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Coal Conversion Technologies: Some Health and Environmental Effects

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Projected limitations on supplies of domestic oil and natural gas, and the need to reverse the country's increasing reliance on foreign petroleum sources, are stimulating consideration of America's vast coal deposits as a way of satisfying more of the nation's energy requirements. Several technologies to convert coal to various synthetic fuels (coal hydrogenation) are being developed in the United States, some with support from the U.S. Department of Energy. Commercial coal-gasification and demonstration coal-liquefaction plants are proposed. Many existing gas- and oil-fired electric power plants are designated candidates for coal-boiler conversion in accordance with the Power Plant and Industrial Fuel Use Act of 1978 (1). Substantial economic incentives exist to convert coal to liquid and gaseous fuels, since most energy-using devices require such fuels.

Adopting any policy that promotes extensive use of coal makes it necessary to consider the traditionally recognized environmental hazards associated with coal combustion and conversion to synthetic fuels. Many hazards are due to sulfur and ash released when the coal is consumed. However, with adequate controls, much of the sulfur and ash in the coal can be removed during conversion. Since liquid and gaseous products, unlike electricity, can be transported economically over long distances, synthetic fuel plants can be located in remote areas near the sources of coal. Thus, the emissions of the hydrogenation plants will not contribute to the emissions burdens of densely populated areas. Sulfur removal during conversion may be a desirable alternative to flue gas desulfurization in meeting the requirements of the Clean Air Act Amendments (CAAA) of 1977 (2). New electricity-generating plants could be built without significant deterioration of air quality, because the emissions of power plants burning synthetic gas would be lower than those of power plants burning coal.

A rigorous quantitative assessment of the risks of coal hydrogenation technologies to human health and environmental quality requires details on technology and site-specific effects, unavailable as yet because of limited operating experience. Liquid fuels produced by direct liquefaction contain carcinogenic polycyclic organics (POM), as do the tarry and oily effluents of many liquefaction and gasification processes. A large pilot liquefaction facility at Institute, West Virginia, operating between 1952 and

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1959 was associated with increased incidence of skin cancer and many pretumorous growths in plant workers (*3*). Although industrial hygiene programs and process design criteria would necessarily be stringent, there is insufficient operating experience with coal hydrogenation plants to ensure unequivocally that risks would be acceptably lowered. One can develop first-order approximations of the risks imposed by different technologies by using estimates of the expected emissions as a surrogate for actual damage. Significant comparative information may be obtained by examining trade-offs among emissions from different technology groupings. Attention can also be focused on those pollutants suspected to be most damaging. Even though the potential for several health and environmental problems from coal hydrogenation is evident, these potential hazards can be controlled if they are given proper recognition. The necessary controls will, of course, be reflected in the cost of the energy delivered.

Summary. Several technologies to convert coal to liquid and gaseous fuels are being developed in the United States, some with support from the Department of Energy. Substitution of these technologies for those currently being used will produce different health and environmental hazards. In this article, selected health and environmental effects of four coal conversion and four existing technologies are compared. For each technology, the emission estimates for complete fuel cycles, including all steps in fuel use from extraction to the end use of space and water heating by electricity or direct combustion, were prepared by means of the Brookhaven Energy System Network Simulator model. Quantitative occupational health and safety estimates are presented for the extraction, transportation, distribution, processing, and conversion activities associated with each technology; also included are some public health damage estimates arising from fuel transportation and air pollution impacts. Qualitative estimates of health damage due to polycyclic organic matter and reduced sulfur are discussed. In general, energy inefficiencies, environmental residuals, and hence implied environmental effects and health damage increase in the order: (i) direct combustion of natural gas and oil, (ii) direct combustion of synthetic gas and oil, (iii) central-station electric power produced from synthetic gas, (iv) central-station electric power produced from coal, and (v) central-station electric power produced by the combustion of synthetic liquid fuels. The compliance and conflict of these technologies with the amendments of the Clean Air Act and other legislation are discussed.

In this article we compare selected health and environmental effects of emerging coal hydrogenation energy-supply technologies. The evaluation was system-wide, including analyses of emissions and health impacts ensuing from the application of a particular technology, beginning with the extraction of raw resources and concluding with the consumption of energy in an end-use device. For comparison, system-wide effects from the combustion of coal, oil, and natural gas—prime candidates for replacement—are given. The energy-supply technologies and end-use applications selected for evaluation include four applications of central-station electricity generation: (i) coal combustion with flue gas desulfurization (FGD), (ii) solvent-refined coal (SRC-II) combustion, (iii) Lurgi low-Btu (British thermal units) gasification for combined cycle, and (iv) coal combustion with atmospheric fluidized bed (AFB) (*4*). We also examined four direct-combustion (small, decentralized end-use combustion) applications: (i) Lurgi high-Btu gasification, (ii) combustion of solvent-refined coal (SRC-II) liquids, (iii) combustion of natural gas, and (iv) combustion of fuel oil (*5*). Consistent end-use demands for residential space and water heating and commercial space heating were specified.

The technologies were assembled into eight supply-to-end-use trajectories by means of the Brookhaven Energy System Network Simulator (ESNS), an energy-environmental accounting model developed by Sevian (*6*). The ESNS model produces process-specific and system-wide totals for the energy flows and environmental residuals examined, including air and water pollutants, land use, water use, and solid wastes. We prepared quantitative occupational health and safety damage estimates for the extraction, transportation, distribution, processing, and conversion steps, using health damage functions developed by Hamilton (*7*) and Morris *et al.* (*8*). We also calculated estimates of public health damage arising from fuel transportation and air pollution impacts, using data from Morgan *et al.* (*9*) and others (*7, 8*). This trajectory analysis is similar to that described by the Council on Environmental Quality (*10*), but it includes more residuals, a wider range of trajectories, and updated residual coefficients. The emissions totals and calculated health damage levels were compared among processes within each trajectory and among entire trajectories to frame general policy recommendations.

Hydrogenation has potentially hazardous emissions and occupational effects. At present, these are difficult to quantify and compare in the trajectory analysis described above. However, to give a more adequate picture, a discussion is included to highlight the most likely hazards of these pollutants.

Environmental Residuals

Air pollutants. The ESNS model (*6*) was used to analyze systematically the health and environmental effects of alternate coal technologies from entire energy systems. This model structures the U.S. energy system as an interconnected network of energy supply and end-use processes. Supply processes are classified by fuel type (for example, coal), activity within the fuel (such as extraction), and process within the activity (say, underground mining by room-and-pillar methods). End uses are classified by sector (for example, residential), fuel (such as distillate oil), and device (possibly a space heater). Associated with each energy process are residual coefficients defining air and water effluents, solid wastes, land use, and other elements. All coefficients are specified in units of pollutant output per unit of energy input to each process [for example, the emission of sulfur dioxide (SO_2) is given for a coal-fired boiler in units of tons of SO_2 emitted per 10^{12} Btu of coal burned in the plant]. The remaining elements that must be specified for the network model include (i) the end-use demands in units of energy service requirements rather than Btu's, for example, dwelling years for residential space heat; (ii) efficiency coefficients for all processes, that is, the ratio of the energy output to the energy input for supply processes; and the amount of input energy required per unit of end-use demand for all utilization processes; and (iii) process allocations for competing supply processes that specify the percentage of energy that each process must deliver. Specification of a network structure and quantities (i) through (iii) suffice to generate the energy required by each process. Once the energy requirements are known, the environmental coefficients are used to compute the

Table 1. Energy processes selected for analysis from the ESNS network. The end-use demands were for residential space heating and water heating and commercial space heating.

Fuel	Supply processes					
	Extraction	Local transport	Processing	Distribution	Hydrogenation*	Conversion (electric)
Coal	Strip mining Underground mining	Truck Rail Conveyor	Breaking and sizing Steam coal cleaning	Rail Barge Truck Conveyors	Lurgi high-Btu gasification Lurgi low-Btu gasification SRC-II liquefaction	FGD electric power plant AFB electric power plant* Low-Btu Lurgi combined-cycle electric power plant* SRC-II liquids, electric power plant*
Oil	Onshore extraction Offshore extraction Imported crude	Pipeline Tanker Barge Tank car Tank truck	Refinery	Pipeline Tanker Barge Tank truck Tank car		
Natural gas	Onshore extraction Offshore extraction	Pipeline	H_2S removal	Pipeline		

*Emerging conversion technologies.

total output of residuals by process, activity, and trajectory.

A subset of the total energy system was selected from the basic ESNS network for this analysis. The processes are shown in Table 1. Trajectories for the technologies under consideration were extracted from this subset. Each trajectory consists of those processes required, from resource extraction to energy consumption in an end-use device.

End-use demands for residential space and water heating and commercial space heating are specified in units of dwelling years, to account for differences in the conversion efficiencies of energy and fuel-specific devices to useful energy. These end-use demands are converted into fuel requirements by the ESNS model through an efficiency factor having units Btu of fuel required per demand unit. In this analysis, a demand of residential water and space heat for 1.1×10^6 dwelling years was specified for each trajectory. As a reference base, it would require about 3200 megawatts of electric capacity to supply this demand with electrically generated heat.

Emissions data used by the ESNS model are available in the *Energy System Network Simulator: Databook* (*11*). The ESNS model uses emissions data specified by pollutant type for each process to compute the emissions generated. Emissions data contained within the existing ESNS data base were reviewed and compared with other similar data sets (*12, 13*) to ensure that the most up-to-date emissions data available were used in our analyses (*14*).

The emissions data used are consistent with control technologies considered likely within the next 10 years. As an illustration, removals of 90 percent of the oxides of sulfur (SO_x) and 99.5 percent of the particulates are assumed for conventional FGD and AFB electricity-generating plants. More detailed descriptions of the specific control requirements assumed for all pollutants and processes used in this study are given in Moskowitz *et al.* (*14*) and in (*15*). Since process characterization for hydrogenation technologies is still in its early stage, limited emissions data are available and subject to change. Although we used the most recent data available, there is uncertainty associated with these emissions data.

Table 2 lists the efficiencies and energy flows for the trajectories used in this study. The high end-use efficiency assigned to the trajectories for central-station electricity generation (Table 2) arises from the assumed use of electric heat pumps for 25 percent of all space heating. This reduces the supply requirements for all electrical fuel-supply trajectories. Subsequently, trajectory and environmental differences among the direct-combustion and central-station electricity-generating technologies are reduced.

Tables 3 and 4 list controlled emission estimates generated by the ESNS model for the eight residential and commercial space- and water-heating trajectories. Included are all processes in mining, processing, transporting, converting, and burning various fuels. Both heating by electricity generation (Table 3) and di-

Table 2. Trajectory efficiencies and energy use.

System factors	Central-station electricity generation				Direct combustion			
	FGD	SRC-II	Low-Btu	AFB	High-Btu	SRC-II liquids	Natural gas	Oil
Energy efficiencies (percent)								
Coal processing and storage	95.6	100	100	95.6	100	100	100	100
Conversion to fuels		62.5	75.8		57.3	62.5		
Generation of electricity	32	35	40	36.8				
Fuel processing, distribution, storage, and transport	91.2	91.2	92.1	91.2	95	99	95	99
End-use utilization	110	110	110	110	72	69	72	69
Overall energy efficiency	30.7	21.9	30.4	35.3	39.6	43.1	66.2	66.2
Energy use (10^{12} Btu/year)	206	287	207	178	159	146	95.1	95.2
Extraction output								
Input to conversion plant		287	207		159	146		
Input to combustion	196	179	157	171	87.6	91.3	87.6	91.3
Useful energy	63	63	63	63	63	63	63	63

rect combustion (Table 4) are considered. Table 5 sums the emissions of each pollutant for each trajectory.

The analysis shows that the emissions of air pollutants from direct combustion are less than those of central-station electricity generation because of large differences in the trajectory efficiency (Table 2). Gaseous fuels are cleaner than liquid or solid fuels (Tables 3, 4, and 5). The natural gas trajectory has the lowest overall emissions; FGD, AFB, and SRC-II central-station electricity generation produce the highest emissions. The emission estimates from oil and SRC-II direct combustion are generally lower than the emissions from the central-station electricity-generation alternatives but greater than the emissions from the high-Btu direct-combustion trajectory.

The emissions of SO_x and particulates follow the same trends as the other air pollutants. In the trajectories for central-station electricity generation, FGD, SRC-II, and AFB have higher emissions than the low-Btu gasification trajectory. Similarly, in the direct-combustion trajectory, high-Btu gasification and natural gas combustion have lower emissions than either of the oil direct-combustion trajectories. The emissions of SO_x and particulates in the central-station electricity-generating technologies exceed those of the direct-combustion trajectories, and the air pollutants produced by solid and liquid fuels exceed those produced by gaseous fuels.

Water pollutants. Most water pollutants, except for organics, are derived from coal mine drainage and conversion activities. Thus, the emissions of water pollutants parallel the amounts of coal used in the trajectories. Increased amounts of water pollutants are found in the central-station electricity-generating trajectories. The natural gas and oil combustion trajectories have the lowest emissions of water pollutants. The two oil-based trajectories have the largest nondegradable organic emissions arising from oil discharges throughout the fuel cycle. Limited quantities of nondegradable organics are produced in the other trajectories.

Solid waste. The production of solid waste also parallels coal use. Thus, direct-combustion technologies produce less solid waste than central-station electricity-generating technologies. Natural gas and oil technologies produce no solid wastes. The solid waste disposal requirements of the FGD electricity-generating trajectory appear to exceed those of all other alternatives.

Land use. The land-use requirements differ for the direct-combustion and central-station electricity-generating technologies because of product distribution rights-of-way. Electric transmission lines have the largest land requirement of all processes considered. The effects of mining and solid waste disposal on land

Table 3. Process and trajectory emission estimates: direct combustion; HC, hydrocarbons; TDS, total dissolved solids; TSS, total suspended solids. Column sums may not equal column totals because of rounding-off errors. Makeup water use means consumptive water loss (*37*).

Process steps	Air pollutants ($\times 10^3$ tons)					Water pollutants ($\times 10^3$ tons)				Solid waste ($\times 10^6$ tons)	Land use ($\times 10^4$ acre-years)	Water use ($\times 10^4$ acre-feet)	
	CO	HC	NO_x	Particulates	SO_x	Bases	Organics	TDS	TSS			Makeup	Total
Trajectory: commercial/residential heat from high-Btu gas													
Mining	0.10	0.01	0.16		0.01	0.16		64.1	0.48	0.93	0.40		
Transportation	0.01		0.02										
Conversion	0.66	0.20	12.0	0.80	8.19		0.03	3.44	0.07	0.73	0.05	0.53	3.44
Distribution			10.5								0.85		
Electrification													
Distribution													
End use	0.85	0.34	2.99	0.81	0.03								
Total	1.62	0.56	25.7	1.61	8.23	0.15	0.03	67.6	0.56	1.67	1.30	0.53	3.44
Trajectory: commercial/residential heat from SRC-II oil													
Mining	0.09	0.01	0.13		0.01	0.15		58.8	0.45	0.85	0.36		
Transportation	0.05	0.01	0.09		0.01						0.01		
Conversion	0.36	0.04	12.9	0.49	2.37			5.10		0.63	0.06	0.35	1.16
Distribution	0.54	0.44	0.88	0.06	0.10		0.18				1.47		
Electrification													
Distribution													
End use	4.29	0.98	12.4	4.18	10.3								
Total	5.34	1.49	26.5	4.74	12.8	0.14	0.19	63.9	0.45	1.49	1.92	0.35	1.16
Trajectory: commercial/residential heat from natural gas													
Mining											0.25		
Transportation			0.25								0.21		
Conversion		0.01	0.02										
Distribution			10.5								0.85		
Electrification													
Distribution													
End use	0.85	0.34	2.99	0.81	0.02								
Total	0.85	0.35	13.8	0.81	0.02						1.31		
Trajectory: commercial/residential heat from oil													
Mining							0.06				0.03		
Transportation	0.15	0.20	0.27	0.03	0.05		0.24				0.32		
Conversion	0.01	1.47	1.24	0.17	1.33		0.28	0.02	0.04		0.06		
Distribution	0.54	0.44	0.88	0.06	0.10		0.18				1.47		
Electrification													
Distribution													
End use	4.29	0.98	12.4	4.18	10.3								
Total	5.01	3.10	14.8	4.44	11.8		0.78	0.02	0.04		1.90		

use, however, produce greater disruptions than those of electricity transmission. There are no other substantial differences in land-use requirements among coal trajectories because of the common land-use needs of product distribution and solid waste disposal. The land-use requirements for all coal trajectories is greater than for the counterpart natural gas and oil trajectories.

Water use. Water is used primarily in power plant cooling towers. Thus, more water is required for central-station electricity-generating technologies than the direct-combustion alternatives. When coal is converted to liquid or gaseous fuels, additional water is required beyond that needed for generating electricity. The water requirements for the use of natural fuels are therefore lower than those for the use of synthetic fuels.

Trajectory comparisons. In the central-station electricity-generating base case trajectory (coal combustion with FGD), fuel combustion during electrification produces most of the air pollutants, SO_x scrubbing produces most of the solid waste, and the cooling towers impose the greatest demands on water use. Boiler blowdown from electric power plants and mine drainage are the largest sources of most water pollutants. Electric transmission rights-of-way dominate the land-use requirements. The trajectory for coal combustion with AFB differs from the base case trajectory principally in the quantities of pollutants released. The sources are identical because of the similarities in the supply-to-end-use processes. Emission sources in the synthetic fuels trajectories (low-Btu gasification and SRC-II combustion) differ because of the effects imposed by the hydrogenation processes, which emit significant quantities of air pollutants and redistribute part of the source locations for air pollutants from the electrification site to the hydrogenation site. Use of liquid and gaseous fuels eliminates solid waste production at the point of end use. The water needs for converting coal to liquid and gaseous fuels are significant; however, cooling towers for electrical production use the greatest amount of water. Land-use requirements are still dominated by rights-of-way for electricity transmission.

In the direct-combustion trajectories, oil and natural gas combustion serve as the base cases. In both trajectories, most air pollutants are emitted at the point of end use. In the oil combustion trajectory, the refining of crude oil produces most of the hydrocarbon emissions. Interestingly, the compressors used to pump natural gas through pipelines produce most of the nitrogen oxides (NO_x) in that trajectory. Use of oil results in the accidental release of significant quantities of nondegradable organics in all stages of the oil fuel cycle. Both base case trajectories produce limited quantities of other water pollutants. Land-use requirements are mainly distribution rights-of-way. Solid waste production is

Table 4. Process and trajectory emission estimates: central-station electricity generation; HC, hydrocarbons; TDS, total dissolved solids; TSS, total suspended solids. Column sums may not equal column totals because of rounding-off errors (*37*).

Process steps	Air pollutants ($\times 10^3$ tons)					Water pollutants ($\times 10^3$ tons)				Solid waste ($\times 10^6$ tons)	Land use ($\times 10^4$ acre-years)	Water use ($\times 10^4$ acre-feet)	
	CO	HC	NO_x	Particulates	SO_x	Bases	Organics	TDS	TSS			Make-up	Total
				Trajectory: commercial/residential heat from an FGD electric boiler									
Mining	0.13	0.01	0.21		0.01	0.20		82.6	0.62	1.21	0.52		
Transportation	0.01		0.02										
Conversion	0.03	0.04	0.10	0.16					0.01	0.60		0.40	1.53
Distribution	0.43	0.28	0.44	3.28	0.39						0.36		
Electrification	4.02	1.20	68.7	4.02	35.7		0.21	3.58	1.46	2.01	0.46	3.61	5.79
Distribution													
End use											5.35		
Total	4.63	1.54	69.6	7.48	36.1	0.20	0.21	86.2	2.11	3.81	6.73	4.01	7.32
				Trajectory: commercial/residential heat from an SRC-II electric boiler									
Mining	0.17	0.03	0.28	0.01	0.01	0.27		116	0.88	1.68	0.71		
Transportation	0.10	0.02	0.17	0.01	0.01						0.02		
Conversion	0.72	0.08	25.3	0.96	4.65			10		1.24	0.12	0.69	2.27
Distribution	1.07	0.87	1.77	0.14	0.19		0.38				2.91	3.30	5.30
Electrification	0.02	1.22	26.9	4.88	24.2			0.61			0.05		
Distribution											4.89		
End use													
Total	2.09	2.22	54.4	5.99	29.1	0.28	0.37	126	0.88	2.92	8.71	3.99	7.56
				Trajectory: commercial/residential heat from low-Btu gas									
Mining	0.12	0.01	0.18		0.01	0.18		83.4	0.62	1.22	0.52		
Transportation	0.01		0.02										
Conversion	0.74	0.22	10.0	1.05	10.6					0.98	0.03	0.50	5.80
Distribution													
Electrification			1.57	2.25	4.49			0.53			0.01	2.89	4.63
Distribution											4.89		
End use													
Total	0.88	0.25	11.8	3.30	15.2	0.20		83.9	0.63	2.19	5.44	3.39	10.4
				Trajectory: commercial/residential heat from an AFB electric boiler									
Mining	0.11	0.01	0.17		0.01	0.17		71.8	0.54	1.04	0.44		
Transportation	0.01		0.02										
Conversion	0.03	0.04	0.10	0.14					0.01	0.52	0.04	0.35	1.33
Distribution	0.38	0.25	0.41	2.87	0.34						0.32		
Electrification	0.43	4.13	12.0	3.52	31.0		0.16	3.11	1.24	2.10	0.39	3.14	5.04
Distribution											4.89		
End use													
Total	0.95	4.44	12.7	6.53	31.4	0.17	0.16	74.9	1.80	3.67	6.10	3.49	6.36

limited. The emission sources for the synthetic fuel direct-combustion trajectories differ from the base cases for oil and natural gas in that water pollutants are produced during coal mining. Moreover, significant quantities of air pollutants and solid waste are produced as a result of the hydrogenation processes, which use the greatest amounts of water.

Health and Safety Impacts

Using health damage functions developed at Brookhaven National Laboratory (*7, 8*), we have estimated some health and safety impacts for the eight trajectories. These damage functions estimate accidental deaths and injuries and occupational diseases for various stages of the fuel supply cycles: coal, natural gas, and oil extraction; processing; transportation; and conversion (hydrogenation and combustion).

The major health hazards to coal miners arise from accidents and occupational diseases. Projected health effects from mining depend upon the ratio of underground mining to surface mining, since underground mining has a higher inherent risk factor, a lower output per worker day, and higher worker exposure to coal dust. In this study, we assume a ratio of 1.5 to 1. In the future, the proportion of surface-mined coal is expected to increase. In this analysis, we also assume that electric power plants that operate on the basis of coal combustion with FGD and AFB are supplied with coal by 500-kilometer rail hauls. This is a major source of deaths and injuries to the general public in this analysis, primarily because of grade-crossing accidents. For the remaining trajectories, we assume that the coal is processed and consumed at the mine mouth. In coal-processing and conversion (gasification, liquefaction, and electrification) plants, only accidental deaths and injuries are considered. Since synthetic fuel hydrogenation plants are not yet operational, we assume accidental injury rates for coal hydrogenation plants equal to those of oil refineries. Accidental injury rates at electric power plants burning coal-derived liquids and gases are assumed to be equal to those of coal-fired electricity-generating plants and are based on the number of workers per unit capacity (*8, 14*).

Estimated health and safety impacts of the trajectories are shown in Table 6. Death and injury data are listed for extraction, transport and distribution, and processing and conversion activities. All estimates except diseases of coal miners (diseases in the extraction process) are presented as 60 percent confidence limits. These diseases are shown as the range over several independent studies.

Table 5. Trajectory emission estimates; HC, hydrocarbons; TDS, total dissolved solids; TSS, total suspended solids (*37*).

Component	Central-station electricity generation				Direct combustion			
	FGD	SRC-II	Low-Btu gas	AFB	High-Btu gas	SRC-II	Natural gas	Oil
Air pollutants ($\times 10^3$ tons)								
CO	4.63	2.09	0.88	0.95	1.62	5.34	0.85	5.01
HC	1.54	2.22	0.25	4.44	0.56	1.49	0.35	3.10
NO_x	69.6	51.4	11.8	12.7	25.7	26.5	13.8	14.8
Particulates	7.84	5.99	3.30	6.53	1.61	4.74	0.81	4.44
SO_x	36.1	29.1	15.2	31.4	8.23	12.8	0.02	11.8
Water pollutants ($\times 10^3$ tons)								
Bases	0.20	0.28	0.20	0.17	0.15	0.14		
Nondegradable organics	0.21	0.37		0.16	0.03	0.19		0.78
TDS	86.2	126	83.9	74.9	67.6	63.9		0.02
TSS	2.11	0.88	0.63	1.80	0.56	0.45		0.04
Solid waste ($\times 10^6$ tons)	3.81	2.92	2.19	3.67	1.67	1.49		
Land use ($\times 10^4$ acre-years)	6.73	8.71	5.44	6.10	1.30	1.92	1.30	1.90
Water use ($\times 10^4$ acre-feet)								
Makeup	4.01	3.99	3.39	3.49	0.53	0.35		
Total	7.32	7.56	10.4	6.36	3.44	1.16		

Table 6 shows that the estimated numbers of deaths and injuries associated with the coal fuel cycles far exceed those of the natural gas and oil trajectories. In the coal fuel cycle, most health impacts are associated with mining. Since mining impacts are proportional to the overall efficiency of the trajectory, the smallest impacts arise from the trajectories with the highest overall efficiencies. Variations in the conversion efficiencies have the greatest effect on overall trajectory efficiency. Thus, the risks of the hydrogenation trajectories exceed those of coal combustion with FGD or AFB. For the same fuels, risks of the trajectories for central-station electricity generation exceed those of the direct-combustion trajectories. For natural gas and oil, the differences in health damage are virtually indistinguishable.

An air pollution health damage model described in detail by Morgan *et al.* (*9*) estimated local health damage from a typical eastern uncontrolled coal-fired power plant to be 0 to 120 premature deaths per year of operation (80 percent confidence interval; median, about 20). This plant emitted 1.5×10^5 tons of SO_2 annually, resulting in 0 to 0.8 premature deaths (median, 0.1) per 10^3 tons of SO_2 emitted. This estimate is applied to the emission estimates in Table 5 to obtain estimates of health damage attributable to air pollutants from central-station electricity-generating and hydrogenation plants. Stack heights, emission parameters (for example, temperature and velocity), and the population distribution around coal hydrogenation plants and some electricity-generating plants (low-Btu gas and AFB) may be significantly different from those of the typical coal-fired plant. The health damage estimates in Table 7 are thus very crude. Consideration of population exposure due to long-range transport of pollutants could increase health damage by as much as tenfold (*16*). The population distribution and the nature of the exposure from the direct combustion of coal conversion products, natural gas, and oil in residential and commercial furnaces are so different (for example, stack heights, emissions characteristics, and proximity to population) from those of a coal-fired electric plant that we have not attempted to quantify the impact.

Comparing Table 7 with Table 6 demonstrates that air pollution impacts are on the same order as occupational impacts earlier in the fuel cycle. Consideration of long-range transport probably leads to the conclusion that air pollution damage dominates the sources of health impacts from these fuel cycles. Air pollution health damage estimates, however, are much more uncertain than estimates of mining deaths or deaths due to fuel transport. Air pollution health damage is spread over a much larger population than the mining impacts. Even if the air

Table 6. Health and safety effects of fuel supply processes. Ranges are 60 percent confidence intervals based on a normal approximation to the Poisson distribution, with the exception of disease in the extraction section which represents the range of various published studies. Because of the indirect method of estimation, this method probably results in too narrow a range for transport and distribution. Transport and distribution effects are highly dependent on assumptions of mine mouth versus remote operation for the coal consumption facilities; SRC-II plants and low-Btu gas plants are assumed to have mine mouth locations.

	Central-station electricity generation				Direct combustion			
	FGD	SRC-II	Low-Btu gas	AFB	High-Btu gas	SRC-II	Natural gas	Petroleum
Extraction								
Disease deaths	0-4.3	0-5.9	0-4.3	0-3.7	0-3.3	0-3.0		
Nonfatal disease	24-46	32-64	24-46	20-40	18-36	17-33		
Accident deaths	2.1-6.2	3.1-8.2	2.1-6.3	1.6-5.7	1.4-5.1	1.3-4.7	0.02	0.01
Accident injury	259-292	371-403	265-293	227-254	201-228	185-210	0.14-2.7	0.4
Transport and distribution								
Accident death	1.3-5.6			1.1-4.9				
Accident injury	51-66	0.2	0.2	44-57	0.1	0.1	0.2-4.0	0.1
Processing and conversion								
Accident death	0.4	0.6	0.3	0.4	0.5	0.3		0.03
Accident injury	27-39	48-61	24-34	24-34	36-38	18-27	0.2	0.9-4.8

pollution damage dominates the total estimates, the individual risk level to members of the public is 1 percent of that facing the coal miner (*17*). In addition to the impacts quantified in Table 7, there is some potential for both occupational and public exposure to toxic materials not associated with coal combustion (see below).

Clean Air Act and Other Environmental Considerations

Air pollution and the CAAA. Constraints imposed by the CAAA and air pollution impacts are among the most important considerations affecting the development of conversion technologies. Fuel combustion in hydrogenation plants, electric power plants, and end-use devices was in general the major source of air pollution in all the trajectories examined.

Coal hydrogenation technologies can shift the sources of pollution from electricity generation and end use to the conversion sites. Thus it may be easier for the needed power generation facilities and services to be built in what are described in the CAAA as nonattainment areas; in this way clean fuels can be manufactured from coal in remote locations. Since synthetic oil and high-Btu gas can be transported economically over long distances, they are prime candidates for this procedure. Because it is more expensive to transport, low-Btu gas may not be as attractive a process for this purpose, although as a source of electric power it has low overall emissions. Use of these synthetic fuel alternatives could frustrate the CAAA attempts to encourage use of locally mined coal. Locational shifts of hydrogenation plants to the West may also exacerbate CAAA requirements designed to prevent significant deterioration of the environment.

The CAAA provides full credit in the new source performance standards for pollutant removal during coal conversion. The amendments do not require that pollution generated in hydrogenation be considered. Generation of electricity with low-Btu coal-derived gas, however, promises substantially lower system-wide emissions than conventional combustion of coal with FGD. The use of SRC-II combustion promises slightly lower emissions than conventional combustion. Both gasification and liquefaction can yield lower emissions at the electricity-generating plant than coal combustion with FGD. An important problem regarding emission controls is reliability of coal combustion with FGD. Since synthetic fuels can be stockpiled, reliability problems can be overcome.

Replacement of oil and natural gas. Use of synthetic oil and gas could facilitate compliance with the requirements of the Power Plant and Industrial Fuel Use Act (*1*) under which oil- and natural gas-fired power plants are required to shift to coal. Although air pollution from combustion in electric power plants is likely to result in lower emissions of polycyclic hydrocarbons and heterocyclic nitrogen, sulfur, and oxygen compounds per unit of energy produced than in smaller, less efficient furnaces, measurement of the emissions of heterocyclic compounds would provide assurance before steps are taken to switch oil-fired plants to synthetic fuels.

Locational factors. Coal hydrogenation plants are likely to be located at the mine mouth, or at least remote from the major population centers where the energy will ultimately be used. From the health standpoint, this will reduce the population exposure to the pollutants produced. Environmental impacts depend more specifically on where the plants are located.

Regional effects—acid rain. Introduction of coal hydrogenation technologies could affect acid rain production in two significant ways. First, shifting the location of SO_x emissions to the drier western states may result in decreased acid rain in the Northeast. Second, the total emissions of SO_x are likely to change. Hydrogenation technologies have lower fuel-cycle emissions of SO_x than coal combustion technologies but higher SO_x emissions than the natural gas or oil they might replace. Changes in the quantities and location of SO_x emissions will affect acid rain production.

Global effects—Carbon dioxide production. Coal fuel cycles have higher CO_2 emissions than petroleum or natural gas because coal has a higher ratio of carbon to hydrogen. The direct combustion synthetic fuel trajectories are less efficient than natural fuel trajectories. Thus, replacing petroleum and natural gas with coal-derived synthetic fuels leads to higher CO_2 emissions.

The bulk of the carbon in the coal mined in all the trajectories considered eventually becomes CO_2. The global CO_2 impact thus depends on the overall trajectory efficiency. Electricity production leads to greater decreases in efficiency. The combination of coal hydrogenation followed by electricity generation leads to the lowest trajectory efficiencies examined. The increased contribution to global CO_2 production is a significant disadvantage of coal hydrogenation, particularly of liquefaction.

Sulfur control and solid waste disposal. Alternative technologies which can reduce sulfur emissions at lower costs than coal combustion with FGD are attractive to the electric utility industry. Synthetic gas central-station electricity generation emits approximately half the SO_x and particulates released by coal combustion with FGD and SRC-II and combustion, and coal combustion with AFB reduces SO_x emissions through inherent bed design characteristics.

If more stringent requirements are placed on disposal of FGD scrubber sludge under the Resource Conservation and Recovery Act (*18*), this may become an important justification for coal hydrogenation. Most of the solid wastes are produced in electricity production and coal hydrogenation. Land for waste disposal, particularly in developed regions in the Northeast, is at a premium. Alternative technologies which could reduce land requirements at the electric power plant or the point of end use are attractive. Coal combustion with FGD or AFB produce large quantities of solid waste at the point of electricity generation. All other technologies, including those leading to direct combustion as well as electrification, produce solid waste predominantly at the point of coal hydrogenation, which may be in a rural area where opportunities for waste disposal are available. Most solid wastes produced at coal hydrogenation plants, however, will be more hazardous and require more careful handling than is necessary for FGD scrubber sludges and fly ash (*19*).

Effects of fuel supply processes. Most of the occupational health effects, water pollution effects, and land impacts in the trajectories examined are associated with mining. Although most of the land area required is for electricity transmission, it is clear that the impact on land is greater in mining. The relative extent of these effects among the trajectories depends on the trajectory efficiency. Low efficiency trajectories such as coal liquefaction demand the most coal and thus have the highest effects in the mining sector. The effects of mining are considerably different for underground and surface mining. We have not considered the possibility that one or more of the trajectories may inherently be more likely to draw from either underground or surface mines.

Occupational health effects specific to coal hydrogenation. Since our knowledge of the effects on occupational health of modern coal hydrogenation plants is limited, we must examine related industries such as coke ovens and older gasworks to predict the most likely hazards. The major hazards are lung, skin, and perhaps other types of cancer and bronchitis (*3, 20*).

The causative agents for lung, skin, and scrotal cancer in these industries were almost certainly polycyclic organics (*21*). These carcinogens become more concentrated in residual oils with successive distillation so that cancer risk presumably increases with increasing process temperature (*3*). The causative agents and the dependence on process conditions such as temperature are unknown. β-Naphthylamine, a bladder (*22*) and pancreatic (*23*) carcinogen, has been found in gasworks and coke ovens (*24*). Although the incidence of kidney cancer among coke oven workers is low, Redmond *et al.* (*20*) reported a sevenfold increase for coke oven workers as compared with steelworkers, a statistically significant difference.

There are radically different lung cancer and bronchitis rates among different classes of workers and in different countries. British workers with more than 5 years experience on top of gas ovens had 69 percent excess lung cancer and 126 percent excess bronchitis mortality, as compared to other workers in British gasworks (*25*). These workers are exposed to greater concentrations of 3,4-benzpyrene than other workers (200 versus 3 micrograms per cubic meter, which is still 100 times the normal London concentrations) (*26*). North American coke oven workers with more than 5 years experience on top of coke ovens have lung cancer mortality seven times that of all steel workers and three times the rate for workers employed only at the side of coke ovens for more than 5 years (*20*). Top-oven workers are exposed to coal-tar pitch volatiles at 3 milligrams per cubic meter as compared to 1 milligram per cubic meter for other coke oven workers (*27*). The recommended threshold limit is 0.2 milligram per cubic meter (*28*). The Japanese have much lower lung cancer rates than workers in either the United States or the United Kingdom. Twelve of 15 malignancies in a group of Japanese gasworkers were lung cancers as compared with none of 46 malignancies among other workers in the same steel plant (*29*).

Scrotal cancer, the first cancer to be occupationally linked (*30*), has been generally reported in workers exposed to oils, tars, and soots (*31*). Although it was first reported 200 years ago, it has not yet disappeared, although it is rare in the United States. It can be completely eliminated with adequate industrial hygiene.

At the Institute, West Virginia, coal hydrogenation plant in operation between 1952 and 1959 (*3*), the incidence of skin cancer was 20 times the incidence for white U.S. males. There was no control group, and the large extent of the excess might reflect the great concern workers showed towards all skin lesions after receiving repeated warnings. On the other hand, there were misdiagnoses of lesions and the actual malignancy rate could have been underreported.

During coal hydrogenation, hydrogen sulfide (H_2S), carbonyl sulfide (COS), and carbon disulfide (CS_2) are formed (*32*). They are later removed from synthesis gas and concentrated in a sulfur recovery unit because of emission requirements. Expected occupational exposure levels are unknown. Eye irritation caused by H_2S can occur at 4 parts per million (ppm) (*32*). Disruption of

Table 7. Air pollution health effects from central-station electric facilities.

Facility	SO_2 ($\times$ 10^3 ton year^{-1})	Premature deaths*
FGD power plant	35.7	0–28
SCR-II electric coal		
Hydrogenation plant†	4.65	0–3.7
Electric plant	24.2	0–19
Total	28.9	0–23
Low-Btu gas electric coal		
Hydrogenation plant†	10.6	0–8.5
Electric plant†	4.49	0–3.6
Total	15.1	0–13
AFB electric plant†	31.0	0–25
High-Btu gas for direct heat‡		
Hydrogenation plant†	8.19	0–6.6
SRC-II oil for direct heat‡		
Hydrogenation plant†	2.37	0–1.9

*Ranges are 80 percent confidence intervals. †These facilities are likely to differ in stack height, population density, and other factors from the base calculation. The health effects are thus only crude guides. ‡These fuel cycles also include unquantified health damage caused by emissions from residential and commercial furnaces.

menstrual cycles was reported at 4 ppm CS_2 (*33*). Chronic exposure to 10 ppm CS_2 may produce excess heart disease (*31*). Very little is known of the health effects of COS. The effects are presumably similar to those of CS_2 but occur at twice the molar concentration since free sulfur radicals are probably the toxic agents. Intoxication may be expected starting at 40 ppm COS (*32*).

Of the many potentially hazardous compounds found in coal hydrogenation process streams, the most common are carbon monoxide (CO) and hydrogen in synthesis gas. Hydrogen is an explosive gas. For example, the high-pressure nitrogen hydrogenation plant operated by I. G. Farben at Oppau, Germany, exploded in 1921, killing or injuring 2600 workers (*34*).

A nonoccupational effect of concern is the presence of CS_2 in the urine of Czech children living near an industrial plant emitting 55.5 kilograms of CS_2 per hour (*35*). Chronic exposure to CS_2 inhibits growth in rats (*32*). This rate is within the range of expected emission rates at new U.S. gasification plants (*36*).

The coal hydrogenation step may produce unique emissions and health effects. Because of limited experience, the extent of potential worker exposure to polycyclic organic compounds, β-naphthylamine, reduced sulfur compounds, and CO and the risk of hydrogen explosion cannot presently be determined. These risks cannot be quantitatively compared with those of alternative ways of using coal but are included to highlight the most likely hazards of coal hydrogenation.

Conclusions

In this quantitative analysis we have considered only a limited set of air and water pollutants, solid wastes, and health and safety factors. A more refined quantitative assessment would be necessary to incorporate locational factors which affect population exposure, changes in the quality of emissions such as increases in polycyclic aromatics, and other factors.

Conclusions cannot be drawn regarding the wisdom of the continuing or expanding development of coal conversion technologies solely from this analysis. Recognition of these hazards during technology development will require that necessary controls be incorporated into process designs. The controls will, of course, be reflected in the additional cost, which must be considered in policy analyses. Nothing herein precludes development of any coal hydrogenation technology, provided that the associated hazards are recognized and provisions are made for adequate control.

References and Notes

1. Public Law 95-620 (42 USC 8301 *et seq.*). This act replaces the Energy Supply and Environmental Coordination Act of 1974 (Public Law 93-319, 15 USC 791 *et seq.*). Many of the original substitution orders were based on this legislation.
2. Public Law 95-95 (42 USC 7401 *et seq.*).
3. R. J. Sexton *et al.*, *Arch. Environ. Health* **1**, 181 (1960).
4. Coal combustion with FGD refers to a coal-fired electricity-generating power plant employing a wet limestone scrubber to reduce sulfur emissions. Coal liquefaction and coal gasification refer to processes for converting coal to synthetic fuels. In the solvent-refined coal (SRC) process, synthetic coal liquids are produced as a result of the noncatalytic direct hydrogenation of coal. The SRC-I process produces a solid product suitable for use in electricity-generating plants. The SRC-II process produces both liquid and gaseous products, which may be burned in electric power plants or in smaller furnaces. In a Lurgi low-Btu gasification plant, gas with a heating value of 100 to 200 Btu per cubic foot is produced as a result of the reaction of coal with steam and air. In this analysis, we assume that the product gas is burned in a combined-cycle, electricity-generating plant. Combined-cycle generation of electricity involves both a gas turbine and a steam turbine. The low-Btu gas is burned in a combustion chamber, and the resulting hot gases are used to drive a gas turbine connected to a generator. The hot exhaust gas from the gas turbine is then used to generate steam which drives a separate turbine generator. In an AFB boiler, granulated coal is suspended in a thick layer of noncombustible granular material (coal ash and limestone) and fluidized by the passage of air upward through a supporting grid. Coal combustion and desulfurization take place at atmospheric pressure in the bed. The reaction by-product is a dry solid sulfate material, which is removed as solid waste from the process.
5. The decentralized applications refer to boilers used in residential and commercial establishments. The Lurgi high-Btu gasification process produces synthetic gas with a heating value of 950 to 1000 Btu per cubic foot by reacting coal with steam and air with subsequent methanation. The solvent-refined coal (SRC-II) liquids are produced in the same manner; SRC-II liquids may require further refining for use in residential and commercial furnaces. This step is not considered in the current analysis. Natural gas (950 to 1000 Btu per cubic foot) and distillate oil refer to fuel types presently supplied to residential and commercial customers.
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37. Metric conversions are as follows: 1 acre-foot = 1234 m^3; 1 acre-year = 0.405 hectare-year; 1 British thermal unit = 1055 joules; and 1 short ton = 907 kilograms.

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