly not impossible) for a new coal-based plant to compete in regions that already have ample generating or import capacities, or with existing fully depreciated facilities. A location-based marginal pricing study can establish whether a particular plant would be dispatched at various electricity prices or whether other plants are likely to be more economical providers. Importantly, large coal-based power plants cannot be started up and shut down rapidly, and since the plants must operate at some minimal level, owners are occasionally forced to offer artificially low bids.

Methanol is produced throughout the world by many for-profit companies, and also by many government-owned or government-controlled entities. The latter often base production and pricing decisions on a variety of factors beyond profitability, such as the need to support local industries and maintain employment, and international geopolitical considerations. A new methanol facility would have to compete in this complex marketplace that is marked by extreme price volatility.

Impact on price levels. Current worldwide methanol production is approximately 46.9 million ton/yr (42.5 million m.t./yr). Assuming a price elasticity [(dQ/Q)/(dP/P), where Q = quantity and P = price] of –0.3, the impact of a single facility that simultaneously produces 250 MW of electricity and 824,200 ton/yr of methanol will be 5.9%. The 2015 price of $237/ton might therefore be reduced by approximately $14/ton, which is quite noticeable (although local markets might be impacted to a larger or smaller extent). This does not, however, reflect changes in demand that are certain to occur.

Volatility. Simultaneous production of electricity and chemicals exposes producers to two volatilities — demand and price — for each of two products. These volatilities interact to varying degrees, depending on each product's economic elasticity.

A serious complication arises because there may be a penalty for not meeting contractual or market demands for one product, but there may be limited flexibility to produce or not produce it without affecting the production of several other products. While this is not unusual in the chemical sector, it typically does not arise in electricity generation (except for cogeneration operations). The situation is further complicated because it is economically impractical to store significant amounts of electrical energy.

Distribution infrastructure. Since products must be transported, an adequate infrastructure is needed. Small quantities of chemical products may be transported by truck; larger volumes require rail, barge or pipeline. Many regions are served by a single railroad that has significant bargaining leverage.

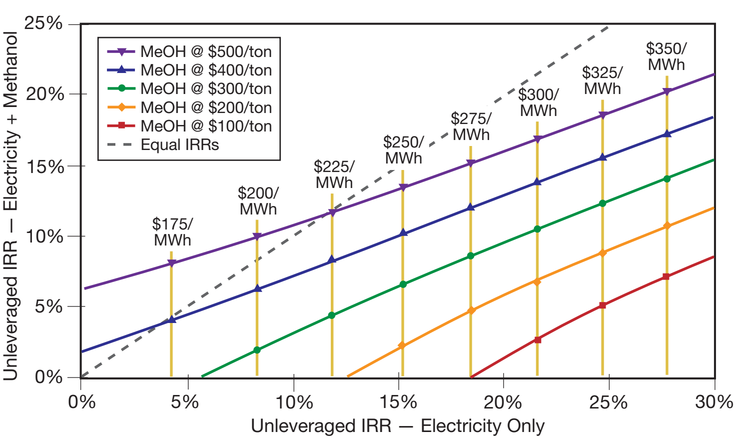
Transportation of electricity requires access to the electrical grid. If the existing infrastructure at a particular site is not adequate, a large capital expenditure may be incurred. In addition, various permits may be required, any of which may incur resistance by communities and competitors — there is no guarantee that permits will be issued.

Regulatory risks. Both the utility sector and the chemical sector are experienced in addressing routine regulatory matters. An additional risk associated with the simultaneous production of electricity and chemicals is that the utility regulator might insist that all, or substantially all, of the profits from the chemical business be passed on to electricity customers.

Technical risks. The concept of simultaneously producing electricity and chemicals is not new — it has been (and continues to be) carried out at many sites for many years. Although pilot plant testing will be required for specific coals, each major chemical process and

Table 7. Levelized cost of production for electricity-only and electricity-plus-methanol alternatives (based on reference values of methanol and CO_2 revenues).

	Electricity Only	Electricity Plus Methanol
Capital Expense	$3,062,500,000	$2,794,000,000
Annual Operating Expense	$574,200,000	$497,900,000
Credits:		
Methanol @ $237/ton (the range of $0–500/ton was evaluated)	0	$195,300,000
CO_2 @ $25/ton (the range of $0–50/ton was evaluated)	$123,000,000	$ 36,000,000
Total Credits	$123,000,000	$231,300,000
Net Annual Operating Expense	$451,200,000	$266,600,000



▲ **Figure 3.** Simultaneous production of electricity and chemicals is more economically attractive only at the highest methanol prices and lowest electricity prices considered.

operation is well-understood, including:

- coal gasification
- syngas purification
- chemical catalyst and reactor design
- final product purification
- solids handling
- product storage and transportation
- materials of construction
- environmental, health and safety aspects.

The startup of a new complex integrated facility is difficult. The annual capacity factor of one IGCC plant was only 55–60% during the first year, rising to 90% after the third year. Although there is a learning-curve period, the technical risk appears to be relatively low.

Improving the economic picture

Although the economics of producing electricity and methanol simultaneously appear to be poor based on today's costs, it is quite possible that the picture will change in the future. Since methanol production is a mature technology, initial improvements are more likely to arise from improvements to coal gasification processes, to effluent gas treatment, and to integration of material and energy flows.

The current economic climate, together with a widespread aversion in the U.S. (and elsewhere) to using coal for almost any purpose, present a difficult political challenge to implementing this concept. Obtaining a permit to construct and a certificate to operate a coal-fired plant is always difficult, time-consuming, and expensive (but absolutely critical).

Overcoming government roadblocks is as important as improving the economic situation of the approach discussed here. A realistic educational campaign will undoubtedly be required, with a strong focus on political leaders, the staffs of state environmental agencies, and the public at large.

It should be noted that although this article focuses on methanol, the production of additional or other chemicals may be more economically viable, either today or in the future.

Policy considerations

At one time, the U.S. was a major chemical producer and exporter. This position has been lost, in part due to declining domestic reserves of oil and gas and the availability of relatively low-cost feedstocks from the Middle East, Africa and elsewhere. Coal, however, remains a low-cost and extremely abundant raw material for energy and chemical production in North America.

The simultaneous production of electricity and chemicals may offer the U.S. a way to use these large reserves of coal to resurrect its declining chemical industry — to help the U.S. regain its prominence as a major international chemical producer and exporter. This can be done in an environmentally acceptable way that would undoubtedly lead to large economic benefits throughout the country. However, it would require tremendous political will. Nevertheless, it might make sense for the federal and/or state governments to provide research and development grants, and perhaps revise their tax structures, to help accomplish this. CEP

HERBERT W. COOPER is founder and president of Dynalytics Corp. (9 Sheffield Hill, Woodbury, NY 11797; Phone: (516) 921-7631; Fax: (516) 921-7632; E-mail: info@dynalytics.com). For more than 40 years he has been involved in all aspects of developing multimillion-dollar projects throughout the world, including process and equipment design, construction, operations, economic optimization, and regulatory compliance. He received his bachelor's and master's degrees in chemical engineering from the City Univ. of New York and his doctorate in engineering science (chemical engineering) from Columbia Univ. He is active in AIChE and is chair of the Metro New York Section, and is a member of the American Chemical Society, New York Section.

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