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PROCEEDINGS OF THE OPPORTUNITIES IN THE SYNFUELS INDUSTRY

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U.S. SENATOR KENT CONRAD

U.S. Senator Kent Conrad (D-North Dakota) was first elected as North Dakota's State Tax Commissioner in 1980. As Tax Commissioner, Conrad received many national leadership awards. He was one of ten state officials nationwide chosen by *Washington Monthly* magazine for outstanding performance on an initiative. *Esquire* magazine honored him in 1984 as one of a "new generation of men and women under 40 who are changing America."

Mr. Conrad was elected to the U.S. Senate in 1986. He is a member of the Senate Agriculture, Budget, Energy, and National Resources Committees and the Select Committee on Indian Affairs. He is an outspoken advocate for the needs of rural America. Senator Conrad is considered a leading visionary regarding issues and opportunities facing the western coal industry. He has been a leader in expanding opportunities for western participation in the Clean Coal Program.

THE NEW COAL AGE--A BRIGHT FUTURE FOR NORTH DAKOTA

by Senator Kent Conrad

The development of North Dakota's vast coal reserves is one of the brightest stars on the horizon for our state's economic health, and for our nation's long-term energy security.

We stand at the threshold of what could be a new coal age in the United States and around the globe. As oil supplies dwindle, the world will demand new energy technology. North Dakota is already one of the world's foremost centers for coal research and development. The coming years will only see our state's prominence increase.

The role North Dakota can play in future energy markets is two-fold: producing power, new energy industries and new jobs at home; and exporting energy know-how to developing countries around the globe. That's what SynOps '90 is all about--the opportunities that exist for North Dakota in synthetic fuels, coal research and related industries worldwide. Like the first conference two years ago, SynOps '90 will also expand North Dakota's international reputation.

Technology transfer is the key to international markets, and the Asian nations of the Pacific Rim will be lucrative markets as their population and energy needs grow. The emerging democracies of Eastern Europe need assistance to expand their energy capabilities, and they desperately require pollution control technology.

Already, UND's Energy and Environmental Research Center (EERC) has launched a venture to find and develop low-rank coal technology markets in Asia and Africa. The Center, which has already hosted delegations from Yugoslavia, the Soviet Union and Czechoslovakia, is planning a 1991 conference in the Czech capital of Prague to strengthen ties to the Eastern European energy community.

Here at home, energy production and spin-off industries are the focus. The United States has sufficient coal reserves to meet our power needs for several centuries. Our recoverable coal reserves are estimated at nearly 300 billion tons. That's one-quarter of the world's coal supplies, and the energy equivalent of all the world's oil supplies. North Dakota alone as 35 billion tons of recoverable lignite coal.

This is an energy-intensive nation that must remain competitive in world markets. If we are to ensure energy supplies and keep the nation's economy vibrant, there is no responsible alternative to expanding the use of coal.

Our challenge is to use this precious resource wisely and well. That means finding cost-effective, environmentally sound coal technology.

The primary use for coal in the United States today is the production of electricity, and will be far into the future. However, our coal reserves have great potential for commercial and industrial use beyond power production. Facilities like the Great Plains coal gasification plant and the many projects underway or contemplated at EERC demonstrate that versatility.

For North Dakota, clean coal technology and by-product development hold the greatest promise. As a member of the Senate Energy Committee, I've sought a renewed federal commitment to clean coal research and development, with an emphasis on low-rank coals like our North Dakota lignite.

The development of low-rank coals presents special problems and special opportunities. The federal government must direct research into high-payoff technologies for our currently underutilized low-rank coal reserves--such as mild gasification, beneficiation techniques to increase the usefulness of low-rank coals, and coal cleaning methods.

Federal research must also focus on matching our coal resources with the most efficient applications. For example, the high reactivity of lignite coal makes it the preferred fuel for direct coal-fired diesel and turbine engines, an advantage we should emphasize over the long term.

Additional research and support for by-product production, as exemplified by the phenol recovery project just begun at Great Plains, offers almost limitless opportunities. This was one of the primary reasons we called the first SynOps conference in 1988. Since then, promising ventures in the production of xenon gas, krypton gas, and methanol have begun.

Research is only one of the federal government's responsibilities in guiding our national energy policy. Energy policy is shaped through pollution legislation, taxation, trade policy, and other environmental measures. Balancing these often conflicting priorities is not a simple matter.

For example, I am leading Senate opposition to a proposed tax on the carbon content of fossil fuels--natural gas, oil and coal. Backers say this "carbon tax" would raise $40 billion and encourage energy conservation. That may be true, but in the process such a tax would destroy the economies of energy-producing states including North Dakota, and cripple the national economy with skyrocketing consumer energy prices and plummeting productivity.

Most legislation which affects our national energy policy is a balancing act, and most has the power to affect North Dakota's future as a premier center for energy research and production. The carbon tax proposal is a current and dramatic example.

How do we develop our resources, maintain a healthy, vibrant economy, and stay competitive in world markets, while at the same time protecting the health of our people and the environment? That's the challenge we face. I'm confident we will meet it.

U.S. SENATOR JAMES A. McCLURE

U.S. Senator James A. McClure (R-Idaho) is his state's senior senator, elected to the U.S. Senate in 1972. He is the ranking Republican member of the Senate Energy and Natural Resources Committee, is a member of the Senate Appropriations Committee, and is the ranking Republican on its Subcommittee on Interior and Related Agencies. In addition, he is a member of the Appropriations Subcommittees on defense, agriculture, energy and water development, labor, and health and human services.

McClure serves as chairman of the Senate Steering Committee, an informal group of conservative senators who meet to review legislation and discuss ways to further the conservative agenda. He has received 12 consecutive "Watchdog of the Treasury" awards for his efforts to curb federal spending and eliminate waste in government.

NO PAPER INCLUDED

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ROBERT H. GENTILE

Robert H. Gentile is the Assistant Secretary for Fossil Energy, U.S. Department of Energy. He oversees the $5 billion Clean Coal Technology Program, the government's largest single energy and environmental initiative. He is also responsible for managing the federal fossil fuel research programs that involve nearly 700 government-sponsored projects carried out by universities, private industry, and federal laboratories.

Prior to his present position, Mr. Gentile headed the Office of Surface Mining Reclamation and Enforcement, was a founding member of the Mining and Reclamation Council, and was a charter member of the National Coal Council. Mr. Gentile holds a B.A. in political philosophy from Franciscan University and an M.B.A. in international trade and finance from the University of Toledo.

REMARKS BY

ROBERT H. GENTILE

ASSISTANT SECRETARY FOR FOSSIL ENERGY

U.S. DEPARTMENT OF ENERGY

TO THE

SYNOPS '90 CONFERENCE

IN

BISMARCK, NORTH DAKOTA

ON

AUGUST 28, 1990

It is a pleasure to be here today, and it is a particular pleasure to be able to talk about the potential for coal-based synthetic fuels. I will be honest--I have been looking for an opportunity to talk about this subject for some time now--even before the current Persian Gulf situation put the subject of alternative fuels back in the news.

The reason I've been anxious to have this opportunity is this: We have made very significant progress with synfuels in this country in recent years. The research we've been doing in this area is some of the most exciting and some of the most important research being done today in our energy program. What has been achieved is one of our success stories--something in which we can take a great degree of pride--something we can brag about.

And so, I'm going to do a little bragging this evening--but I also want to temper my optimism with a healthy dose of reality.

I'm going to paint for you, hopefully, the very clear picture that synthetic fuel technology is alive and well in this country.

I'm going to impress upon you, hopefully, the need to convey to the American people the importance of synfuels technology--the significance it holds for the long-term energy security of this country--and the potential it has for ultimately breaking the dangerous dependence we have today on unstable foreign oil.

But I don't want to oversell synfuels as a near-term response.

[HOLD UP NEWSPAPER]

Many of you may have seen this page from the business section of USA Today last week. Headline: OIL FROM COAL MAY CUT MIDDLE EAST DEPENDENCE.

The story was essentially accurate--but the headline implies that synfuels are an overnight solution. And of course, those of us here today know that they aren't--at least in terms of large-scale commercial deployment.

But that shouldn't detract from the imperative of continuing synfuels-related development.

There is no question--absolutely none--that the day will come when synfuels will be commercially viable. The only question is when?

In the many speeches I've given since becoming the Assistant Secretary for Fossil Energy, I've repeated one thought time and time again. Usually I save it for the end of the speech--to wrap everything up. But today, I want to use it at the beginning--because I believe it characterizes very clearly our rationale for continued synfuel development.

I firmly believe that the mark of a mature society is its will and capacity to invest in its future--to allocate resources not only to solve immediate problems but to produce a stream of benefits well into the future.

Today, the crisis in the Persian Gulf is a test of that maturity.

Our nation stands ready to solve immediate problems. The President has taken forceful action to stop aggression. He has been joined by an unparalleled cadre of nations who recognize the need to protect vital interests and who understand the strength that comes from multinational solidarity.

Here at home, Americans have been asked to do their part to reduce demand for Mid East oil. The nation's energy industry has been asked for increased production where possible--and they have largely responded to the call. Should the situation worsen, we stand ready to draw upon the Strategic Petroleum Reserve at a moment's notice from the President.

Together, these actions create a formidable response to the aggression of Saddam Hussein--both militarily and domestically. But these are immediate reactions--important and essential--but short-term.

But if we are truly a mature society, we will recognize that the linkage between energy and our national wellbeing does not go away when Saddam Hussein disappears off the front pages.

If we are truly a mature society, the real victory will not be won on the sands of the Middle East but on our own turf here at home.in the U.S., where we must come to grips with the recognition that energy--stable, reliable and affordable--is the fundamental component of our economic security, our wellbeing, and ultimately world peace.

Three times we have been confronted with harsh lessons from the Middle East. Three times we have been given a glimpse of a future that repeatedly will bring the world to the brink of war over energy--unless, and until, we take action to change it.

Winston Churchill once said that "we will know the true value of water only when the well runs dry." That's certainly true. But for oil, the disturbing fact is that its true value--or its true cost--must also be measured in the lives of young Americans placed in harm's way to protect the flow of that oil.

And if we are truly a mature society, we will ask ourselves the question: "How long do we want to continue paying that cost--and how long do we want to risk the chances that one day, one very dark day, we will ask our young men and women to pay the ultimate price for foreign oil?"

These are harsh realities that most Americans would just as soon not confront. But world events make that impossible.

Twice before, when these realities have been put in front of us, we ultimately turned our heads, refusing to recognize the dangers. Now, as a nation, we are being forced to look again at threats from a region that is unstable, unpredictable and governed by cultures unfamiliar to us.and yet a region that is vital to our national health and wellbeing.

And the question is: as a nation facing harsh realities for the third time in just two short decades, how will we respond? Can we change the course of future events? Have we learned our lesson? Will we ever learn?

A lot of people are saying today that we have wasted the last 17 years since the Persian Gulf sent out its first economic tremors. A lot of people like to point fingers and say that the nation squandered opportunity after opportunity--that we sat idly by while the Middle East tinderbox continued to smolder.

I'm not one of those people. I don't believe we have wasted 17 years. I don't accept the accusations that we've done nothing to change the future. And to show evidence of that, I have to look no farther than the subject we are discussing here today.

A large part of our energy problem today is a liquids problem--no different from 1973 or 1979. A large part of our answer to that problem is American coal--also no different from 1973 or 1979. But today, a major part of our arsenal is new technology--and here, there are major differences.

During the 1970s, the state-of-the-art in coal liquefaction produced a product costing $70 a barrel or thereabouts--economically promising when projections showed oil prices hitting the $100 per barrel mark in the 1990s.

By the time we entered the 1980s, the technology had improved and projected costs were in the range of $50 to $60 per barrel.

Despite these improvements, synfuels technology was still very much a brute-force approach--single-stage concepts relying on high heat and severe pressures with, perhaps, a catalyst or two thrown into the pot.

I would speculate that most people think the concept of making liquids from coal died when the crash program started by the Carter Administration did just that--crashed. But one of the great untold energy stories has been the fact that coal liquefaction didn't die. Rather, it retreated back to the laboratory. And in the laboratory, we made great strides.

We learned that making liquids directly from coal was not one complex chemical reaction that had to be engineered by brute force.

Instead, it was a series of chemical steps:

-- steps that could be separated and tailored to achieve maximum effectiveness
-- steps that could be optimized by the right combination of conditions, suited solely for that part of the liquefaction process
-- steps that could be made efficient by the addition of more effective catalysts

In short, the science of synfuels grew enormously in sophistication during the 1980s. It was time not wasted. Today, tests at our Wilsonville liquefaction facility in Alabama show the prospects of producing coal liquids at $35 per barrel--half the costs of the 1970s.

And let me read you a sentence from a recent report:

"There are clearly many opportunities to improve the economics of direct coal liquefaction. DOE hopes to reduce costs at Wilsonville by another 15 percent within the next 3 or 4 years. This target seems conservative."

That's not DOE talking. That's what the National Academy of Sciences told us in their study "Fuels to Drive Our Future." They concurred with our view that we are on a path to break the $30 per barrel threshold during the 1990s.

$30 a barrel oil from coal...what does that buy America?

Well, what it buys America is a cap on the long-term price of foreign oil.

Does that mean it will create a revitalized <u>commercial</u> synfuels industry? That remains a question mark. Price thresholds are only one part of the equation. Price <u>stability</u> is an equally important part. Obviously, companies are not going to risk the enormous front-end investments required for coal liquefaction facilities unless they know that prices will not only <u>start</u> <u>out</u> competitive but <u>remain</u> competitive.

Still, we are making progress. And that progress will absolutely put downward pressure on the world price of oil.

That's why coal liquefaction research has been elevated to one of our highest R&D priorities. That is why we are putting together a major new effort to take the next quantum step.

As the National Academy pointed out, we can make further improvements in the processes tested today. But more importantly, we can also potentially leapfrog those incremental improvements.

- Pretreating the coal -- through physical, chemical or even biological means -- offers exciting possibilities.

- New reactor configurations, building upon the staged concept or moving into slurry phase reactors with dispersed catalysts, could be another approach.

These, and other techniques, could open the door to $25 a barrel liquids from coal. And that will certainly make the world--particularly the Persian Gulf--sit up and take notice.

A mature society has the will and the capacity to invest in its future. That's what we see driving our coal liquefaction research.

Ten years ago, the federal government signed a research contract with a company known as Air Products to investigate a concept known as "liquid phase methanol synthesis." Five years ago, we began operating a pilot facility to test this advanced method for making methanol from coal gas.

Today, after half a decade and more than half a million gallons of production, we have a technology on the doorstep of commercialization. And if all goes as planned, the Great Plains project will serve as the host for its final scaleup to commercial operation.

The Great Plains Coal Gasification Plant remains one of our nation's outstanding technological achievements. Now we have the opportunity to build on that achievement--but perhaps not in the same way as we envisioned 10 or 15 years ago.

In the 1970s, coal gasification was viewed as a way of replacing natural gas. Today, we know that more natural gas exists than we imagined a decade ago. But interest in coal gasification remains, and it is growing--driven today not by the need to find a substitute for natural gas but by the need to generate increasing amounts of electricity cleanly, efficiently and economically.

Combined cycle gasification can give us that "ultraclean," high-efficiency power option. We think so. Dow Chemical thinks so. Shell Oil thinks so. Texaco thinks so.

Commonwealth Energy in Massachusetts thinks so. They are planning a 400-megawatt commercial-scale plan patterned after the Cool Water facility to be built in the first half of the 1990s.

CRS-Sirrine and Combustion Engineering think so. They've been selected in our Clean Coal Technology Program to build the next generation of gasification combined-cycle demonstration facilities.

And as we move into the coming decade and into the next century when fuel choices will be dictated largely by their impact on the environment, coal gasification--as the core of a utility power plant--will grown in significance. It will grow because of the groundwork laid in the 1980s.

Have we wasted the last 17 years since the first oil crisis? No, not at all. Energy may have dropped off the front pages, but thank God, it did not drop off the R&D agendas of either the federal government or much of the private sector.

Today, advanced two-stage catalytic liquefaction, liquid phase methanol synthesis, and gasification combined cycle are just three of the techniques that stand as testament to the perseverance and foresight of those who knew that coal remains one of this country's great energy strengths.

And in large measure, the country has those of you in this room to thank for that perseverance and foresight--and for the progress that has resulted.

Today, because of your work, we have the clearly preferable option of taking a technological route toward a more secure energy future--and that route can steer us away from the oil fields of the Middle East.

This country has enormous strengths. President Bush has called upon America to join with its allies in a massive demonstration of military strength--strength not meant for aggression but for protection.

But our greatest strength comes from our abundance of domestic resources here at home and our abundance of human talent determined to find better ways to use them.

Three weeks ago, the President began his address from the Oval Office by saying "In the life of a nation, we're called upon to define who we are and what we believe." When the choices meant stopping aggression or risking our freedoms, the nation spoke quickly and forcefully.

But ultimately we must ask the question, do we as a nation have the will to learn from the past?

Will we make greater use of all our strengths? Will we turn more to energy resources

- that don't require military escorts to transport,

- that don't require lines to be drawn in the sand,
- that don't require Americans to be placed in harm's way?

Will today's crisis be the turning point...the point at which America decides that energy security is no less important than national security? That, indeed, they are one-in-the-same?

How we answer these questions--and what resources we will bring to bear--I believe, will determine our energy and economic future. And I believe, those answers will be the most telling measure of our maturity as a nation.

Thank you very much for your attention this evening.

U.S. SENATOR MALCOLM WALLOP

U.S. Senator Malcolm Wallop (R-Wyoming), a ranger and businessman from Big Horn, Wyoming, was elected to the U.S. Senate in 1976 and reelected in 1982 and 1988. In March of 1985, Senator Wallop was chosen as one of 12 members of Congress to serve on the Commission on Security and Cooperation in Europe. In January of 1985, he completed the allowed maximum of 8 years of service on the Select Committee on Intelligence and also served as Chairman of the Subcommittee on Budget.

Senator Wallop is currently the ranking minority member of the Public Lands, National Parks and Forests Subcommittee, and is a member of the Mineral Resources Development and Production, Water and Power, and Rural Economy and Family Farming Subcommittees.

SPEECH OF SENATOR MALCOLM WALLOP

TO THE INTERNATIONAL SYMPOSIUM ON SYNFUELS TECHNOLOGY

Bismarck, North Dakota August 29, 1990

The Dictionary defines synthetic as something "produced artificially, or man-made". It has an aura of something which is not natural, but based on human effort. When someone mentions synthetic, most people think of rayon or polyester, man-made substitutes for cotton or wool. But, what do you imagine they think of when discussing synthetic fuels. For most, it likely conjures up images of an alchemist trying to turn stone into oil.

One of the basic problems of the synfuels effort is this issue of definition. Can we argue that tar sands, oil shale, or coal gasification are artificial, man-made fuel projects. Or, are they simply sophisticated extensions of fossil fuel recovery projects. They certainly resemble the latter. If that is the case, should they receive special incentives, such as preferential tax treatment or price supports, from the federal government. Or, should synthetic fuels be left to the challenges of the free market. Some would argue that they should be treated as any other fossil fuel extraction process. The inherent soundness of a project would presumably determine its success, rather than government directives.

While this broad free market theory has been the driving force behind our economy, it can malfunction in specific instances. If there are no investors of the financial, intellectual or physical resources, the project will stagnate. The potential for eventual reward, whatever the form, may not be evident or sufficient to encourage risk. Risk taking is a fascinating process. It is not an endeavor which is encouraged by federal bureaucrats to be sure. The private sector also can hinder innovation. Even after twenty years of intense competition with the Japanese, American corporate thinking too often focuses on the profit statement for the next six months. Long range planning and investment is stunted by the drive to provide annual dividends to stock holders.

The real bottom line is that too many of our incentives are misguided. For example, everyone has heard of the MacArthur Awards. The Foundation gives a one or two year award to individuals who have made significant contributions in a variety of fields. It is a recognition of past work. It is not an incentive for new creativity. A counter argument is that a more useful award would be one that rewards an individual for achieving a specific goal.Charles Lindbergh did not solo across the Atlantic merely for the media coverage. He was after the cash award that had been promised for the first non-stop flight between North America and Europe. His flight was preceded by many failures. The prize was the incentive for individuals to innovate and discover.

In the energy field, our challenge is only too apparent. We must reduce our dependence on foreign, fossil fuels by developing new energy sources. The energy glut of recent years and the "end" of the Cold War left us complacent. The tumultuous situation in the Mid East has been an abrupt, sobering experience. The world is not at peace, and plentiful energy is not a transcendent right. No one worried that over half of our oil comes from abroad -- until Saddam Hussein suddenly controlled twenty percent of all oil reserves.

We had developed a belief that a new inter-dependence existed between the Oil States and the West. The oil producers have invested heavily in the West, as well as in facilities to refine and market their oil. The Oil States have a vested interest in a stable world economy. This was the pundits' argument. We now realize that events in the Mid East are motivated by other factors. And, we are left with the threat of dependence, rather than interdependence.

The solution, the challenge, is to develop new energy resources. Discovering new oil and gas reserves is one answer. Yet more and more areas are being closed to exploration. New resources also involves alternative energy sources. At the extreme, some propose that solar and wind power are available to replace fossil fuels. While it is true that solar does and wind farms do now exist, they exist because prices are mandated, rather than determined by the marketplace. The mandates for the wind farms are expiring, and I wonder what will happen to areas like Altamont in California when they have to negotiate new prices at market rates. We this effort at risk taking while we subsidize it. If government has a hard time siting an oil well on public land, just imagine siting two to three thousand acres of windmills in Wyoming or North Dakota.

Another alternative is nuclear power. It has been interesting observing the greens discomfort in rediscovering nuclear energy as a "clean" energy source. They are finally acknowledging that nuclear power does have a role as a source of electric energy. It should be a ideal answer for the environmental concerns over both acid rain and global warming, the two new crises of the environmental movement. The nuclear industry, with the support of federal funding, is developing a new generation of safe and affordable reactors. But, the political climate in this country will have to shift before new investment in nuclear power plants will come about. The stupidity exhibited by opponents of the Shoreham and the Seabrook nuclear plants is comparable to an oil embargo in terms of the harm to our future energy security. Mothballing these investments was arrogant posturing -- and irresponsible in light of the up-coming heating problems in the Northeast.

A third source of new energy is the subject of your conference, the synthetic fuels. While they may seem as a natural source of energy, they have the same environmental and financial problems associated with nuclear and renewable fuels. But, they also have an additional perplexing problem. There are few risk takers willing to explore this field. At the moment, we have only one oil shale experiment on the Western Slope sponsored by Unocal. This facility has lost money ever year of operation. There is a chance they may break even this year. But will corporate headquarters continue to put resources into a project that has cost over one billion dollars to date? The problem is getting the engineering right to make the facility run consistently. Even if this is achieved, the cost of the oil produced is still two and a half times current market rates. Presumably, cost would come down as production improves. Since the oil shale reserves on the Slope are equal to the reserves of all of OPEC, it is somewhat surprising that the industry involvement is so meager.

Coal gasification has attracted more interest, as demonstrated by the Great Plains facility here in Bismarck. The technology has been around for decades. Companies, such as Texaco, have developed gasification plants as a commercial venture. As promising as this effort has been, the coal gasification project has attracted that negative aura that seems to follow all synthetic fuels projects. This may explain why even risk takers are scarce.

This aura includes two perceptions, or perhaps, misperceptions, about the synthetic fuels industry. It is viewed as an industry that consumes almost as much energy as it produces. This criticism reflects an impatience with technology. In all honesty, there is some truth to this view. Some of the projects in synthetic fuels and clean coal technologies have been suspect. The problem is determining when a project should be cutoff. It becomes even more difficult when the federal government has become involved, as the history of the Clinch River Breeder Reactor demonstrates.

The second misperception is the environmental issue. I recall discussing one clean coal project, and the question came up about the waste stream. The proponents stated it would be minimal. That proved not to be the case, and the question then became what was the benefit of the process. Thus, the challenge to the industry is to demonstrate technologies that have a net reduction in pollution and a net increase in energy -- alchemy!

I should warn you that the synthetic fuels industry will have an incredible environmental problem when the Clean Air reauthorization becomes law. I do not doubt that it will become law, since the Administration has given up on insisting on a reasonable cost bill. The only drama is over how onerous the final act will be for all industries. A new study prepared by the Clean Air Working Group estimates that the measure will cost $51 to $91 billion per year!

Some argue that syn fuels are a clean air substitute for normal fossil fuels. What the industry is doing, therefore, fits the goals of the Clean Air Act. It is true that the final products of various technologies will be cleaner than existing fuel, but the problem is getting to the end result. This is where the Clean Air Act will create challenge.

Will our mandated experiment with ethanol parallel Brazil's lack of success with its alcohol fuel program? Just as the United States and Europe are moving closer to using alternative fuels in cars, the country that pioneered them is abandoning the program as a failure. Alcohol producers are abandoning the industry and the four million Brazilian cars now powered by alcohol. Despite huge government subsidies, the program has not worked because of one uderlying fact of life -- when oil prices remain low, sugarcane alcohol is far too expensive at $50-60 a barrel to be competitive.

In particular, there are two titles in the bill which will disrupt, if not eliminate, syn fuel projects. The first is the Air Toxics section. There is a rather incomplete science which attempts to measure the health effects on humans of exposure to the various substances we encounter in an industrialized society. There is a fair amount of controversy over the measurement of risk. Much of the work is done through lab experiments on mice or through computer modeling. The intent is worthwhile, to determine what risks we face in our homes and workplaces.

But, there is not a consensus in the scientific community on risk measurement. You have heard about the exposure test used for air toxics. An individual will stand stark naked next to a factory or power plant twenty four hours a day for seventy years. Any health effects will be attributed to emissions from the plant. The offending emissions will then have to be eliminated. And, the individual can finally put his clothes on and go home.

This is the theory behind the computer model which will actually measure risk. Any substance which fits the model will have to be controlled, no exceptions. The cost factor for emissions control is subordinate to health risk. Unfortunately, the proponents of this title are driving by the utopian desire of a risk-free society. Unless this language is corrected in the Senate-House conference, you will face unachievable requirements. It does not matter that your end product will be the cleanest fuel ever developed. It is the process that will be affected by this title.

The second provision is the permitting requirement. While the permit language is one title of the bill, other titles will also require a permitting process. And, what a process it will be! I have seen a chart which shows the permitting process required by the Senate-passed bill. It will require at least six years to set up the review and approval program, and to issue permits. And, the final legislation may include a provision to require a permit for each modification, no matter how minor, of an existing facility. In fact, companies will have to go through a lengthy permit process even if they want to put in procedures which reduce pollution. This bill will be an excellent device to reduce the competitiveness of American industry. It will be a nightmare for an experimental facility, such as a syn fuels plant, which requires numerous modifications to operate properly. The cost in delays due to permitting could shut down some of these projects. Dealing with the clean air bill is one reason the fall session of Congress will be ugly.

You may have heard that we are actually developing a new National Energy Strategy. The Department of Energy has conducted hearings around the country, and put together an interim report. It simply reflects the various comments presented at the hearings. While there is reference to "non-conventional fuels", I could not find mention of synthetic fuels. Here is an immediate challenge for you -- to put together a coherent strategy for advancing synthetic fuels. But, please be realistic. It will be extremely difficult to obtain any new federal spending or tax credits in this area.

Now that the Mid East crisis has reawakened our energy awareness, perhaps we will develop a real energy policy out of the National Energy Strategy. It is discouraging to go through a briefing on the energy consequences of the latest Mid East conflict. The same briefings were given back in the late seventies during the last crisis. We have barely advanced in a decade.

Now we have a challenge. It is driven by crisis -- yet, major advances, such as the Manhattan Project, the space program, and now the AIDS research, have all come out of crisis. Perhaps a Mideastern despot will at last open political eyes long enough, to advance the science of independence from foreign energy and domestic pollution. This is a fight I pledge to continue.

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INTERNATIONAL MARKETS FOR COAL

Session Chair: **Dr. Gerald H. Groenewold**
Energy & Environmental Research Center, UND
Grand Forks, North Dakota

1. "World Oil Price and How It Relates to Future Coal Mine Development"

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2. "Synfuels in Japan"

   by: Mr. Nobuo Nagata
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3. "German Coals; Utilisation Now and in Future"

   by: Professor Dr.-Ing. Klaus R.G. Hein
   Head
   Research and Development Group
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Session Chair: **Dr. Gerald H. Groenewold**
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4. "The Outlook for Coal in Korea"

   by: Dr. In-Chul Lee
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5. "Coal Opportunities in Eastern Europe"

   by: Dr. Blazo Ljubicic
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6. "Canadian Coal Export Future"

by: Mr. W. (Bill) Irwin
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7. "The Future of Coal in Southeast Asia"

by: Dr. Ukar W. Soelistijo
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Ministry of Mines and Energy
Jakarta, Indonesia

8. "Australian Coals in the Domestic and International Energy Scenes, the Present and Future -- An Overview"

by: Dr. R. (Bob) A. Durie
Consultant and Honorary Research Fellow
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9. "Prospects and Constraints in the Use of Coal in Italy"

by: Dr. Luigi Carvani
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Milano, Italy

10. "U.S. Coal Export Opportunities"

by: Mr. Herbert G. Lesnoy
Manager of Planning
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"WORLD OIL PRICE AND HOW IT RELATES TO FUTURE COAL MINE DEVELOPMENT"

By: Mr. Richard T. Marshall
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ABSTRACT

Canada has extensive resources of coal ranging from lignite to anthracite. 97 per cent of this coal is low in sulphur averaging less than 0.5% SO_2. Canadian coal is utilized domestically and internationally. The paper describes the Canadian coal industry and its potential with specific comments on environmental concerns both nationally and globally. A discussion on how world oil price relates to coal development is included.

INTRODUCTION

Good morning, ladies and gentlemen. It is indeed a pleasure for me to have the opportunity to visit the fine state of North Dakota once again and to speak on one of my favorite topics -- coal.

When I received a copy of the preliminary program, I noted that my presentation was to be entitled "World Oil Price and How it Relates to Coal Development". Well, that certainly is an interesting topic, but it is also a very complex one and, one that is open to all sorts of philosophical debate. It brought to mind the old saying..."Those who live by the crystal ball had better learn how to digest glass".

Acceding to the request, I have used this title, but I have also taken the liberty of expanding the topic somewhat, because I do not believe one can address the subject of coal development these days without also considering environmental concerns.

Being a Canadian and having just stepped down as President of The Coal Association of Canada, I feel compelled to talk a little bit about Canada's coal industry.

Therefore, my plan for this morning is to present a very brief overview of the Canadian coal industry, then delve into some of the global environmental issues with specific reference to the Canadian position and finally put forward some views about oil price relationships with coal and to tie this into coal and synfuels development.

THE CANADIAN COAL INDUSTRY

If, instead of a sector of the economy, energy were a social club, then the coal industry would be its most senior member. The first producing coal mine in Canada commenced operation in the year 1720 on Cape Breton Island in what is now the eastern seaboard province of Nova Scotia. The first coal exports out of Canada were, believe it or not, to Boston, Massachusets in 1724. On a historical note, this was fifty years before the Boston Tea Party.

I don't know what happened, but Canada must have missed a marketing opportunity because today, we import some 15 million tonnes from the United States, while our return exports are only a little over 1.0 million tonnes per year.

From the industry's modest beginnings coal production in Canada rose steadily to a peak of 29 million tonnes in 1948. By then however, Alberta's oil boom was underway. With the new found abundance of petroleum the railways switched to diesel fuel. Shortly, the domestic market of coal virtually evaporated - - for a while.

With the advent of coal fired on-site electric power stations on the prairies followed by the Japanese demand for metallurgical coal and the growing seaborne coal trade, the Canadian coal industry experienced a phenomenal rise in production.

Today Canada produces over 70 million tonnes of coal annually of which 28 million is metallurgical and 42 million is thermal. We export 32 million tonnes to some twenty odd countries.

Today we have 11 companies producing 70 million tonnes of coal from 27 mines with 11,500 employees. Obviously there has been a significant change to the modus operandi of our industry. (Figire 1) Until the 1960s the bulk of Canadian coal was produced from underground mines, whereas today 94 percent of Canada's coal is recovered via surface mining operations.

We have 3 underground mines in Nova Scotia, one in Alberta and one under development in British Columbia. The balance of our production is from surface mines, most of which are located in British Columbia, Alberta, Saskatchewan and New Brunswick (Figure 2). All of these mines, whether surface or underground, are efficient, safe and employ the latest technologies.

Our coal reserves generally follow this same geographical pattern. (Figure 3 & Figure 4). More than 90 per cent of Canada's recoverable reserves of six billion tonnes are located in British Columbia and Alberta. In situ reserves of coal are estimated to be 475 billion tonnes.

Canada's production figures and reserves may appear small when compared to the U.S.S.R., China and the U.S.A., but we are significant in the world scene.

Living next to the U.S.A., we seem suffer from a 10 percent syndrome. Our population is 10 percent of the U.S.A.'s, our coal production is 10 percent of the U.S.A.'s, our reserves are 10 percent and I am sure we have Canadian mines selling in U.S. dollars who wouldn't mind our exchange rate being 10% lower than it is now. Canada's coal industry may only be 10 percent of that of the U.S.A., but we are a vibrant group and a major factor in the international markets. It reminds me of the time when I was with Fording Coal Ltd., a Division of Canadian Pacific Railway, and visiting one of your coal mines in Alabama. The company had their own incorporated railway from mine to the barge terminal some twenty miles away. The owner reminded me that my company, the CPR, may own one of the longest railways in the world, but his tracks were just as wide. Canada's coal production may be 10 percent of that in the U.S. but our product is just as good.

We in Canada have achieved success by overcoming obstacles to development such as a long distance from tidewater, cold winters and many mines operating in mountainous terrain. We have a complete range of coals in our resource base from lignite through to anthracite. To succeed in the market place, we had to learn to be responsive to change and be innovative in our thinking. I believe on the whole we have done this well, however, there exist geographic factors that make some markets more attractive than others. It is for this reason that we import much of the coal used in Ontario and we concentrate on offshore markets.

Of course, we participate in the Ontario market where we can compete. But in many instances U. S. coals are closer and have been the traditional suppliers of both met and thermal coal, satisfying the bulk of Ontario's coal requirement. Due to a more favorable tax regime for the U.S. railways, Wyoming coal can compete in Ontario with our western Canadian coals.

Even though we have a longer average rail haul to get our coal to tide water than many of our worthy competitors, through technological advancement, we have developed systems that keep us competitive. This is an on-going process and a fact that we never lose sight of. (Figire 5).

GLOBAL ENVIRONMENTAL ISSUES

Of all the issues the coal industry has had to deal with this century, I view the concern over the environment as being one of the greatest. Over the last twenty odd years the coal industry has led the way in Canada in dealing with environmental considerations to the point that mine site environmental concerns today are only a shadow compared to that of a few years back. Through diligent efforts with respect to developing environmental protection programs and mine site reclamation practices, looking after the environment has become standard operating procedure. I am personally delighted to see individual mines now vigorously competing to have the best programs with respect to environmental protection.

The challenge today has moved from the mine site to users of coal, specifically to emissions of radiative gasses. Consequently, acid rain, greenhouse gasses and global warming have become household terms in the developed world. Unfortunately for us in the business, coal is fingered as the major culprit.

Again, I am not saying that global warming is not a threat. We know that CO_2 is building up in the atmosphere...but when you stop to consider that CO_2 is an extremely abundant gas and we do not know at this point how our ecosystem can or will handle such a build-up.. and when you realize the costs involved in radical change, you must, I repeat, MUST, make the crucial decisions in an extremely careful fashion. To get caught up in an international competition to see who can be the most "environmentally friendly" nation in the world will be ruinous.

One of the greatest concerns the coal industry in Canada has is that hastily developed legislation could be enacted as a result of public pressure prior to clearly understanding the cause of the problem. This will not effectively deal with the issue, but worse still, it could have serious economic implications affecting the welfare of the country.

Let me provide you with an example; a local magazine made the following comment:

"Nearly a quarter of the 385.8 million tonnes of CO_2 emitted into the atmosphere in Canada in 1988 resulted from the burning of coal, making it a significant contributor to global warming, in the opinion of some scientists".

Now, without even questioning the accuracy of the numbers, let me restate that slightly differently:

Coal burning in Canada contributes less than 0.25% of man-made gases which may contribute to global warming.

What is my point? My point is that is a tremendous amount of sensationalism put forward by the media that tends to confuse the public, this then leads to a search for quick and easy solutions to an extremely complex problem, and one of the easiest exercises in finger pointing is to say that coal emits more CO_2 per unit of energy produced than oil or gas. This, then, seems to have become the basis for assuming that reducing the burning of coal is the answer to all our problems. It isn't.

The first reason I say that relates to the problems of acid rain and particulate emission. When these problems became apparent, technology was developed to handle them, and I believe it is fair to say that these problems are now under control, notwithstanding intergovernmental problems with getting the technology put into place. The parallel situation exists with CO_2.

I believe that the coal industry can develop the technology required if it is established that the role of CO_2 in atmospheric change and potential climate change demands high level attention. Indeed, research in this direction has already begun.

The second reason that I say that reducing the burning of coal is not the answer to our worries about potential climate change is simply this: Like it or not, the world is going to be burning more coal 20 years from now than it is today. A lot more.

Let's look for a moment at its current use. Worldwide, close to 5 billion tonnes of coal are consumed each year and coal produces 31% of the world's primary energy, second only to oil as a source of energy worldwide. More specifically, coal generates 44% of the world's electricity and is used in the production of about 75% of the crude steel produced every year.

In many countries, coal is still essential for cooking and heating, and around the world over 250,000 consumer products are produced from chemicals derived from coal.

Now let's look at what kind of growth we can expect in the demand for energy. In 1987, global population was about 5.6 billion people. By 2025, the world's population is forecast to be 8.2 billion, and 90% of this growth will take place in the developing world. Every one of those additional people is going to consume energy and at the same time be striving for an improved quality of life met by an increasing use of energy. Where is this energy going to come from?

Looking at global resources of energy, there is worldwide about a 40 year supply of oil, a 60 year supply of natural gas, and at least a 220 year supply of coal. Not only is there plenty of coal, it is distributed in such a way that the developing nations have easy and low cost access to much of it.

With something as easy to mine, in such abundance, and located in regions where it will be required, combined with its economics and a relatively simple technology needed to use coal, is it any wonder that I say we are going to burn more coal 20 years from now than we do today? Can you honestly believe that the newly developing countries will use oil and gas for much more than domestic use and transportation fuel, or that they can afford - and cope with - nuclear technology? Personally I doubt it.

Therefore, not only can we not live without coal today, you can be sure we will be living with it in the future as well. What we do need to do today is to learn how to live with it.

We have seen the photos coming out of Eastern Europe of coal blackened landscapes. We're told about the high acid rain causing emission levels from old technology power plants burning high sulphur coal in the U.S. mid-west. We know in China close to a billion tonnes of coal are burned each year at efficiency levels that are lucky to reach 10%. These are certainly not the ways to live with coal.

But, there are ways to live with coal and Canada is a good example. I'm not going to say that coal is, or even can be, totally environmentally benign - no large scale energy source is. But in Canada, with coal, we are moving in the right direction to minimize coal's impacts. Let me cite some examples of where we are headed.

Firstly, we have embarked on a public awareness program targeted to those who influence public opinion, to foster a better understanding of the role coal plays in society. It is a modest program; however, it is a beginning.

Secondly, and more importantly, we are moving forward on the technical side with developments that will lead to the reduction in emission of radiative gasses.

The Coal Association in conjunction with the federal government and a number of provincial governments have embarked on the first phase of developing an IGCC demonstration plant. Now IGCC technology is not new, and there are already a number of demonstration plants in the world. But in addition to having the capability of testing Canadian coals, what is unique about our plant is that we are incorporating a pilot CO_2 recovery plant in the process. Thus in addition to removing and/or reducing SOx and NO_x, we are also going after CO_2.

The third initiative we have underway is the development of a low NOx /SOx burner by TransAlta Utilities Corporation. A 3 year project was initiated this year to demonstrate the application of a LNS burner for use in heavy oil recovery near Cold Lake, Alberta.

The principal objectives of the project are to demonstrate:

- the ability to burn coal in an existing heavy oil recovery (HOR) steam generator using the LNSB. A stand-alone, 52.7 GJ/h steam generator will be built for this purpose;

- the capability of the LNSB to control SO2 and NOx emissions at satisfactory levels while firing Alberta subbituminous coals at a commercial scale under regular operating conditions, and

- the reliability and durability of auxiliary systems operating with the burner and steam generator.

Thus far, detailed engineering has been completed to allow the LNSB to be retrofitted to a heavy oil recovery steam generator. Approval for the design has been received from the Energy Resources Conservation Board, and other permits have been received to allow construction to begin. The demonstration plant is scheduled to begin operation in early 1990.

These actions alone will not eliminate the perception that coal and global warming are synonymous, but if we in the developed world can advance these technologies, we will then be in a position to exchange this knowledge with the lesser developed economies. This is very positive action which enhances the use of coal in the longer term.

To confirm this point let me quote from the Japanese Steel Mills report of this past month wherein the Subcommittee on Coal of the Advisory Committee for Energy in forecasting Japan's coal consumption in the fiscal year 2000 stated:

"Coal is now regarded as a major source of CO_2 emission which causes global greenhouse effects. Coal consumption is thus cautiously received in many countries. Coal is however, superior to other sources of energy such as oil and natural gas, both in supply and economy. Advanced technologies related to coal in Japan will be able to support coal utilization especially by the use of clean coal etc. in the future. In order to control CO_2 emissions, coal use efficiency should be improved." unquote.

I am glad you are sitting down, because I would not want you to fall over with my next statement which is:

I believe the issues of global warming, and greenhouse effect are a blessing in disguise for the coal industry...Why? Because it is moving technology that we were developing for use early in the next century forward by some ten to fifteen years. This is good.

Also, it is focusing public attention on the use of coal and this will force the industry to ensure the public has the true facts about coal and its role in society. Already, programs through the World Coal Institute and your own National Coal Association are focused to achieve this objective.

If coal is going to achieve the role it should and can play in the world economy, the public must understand what coal is all about.

WORLD OIL PRICE AND HOW IT RELATES TO FUTURE COAL DEVELOPMENT

Let me now try to address the topic of the relationship between world oil price and future coal development.

There are those who argue strongly that the price of coal is directly related to the price of oil. If oil prices go up, coal prices follow and the converse is true, should oil prices fall.

There are also those who argue equally as strongly that it is coal that impacts or tends to stabilize the price of oil.

I cannot say which position is correct or if either is incorrect. I firmly believe there does exist an interrelationship between oil and coal price, but it is not clear cut or easily defined in terms of dollars and cents. It is the market place that determines the price of each energy commodity. One must remember that oil is what I refer to as a convenience fuel. It is easy to use, easy to transport and easy to handle. Characteristics that coal in solid form does not have. So what does coal have going for it? Well, the reserves of coal in the world far outstrip all other energy sources. It is also fairly evenly distributed around the world and thus cannot be held up to ransom. Therefore it tends to be priced lower than oil.

Let us not disillusion ourselves. If oil had the reserves and global distribution that coal has, we wouldn't be producing much coal and the price of oil wouldn't even be as high as it is today. Therefore it comes down to a question of supply and demand. If you are a large energy consumer who must be able to predict fuel costs for a long time into the future, tied to the requirement of having a stable predictable fuel source and the ability to store solid fuel, you will probably go with coal if it can be delivered at a cost equal to or less than that of oil.

Should the aforementioned criteria not apply, and you are prepared to pay the price for oil to have its conveniences, you will obviously prefer oil.

With this simplistic description, I return to the question, "Does oil price dictate coal price, or vice versa?" I believe to some extent both are true because you are dealing in a competitive market.

This, then, leads us to the question, "How does oil price relate to future coal development?" Obviously the answer is that oil prices can and do have a direct impact on coal mine development because we are in competition to supply energy but in different forms.

We all know it takes "X" number of dollars to explore for, develop, produce and transport coal to any given point on the globe. When we can do this and effectively compete with the price of oil, and apply some of the previously mentioned criteria, we normally end up using coal. However, I mentioned that oil is a convenience fuel and has uses that for some time will displace coal. For example, fuel and lubricants for the auto industry. It is the preferred fuel for space heating when available. Therefore there are situations where premiums can be paid to use oil.

The area where we most frequently compete is in base load energy requirements. There it becomes a function of price, availability and reliability.

In the scenario of oil being the premium fuel, with lesser reserves that through conservation should be extended over time, then coal becomes the favoured choice for many industrial applications. Having then established the market opportunity, I believe a more important factor affecting price is the creation of an oversupply situation in coal. We then end up with two factors impacting the price of coal -- the price of oil and the price of competing sources of coal. Therefore, to maintain a viable oil and coal industry, prices for both are going to have to be such to provide a reasonable return to the investor. At the same time to maintain realistic prices for coal, development of new supply sources must be carefully examined.

There are certain fundamental criteria that must be met:

1. An adequate economic return must be achieved for the use of the resource;

2. Natural resources must be conserved with realistic development policies;

3. Environmental considerations have to be included in the use and cost/price of the resource.

With this in mind, I see a future where all our energy resources will be used.

- Oil and gas as premium, convenience fuels

- Coal and nuclear for large base load requirements

- Renewable energy where applicable, but to a lesser degree than with the above; and

- Coal synfuels in specific applications and circumstances

Synfuels is one area of development that can be related directly to the price of oil. This is because they compete directly with oil or its by-products. At current values oil from oilsands is fully commercial at about $25.00 per barrel of oil. I was advised recently that coal liquefaction would also be competitive if costs could be reduced to $25.00 to $30.00 per barrel.

With oil prices where they are at the moment then the synfuels, in pure economic terms have difficulty competing with oil. There are other factors that come into play, however, and these are site specific situations, national security and the requirement to prove technology today for use in the future.

I know you are well aware of this situation here in the U.S. Worldwide there is an adequate supply of oil in the short term but the sources are concentrated. At current consumption levels and if the trend continues, the United States, it is reported, will have to buy nearly two-thirds of its oil requirements from abroad by the end of this century.

This places increased importance on the development of synfuels in the U.S.A. and I am sure the same applies to many other countries.

The latter must be good news for this gathering. Clean coal technologies including coal/water fuels, coal gasification, IGCC, coal liquefaction, etc. will all play an increasingly important role, in meeting the future energy requirements of the world cognizant of environmental objectives.

If there is a direct relationship between the price of coal and coal snyfuels with that of oil, it will result in a cap being placed on the maximum price for oil. This cap will be determined by the lowest cost synfuel used to replace oil. Recent events confirm this.

This morning I have attempted to present a brief description of the Canadian coal industry. I have also attempted to bring some perspective to current environmental issues and finally, although having not answered any questions, have given you something to think about with respect to coal mine development and world oil prices.

I only hope in doing this that I have been able to create a base that leads into the many excellent papers that follow.

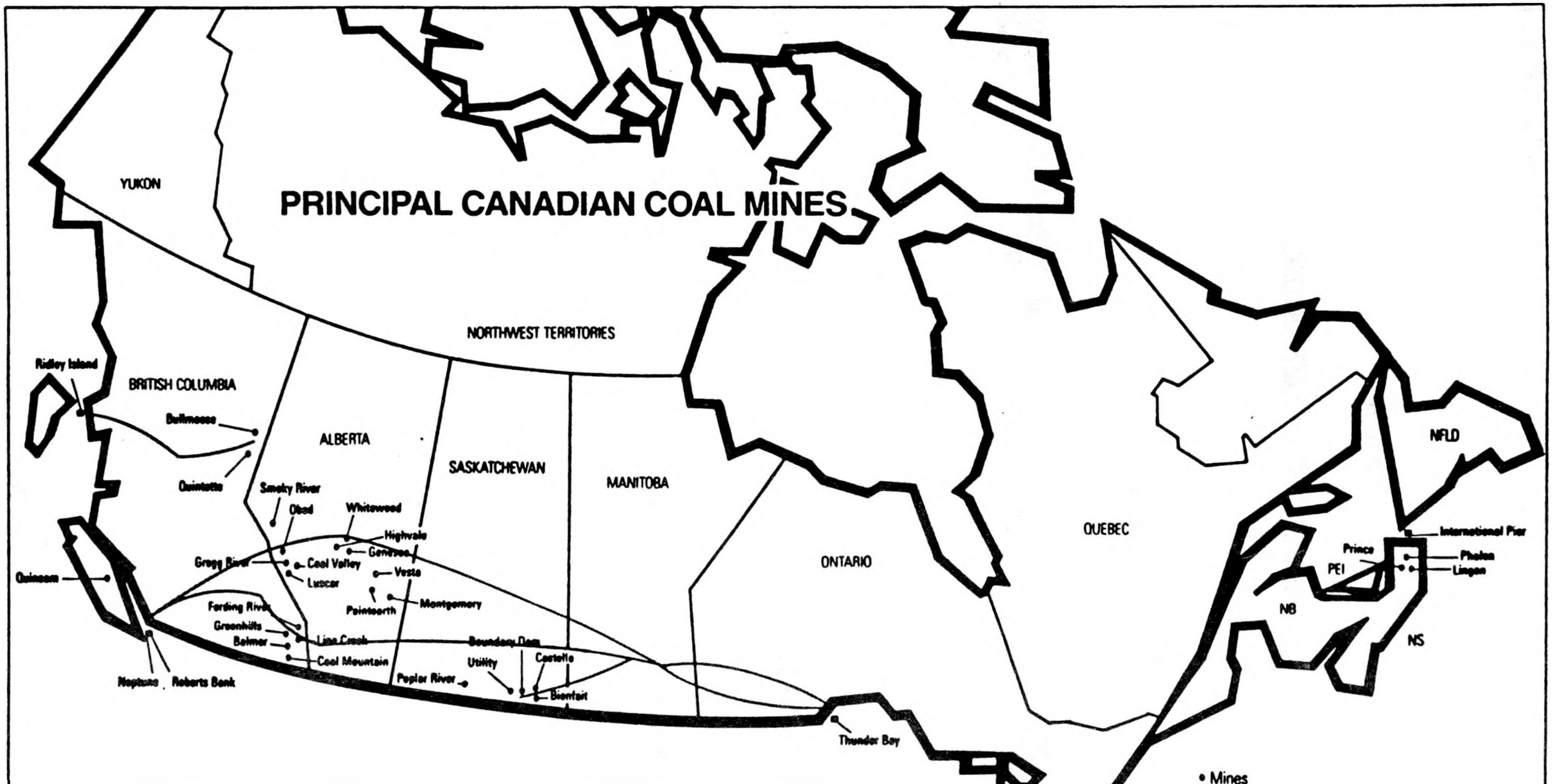
FIGURE 1

CANADIAN COAL PRODUCTION

YEAR	ANNUAL PRODUCTION	NUMBER OF EMPLOYEES	NUMBER OF MINES	NUMBER OF COMPANIES
1948	29 million tonnes	24,000	360	340
1989	70.5 million tonnes	11,500	27	11

June 1990

FIGURE 2

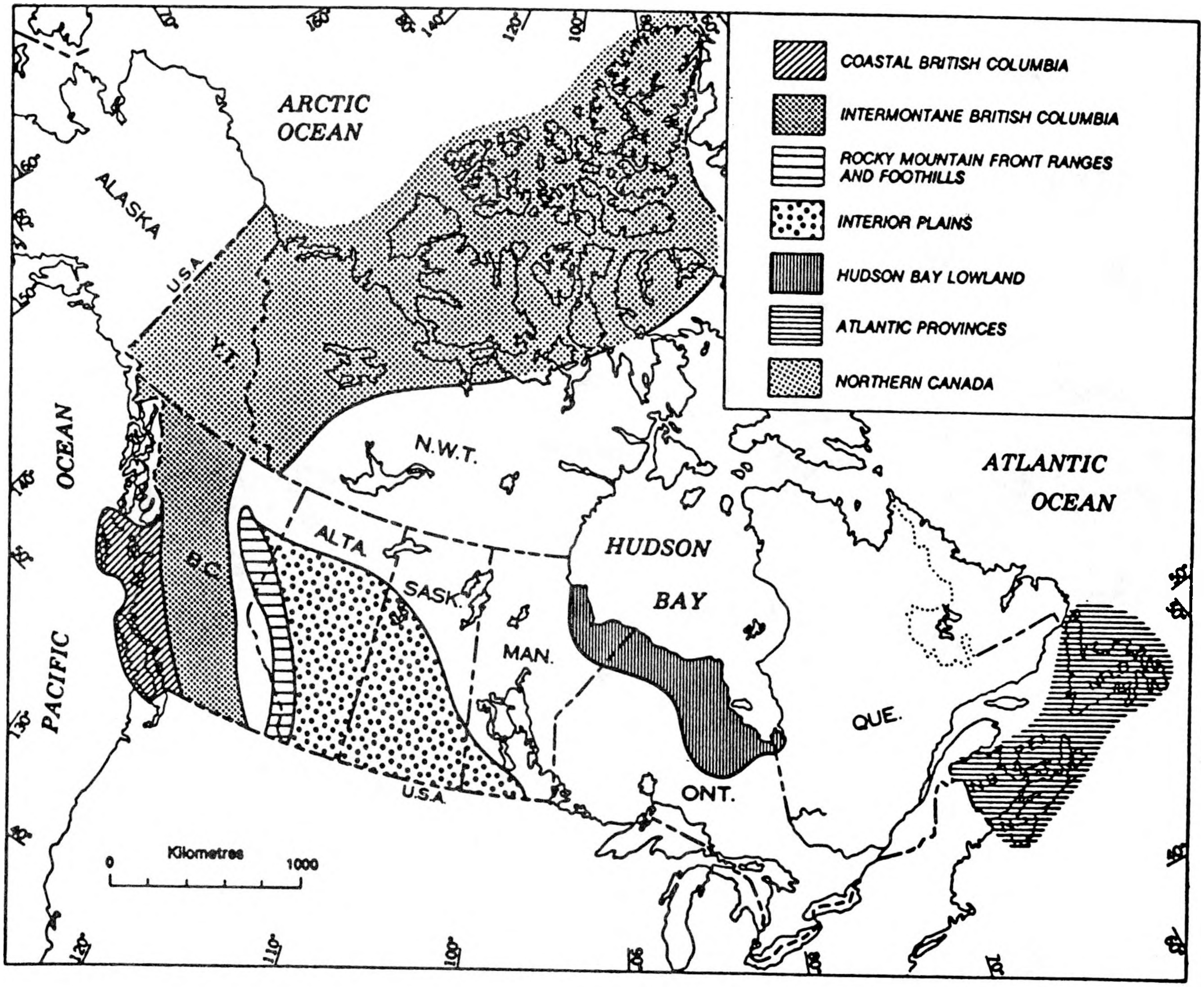


MINE	OPERATOR	OWNER	MINE	OPERATOR	OWNER
Balmer	Westar Mining Ltd.	Westar Mining Ltd	Luscar	Cardinal River Coals Ltd	Luscar Ltd & Consolidation
Bienfait	Estevan Coal Corp.	Luscar Ltd.	Montgomery	Manalta Coal Ltd	Manalta Coal Ltd.
Boundary Dam	Estevan Coal Corp.	Luscar Ltd.	Obed	Obed Mountain Coal Ltd.	Luscar Ltd.
Bullmoose	Bullmoose Operating Corporation	Tech-Bullmoose Coal Inc.	Paintearth	Forestburg Collieries (1984) Ltd.	Luscar Ltd.
Coal Mountain	Byron Creek Collieries	Esso Resouces Canada Limited	Phalen	Cape Breton Development Corporation	Cape Breton Development Corporation
Coal Valley	Luscar-Sterco (1977) Ltd.	Luscar Ltd. (75%)	Poplar River	Prairie Coal Ltd	Manalta Coal Ltd.
Costello	Prairie Coal Ltd.	Manalta Coal Ltd	Prince	Cape Breton Development Corporation	Cape Breton Development Corporation
Fording River	Fording Coal Limited	Fording Coal Limited	Quinsam	Quinsam Coal Limited	Brinco Coal Corporation
Genesee	Fording Coal Limited	Fording Coal Limited & Edmonton Power	Quintette	Quintette Coal Ltd	Denison Mines Limited (50%)
Greenhills	Westar Mining Ltd.	Westar Mining Ltd.	Smoky River	Smoky River Coal Limited	Smoky River Holdings Ltd.
Gregg River	Gregg River Resources Ltd.	Manalta Coal Ltd.	Utility	Prairie Coal Ltd	SaskPower
Highvale	Manalta Coal Ltd.	TransAlta Utilities Corporation	Vesta	Manalta Coal Ltd.	Alberta Power Limited
Line Creek	Crows Nest Resources Limited	Crows Nest Resources Limited	Whitewood	Fording Coal Limited	TransAlta Utilities Corporation
Lingan	Cape Breton Development Corporation	Cape Breton Development Corporation			

Courtesy of The Coal Association of Canada

FIGURE 3

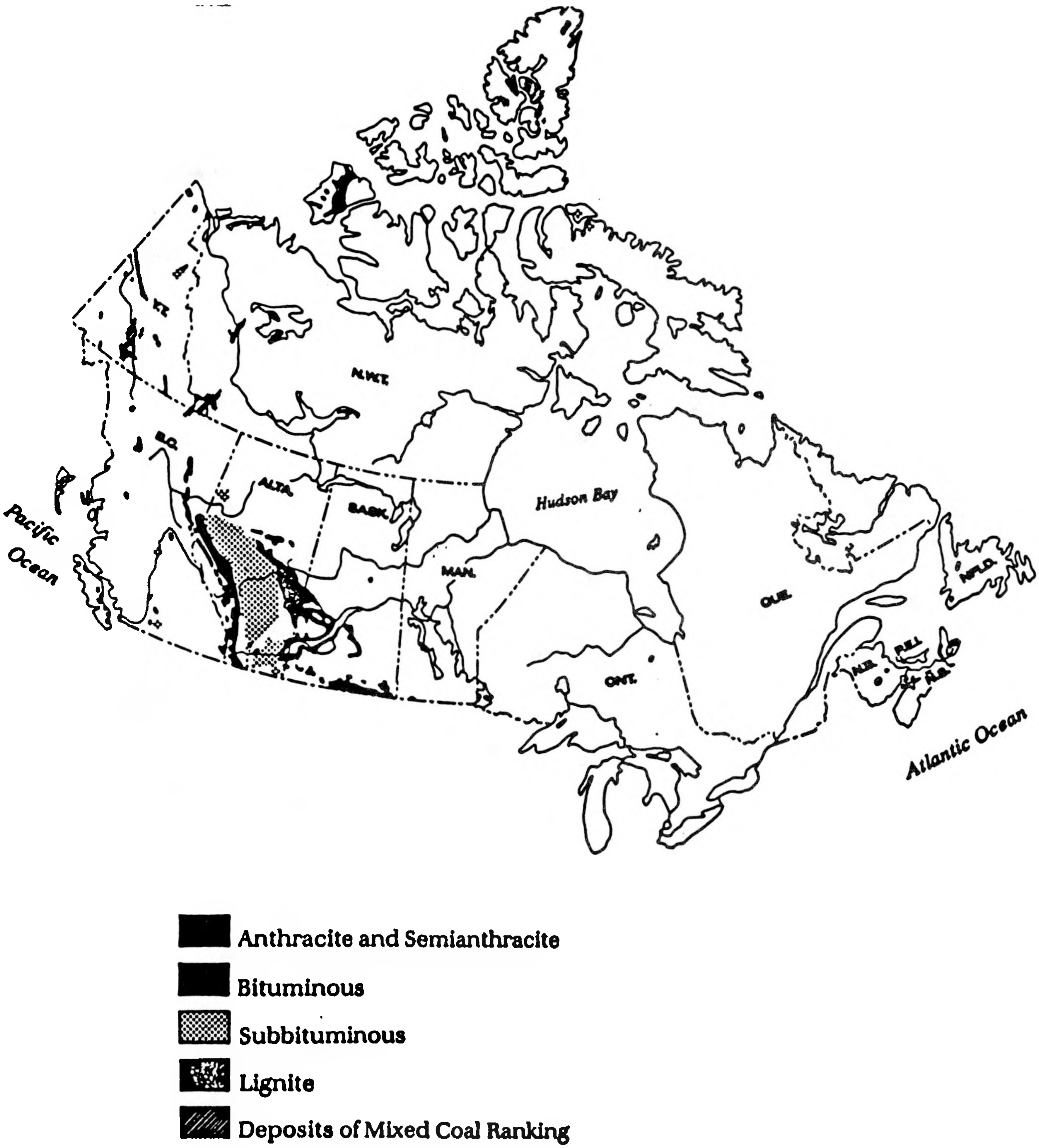
COAL REGIONS OF CANADA



Courtesy of the Geological Survey of Canada

FIGURE 4

PRINCIPAL CANADIAN COAL DEPOSITS



Courtesy of The Coal Association of Canada

FIGURE 5

AVERAGE RAIL HAUL - COAL

AUSTRALIA	200 Km.
SOUTH AFRICA	533 Km.
U.S.A.	700 Km.
CANADA	1060 Km.

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"SYNFUELS IN JAPAN"

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SYNFUELS IN JAPAN

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ABSTRACT

Since the second oil shock, NEDO has been engaged in extensive R&D and demonstrations related to increasing coal utilization in an environmentally consistent manner. Support for coal gasification and liquefaction, has been an important component of this program. This includes participation in the brown coal liquefaction project in Australia, and a series of bituminous coal liquefaction and gasification projects in Japan.

Reflecting the importance of coal in the total energy mix of Japan, NEDO has also provided extensive support for a series of projects expected to make coal a more convenient fuel for a range of industrial consumers. Numerous private companies and the Japanese government have cooperated to develop CWM technology and to promote its commercialization in Japan. This paper describes these development activities, including some aspects involving international cooperation.

Despite the unfavorable effect of current world oil prices, CWM is expected to become a reliable alternative fuel. The importance of supply stability for encouraging commercial development is discussed. The need for further technical cooperation and industrial effort is noted to ensure competitiveness of CWM with both oil and pulverized coal.

JAPAN'S ENERGY SITUATION AND ROLE OF NEDO

In 1973, at the time of the first oil shock, Japan imported 289 million kiloliters of oil, and enjoyed a high level of economic growth, based partly on the use of abundant and low cost oil, 92% (266 M kl) of which was imported from the OPEC countries. Even though oil represented 65% of Japan's total energy requirement, domestic oil production was less than 0.2% of oil imports.

In response to the oil shock, the Japanese government adopted three countermeasures in order to stabilize economic growth and national security:

1) Stabilization of oil supply by stockpiling,

2) Restriction of energy demand and conservation of energy based on rational use, and

3) Development of oil alternative energy sources and establishment of associated infrastructure.

In 1980, the Law for Oil Alternative Energy Development and Promotion of its Introduction (Oil Alternative Law) was enacted and the New Energy Development Organization (NEDO) was created. Simultaneously, the system of special accounts was increased, and tax and investment/loan programs were strengthened to ensure financing would be available. As a result of these initiatives, oil imports decreased significantly to 197 Mkl in 1985, representing approximately 68% of peak imports in 1980. The dependency on OPEC oil decreased to 65%. Since 1986, Japan's energy requirements have again increased. In FY1988, oil demand reached 276 Mkl which was 57.3% of total energy requirements.

More recently, global environmental issues, and CO_2 in particular, have caused the government to deal with the co-existence of environmental protection and economic growth.

Consequently, after considering the potential for alternative energy supply sources, including atomic, geothermal, solar and other non-fossil energy, the government has recently released a revised long-term energy demand/supply forecast as shown in TABLE 1. According to this plan, the emission of CO_2 will be restricted to not exceed the level reached in 2000 thereafter. Subsequently, the oil ratio will be reduced below 46% in 2010. Coal consumption will increase from the level of 114.6 M tonnes in 1988 to 142 M tonnes in 2000, and remain at that level. In this scenario, the coal ratio will be reduced from 18.1% of total energy in 1988 to 15.5% in 2010.

NEDO was established in October,1980, by the Oil Alternative Law as a semi-governmental organization to provide a focus for developing alternative energy sources other than nuclear energy. The president is nominated by the Minister of International Trade and Industry (MITI). The budget is entirely supported by government; management, research and support staff include both permanent employees and staff seconded from industry, national laboratories and government offices.

TABLE 1

LONG TERM ENERGY FORECAST FOR JAPAN

(May 1990)

	Units	FY1988 Actual	%	FY2000 Proj	%	FY 2010 Proj	%
Petroleum	Mkl	276	57.3	308	51.6	306	46.0
(including LPG)	M tonnes	(17.4)		(22)		(23)	
Coal	M tonnes	114.6	18.1	142	17.4	142	15.5
Natural Gas	Mkl	46.1	9.6	65	10.9	80	12.0
Nuclear	Mkw	28.9	9.0	50.5	13.2	72.5	16.7
(generation)	B kwh	(179)		(330)		(474)	
Hydraulic	Mkw	20.3	4.6	22.7	3.7	26.2	3.7
(generation)	B kwh	(92)		(91)		(105)	
Geothermal	Mkl	0.4	0.1	1.8	0.3	6.0	0.9
New Energy	Mkl	6.2	1.3	17.4	2.9	34.6	5.2
Total	Mkl	482	100	597	100	666	100
Energy Conservation Target				6.0%		11.2%	

NEDO's initial work focused on the development and introduction of new energy technologies which usually need long lead times and have higher risk. NEDO has provided the necessary leadership in several areas, including:

1) Development of oil alternative energy technologies,

2) Miscellaneous survey activities in support of these technologies, and

3) Domestic geothermal and overseas coal resource surveys with partial funding through loans and loan quarantees.

NEDO is also involved with the rationalization of the domestic coal industry, alcohol manufacturing (formerly a government monopoly) and research related to industrial technology development. Very recently, in June 1990, a new division for global environmental protection was formed at NEDO to address the technical requirements of important concerns such as the "green-house effect".

STATUS OF THE COAL INDUSTRY AND EXPECTATION FOR COAL UTILIZATION

Japan's coal production in the post WW II period reached a peak of 55.4 million tonnes in 1961. However, the coal mining industry has been losing its competitiveness and most of the traditional collieries have now been closed. Despite the growth in Japan's coal demand since 1980, the current 8th National Coal Mining Plan establishes a target for domestic coal production below 10 million tonnes by FY 1991, including 8.5 million tonnes of steam coal for use by electric power utilities.

FIGURE 1 shows the coal supply trend in Japan for the period from FY1970 through FY1986. Initially, much of the growth in Japan's coal demand resulted from the need for coking coal by the steel industry. However, since the second oil crisis in 1979, demand for steaming coal has increased significantly as the cement and electric power industries switched from petroleum. More recently, the small to medium size users in the general industrial sector have also begun to convert from oil to coal, primarily to realize the associated energy cost savings.

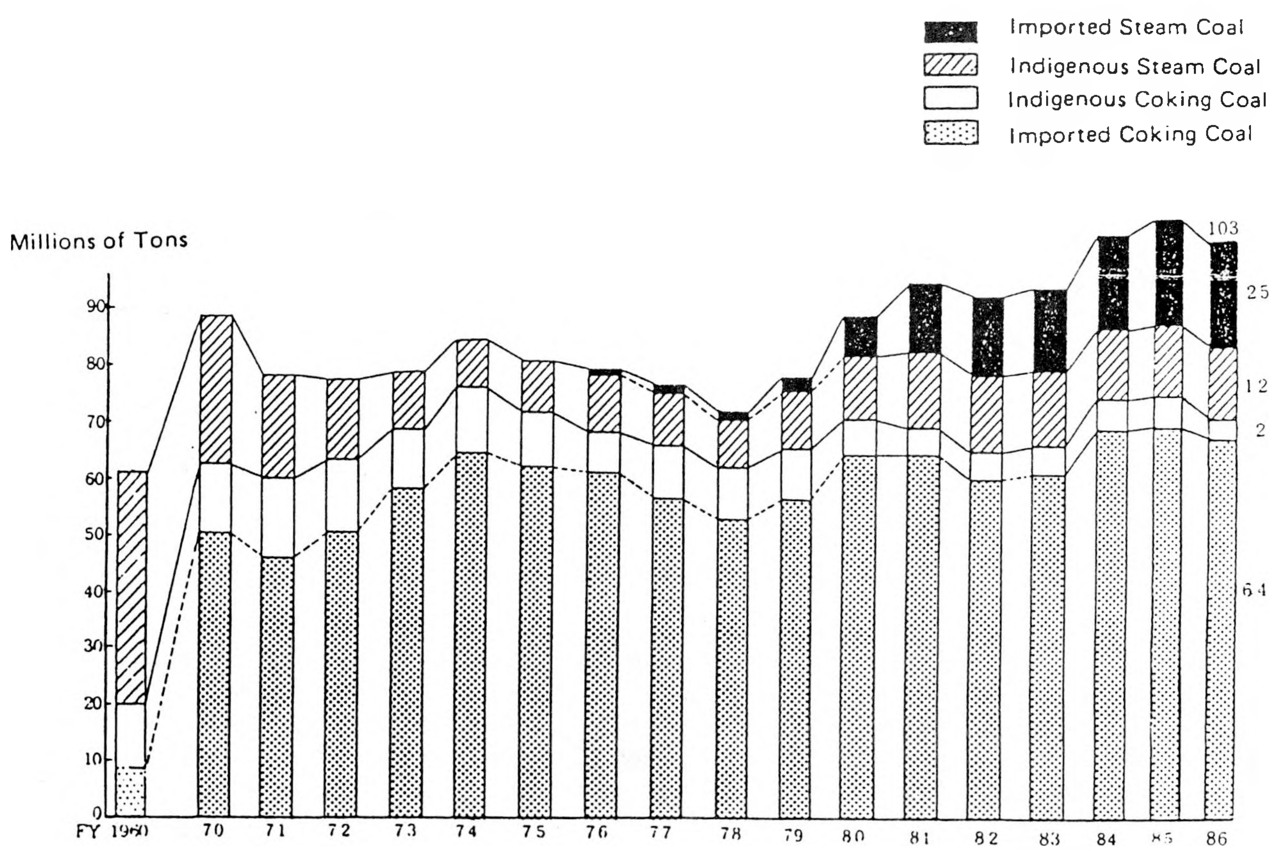


FIGURE 1 - COAL SUPPLY TREND IN JAPAN - 1970 THROUGH 1986

To further encourage this latter trend, a campaign called "Coal Renaissance" was initiated a few years ago to promote the use of coal by improving both processing and delivery of coal.

The anti-pollution rules in Japan are amongst the most severe in the world, partly as a result of Japan's high population density (320 persons/km^2) but also because of the strict environmental regulations of each independent local administration. Consequently, Japan is ranked as one of the leading countries for both the installation and utilization of desulfurization facilities to prevent air pollution.

The world's coal reserves are considered to be more than five times greater than oil reserves and are much more widely distributed. Coal is highly ranked in Japan as an oil alternative energy because of its supply stability and economic advantages in the medium to longer term. We believe that coal will be the most important and reliable energy source for Japan. Coal is necessary to support Japan's long term stabilized energy supply and will be an important component in our pursuit of the so called "best energy mix" under our national policy of energy supply diversification.

DEMAND AND SUPPLY OF COAL IN JAPAN

According to the FY1989 trade statistics issued by the Ministry of Finance, Japan's coal imports of 106.11 million tonnes were the highest ever, and were 1.85 million tonnes higher than FY1988. Japan's domestic coal production in FY1989 was reported by the Agency of Natural Resources and Energy (ANRE) as 9.63 million tonnes. The resulting total coal supply in FY1989 was 115.74 million tonnes, details of which are shown in TABLE 2.

FIGURE 2 shows the growth in imported steam coal consumption in Japan for the seven year period from FY1983 to FY1989, by industrial sector.

The distribution of steam coal markets in FY1989, classified by major customers are shown in TABLE 3. Differences in the totals from TABLE 2, are a result of stockpile changes.

TABLE 4 provides a breakdown of imported steam coal sales by industry sector for FY1989 and the changes from FY1988.

The reduced coal purchased by the cement industry may reflect tighter control of coal inventory and reduced stockpiles, particularly since clinker production increased from 68.46 million tonnes in FY1988 to 71.69 million tonnes in FY1989.

TABLE 2

JAPAN'S COAL SUPPLY - FY1989

		Volume	Ratio (%)	
Coking Coal	Imported	73.612	99.3	63.6
	Domestic	.540	0.7	0.5
	Total	74.152	100.0	64.1
Steam Coal	Imported	30.228	76.9	26.1
	Domestic	9.094	23.1	7.9
	Total	39.322	100.0	34.0
Anthracite	Imported	2.273		1.9
Grand Total		115.747		100

unit = million tonnes

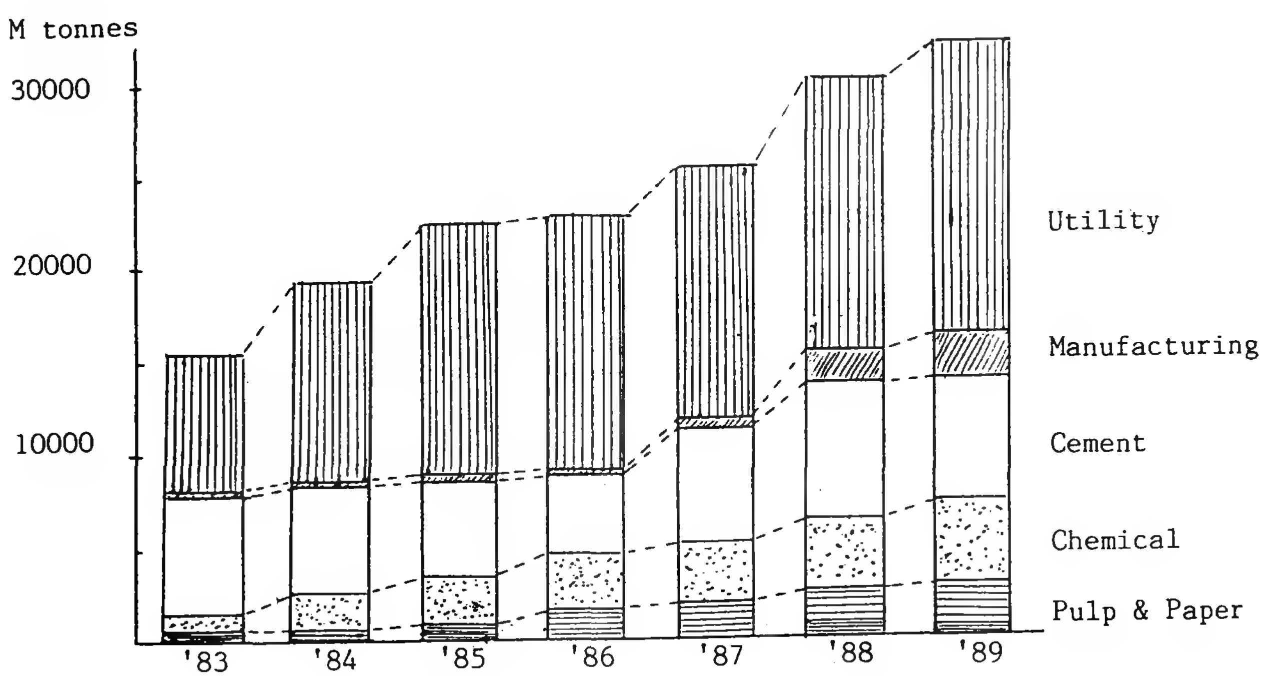


FIGURE 2 - IMPORTED STEAM COAL SALES IN JAPAN 1983 THROUGH 1989

TABLE 3

STEAM COAL MARKET IN JAPAN - FY1989

	Manufacturing	Utilities	Others	Total
Imported Coal	16.160	15.640	0.029	31.829
Domestic Coal	.459	9.452	0.802	10.714
Total	16.659	25.092	0.831	42.543
Ratio (%)	39	59	2	100

units = million tonnes

TABLE 4

UTILIZATION OF IMPORTED STEAM COAL - FY1988/FY1989

	FY 1988	FY1989	%	Changes	
Utilities	14.693	15.640	49.1	+.947	+6.4%
Cement Industry	7.328	6.546	20.6	-.782	-10.7%
Chemical Industry	3.859	4.399	13.8	+.540	+14.0%
Pulp/Paper Industry	2.448	2.811	8.8	+.363	+14.8%
Steel Mills	0.057	0.428	1.3	+.371	+650.9%
Miscellaneous Manufacturing	1.145	1.702	5.3	+.557	+48.6%
Others	0.455	0.303	0.9	-.152	-33.4%
Total	29.985	31.829	100	+1.844	+ 6.4%

units = million tonnes

The rapid growth in coal use by the steel mills suggests a major effort to reduce their heat costs by replacing oil with pulverized steam coal.

The increased requirements for coal, particularly in the miscellaneous manufacturing industry, are expected to continue and result in further demand for imported steam coal.

The use of imported steam coal is dominated by the electric power utilities. The installed capacity of the utilities coal fired power stations, most of which are shown in FIGURE 3, totalled 11 525 MW at March 31, 1990.

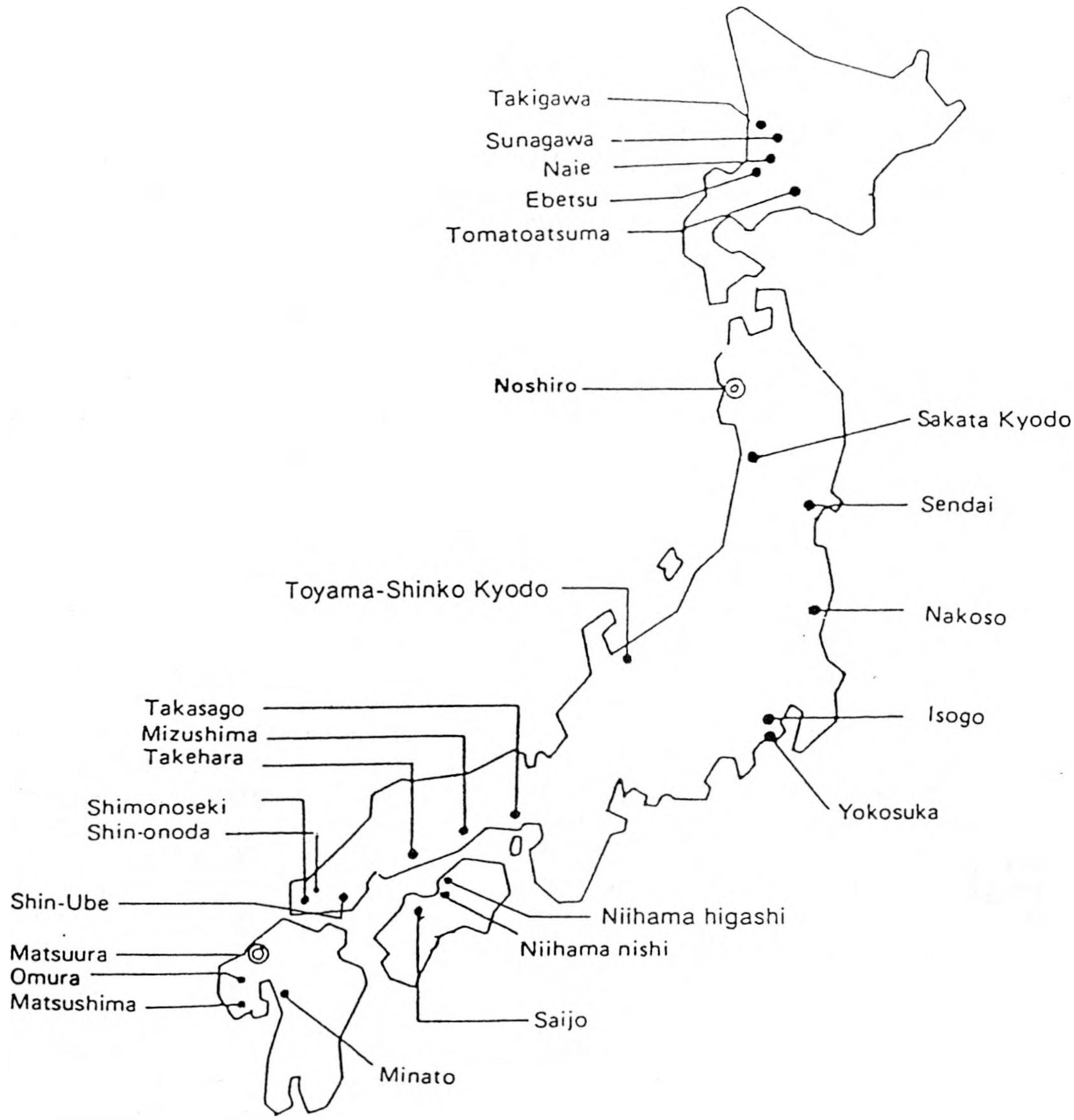


FIGURE 3 - LOCATION OF COAL FIRED POWER STATIONS - OCTOBER 1987

A recent forecast of electric power generation, summarized in TABLE 5, shows a significant increase in coal fired power generation capacity and supply during the next ten year period to FY2000. After FY2000, coal's share of power generation is expected to decrease in favour of nuclear and other new energy sources. Use of oil for power generation will decrease significantly throughout the period.

TABLE 5

FORECAST OF ELECTRIC POWER GENERATION IN JAPAN

	Capacity			Generation		
	FY1988	FY2000	FY2010	FY1988	FY2000	FY2010
Coal	6.7%	13 %	15 %	9.5%	16 %	15 %
Nuclear	17.4	22	27	26.6	35	43
LNG	20.1	22	20	21.2	20	18
Hydro	21.9	20	19	13.3	11	11
Oil	33.8	22	15	29.2	17	9
Others	0.1	1	4	0.2	1	4
	100	100	100	100	100	100
Total (MW)	164 820	227 700	267 000			
(GWH)				665.8	946.0	1109.0

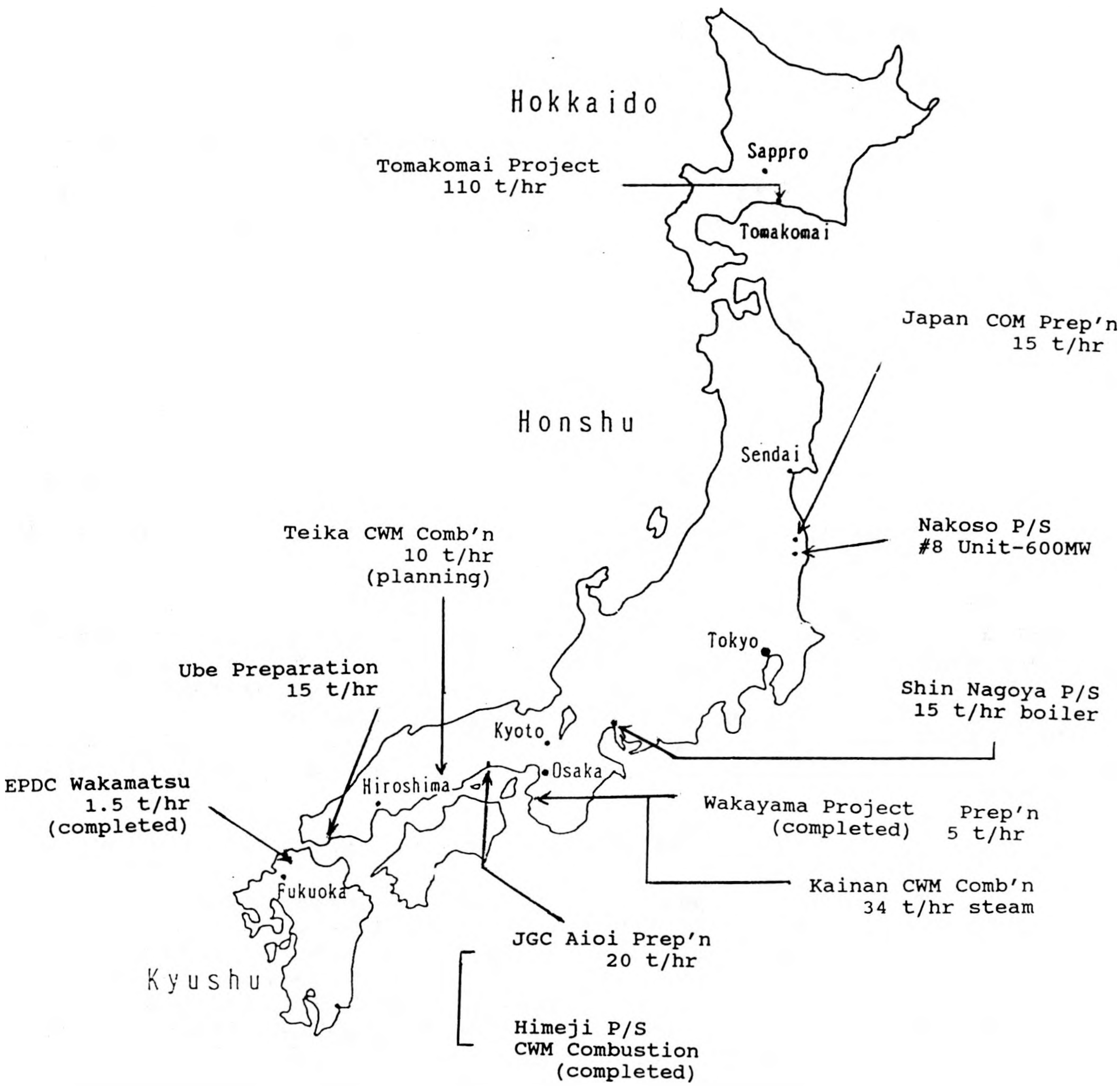
The resulting FY2000 coal fired power generation capacity of 25 031 MW is an increase of 219%.

Total power demand in FY1989 was 713.5 GWH, 6.1% higher than that in FY1988 and exceeded 700 GWH for the first time in Japan. Power demand is expected to increase further in FY1990, with a corresponding increase in coal consumption of approximately 1 million tonnes to 26 million tonnes. Imported coal demand by the utilities is expected to be 17 million tonnes in FY1990, and could increase to 33 million tonnes in FY1994, and to 50 million tonnes in FY1999.

GOVERNMENT SUPPORT FOR CWM FUELS

Since 1980, the Japanese government has provided active support for a number of CWM projects related to development and promotion of commercialization of CWM fuels. Most of these projects have been carried out with various private companies. These projects are highlighted here and some are described in more detail in the following section of this paper. The sites of Japan's major CWM related projects are shown in FIGURE 4.

In FY1980, Japan's national CWM project was started at the Wakamatsu coal utilization test facility of the Electric Power Development Company, Ltd. (EPDC), with financial subsidies from MITI. This project, operated by EPDC, was a 2 tonne/day scale and included both slurry preparation techniques and associated combustion tests.



<u>FIGURE 4</u> - LOCATION OF JAPAN'S MAJOR CWM PROJECTS

In March, 1981, on behalf of Japan, NEDO joined the IEA COM/CLM Implementing Agreement. Since then, NEDO has participated in the IEA activities currently covered by the CLM Annex II agreement, the purpose of which is "international cooperation to exchange information on the basic technology of Coal Liquid Mixtures (CLM) as an oil alternative fuel for business and industrial uses".

In FY1982, Japan initiated a further project at Wakamatsu, called "highly dense coal slurry for big boilers" in which a 1.5 tonne/hour pilot plant was built. Several tests were performed over a four year period beginning in FY1983, related to coal cleaning, slurry preparation, storage, ship transportation, and combustion. This project confirmed the technical feasibility of a total CWM fuel system.

A joint government/industry sponsored national CWM project was initiated in FY1985 at Wakayama, following a feasibility study. The purpose of this project was to demonstrate CWM preparation and combustion for small and medium sized boilers of general industry. Most of the funding for this project was provided by MITI with additional contributions from several companies, including Kubota, Ube, and Hitachi Shipbuilding. The Coal Mining Research Center, Japan (CMRC) managed the project on behalf of the participants.

Two other CWM projects are currently underway in Japan, with funding assistance from MITI. The first is being performed jointly between Japan COM and Idemitsu Kosan Ltd. at Tomakomai in southern Hokkaido. Ultra low ash CWM will be tested in a modified 110 tonne/hour oil burning boiler during a three month combustion trial beginning in August, 1990.

The second project is being performed by Ube Industries Ltd. to demonstrate both the combustion of CWM in a modified 95 tonne/hour oil burning boiler and the preparation of CWM in a modified pre-existing 15 tonne/hour mill. This project, with 67% of the funding provided by MITI, will run from September, 1990 through FY1992 in order to promote the commercialization of CWM.

To further promote the commercialization of CWM, the Center for Coal Utilization, Japan (CCUJ) is performing an economic feasibility study for a domestic CWM preparation and supply system based on a conceptual 250 - 500 000 tonne/year CWM preparation plant sited near Nagoya City in central Japan.

MITI's budget for the promotion of Coal Utilization Technology is shown in TABLE 6.

This budget is assigned to the Coal Industry Administration Division of ANRE, and is part of that division's total FY1990 budget of approximately 25.8 billion yen. It is noteworthy that the coal utilization budget has increased by 9.6% from FY1989, despite a 16.5% drop in the total divisional budget. The 36% increase in the CWM budget allocation is considered to reflect MITI's high expectations for this alternative fuel.

TABLE 6

BUDGET FOR PROMOTION OF COAL UTILIZATION TECHNOLOGY

Budget Item	FY1989	FY1990	Change	Ratio
Fluidized Bed Combustion	1769.4	1817.7	+ 48.3	+ 2.7%
Coal Water Slurry	861.5	1171.5	+310.0	+36.0
Coal Handling	11.4	471.8	+460.4	+403.9
Utilization of Coal Ash	318.1	123.2	-194.9	-61.3
Coal Partial Combustor	487.6	106.0	-381.6	-78.3
Direct Reduction Iron	800.0	965.4	+165.4	+20.7
Total	4248.0	4655.5	+407.5	+ 9.6

unit = million yen

PRIVATE BUSINESS ACTIVITIES IN CWM

The CWM related activities in Japan can be divided easily into four company groupings. Each of them has been involved with CWM demonstration tests related to preparation and/or combustion and are now interested in commercial development, either in Japan or internationally.

The status of the current activities by these groups, according to available information follows.

Japan COM Group

The Japan COM Company Ltd. was established in April, 1981, with capitalization of 13 billion yen of which 51% was provided by Tokyo Electric Power Company, 19% by EPDC and 10% by the Tohoku Electric Company. It has supplied 3.1 million tonnes of coal oil mixture (COM) between the start of production in November, 1984 and March 31, 1990. All of this production was sold to the Yokosuka thermal power station of Tokyo Electric Power Company.

Japan COM constructed two 15 tonne/hour CWM production plants in 1988 at their Onahama factory and has provided 150 000 tonnes of CWM between January, 1988 and March, 1990 to the 600 MW No.8 unit of the Nakoso thermal power station of Joban Joint Thermal Power Company, Ltd.

These fuels are described in TABLE 7.

TABLE 7

COM AND CWM FUELS FROM JAPAN COM COMPANY LTD.

	COM	CWM
Start of Production	Nov. '84	Jan. '88
Coal Selection	5 types	4 types
Total Production (tonnes)	3 100 000	150 000
Heat Content (kcal/kg)	8 500	4 500-5 000
Slurry Density (%)	48-49	67-69
Viscosity (cp)	1 200-1 400(64°C)	900-1 200(25°C)
Average Grain Size(micron)	25	18
Additives (wt %)	0.25	0.45

Initial CWM combustion trials were done using 56 000 tonnes of CWM at the 75 MW No. 4 unit of the Nakoso power station from August, 1985 to March, 1986, prior to the start-up of the current program. Since January, 1988, the Nakoso power station No. 8 unit has been running on a combined fuel of coal (40-45%), heavy oil (50-55%) and CWM (5%). Australian coals from the Warkworth, Mt. Thorley, Bayswater and Leamington mines have been tested to assess their availabilities at the scale of a total 50 000 tonnes of dry coal/year.

In March, 1990, a study was undertaken to determine the potential to increase the use of CWM from the current rate of 70 000 tonnes/year to 100 000 or greater tonnes/year.

Ube Industries Group

Ube Industries consumes 2.5 million tonnes of coal annually. It ranks as one of the largest chemical and resource based companies in Japan, with capitalization of 41.7 billion yen, 7 000 employees and annual revenues of about 500 billion yen.

Ube's main factories for both petrochemicals and fine chemicals and their headquarters are located in Ube City, Yamaguchi Prefecture, where they have large limestone reserves in their Isa Mine, located approximately 30 km northwest of the city. Ube's annual cement production capacity is 12 million tonnes /year. It operates a synthetic ammonia plant based on coal gasification, provides engineering of heavy industrial facilities and imports and distributes coal. Ube has developed a proprietary high density CWM containing less than 3% ash (U-Coal) and has also developed an ultra-low ash CWM, (less than 1%) in the 0.5 tonne/hour pilot plant at Wakayama as part of the national project. In addition, Ube has been testing a small scale, 0.2 tonne/hour CWM burner in its facilities.

Since FY1989, Ube has been engaged in a long term CWM demonstration project subsidized with funding from MITI. The company has refitted an existing grinding facility at a cement plant into a 15 tonne/hour CWM preparation plant (approximately 120 000 tonne/year), and modified a 95 tonne/hour boiler of Ube Chemicals Ltd. to burn CWM. Combustion tests are scheduled to begin in August, 1990, with approximately 20 000 tonnes of CWM expected to be burned during FY1990.

JGC Group

JGC Corporation is a comprehensive engineering company based in the petrochemical industry and has experience in CWM preparation, transportation and storage in cooperation with Kansai Electric Power Company and other heavy industry companies. In 1984, JGC constructed a 4.5 tonne/hour pilot scale CWM preparation plant based on the Carbogel process at Aioi, Hyogo Prefecture. Two years later, this plant was expanded to 20 tonnes/hour and supplied de-ashed CWM to the Himeji thermal power station of Kansai Electric Power Company, located approximately 20 km. from the processing plant, for five years from 1984 to 1988. The 33 MW No. 1 Unit used for these tests began operation in 1955 using pulverized coal combustion, but was converted to oil burning in 1973. It was found from these tests that CWM was fully competitive with oil combustion for both low load and load following conditions.

JGC has compared the use of both Canadian and Japanese coal for producing CWM. The Canadian coal was reported to give higher pulp densities with lower viscosity.

	Canadian	Japanese
Volume Prepared(tonne)	4500	3000
Pulp Density (%)	68	62
Ash Content (%)	8	7
Viscosity (cp)	690	840

Internationally, JGC is actively planning a CWM project in China. X'ing L'ong Zhuang coal, with 9% ash, will be transported 340 km by rail from the mine to the port of Shijui, where CWM will be produced and exported to Japan. In May, 1990, Yan Ri CWM Ltd. was established as a limited company in Shijui, with capital of approximately 1.2 billion yen which is shared among the Chinese partners (51%), Nissho Iwai (34%) and JGC (15%). Construction of the CWM preparation plant is expected to cost 3.8 billion yen. Japan is expected to contribute 83% of this cost, of which 2.36 billion yen will be a loan through the Japan International Cooperation Agency (JICA). Nissho Iwai and JGC Corp share responsibility for this loan, which has a 20 year term.

Coal reserves in the Yanzhou field are reported to be over 7 billion tonnes, of which 10 million tonnes are currently supplied, using modern techniques, to steel mills and power utilities. Plans include expanding the mine production to 30 million tonnes/year in 2000.

The CWM preparation plant is designed with an initial annual capacity of 250 000 tonnes/year. Construction is expected to be completed by Autumn, 1990. Future plans include expanding the production capacity to 1 000 000 tonnes as overseas markets increase.

Specifications of the Yan Ri CWM include a coal concentration of 68 to 72%, heat content of 4 790 to 5 170 kcal/kg, viscosity of 1 000 cp, specific gravity of 1.25, ash of 6%, sulfur of 0.2%, particle size of 75 to 85% minus 200 mesh, and expected stability of longer than 6 months.

The initial production volumes will be transported 1 000 km from Shijui to the Hibiki Coal Center, Kita Kyushu City, using 5 000 tonne class CWM ships and stored in two 10 000 tonne CWM storage tanks. The terminal at the coal center is designed with two slurry unloading facilities and will be capable of handling 10 000 DWT ocean tankers. Nissho Iwai will be responsible for marketing and distribution of CWM to customers.

Teika Company Ltd., a manufacturer of titanium oxide, announced that it will use 50 000 tonnes/year of this product at its Okayama factory to meet an increased power requirement. Teika intends to install a new CWM burning, double walled water tube type boiler of 45 tonne/hour capacity. This boiler will also be able to burn oil or other coal-based fuels. After an initial start-up using heavy oil, the company plans to switch to CWM in January, 1992.

In this case, the CWM will be transported 300 km from the Hibiki Coal Center to the Okayama factory using 500 tonne CWM ships.

In early July, 1990, it was reported that MITI requested the Ministry of Finance (MOF) to allocate budget funding to support the promotion of new markets in Japan for the Yan Ri CWM product. Of particular interest is the development of a commercialized CWM distribution system to stimulate further demand.

Kubota/Hitachi Group

This group has not reported any new CWM related business activities since the completion of the Wakayama CWM demonstration project which ended in FY1989.

The results of the Wakayama project include:

Non-deashed CWM Preparation

A total of 17 850 tonnes of CWM was prepared from three different coals. Typical specifications for these different slurries include slurry density of 63 to 68% coal by weight, viscosity in the range 700 to 1200 cp, and grain size of 83.5 to 88.5% minus 200 mesh.

De-ashed CWM Preparation

A total of 1 150 tonnes of CWM containing between 1 and 2% ash was produced from three different coals by means of an improved oil agglomeration method. Typical specifications of these CWM products include slurry density in the range of 66 to 68%, viscosity in the range of 490 to 1 280 cp, and grain size of 69.3 to 77.2% minus 200 mesh.

CWM Combustion

A total of 17 600 tonnes of CWM were combusted during 4 300 hours of tests from April, 1988 to January, 1989, including a continuous 30 day test. Combustion efficiencies of 98% with NO_x emissions below 185 ppm were attained, as expected. These tests also confirmed the successful development of numerous related component techniques.

Related Technologies

This project resulted in the group members demonstrating the practical application of CWM related techniques including storage, quality control, tank truck transport, flue gas disposal, electrostatic particulate control, wet desulfurization, extraction of molten ash as well as the development of a series of CWM additives.

Other Activities

Currently, the Kansai Electric Co., Ltd. is participating in a three year project to evaluate CWM supplied from the Nagasaki factory of Mitsubishi Heavy Industry Co., Ltd.

Chubu Electric Power Company has been reported to be studying a series of combustion tests on coal, Orimulsion, and CWM at their Shin-Nagoya thermal power station using a newly installed 15 tonne/hour fuel testing boiler.

EXPECTED COMMERCIALIZATION OF CWM

Japan depends almost entirely on overseas energy sources except for hydro power, particularly with the rapid decrease in domestic coal production. As a result, Japan must find stable, economic and diversified supply for oil, coal, natural gas, nuclear and other new energy resources.

In the current age of world peace, which enables global free trade and where economic interdependence becomes universal, Japan is fortunate to have the opportunity to be able to choose the most economic combination of energy resources. It will be necessary that this choice keep pace with advancement in energy technology, evolution of the world economy, global climate change and other environmental issues.

Accordingly, Japan's pursuit of its best energy mix, as summarized in the national long term energy plan, is expected to result in the most reasonable solution.

This national plan is usually revised every two to three years. Successive revisions of the plan need both the collection and analysis of the latest information on world-wide political, economic and technical events on energy supply and demand. Results of the analysis should be considered, not only in terms of Japan, but also the impact on other countries. For example, Japan currently imports over 100 million tonnes of coal, about one third of the world coal trade. This will increase, sooner or later, to the range of 150 million tonnes, which can bring additional benefits to the exporting countries.

The source and form of supply of this coal will be important to Japan. The oil supply situation and the relative price of coal will strongly influence the rate of this increase. CWM has proved to have inherent advantages against coal; its relative price will be the most important factor influencing its success in the Japanese market. Lower price and stabilized supply, under long term contracts, will be key for CWM to achieve a dominant share.

The "Coal Frontier Program" is a domestic initiative, which combines the efforts of both the government and the private companies to promote increased coal use by the general industry. Similarly, the "Clean Coal Program" calls for CWS and CCS (coal cartridge system) to become reliable means for the expanded use of coal all over Japan.

These two initiatives should eventually benefit coal development and utilization throughout the world. At the same time, Japan needs to learn more about other CWM related demonstration and development activities throughout the world in order to promote the commercialization of CWM in Japan through improving both quality and price for industrial use.

Forecast of Electric Power Generation in Japan

Item / End of / Source	Composition of Power Source						Target of Power Supply					
	1988 FY		2000 FY		2010 FY		1988 FY		2000 FY		2010 FY	
Nuclear	2,870	17.4 %	5,000	22 %	7,200	27 %	1,776	26.6 %	3,290	35 %	4,730	43 %
Coal	1,112	6.7	2,960	13	4,000	15	636	9.5	1,560	16	1,630	15
LNG	3,306	20.1	5,030	22	5,300	20	1,414	21.2	1,880	20	2,010	18
Hydraulic	3,613	21.9	4,450	19	5,170	19	886	13.3	1,010	11	1,180	11
General	1,913	11.6	2,150	9	2,500	9	801	12.0	850	9	990	9
Pumped	1,700	10.3	2,300	10	2,670	10	85	1.3	160	2	190	2
Geothermal	18	0.1	100	0.4	350	1	11	0.2	60	1	210	2
Petroleum, etc.	5,563	33.8	5,120	22	4,020	15	1,944	29.2	1,630	17	1,050	10
Methanol	---	--	---	--	100	0.4	---	--	---	--	40	0.3
Fuel cell, Solar Photv. and Wind	---	--	110	0.5	570	2	---	--	30	0.3	250	2
Total	16,482	100	22,770	100	26,700	100	6,668	100	9,460	100	11,090	100

Unit: 10 MW

Unit: Hundred Million kwh

Comparison of Imported Coals to Japan

Item / Unit / Country	Coal	Ash	Volat.	Fixed Carbon	Calorie	Total S	Melt. pt.	Crush Ability	Fuel Ratio
	Brands	(%)	(%)	(%)	(kcal/kg)	(%)	(°C)	(HGI)	(FR)
Australia	34	13.6	32.4	51.4	6,921	0.51	1,431	49	1.55
South Africa	5	11.2	25.0	60.9	6,960	0.77	1,307	49	3.28
U.S.S.R.	4	13.6	26.6	57.1	6,808	0.42	1,342	60	2.53
Indonesia	4	6.1	39.6	45.1	6,361	0.45	1,287	50	1.14
P.R.C.	2	10.6	26.7	60.0	7,000	0.71	–	50	2.29
U.S.A.	1	10.0	37.7	47.6	6,750	0.60	1,250	49	1.26
Canada	1	11.0	22.0	65.6	7,560	0.30	1,450	78	2.98
Columbia	1	9.6	33.2	48.2	6,560	0.70	1,240	49	1.45

Japan's Coal Import in 1988/1989 FY

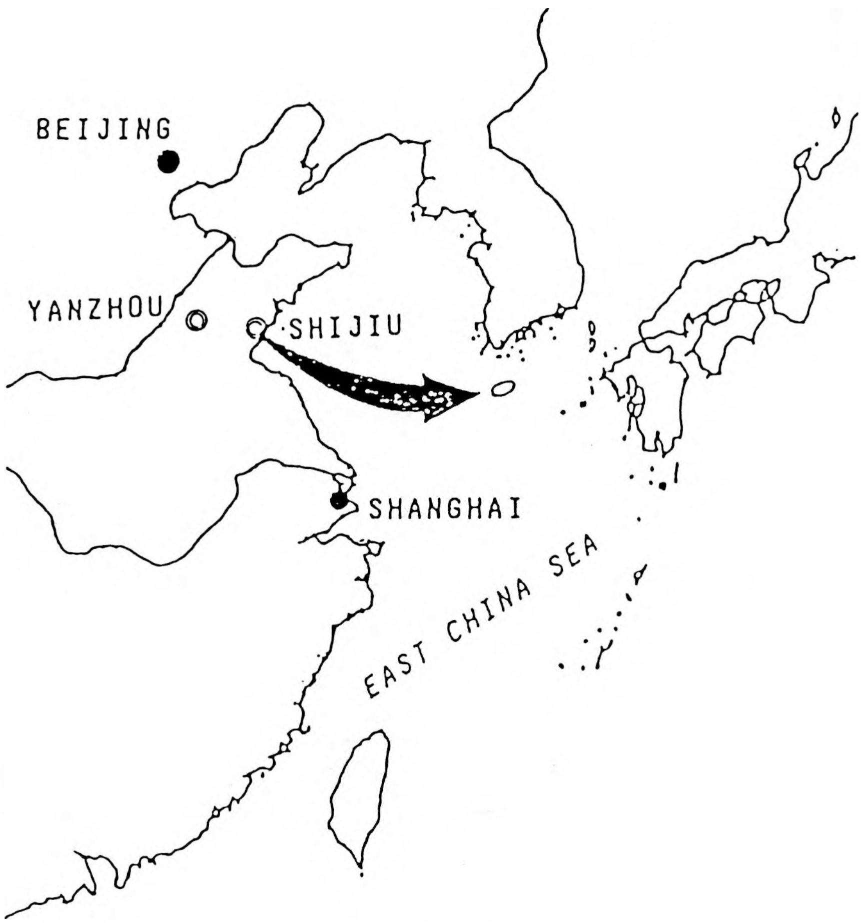
Unit: thousand ton

		1988 FY	1989 FY	'89 FY/'88 FY
Caking Coal	Sub total	74,077	73,612	99.4%
	Australia	30,229	34,183	113.1
	Canada	19,271	17,428	90.4
	U.S.A.	12,504	10,602	84.8
	South Africa	3,791	3,385	89.3
	U.S.S.R.	5,916	5,630	95.2
	Others	2,365	2,385	100.8
Steaming Coal	Sub total	27,698	30,228	109.1%
	Australia	19,046	20,904	109.8
	Canada	1,374	1,350	98.3
	U.S.A.	469	1,418	302.3
	South Africa	2,116	1,533	72.4
	P.R.C.	2,519	2,434	96.6
	U.S.S.R.	2,066	2,450	118.6
	Others	109	138	126.6
Anthracite	Sub total	2,492	2,273	91.2%
	P.R.C.	697	532	76.3
	U.S.S.R.	514	542	105.4
	North Korea	505	551	109.1
	South Africa	466	310	66.5
	Others	310	339	109.4
Total		104,267	106,113	101.8%

MAJOR CONSTRUCTION PROGRAM OF COAL FIRED POWER STATIONS

	End of FY '87	FY '88	FY '89	FY '90	FY '91	FY '92	FY '93	FY '94	FY '95	FY '96	FY '97	FY '98	FY '99	Total
HOKKAIDO EPC*	2,150	Takigawa (-75)	Takigawa (-150) Sunagawa (-125) Ebetsu (-125)	Ebetsu (-125)	Ebetsu (-125)									2,150 (-725)
TOHOKU EPC	525	—	—	—	—	—	Noshiro 600	—	—	—	Haramachi 1,000	—	—	2,125
TOKYO EPC	530	—	—	—	—	—	—	—	—	—	—	—	—	530
CHUBU EPC	—	—	—	—	Hekinan 700	Hekinan 700	Hekinan 700	—	—	Shimizu 1,000	Shimizu 1,000	—	—	4,100
HOKURIKU EPC	—	—	—	—	Tsuruga 500	—	Nanao Ota 500	—	—	—	—	—	—	1,000
KANSAI EPC	—	—	—	—	—	—	—	—	—	—	—	Maizuru 2x900	—	1,800
CHUGOKU EPC	1,762	Shin-Ube (-75)	Shin-Ube (-75)	Shin-Ube (-156)	—	—	—	—	—	—	—	—	—	1,762 (-306)
SHIKOKU EPC	406	—	—	—	—	—	—	—	—	—	—	—	—	406
KYUSHU EPC	312	—	Matsuura 700	—	—	—	—	—	Reihoku 700	—	—	—	Reihoku 700	2,412
OKINAWA EPC	—	—	—	—	—	—	Gushikawa 156	Gushikawa 156	—	—	—	—	—	312
EPDC*	3,292	—	—	Matsuura 1,000	—	—	—	—	Takehara 350	—	—	—	—	4,642
TOYAMA JTP*	500	—	—	—	—	—	—	—	—	—	—	—	—	500
SAKATA JTP	350	—	—	—	—	Sakata 350	—	—	—	—	—	—	—	700
JOBAN JTP	1,450	—	—	—	—	—	—	—	—	—	—	—	—	1,450
SOMA JTP	—	—	—	—	—	—	—	Soma 1,000	—	—	—	Soma 1,000	—	2,000
SUMITOMO JTP	173	—	—	—	—	—	—	—	—	—	—	—	—	173
Change in capacity	—	(-150)	700 (-425)	1,000 (-281)	1,200 (-125)	1,050	1,956	1,156	1,050	1,000	2,000	2,000	700	14,612 (-1,031)
Total capacity	11,450	11,300	11,525	12,244	13,319	14,369	16,325	17,481	18,531	19,531	21,531	24,331	25,031	—

NOTE: EPC* (Electric Power Company) EPDC* (Electric Power Development Corporation) JTP* (Joint Thermal Power)



SHIP TRASPORTATION OF CWM FROM CHINA TO JAPAN

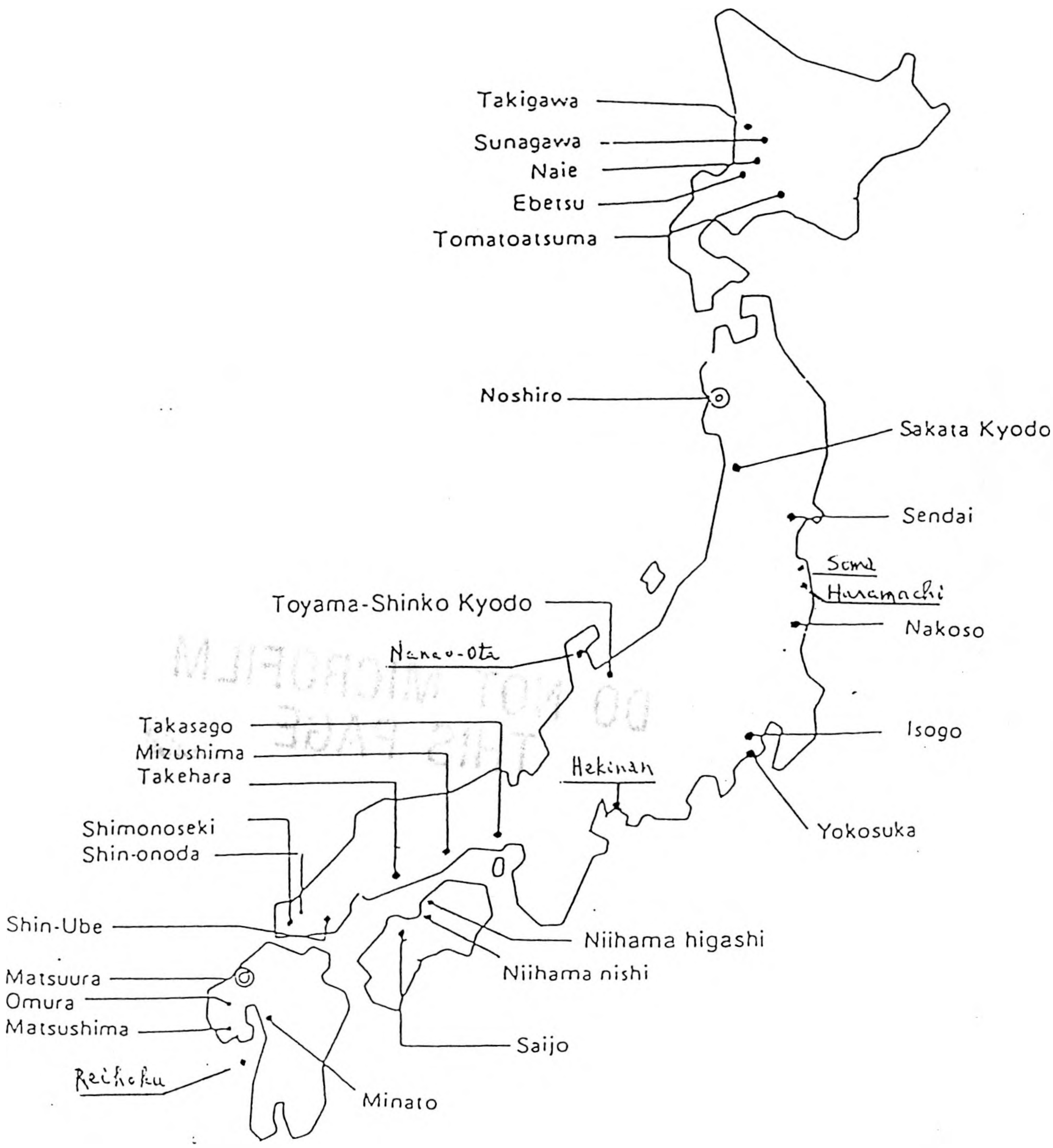


FIGURE 3' - LOCATION OF COAL FIRED POWER STATIONS

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"GERMAN COALS; UTILISATION NOW AND IN FUTURE"

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GERMAN COALS; UTILISATION NOW AND IN FUTURE

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THE IMPORTANCE OF COAL

During the last two decades the world wide industrial and domestic utilization of energy has increased drastically world wide. The consumers' demand for usable forms of energy is satisfied, apart from a certain portion of nuclear power, predominandly by the conversion of fossil fuels. Of these at present oil as the most versatile source plays the major role, followed by natural gas, which is in growing demand since the sixties. Coal - having been the most important source of primary energy since the start of industrialization - gained renewed interest during the last 15 years due to the two major oil crisises in the early seventies.

The Federal Republic of Germany (fig. 1), as one of the leading economical countries in the world, holds a 4,2% share of the world energy utilization. This utilization is provided by a variety of primary energy (fig. 2). Coal - bituminous and brown - providing 27,5% of the Republic's primary energy needs, is an important contributor. The significance of coals for the economy of the Republic is emphasized by the fact that the predominant portion of coal is domestically mined which reduces import dependency.

Coal is naturally available in western Germany. The major bituminous coal mining area is in the Ruhr region, with other smaller contributors being the Saar region, near Aachen, and at Ibbenbüren in Westfalia. Brown coals are predominantly mined in the Rhineland region but also near Helmstedt. The annual production distribution is shown in table 1; the typical coal analysis in table 2.

Looking at the development of the coal market in Germany over the past two decades - fig. 3 reports the data for 1973 and 1986 - it can be noted that the production of brown coal remainded almost constant over time, while bituminous coal mining diminished. This has lead to a decrease in total coal output.

Besides changes in markets demand, the main reason for this tendency is the differences in production costs: Brown coal is surface-mined from almost horizontal seams with thicknesses up to 40 m. This allows a specific production of about 90 tons per person per shift. The production costs are low when compared with the underground mining of bituminous coals. Bituminous coals are found in sloped and tectonically heavily distorted seams of 1 - 1,8 m thickness, at a depth of down to 1200 m below the ground. These specific geological features lead to a specific production of about 4 tons per person per shift only resulting in production costs which are, even when having been subsidized, not competable on the world market.

Fig. 3 also indicates a change in coal utilization. The export of bituminous coal decayed drastically due to the above stated reason. In addition, fig. 4 shows that traditional markets, like the application for domestic purposes and use in the steel industry, lost importance in absolute and relative terms. In contrast, the utilization of coal for direct heat generation in industry - although having a small share - increased. However, the major coal application was, and still is, electricity generation. The share of the coal production burnt in utility boilers went up to almost 60% and is still rising. Therefore, the future utilization of coal is strongly linked with the development of electrical power generation technology.

PRESENT STATUS OF COAL FIRED UTILITY BOILERS

At present, utility boilers in Germany are under operation in single unit sizes up to 600 MWe for brown coal and 770 MWe for bituminous coals. The high technical standard is mirrored by the fact that availabilities for base load stations are typically above 90%, with overhaul intervals of up to 3 years. For modern stations, typical steam conditions are 535 °C/250 bar for bituminous coal firing and 542 °C/180 bar for brown coal firing with overall efficiencies (prior to the installations of flue gas treatment plants) close to 40% and 37% respectively.

During recent years all boilers with capacities of 300 MW_{th} and greater had to be retrofitted with gas treatment plants in compliance with emission control standards. Experience has shown, that with the present techniques, efficiencies for fly ash removal of above 99,9% and SO_2 and NO_x-reduction of above 90% can be obtained. However, costs for these retrofit measures were not cheap. Investment costs for single units were as high as 50 % of the total plant costs.

The expected positive effect on the environment can be clearly seen from fig. 5. However, the installation of these plants has led to a reduction of the overall efficiency of the electricy generation unit by 1 - 2%. This decrease, as well as the cost of retrofitting, led to a substantial increase in price of electricity for the customer.

REQUIREMENTS FOR FUTURE COAL UTILIZATION TECHNOLOGY

Emphasized by the discussion of the harmful influence of carbon dioxide (CO_2) on the global climate via the "greenhouse" effect, fossil fuel combustion processes - being one of the major sources of antropogenic CO_2-production - became a topic of controversy in public discussion.

Because of the strong growth of world population, the expected increase in industrialization, and the subsequent rise in living standards - in particular in developing countries - a further increase of fossil fuel utilization and a subsequent rise in CO_2-emision is prognosted. Therefore, the first political and technical actions have already been taken in order to combat the danger of heating of our environment. As formulated by the recent international conference in Toronto, and since adopted by various countries, a 25% reduction of the CO_2-emission should be achieved by 2005.

Due to the nature of fossil fuels, the CO_2-emissions per energy unit converted can vary (fig. 6). The exchange of fuels for reasons of CO_2-reduction is, however, technically and/or economically very limited and other options must be sought of.

Because the utilization of non-carbon fuels is either only locally accessible with small quantities available, and thus economically not attractive (regenerative energies) or suffers from an only limited acceptance (nuclear energy), emphasis must be placed the improvement of fossil fuel, in particular coal based processes.

Based on the presently available optimal power station technique and in consideration of the CO_2-issue, various important requirements are essential for a new concept of coal utilization in electricity production:

- satisfy required demand at any time
- maintain low emissions of noxious species in compliance with present or future control regulations:
- maintain high availability
- provide high safety of operation
- reduce losses
- permit favorable costs for competition
- improve fuel conversion efficiency for
  - reducing the specific costs of the final energy

-- covering losses caused by emission reduction processes

-- saving primary energy resources for the future

-- reducing the CO_2-emission significantly in agreement with political goal settings.

PRINCIPAL OPTIONS AND TECHNICAL REALIZATION

In light of these requirements, the major task of the scientist and engineer is the design of fuel utilization systems which allow for an increase of the present conversion efficiencies. In addition, systems with a reduced impact on the environment and the most cost effective product are preferred.

A critical review of the conventional steam cycle reveals that technical changes, such as multiple steam reheating, further optimization of preheat, reduced condensing pressure, and supercritical operation, will be successful. However, these improvements will only be marginal. Material questions still have to be solved and the costs involved may prove that these technical options may not be economical.

Substantial improvements in fuel conversion efficiencies can only be expected by making better use of the thermodynamics, hence, by providing for energy conversion at elevated temperatures above the ones of the water/steam cycle.

As one option, multiple cycle concepts using other heat transfer media (e.g. alkalines) prior to the steam cycle have been studied but proven to be uneconomical.

However, an attractive solution offers the combination of a gas turbine with a steam turbine, due to an increase of the usable temperture difference. The gas turbine is already widely used for electricity generation. Depending on the gas turbine inlet temperature, efficiencies of 43% and higher have been reached. Also, the combination of a gas turbine with an oil or gas fired boiler is a common technique. In one case the combination of a gas turbine in front of a coal fired boiler has been operating since 1986, having a total capacity of 770 MWe and an efficiency of 42%.

With regard to coal, the discussion about CO_2-emissions caused the known principles of pressurized fuel conversion to become of renewed interest for the integration into a combined cycle. At present, various technical options are proposed which are summarized, in principle, in fig. 7: Coal is gasified under pressure, cleaned and burnt in a gas turbine combution chamber (left). The energy of these gases is to one part converted to electricity in the gas turbine. The sensitive heat of the gases leaving the turbine can furthermore be used for steam raising in a waste heat boiler and subsequent electricity production in the steam turbine.

Coal based combined cycles can alternatively be applied to pressurized combustion instead of gasification (fig.7, right). In these cases, the flue gases from the combustion chamber will, after cleaning, enter the gas turbine. All further process steps remain as described above.

Depending mainly on the fuel properties, the conversion principle and different process parameters (fig. 8 and 9) can be chosen.

Combined cycles, using only coal are in different stages of development (concept studies, research investigations, planning, construction and large scale demonstation respectively). Fig. 10 shows the typical efficiencies as a function of gas turbine inlet temperature for various combined cycle principles. As an example, data for the development of the efficiency increase are given in fig. 11 for German brown coals.

Finally, table 3 shows the state of large scale demonstration plants. As shown, the first coal combined cycles will start their demonstration operation in Europe within the next few years. Successful demonstration provided by the combined cycle technique is expected to be available by the end of this decade.

Concluding, it can be stated that in the Federal Republic of Germany coal is expected to maintain its important role as primary energy source and to expand its already predominant position as the basis for electricity production. The experience to be gained with the new conversion techniques is believed to ensure the envisaged tendency.

Coal type	Area	10 t/a
Bituminous coal	Ruhr	56.4
	Saar	10.0
	Aachen	4.3
	Ibbenbüren	2.3
	Total	72.0
Brown Coal	Rhineland	90.0
	Helmstedt	21.3
	Hessen	19.6
	Total	130.9

TABLE 1: ANNUAL COAL PRODUCTION IN THE FEDERAL REPUBLIC OF GERMANY (DATA BASE 1988)

Area	as received		Moisture- and ash-free						HHV	
	% ash	% moisture	% volatiles	% C	% H	% O	% N	% S	Btu/lb	MJ/kg
Ruhr (anthracite)	4–7	3–5	7.7	91.8	3.6	2.6	1.4	0.7	15.440	35.9
Ruhr (Low–Vol.Bit.)	6–9	7–10	10.5	90.8	3.8	2.7	1.7	0.8	15.500	36.0
Aachen (Low–Vol.Bit.)	6–9	8–10	13.8	89.8	4.8	2.8	1.5	0.5	15.410	35.8
Ruhr (Med–Vol.Bit.)	6–9	7–10	24.4	88.7	5.0	4.1	1.6	6.7	15.550	36.2
Saar (Med–Vol.Bit.)	7–9	8–10	32.5	86.9	5.2	5.4	1.3	1.1	15.320	35.6
Ruhr (High Vol.Bit.)	6–7	8–10	33.7	85.9	5.5	6.2	1.6	0.8	15.160	35.2
Saar (Hig Vol.Bit.)	5–8	3–5	38.2	82.7	5.2	9.4	1.2	1.5	14.220	33.0
Helmstedt (Brown Coal)	12–22	42–46	59.4	72.6	5.8	16.7	0.4	4.4	12.790	29.7
Rheinland (Brown Coal)	5–20	50–62	55.0	68.3	5.0	27.5	0.5	0.5	11.340	26.4

TABLE 2: ANALYSES OF TYPICAL COALS

company	project	fuel conversion principle	location	capacity	status
Lurgi	BGL	fixed bed	Westfield (GB)		planning
RWE	KoBra (HTW)	fluidized bed	Go-Werk (FRG)	270 MW	start up 1995
DBA	KRW	fluidized bed			planning
Shell		fluidized bed	Buggenum (B)	285 MW	start up 1993
Texaco		fluidized bed	Freetown (USA)	440 MW	planning
Krupp Koppers	PRENFLO	fluidized bed	Duisburg? (FRG)		planning
VEW	GDK250	fluidized bed	Werne (FRG)	250 MW	planning
DBA	GSP	fluidized bed	Freiberg (DDR)	175 MW	planning

TABLE 3: COMBINED CYCLES WITH INTEGRATED COAL GASIFICATION

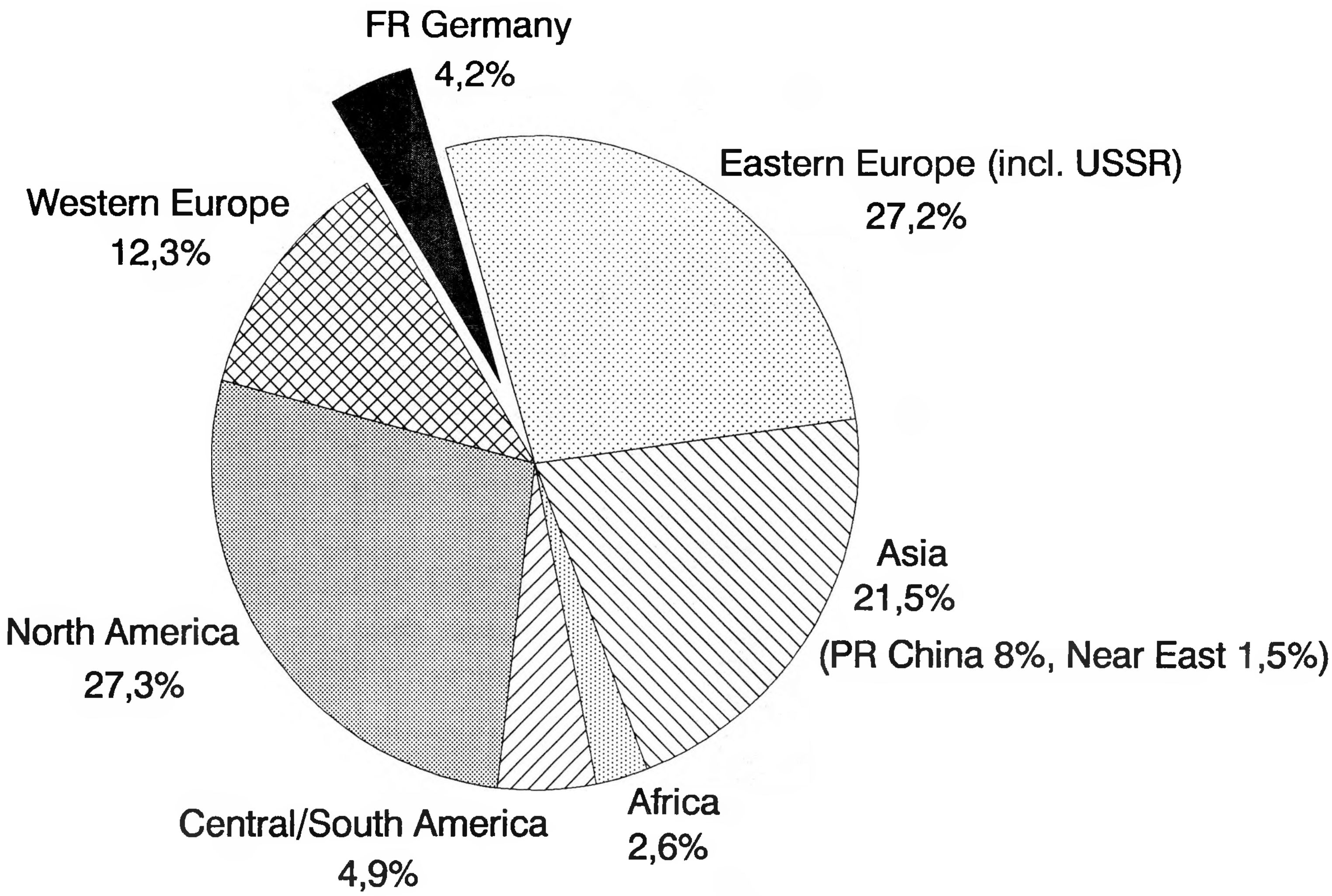


Fig. 1: World energy utilization 1986

(total $272 \cdot 10^6$ GJ $\hat{=}$ $9{,}3 \cdot 10^6$ TCE)

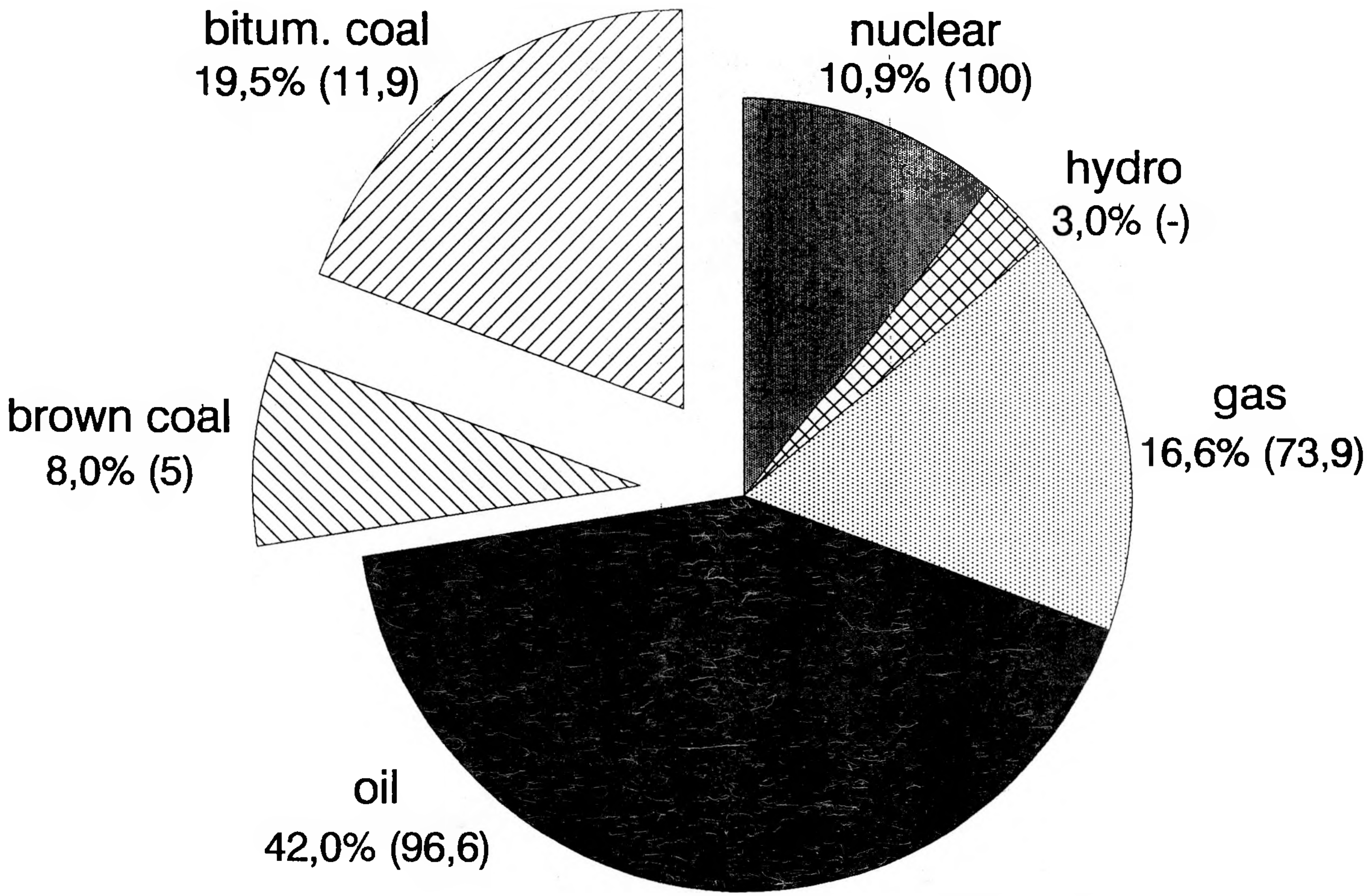


Fig. 2: Primary energy utilization; FRG 1987

(total $11{,}4 \cdot 10^{6}$ GJ $\hat{=}$ $0{,}39 \cdot 10^{6}$ TCE; in brackets: % imported)

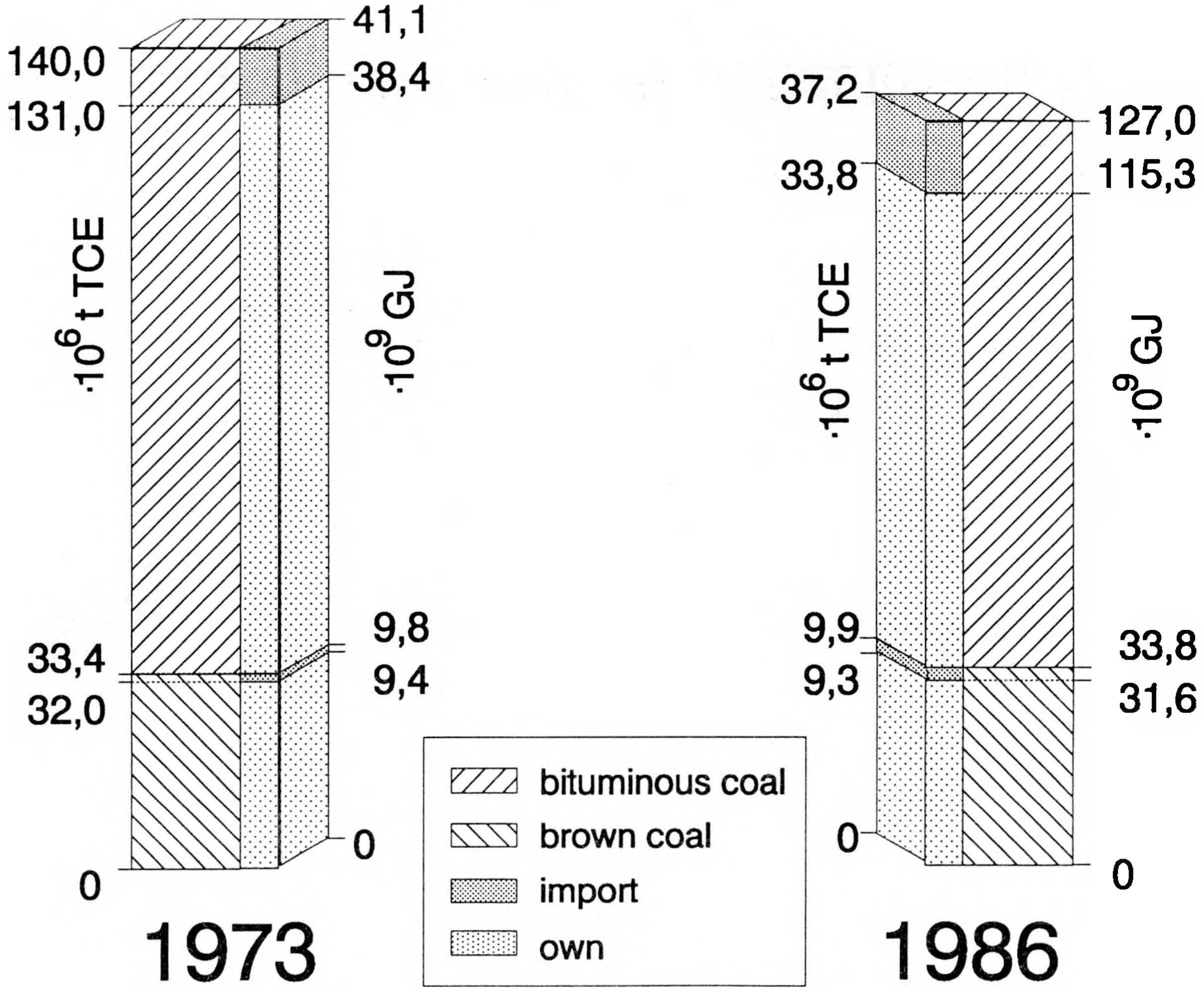


Fig. 3: Development of coal production (FRG)

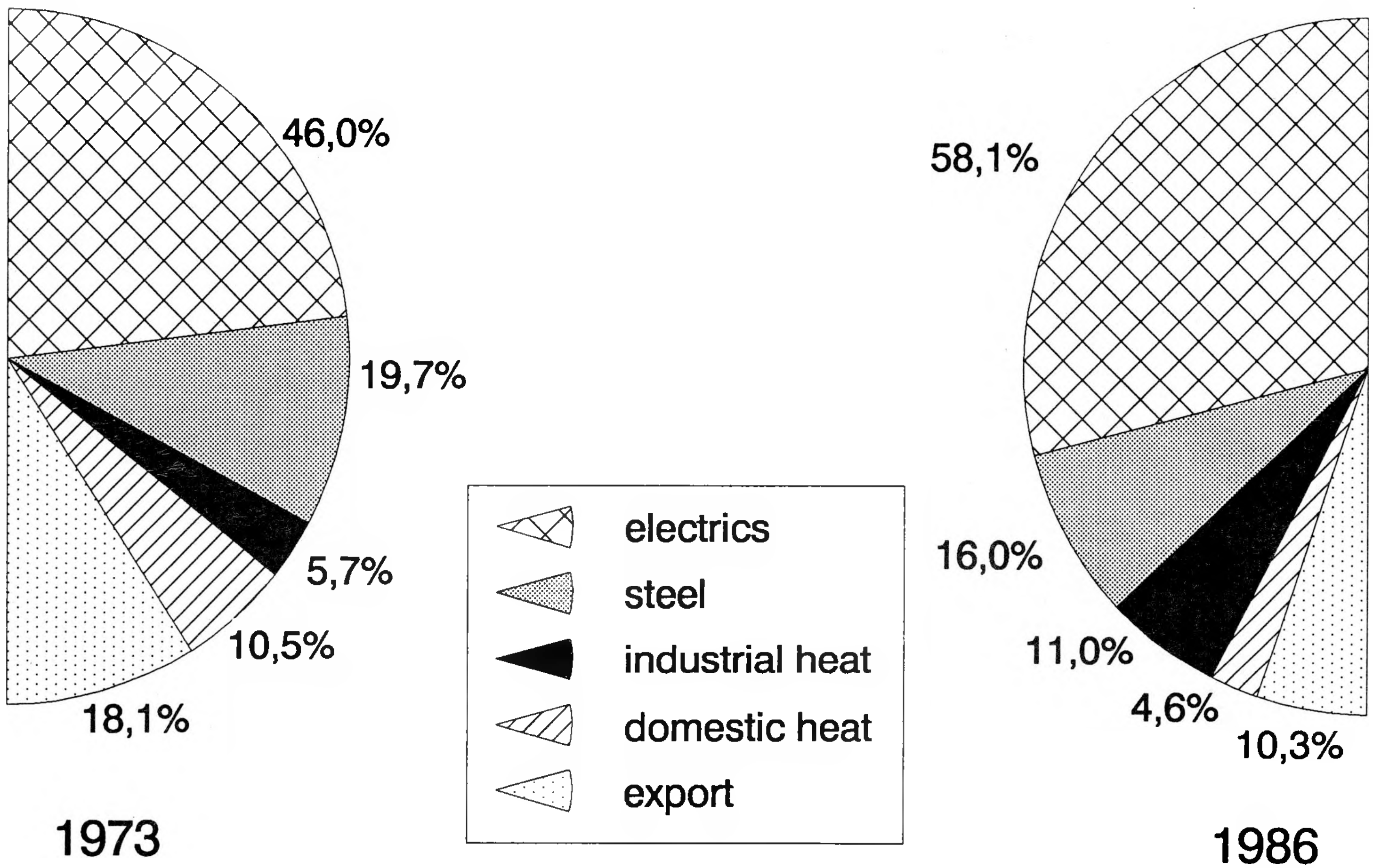


Fig. 4: Development of coal utilization (FRG)

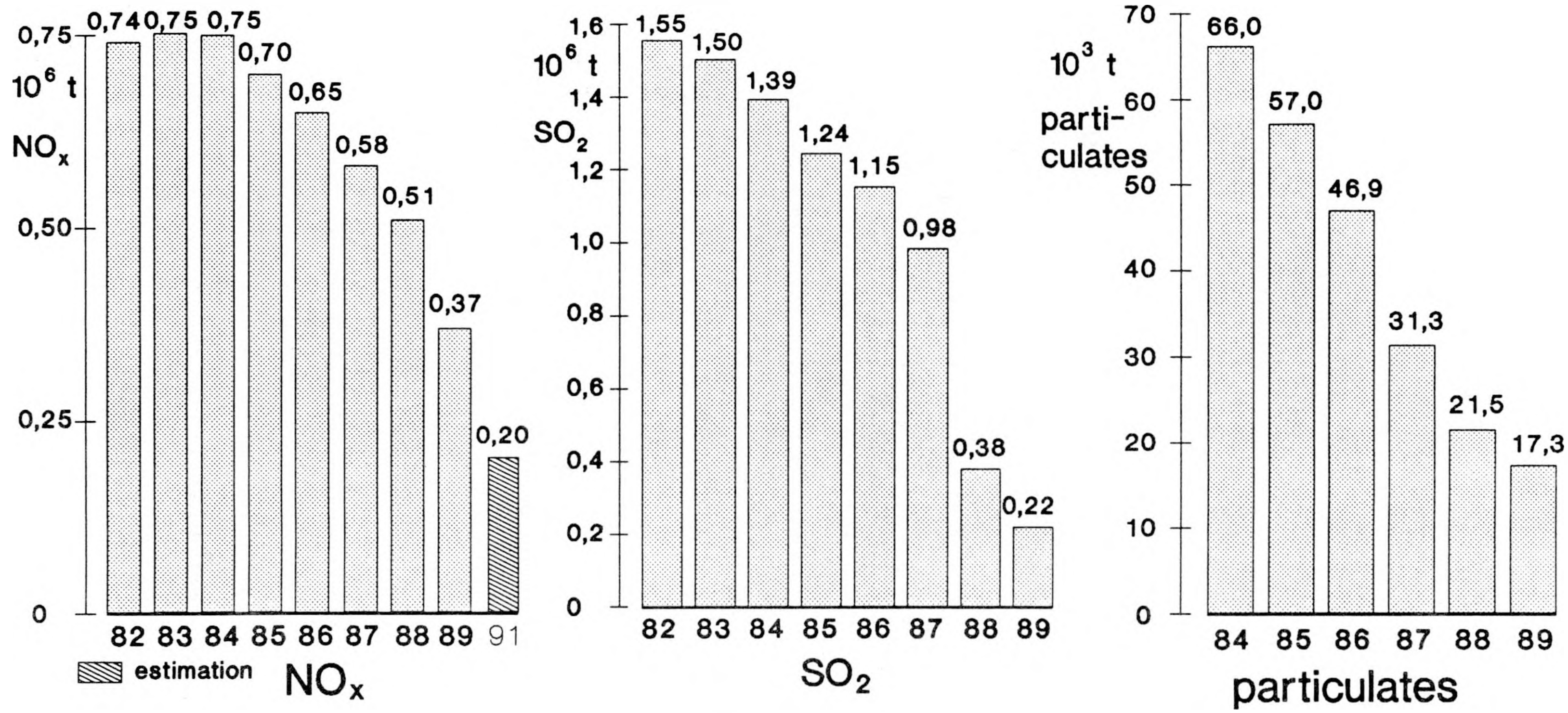


Fig. 5: Development of annual emissions from power stations

Federal Republic of Germany

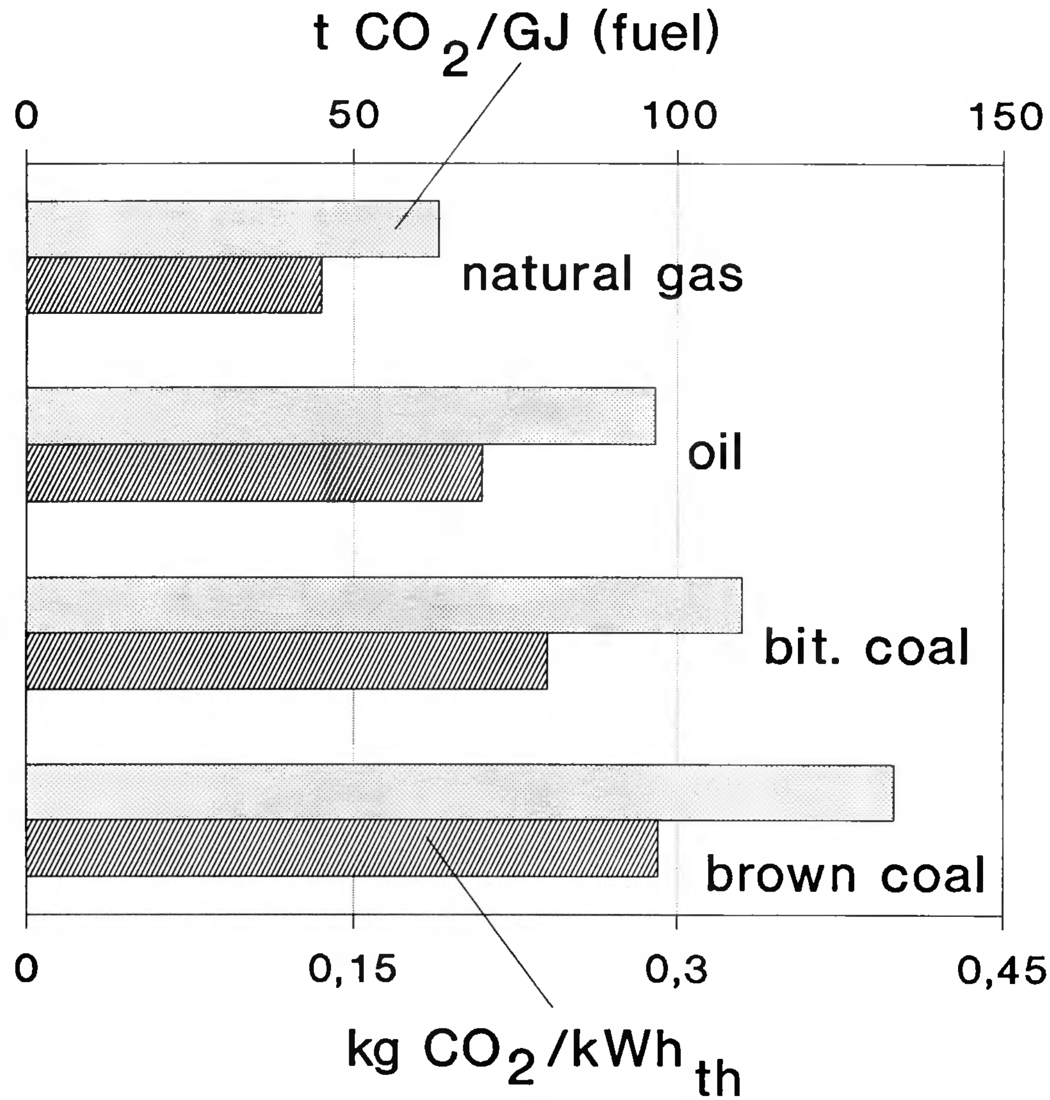


Fig. 6: Specific CO_2-emissions from fossil fuels

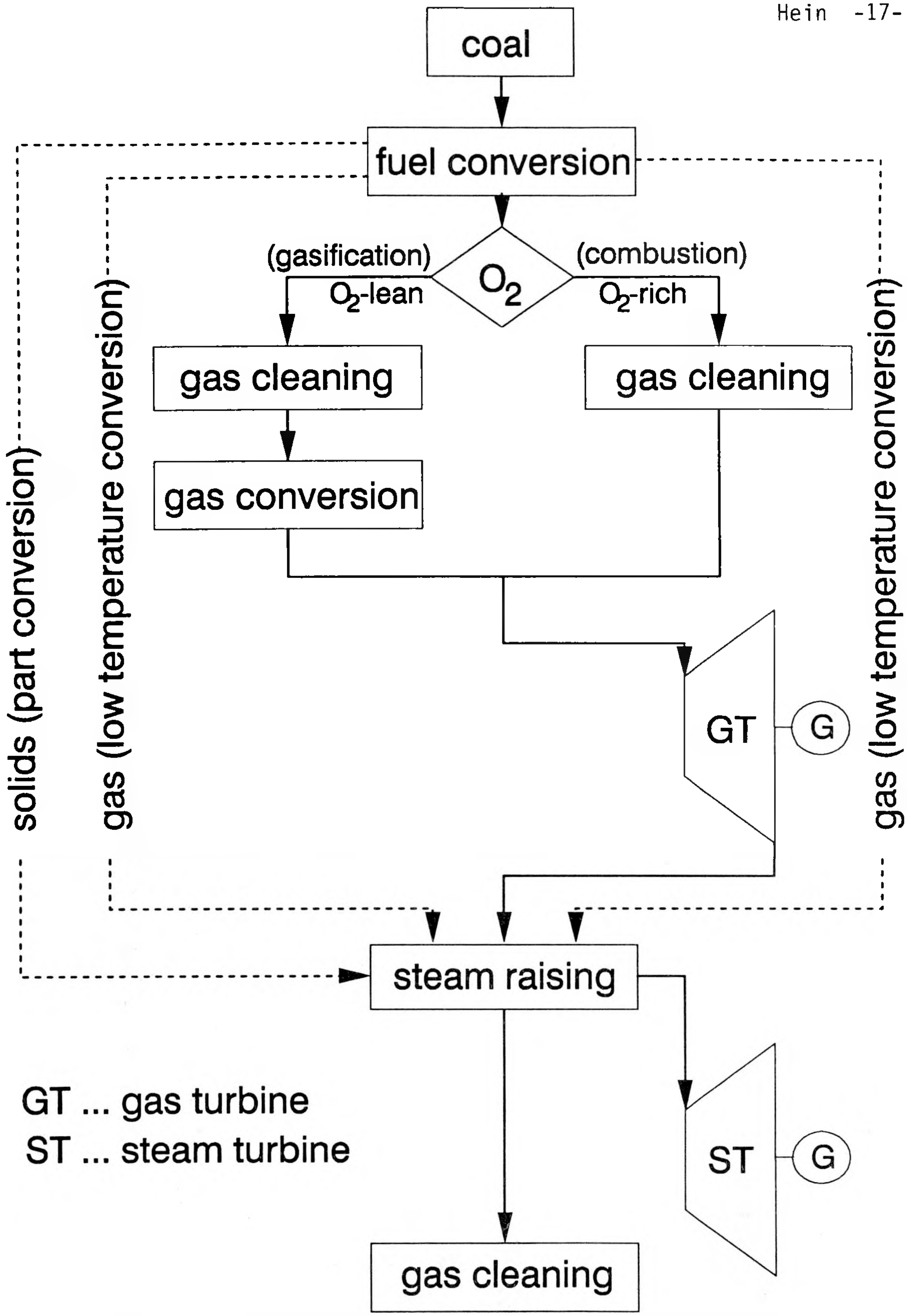
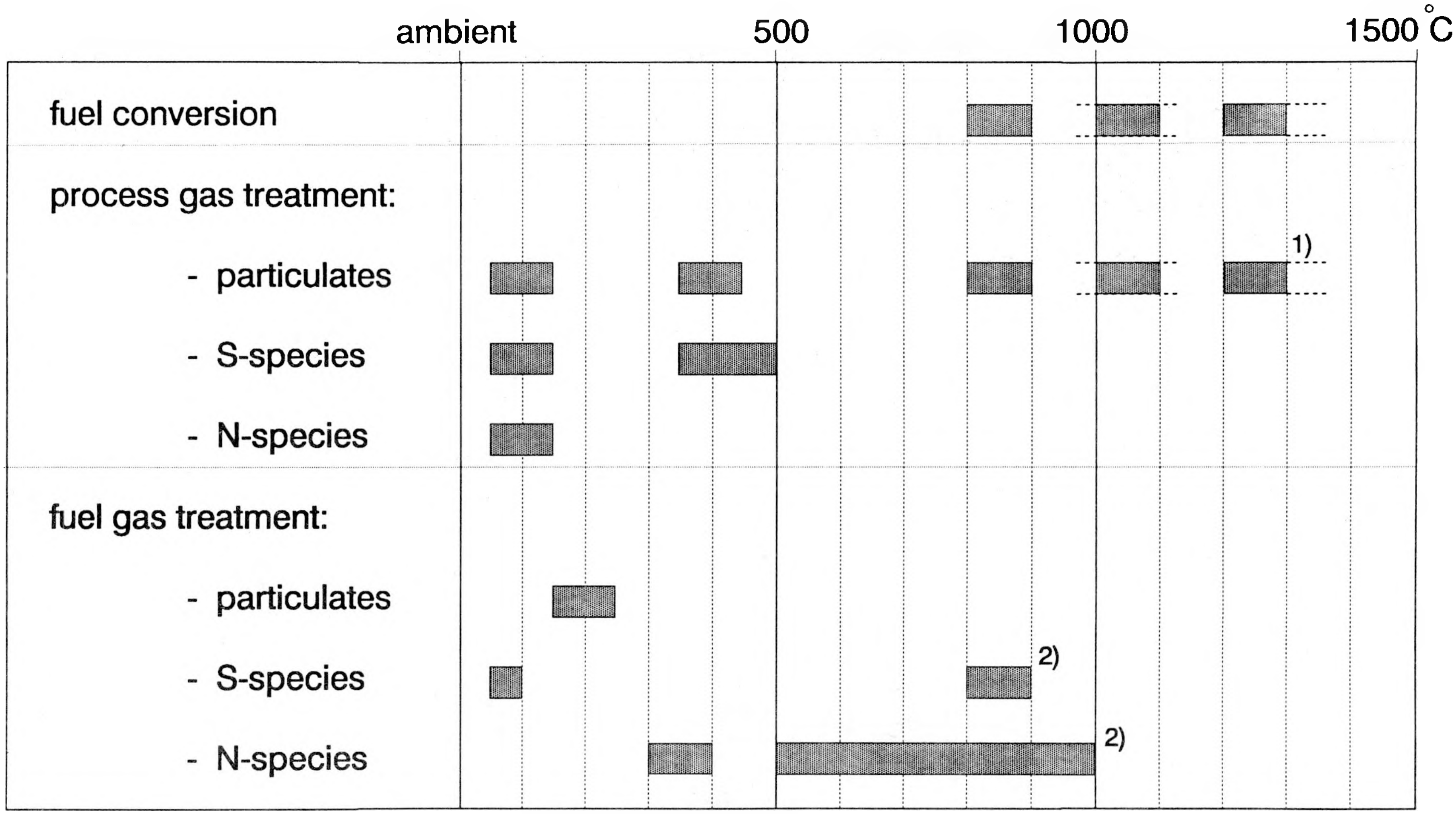


Fig. 7: Gas/steam combined cycles for electricity generation

Conversion principles:	gasification	combustion	
Process mode:	fixed bed	fluidized bed	entrained flow
Reaction partner :	oxygen	air	
First step of fuel utilisation :	full conversion	part conversion	

Fig. 8: Coal conversion processes;
various alternatives for process steps



1) liquid phase removal
2) reduction during conversion process in case of combustion available

Fig. 9:Coal conversion processes;
temperature ranges of major process steps

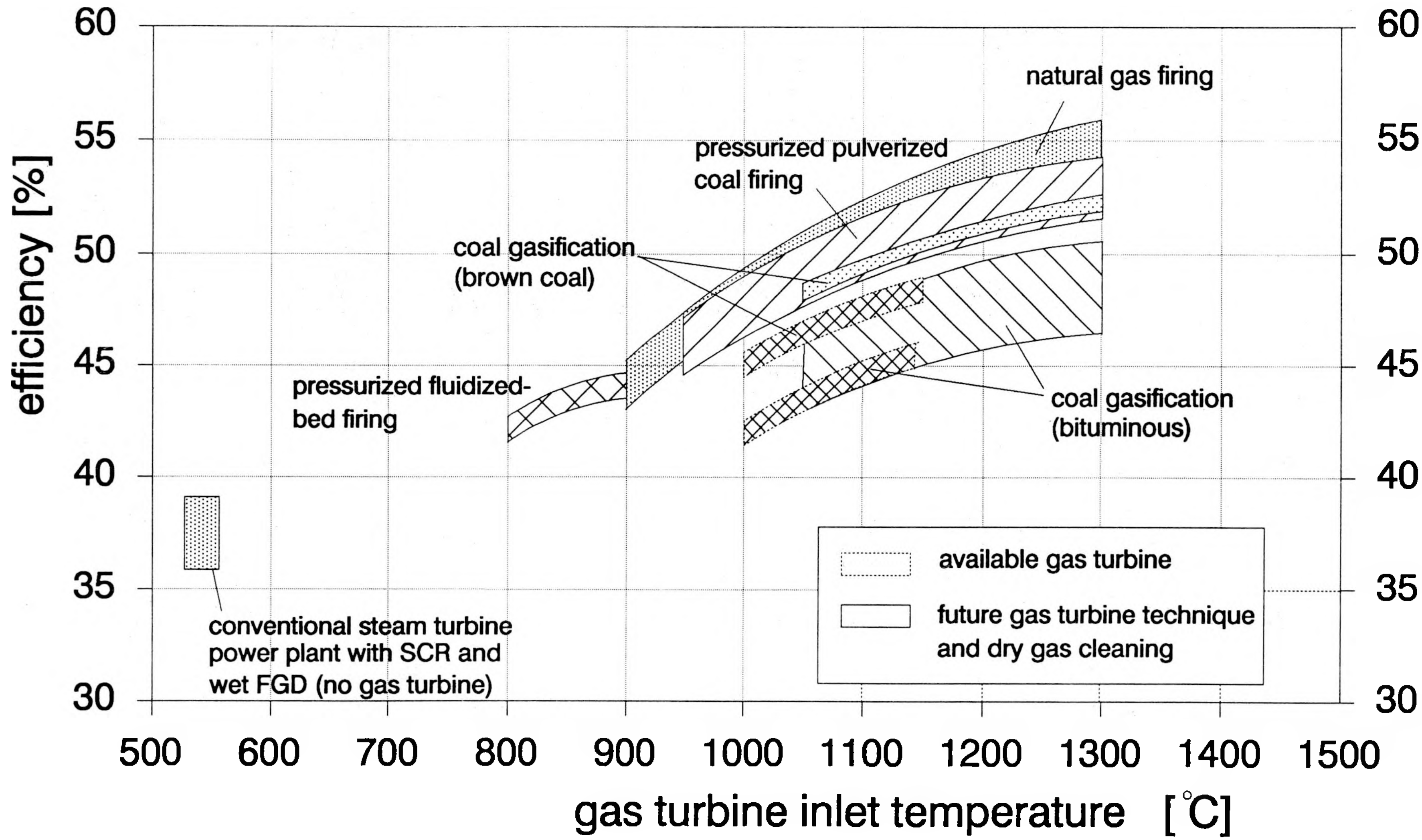


Fig. 10: Combined cycle plants; Comparison of efficiencies

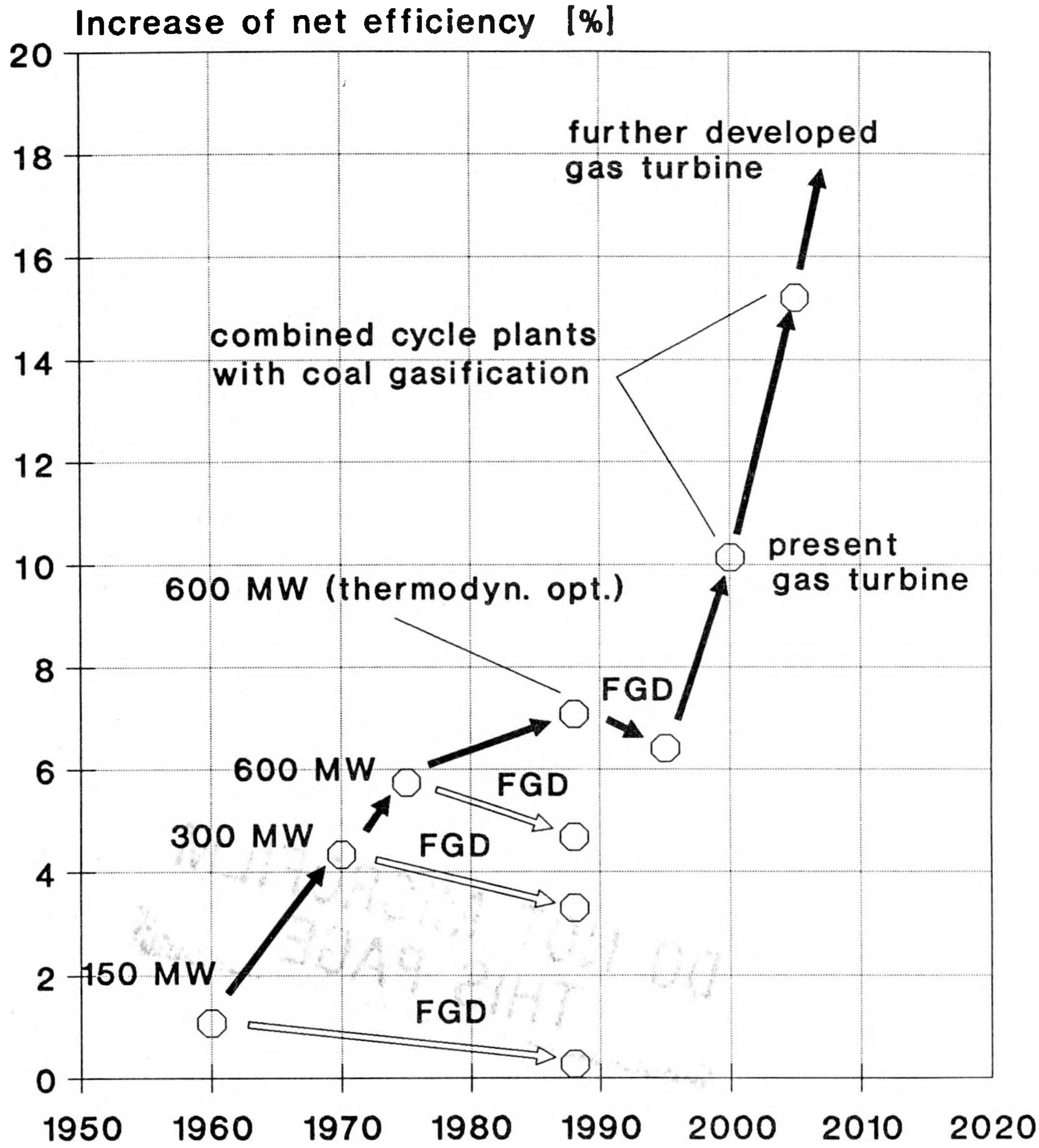


Fig. 11: Development of efficieny for brown coal based electricity generation

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"THE OUTLOOK FOR COAL IN KOREA"

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THE OUTLOOK FOR COAL IN KOREA

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ABSTRACT

In Korea, not only a significant increase in total energy consumption, but also structural changes in energy consumption pattern has been changed during last 3 decades. Since Korea does not have sufficient energy resources, more than 80% of energy need to be imported. Due to the government policy to reduce the dependency of oil, coal will be a major energy source second to oil. It is projected that the demand for coking coal and for power generation will be increased at a rate of 6.7% per year up to 2010. 71.6 million tons of bituminous coal need to be imported in 2010.

INTRODUCTION

Since the launching of the First Five-Year Economic Development Plan in 1962, the most important implication for the energy sector is not only a significant increase in total energy consumption, but also structural changes in energy consumption pattern.

Table 1 shows major energy economic indicators in Korea. Total consumption of the primary energy in Korea has increased more than seven times over the last three decades, from 9.7 million tons of oil equivalent (TOE) in 1961 to 81.2 million TOE in 1989, at an increase rate of 7.8% per year. Energy consumption in Korea increased at a growth rate of 8.4% per year in the 1970s while it fall slightly to 5.0% per year in the first half of the 1980s as a result of the second oil shock. Since 1986, however, the growth rate has soared up to 10.4% per year, as the Korean economy has grown at a rate of about 12% per year and energy price has fallen.

Per capita energy consumption has also increased from 0.38 TOE in 1961 to 1.92 TOE in 1989. Meanwhile, the energy/GDP ratio (TOE/million Won at 1980 constant price) has declined from 1.27 in 1961 to 0.99 in 1988, which implies the improvement of efficiency in energy use, due possibly to the energy conservation efforts and to the reorganization of industrial structure.

Korea's domestic energy resources are limited to anthracite, firewood and hydropower. However, these domestic energy sources appeared to be not sufficient enough for fuelling the continuous industrialization of the economy, particularly with emphasis on the expansion of the energy intensive industries, so that all incremental needs of other energy sources, such as oil, bituminous coal and natural gas, have to be totally imported from overseas. Consequently, dependency ratio of Korea's energy consumption on overseas supply is very high. The ratio has steadily increased from 8.6% in 1961 to 83.1% in 1988, with nuclear energy included, and seems likely to continue to increase regardless of the future energy environment.

Structural Changes in Energy Consumption Pattern by Source

As shown in Table 2, the structural change in energy consumption pattern by energy source has significantly occurred in Korea over the last three decades. Until 1961, more than 90% of the nation's total energy consumption was met by the indigenous resources, such as anthracite, firewood and hydropower. In 1962, firewood and anthracite accounted for 51.7% and 35.7% of the total primary energy demand, respectively. However, the share of firewood has significantly declined to 1.3% in 1989, and the share of anthracite has also declined to 16.6% in 1989.

On the other hand, oil consumption continued to increase and became the principal energy source from 1968. Along with the rapid industrialization of economy, oil consumption significantly increased over the 1960s and 1970s, at an average growth rate of 27.9% per year in the 1960s and 11.2% in the 1970. The share of oil demand in total energy demand increased from 9.8% in 1962 and reached its peak

TABLE 1

MAJOR ENERGY ECONOMIC INDICATORS IN KOREA

	1961	1966	1971	1976	1981	1986	1987	1988	1989
Primary Energy Consumption (million TOE)	9.7	13.1	20.9	30.2	45.7	61.1	67.4	75.4	81.2
Per Capita Energy Consumption(TOE)	0.38	0.44	0.63	0.84	1.18	1.47	1.60	1.80	1.92
Energy/GDP Ratio (TOE/Million Won)	1.27	1.16	1.13	1.02	1.12	1.00	0.99	0.99	
Elasticity (Energy/GDP)	-	0.77	0.93	0.78	1.31	0.70	0.85	0.98	
Overseas Dependence Rate (incld.nuclear)	8.6	17.1	50.8	62.1	75.0	78.1	79.9	83.1	

TABLE 2

COMPOSITION OF PRIMARY ENERGY DEMAND BY SOURCE IN KOREA

(Unit ; %)

	1962	1970	1980	1985	1988	1989	Change rate			
							71-80	81-85	86-88	89
Coal	36.8	29.6	30.1	38.8	33.4	30.0	8.5	10.5	4.5	
Anthracite	35.7	29.4	22.5	21.5	16.5	13.4	5.5	4.0	0.3	-12.0
Bituminous	1.2	0.3	7.6	17.3	16.9	16.6	51.3	23.9	9.5	6.2
Petroleum	9.8	47.2	61.1	48.5	47.0	49.5	11.2	0.2	9.2	13.9
LNG	-	-	-	-	3.6	3.2	-	-	-	-3.2
Hydro	1.7	1.6	1.1	1.6	1.2	1.4	5.0	13.0	-0.8	27.8
Nuclear	-	-	2.0	7.5	13.3	14.6	-	36.9	33.8	18.1
Firewood	51.7	21.6	5.7	3.6	1.5	1.3	-5.1	-4.2	-16.9	-11.3
(Million TOE)	(10.3)	(19.7)	(43.9)	(56.0)	(75.4)	(81.2)	8.4	5.0	10.4	7.8

level of 63.3% in 1978. But after the second oil shock, new energy sources such as bituminous coal, nuclear energy, and LNG have been introduced into the energy matrix and contributed greatly to the reduction of oil dependence to 49.5% in 1989. Nuclear energy, of which consumption greatly increased after 1983, accounted for 14.6% of the total energy demand in 1989, and bituminous coal and LNG accounted for 16.6% and 3.2% respectively.

Coal Supply and Demand

As a result of sharply increased oil prices in the 1970's, the role of coal in the Korean economy has increased. However, Korea's domestic coal reserves are limited and of poor quality, and therefore additional coal requirements have to be filled with imports.

Anthracite, which is the only indigenous fossil fuel in Korea, has been the principal energy source in the residential and commercial sector in the form of briquette. The other sectors, such as power generation, industrial, and public, consume only about 10% of total anthracite coal as shown in Table 3. Anthracite consumption in the residential and commercial sector has increased as a rate of 4.6% per year over the period of 1976 to 1987. Such a slow but steady increase in anthracite consumption is due mainly to the fact that the anthracite, as the unique domestic produced fossil fuel in Korea, had to be inevitably responsible for satisfying the residential and commercial energy demand. Moreover, two oil crises in the 1970's highlighted the danger derived from the Korea's high overseas over-dependence in

TABLE 3

SUPPLY AND DEMAND OF ANTHRACITE COAL

(Unit; 1,000M/T)

Year	Supply			Demand				
	Total	Production	Import	Total	Industry	Res. & Comm.	Electric Uitilites	Public & Others
1978	18,699	18,054	645	17,953	684	16,526	518	225
1979	20,225	18,208	2,017	18,820	640	16,942	1,064	174
1980	21,315	18,624	2,691	20,830	708	18,037	1,865	220
1981	24,128	18,865	4,263	21,413	787	18,543	1,878	206
1982	22,438	20,116	2,322	20,865	492	17,887	2,326	160
1983	20,674	19,861	813	21,670	518	18,960	2,074	118
1984	22,174	21,370	804	24,154	436	21,316	2,251	151
1985	24,876	22,543	2,333	25,339	353	23,100	2,778	108
1986	28,167	24,253	3,914	26,928	277	24,250	2,285	116
1987	27,056	24,274	2,782	26,327	206	23,587	2,444	90
1988	25,950	24,294	1,656	25,641	209	22,926	2,407	99
1989	22,538	20,785	1,753					

energy consumption, and thus the use of domestic anthracite was highly emphasized. On the other hand, a considerable substitution of anthracite for firewood has occurred, due mainly to a change in the consumer's preference for convenient heating fuel as well as to the government's policy to protect the forest. The annual growth rate of anthracite consumption during the period of oil crisis jumped up to 23.8% in 1973 alone and also rose sharply to 6.5% in 1980, which is higher figure than that of 4.5% in the period of 1974-1979. However, recently, anthracite consumption in residential and commercial sector has begun to significantly decline since 1987 owing to its weakened price competitiveness in the heating fuel market. The rapid increase in consumption of other energy sources, such as oil, bituminous coal and LNG, has relatively lowered the share of anthracite coal in total energy consumption from 40% in the 1960s to 13.4% in 1989.

Demand for bituminous coal which is totally imported from overseas has significantly grown in Korea, as it has been used as oil substitute in industry and power generation. Therefore, the consumption of bituminous coal has significantly increased from 0.8 million ton in 1975 to 20.5 million tons in 1989 at an average growth rate of 27.9% per year as shown in Table 4, and its share in total energy consumption has increased from 1.9% in 1975 to 16.6% in 1989 as shown in Table 2,

TABLE 4

SUPPLY AND DEMAND OF BITUMINOUS COAL

(Unit; 1,000M/T)

Year	Import			Demand			
	Total	Coking Coal	Steam Coal	Total	Steel	Utilities	Cement & Others
1973	612	-	612	649	424	-	225
1974	773	-	773	839	839	-	-
1975	672	-	672	786	786	-	-
1976	1,494	1,394	100	1,586	1,506	-	80
1977	2,007	1,984	23	2,100	1,795	-	305
1978	2,067	1,995	72	2,169	2,009	-	160
1979	4,217	4,190	27	4,349	3,676	-	673
1980	4,911	4,429	482	5,032	3,987	-	1,045
1981	7,245	5,825	1,421	7,434	5,941	-	1,493
1982	9,039	6,439	2,600	8,504	6,033	-	2,470
1983	10,151	6,394	3,757	9,633	6,199	546	2,889
1984	12,194	6,321	5,873	12,745	6,888	3,342	2,514
1985	17,131	8,125	9,006	14,697	6,959	5,140	2,598
1986	16,437	6,575	9,862	15,290	6,995	5,363	2,932
1987	17,834	9,247	8,587	16,218	8,348	4,442	3,428
1988	21,913	11,237	10,676	19,274	9,722	5,579	3,973
1989	23,500	11,651	11,849	20,500	11,200	5,200	4,100

gradually substituting oil. In 1989, 55% of bituminous coal was used in steel industry, 25% of them was used in power generation and the remainder 20% was used in other industries such as cement industry.

Share of bituminous coal in total energy consumption in the industrial sector has increased 5.8% in 1975 to 32.0% in 1988. In particular, since the operation of the Pohang Steel Company (POSCO) in 1973, consumption of coking coal has significantly increased 0.4 million ton in 1973 to 11.2 million tons in 1989. With the completion of the Kwangyang Steel Works of POSCO in 1987, use of coking coal noticeably increased by 19.3% in 1987 and 16.5% in 1988.

TABLE 5

COMPOSITION OF FUEL CONSUMPTION FOR POWER GENERATION

(Unit;%)

	1962	1970	1980	1985	1988	1989
Anthracite Coal	47.4	11.2	7.6	5.6	4.4	4.0
Bituminous Coal	5.3	-	-	24.4	18.2	15.0
Oil	19.7	76.6	77.3	33.1	13.0	14.8
LNG	-	-	-	-	11.0	9.5
Nuclear	-	-	9.6	30.3	48.4	51.7
Hydro	27.5	12.2	5.5	6.6	4.2	5.0
(1,000 TOE)	(-)	(2,500)	(2,035)	(13,828)	(20,701)	(22,915)

On the other hand, consumption of steam coal in the industrial sector had been limited to the cement industry. The initial growth in steam coal consumption was in 1979/80, due to the conversion of the cement industry from oil to coal-firing systems. Steam coal consumption in other industries has just started in Korea. A small number of boilers has recently converted to coal-firing with the assistance of government loans. During the period of 1979-1988, consumption of steam coal in the industrial sector has increased about six times, from 6.7 million tons in 1979 to 4.0 million tons in 1988. Average annual increase rate over the period is 21.8%.

Until 1962, the major fuels for power generation in Korea were anthracite and hydropower, accounting for 74.9% of total fuel consumption for power generation as shown in Table 8. Oil consumption steadily increased and its share reached 88.3% in 1977, while shares of anthracite and hydropower decreased to 6.2% and 5.2%, respectively. After the second oil shock, the oil consumption for power generation

TABLE 6

OUTLOOK FOR GENERAL INDICES OF ENERGY PROSPECTS

	1990	1995	2000	2010	Change rate(%)
Total Energy Demand(1.000 TOE)	86,853	113,382	138,764	180,119	4.4
Final Energy Demand(1,000 TOE)	70,135	90,857	109,382	135,207	4.0
Energy Input Ratio to GNP	1.007	0.933	0.828	0.612	-2.2
Energy Consumption per capita(TOE)	2.03	2.53	2.97	3.53	3.5
Electricity Consumption per capita(KWH)	2,057	2,694	3,344	4,798	5.1

TABLE 7

PROJECTION OF PRIMARY ENERGY CONSUMPTION IN KOREA

(Unit; 1,000TOE)

	1990	1995	2000	2010	Change rate(%)
Oil	43,267 (49.8)	57,413 (50.4)	66,471 (47.9)	77,669 (43.1)	4.3
Bituminous Coal	14,484 (16.7)	23,799 (21.0)	31,548 (22.7)	47,243 (26.2)	6.7
Anthracite	10,795 (12.4)	9,300 (8.2)	7,903 (5.7)	4,579 (2.5)	-4.3
New & Renewable	1,643 (1.9)	2,169 (1.9)	2,794 (2.0)	5,551 (3.1)	6.4
LNG	2,838 (3.3)	5,517 (4.9)	8,234 (5.9)	13,543 (7.5)	8.4
Nuclear	12,993 (15.0)	14,533 (12.8)	20,892 (15.1)	30,612 (17.0)	5.1
Hydro	833 (1.0)	922 (0.8)	922 (0.7)	922 (0.5)	-1.6
Total	86,823	113,382	138,764	180,119	4.4

( ) : Share in %

significantly declined and its share fell to 14.8% in 1989. With the completion of coal-fired power plant in 1983, consumption of steam coal for power generation began to grow as shown in Table 4, and its share in total fuel consumption for power generation reached 15.0% in 1989.

OUTLOOK FOR ENERGY DEMAND IN KOREA

Major future energy indices are shown in Table 6. Total energy consumption in Korea is excepted to increase by 4.4% per year during the period of 1990 to 2010 to 138.8 million TOE by the year 2000 and to 180.1 million TOE by 2010. The energy intensity of the Korean economy (expressed in TOE/Million won) is projected to decline by about 2.2% per year from 1.017 in 1987 to 0.612 in 2010. On the other hand, per capita energy consumption is expected to increase 1.60 TOE in 1987 to 3.53 TOE in 2010. Electricity consumption per capita will also increase from 1,525 KWH in 1987 to 4,798 KWH in 2010.

Projection of primary energy consumption is shown in Table 7. Oil consumption is projected to grow at only 4.3% during the period of projection. Consequently, the

TABLE 8

COAL DEMAND PROSPECT

(Unit ; 1,000 M/T)

	1990	1995	2000	2010	Change rate(%)
Anthracite	24,266	20,971	17,866	10,398	-4.0
Resi. & Comm.	21,540	18,132	15,083	8,386	-4.4
Others	2,726	2,839	2,783	2,012	-1.3
Bituminous Coal	21,946	36,105	47,800	71,580	6.7
Industry	15,534	21,688	27,757	33,068	4.6
Power Generation	6,412	14,417	20,043	38,518	9.8

share of oil in total primary energy consumption is projected to slightly decline from 49.5% in 1989 to 43.1% in 2010. While the share of bituminous coal in total energy consumption is projected to increase from 16.6% in 1989 to 26.2% in 2010, of which the growth rate will be 6.7% per year. So bituminous coal will be a major energy source second to oil. However, the share of anthracite is expected to significantly decline from 13.4% in 1987 to 2.5% in 2010.

Demand for anthracite in Korea is predicted to decrease at a rate of 4.0% per year during the period of 1988 to 2010 as shown in Table 8. This gradual reduction of demand for anthracite will be due to the increasing production cost and unfavorable marketability as well as to consumer's taste change to the high quality fuel, such as electricity and gas, following the improvement of living standard and also due to the increasing concerns on environmental problem. Anthracite currently accounts for 61.4% in total residential and commercial energy consumption. However, the share is expected to decline to 12.9% in 2010.

The demand for bituminous coal will show more or less high growth rate of 6.8% per year during the period of 1988-2000. so its share of total energy demand in the industry will be 34.7%. Thereafter, however, the demand for bituminous coal is expected to slightly increase at a rate of 1.8% per year. The demand for bituminous coal in the industry sector is expected to increase by 4.6% per year to 21.8 million TOE (33.1 million ton) in 2010 due to increases in use of the industrial boilers and in consumption in the cement industry.

Demand for coking coal in the steel industry is expected to increase at a rate of 6.4% per year by 2000 in proportion to the increase in production of pig iron. The production of pig iron, which is the highest energy intensive product within the industry, will be greatly increased by the early 1990's, due to the expansion of production capacity, and thereafter the growth in the production will be slackened along with the process of industrial maturation. However, as the production growth of the steel industry will slow down during the period of 2000 to 2010, the demand for coking coal is expected to show a slight increase rate of 1.6% per year.

Electricity demand in the residential and commercial sector is expected to show a high increase by 7.8% per year, due to the expansive use of electrical appliances in the residential sector. On the other hand, in the industrial sector, the increase rate will remain at 5.1% due to the development of technology intensive industries. Table 9 shows the power plant construction plan based on the current long-term power development plan. The composition of fuel for power generation in 2001 will be nuclear 36.1%, bituminous coal 29.1%, oil 11.3%, LNG 10.7%, hydro 10.5%, and anthracite 2.3%. Nuclear and coal power plants will supply most of the base load, while gas and oil power plants will be operated for meeting peak load demand. The completion of 14 additional bituminous power plant will cause more increase in bituminous coal demand greatly. So that total demand for bituminous coal is expected to increase to 71.6 million tons in 2010 at an average increase rate of 6.7% per year as shown in Table 8.

COAL POLICY

During the period of the second oil shock, the Korean economy appeared to be highly vulnerable to overseas energy situation, and bitterly suffered from the recession, high level of inflation, increased deficit in the balance of trade, and so on. Consequently, energy security has become one of the most challenging policy objectives for Korea. The second oil shock in late 1970, although it seriously affected the Korean economy, provided the motive for Korean energy policy to enforce all-out energy conservation measures and oil substitution policy through diversification of energy sources.

TABLE 9

POWER PLANT CONSTRUCTION PLAN

1,000 KW x Unit

	'90-'92	'93-'95	'96-'98	'99-2001
Anthracite		200 x 2		
Bituminous Coal		500 x 7	500 x 4	500 x 1 900 x 2
LNG	400 x 2		400 x 2	
Nuclear		1,000 x 1	1,000 x 2 700 x 1	1,000 x 1
Hydro	190 x 2	300 x 2	250 x 2	

In order to complement the structural weakness and to cope with the possible disruption caused by entire reliance on import, Korean government is now strongly stressing the direct overseas investment development particularly in the field of energy resources and encouraging private sector through various financial and tax incentives. The ambitious goal is set-up to self-supply 30% domestic coal demand by the year 2001.

As mining level is deepened and labor cost rises, domestic anthracite price always has upward pressure. But anthracite demand continues to decrease because consumers preference to the clean fuel. These situations lead the government to change coal policy from the promotion of production to its rationalization. The Korean government decided in 1988 to help close small unproductive mines under the condition that the agreement for the closure be concluded between labor and management. On the other hand, measures are undertaken to stabilize domestic coal production in the long run through improving competitive power of coal mines and government support system as well as ensuring the demand of anthracite coal produced.

In contrast, bituminous coal usage will be promoted in power plants and industry. The demand for imported bituminous coal is expected to increase to over 50 million tons by the year 2001, becoming a major energy source second only to oil.

However, the use of coal can not be promoted without solving the environmental issue. From the middle of 80's, public awareness for the environment has been increased as the improvement of living standard. Government will balance the economic development and the environment protection.

For the effective dissemination of new & renewable technology and to diversify the energy sources, "New & Renewable Sources of Energy (NRSE) Development Promotion Law" was enacted in 1987 and a long-term R&D plan was formulated. For New & Renewable Energy to supply 3% of total energy by 2001, policy efforts will be focused on building up a technical foundation for NRSE utilization by directing systematic R&D efforts among government, academia and industries concerned. About $70 million will be invested in R&D from 1989 to 1991.

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"COAL OPPORTUNITIES IN EASTERN EUROPE"

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COAL OPPORTUNITIES IN EASTERN EUROPE
Domestic Energy Development Instead of Imported Energy

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ABSTRACT

The question of using energy more efficiently is basically one of technology, economics, and social change. That is to say, we can have access to new technological developments, understand how to benefit by the use of alternative sources of energy, and understand the processes involved in using energy more efficiently; but without recognizing the complexity of those changes, efficient energy use may never become a permanent part of our lifestyle. In this paper an up-to-date review of the status and prospects of coal, with the emphasis on Coal Water Mixtures (CWMs), in Eastern Europe is given, although it is much easier to comment on present <u>status</u> than on the <u>prospects</u>.

INTRODUCTION

Energy represents politics in its highest form. More than any other commodity, energy is tied to nationalism and executive (bureaucratic) power, and political and other confrontations over its control are very common. It has an influence on our way of life, it gives us light, it runs our factories, and gives us the freedom to move. On the other hand, we are expending our world resources, and we are polluting our environment. The basic challenge lies in reliable and efficient energy supply, without pollutants, and at moderate expense; to that goal, we have to devote our work not only in Eastern Europe, but all around the world as well.

Events since 1973 have changed the position of oil in the overall energy equation. Even today nearly 20 years later, the coefficients of safe energy assessment in this equation have not been unambiguously defined in any of the East European countries. To talk about uncertainty is not an escape mechanism, but rather a way of coping with reality. The identification and understanding of key problem unknowns are of crucial importance when taking decisive and practical steps.

In past decades the incapacity to control energy has cost most of the east European countries a significant part of their potential growth -- in some cases, more than half.

Problems in the area of energy supply are reflected in uncertainties of energy consumption growth, primary electricity supply, and motor vehicle fuels. All these facts point to a lack of improvement in efficient energy consumption. The growing dependence on imported fuel by many countries escalates this tendency. This has contributed to high unemployment and/or serious constraints on credibility and finance in the international domain.

At the moment, the energy policy of East European countries are not clear. Indeed, an understanding of the basis of future policy barely exists. Consequently, there is a need for open debate to shape the energy structure and define the interaction between energy policy, economic growth and environmental protection. But problems can not be solved by simply bringing situations out in the open. Many individual decisions must be made in the chain from energy producer, to consumer to insure that the required energy is available when needed. Delays at any point affect the entire chain. This points up the need for prompt and related action by consumers, producers, governments, and other public agencies. Today, the energy base in Eastern Europe is much firmer than in the period before the first oil embargo in 1973; given similar conditions, this situation could exist for the next two decades. This stable period is a chance for Eastern Europe to improve its energy producers position with the knowledge that situations can change quickly.

In addition, it is apparent that the world is acknowledging that unless all people end wasteful practices and discover new sources of energy, a global shortage of energy will eventually occur.

This presentation of the energy situation is not generally characteristic of all the countries in Eastern Europe. Each is on a different level of development, and some of them are exporting energy and/or technology. It is clear that the benefit of lower prices, which positively affect the financial balance, belongs to nations that import energy.

The influence oil has had on international policy is considerably weakened, to the point where on today's market, the threat that oil might be restricted affects the exporter more than the importer. The fact is, however, that only countries exporting technology show an intense interest in adjustment, with energy and environmental equilibrium considered as strategy options. The developing countries are confronted with an historical chance to recognize and accept wise energy policies as a universal behavior model, and avoid many of the complex problems which are today characteristic of the industrialized world.

The people of Eastern Europe, therefore, must realize that we are becoming more and more "energy dependent" and must act now to make the most efficient use of energy, as we shift our emphasis to sources such as coal, in forms that are economic and practical.

The Present Status

The current situation in Yugoslav coal mines, as an example, is marked by an everyday struggle to survive. Based on the expectations from the 1970-ies, it was predicted that coal consumption would increase. This did not happen, mainly due to adverse economic conditions. Without the assistance of the free market economy and with restrictions that followed as a result of unpaid foreign debts, all investments have been frozen for the last four years. It follows that conditions in the mines are exceedingly difficult. Of primary interest should be the reconstruction and modernization necessary to increase productivity and improve harsh working conditions to a tolerable level. These, among other factors, raise the question of whether there is any sense in performing such a difficult and unappreciated task.

Organizationally, status of advanced coal technologies in Eastern Europe is very much the same as in North America and in other parts of the industrialized world. The reason for this is, of course, the intense crossfertilization that has taken place between East and West in the past few years. The companies and organizations in western countries working in the front line of the development, demonstration, and commercialization have had a tendency to spread their activities not only to Eastern Europe, but also to other parts of the world. The result of all this is that access to technology is easily within reach of interested parties everywhere.

Another factor which underlines the global similarity is the fact that a really convincing, large-scale commercial breakthrough has not yet occurred anywhere, although several appear to be in the works. It seems that the probability of a breakthrough in the very near future is rather high, almost equally in West and East. In most of the Eastern countries, particularly in the Soviet Union and Yugoslavia, it is assumed that most of the elements of the Coal Water Mixture technology have been convincingly demonstrated, including its degree of economical attractiveness under most conditions. Coal oil mixtures are clearly a thing of the past, primarily because they cannot compete economically with Coal Water Mixtures. Mixtures of coal with other liquids are still at the early devleopment stage. For certain uses though, they may be quite practical.

In Yugoslavia, two attempts at using advanced coal technology have been made. First, a gasification plant in Kosovo has been operating for several years, although without any significant conclusions. It is not clear whether the unstable political situation in this region, technical and economical reasons, or simply bad judgment, contributed to this.

A good example of a broadening of established technology is the dredge mining trial designed for the "Kovin" open pit mine. The current activity, lignite dredging from the bed of the Danube within the "Kovin" deposit, has already attracted great interest. The equipment required for the dredging programme is specified, and the testing is scheduled for the beginning of the next year. This trial will allow complete data to be gathered, which will enable the full scale mine to be designed.

As presented to the SynOps conference two years ago, potentially, the most attractive way to utilize these reserves for power generation would be to combine the hydraulic mining technique with hydrothermal processing commonly known as hot water drying, solid concentration, and coal/water fuel combustion.

The Russion CWM programs, both basic and applied, have been in operation for more than 20 years and have involved combuston tests of several different types of coal fueled boilers and furnaces. During the early seventies, the Russians acquired a wide range of combustion experience with CWMs. Particular emphasis was put on the utilization of waste materials from coal beneficiation plants and coke plants. For example, the energy recovered from burning fine coal slurry can be used to run the driers in conventional coal preparation plants.

The main driving force behind the Russian effort has been the lack of accessibility of the vast Russian coal reserves to major population centers. The USSR is believed to possess more than half of the world's total reserves of coal. The high cost of exploiting these reserves and transporting them to distant energy markets has rendered coal an uneconomical fuel for industrial utiization. A great deal of this coal is of low quality, located in thin or steep seams in an Arctic environment, and must be transported over vast distances on unreliable rail systems. Millions of tons of coals are lost in transit every year. If the USSR could remove these logistical bottlenecks and increase its domestic utilization of coal, particularly in the area of power generation, it would free Russian oil and gas production to earn desperately needed currency in world fuel export markets.

This need has stimulated a considerable interest in converting coal into a more readily transportable and conventionally usable liquid fuel. Slurry pipelining of coal is presently regarded by most of Eastern countries, as an extremely promising form of transport. However, the construction of commercial-scale long distance slurry pipelines represents a high capital and technology intensive venture.

The USSR is the first country where an integrated system for the production, transportation by pipeline, direct combustion of CWM in a thermal power station without dewatering, before combustion will be implemented. The location of the project is in southwestern Siberia. The slurry production plant will be built near the city of Bolovo, in center of coal fields of the Kuzbass region. The CWM (3 million metric tons/year of dry coal) will be transported through the 20 in. diameter, 256 km long pipeline to a power station at Novosibirsk.

In the area of CWMs combustion, the Russians have made several notable accomplishments. Experimental research and theoretical modeling work on the mechanism of combustion has characterized the burning process as explosive in character. Coal devolatilization and water evaporation take place simultaneously, and the presence of water tends to accelerate the combustion process. An increase in the particle reaction surface and its activation occur during the initiation stage, and steam-carbon reaction becomes significant during the combustion stage.

Wet grinding using a ball mill has been successfully applied by the Russians in preparing CWMs. They have been able to prepare, transport, and burn 50% CWMs without additives. Mixtures consisting of 66% coal and 34% water have been successfully burned by properly blending coarse coal and fine coal. The Russians also determined that the ash from CWMs combustion is much more friable and benign in character than the fly-ash obtained from combustion of the original coal. This leads to the conclusion that the use of CWMs may mitigate ash fouling, erosion, and slagging of heat transfer surfaces for certain coals.

One way to describe the status of the CWM field is to point out the fact that anyone wanting to use the technology, as a fuel customer or as a fuel producer, can pick and choose between a number of commercial companies for either the whole system or for singular elements. In this respect, the technology in Eastern Europe is considered already commercial. For most of the competing companies the field is, unfortunately, not profitable, hampering further development.

Finally, to summarize the status in Eastern Europe as well as in the other regions: commercial breakthroughs are now imminent. When the breakthrough occurs, many customers now sitting on the fence wanting to avoid the high cost of pioneering, will follow. We believe the CWM technology has clearly passed its "credibility crisis."

The Prospects

Although the situation in the East European countries is more or less the same, prospects seem to vary. There are many reasons for this:

1. In some East European countries coal has always played an important role in energy production. In other countries coal has never been used or ceased to be used when cheap oil flooded the world after the second World War. These countries might be referred to as "new coal countries."

2. The new coal countries are today in an interesting situation. In their technical considerations they are not bound by conventional coal utilization, or by investments made or established by coal consumption habits and constraints. They have the possibility of choosing among a number of new and promising coal technologies. They will, of course, see this as an opportunity to do something better and different than what takes place in those countries using coal in the traditional manner. Initially these new coal countries will probably advance the state-of-the-art of coal utilization.

3. The East European countries have different industrial traditions, and this will, to some extent, determine their preferences in choosing their own particular new technologies.

4. Many East European countries differ drastically in how they require their primary energy. This leads to quite different energy transmission and consumption infrastructures, which in turn determines to what extent the demand for coal fuels comes from large or small facilities, which fuels have to co-exist and be switched in particular plant, and to what extent coal using plants and situated in urban areas. The characteristics of the infractructure are quite important for the prospects of Coal Water Mixtures.

5. Dependance on imported oil and gas is a major predicament for some countries in Eastern Europe, but certainly not for all. Those countries that share the predicament of import dependence have different strategies for developing new primary energy sources. Some countries see coal as their logical first choice; others see it as a last resort. The first group has introduced government incentives to stimulate and speed up the introduction of new coal technologies and increase the use of coal. Other countries have increased the taxes on coal to slow down the introduction of coal use that would otherwise inevitably occur.

6. Energy production in Eastern Europe has changed. Oil consumption has been stimulated, gas is becoming much more important energy source, and use of nuclear power and coal generation of electricity has been increased. The influence of these changes, as well as more efficient energy consumption, are still being felt. The energy sector in Eastern Europe is in a transitional phase, but most energy sources today come with advantages and disadvantages. The Nuclear energy is associated with radiation, oil with price volatility, coal and gas with carbon-dioxide and other pollutant emissions.

7. The difference in price between coal and oil is perhaps the single most important factor in the commercialization of CWMs. The differential varies geographically and with time, and seems to be due to regulation of prices for oil and natural gas, sulphur emission standards and fuel import factors. The price differential determines the investment pay-off time for conversion of an oil fired facility. Price differences lead to variations in the pay-off time from less than a year to more than five years. In reality, this means the difference between an investment attractive enough to offset the considerable technical risk, and an investment which is not feasible.

8. To all this has to be added the immense influence of the mass media and their impact on the energy markets. Today most market information is accessible to all interested parties in the world almost immediately. This means that reaction time is far shorter, and that the various energy markets are interconnected and directly influence one another.

The Market

The CWMs market is not one but several markets. A breakthrough in one area will not necessarily have positive consequences in another, and some markets may never be penetrated.

The first large-scale commercial applications will probably be CWMs applications in industrial boilers where energy cost is crucial for the competitiveness of the product, and where emission problems or processing restraints may not be so acute. Cement furnaces and glass furnaces are examples of this category. Another market of early interst will be steam generation in the chemical industry.

The electric power industry obviously represents the most significant market. European studies continue to show nuclear energy as more competitive, with cost difference varying between countries. Coal's advantage may lie in less easily quantified problem areas in the nuclear industry such as the lower output ratings, arising from faulty operation reported in some East European stations; the economic concern about wholesale plant shutdown if serious problems are discovered; uncertainty over fuel costs; reprocessing and disposal of spent fuel; and plant decommissioning. Basic decisions about nuclear power expansion, which currently are stalemated, will be made in the next decade by a number of East European countries and this will clearly affect coal's prospects.

The high requirements in reliability and long-term performance that traditionally apply in this field slows the introduction of CWMs in retrofitted oil-fired boilers. EPRI in the United States has for a number of years been implementing a step-by-step preparatory program. The East European countries have followed the EPRI program closely. A key issue all through the program has been what derating to expect in converted boilers. Today, the consensus is that derating can be kept at acceptable levels -- perhaps less than 20% if clean CWMs are used. Fuel cost will also, of course, be of extreme importance in this application.

Municipal heating is another important market segment. CWMs here offers quite new possibilities compared to conventional coal use because the fuel can be brought to and stored at plants located in urban areas as easily and unnoticeably as fuel oil.

One of the still open promising options to extend the use of coal from "Kovin" is by CWM pipeline network which would supply fuel for seven co-generating power plants in the county of Vojvodina. They would be used to generate electricity and heat for seven towns located in the area 200 km from "Kovin."

In some East European countries all market segments are of equal interest. In most, if not all countries, at least one market segment should be of interest.

Looking at the future market in Eastern Europe, it is obvious that there is no such thing as a CWM suitable for all purposes. Some applications call for particular handling characteristics, other applications for low sulfur and/or low ash characteristics. Other applications again require that the fuel be made from a particular coal. The customer will be willing to pay the premium prices only for those performance characteristics that he requests. This will eventually lead to there being several, probably standardized CWMs in the market, and to large production facilities, handling several coals and having several production lines. Coal will cease to be regarded as a fuel in itself, and will instead be looked upon as a new material to make "coal fuels" from. CWMs will then be just one type of these "coal fuels."

Looking a bit into the future, it seems probable that there will be several companies selling more, or less similar products.

The equipment makers in all probability will be the ones we are familiar with today. It is more difficult to foresee who the CWMs producers will be. Oil companies and operators of coal terminals seem to have the best starting position. The question is whether they have realized it.

There is no doubt that a substantial market will appear in Eastern Europe. Some preliminary assessments show that the market could eventually be equal to more than half the present fuel oil market. Even a fraction of this market is enough to make the CWMs industry a major growth sector in the East European economy.

Conclusions

Coal can provide the principal part of the additional energy needs of the next two decades. In filling this role it will act both as a bridge to the energy systems of the future and as a foundation for the continued part that coal will play in the next century. A recognition of the urgent need for coal, and determined action to make it available in time, will insure that Eastern Europe will obtain the energy it requires for its economic growth and development.

The main obstacle to greater coal consumption are related to the protection of the environment. Whereas in the 70-ies and 80-ies energy security and purely economic issues represented the propelling force which encouraged energy savings, a new imperative shows up today: concern about environment. The present pollution of the atmosphere and consequent changes in the climate, including the rise in global temperature and the so-called greenhouse effect could be a strong motive for increasing efficiency in energy production and a better understanding of how to protect our environment. Environmental sensibility has already gained prominence on the political agendas of most East European countries. Efficiency of production and the market economy of the West have definitely dispelled the illusions of the socialist countries about planned economies. This means, however, that from now on every new technology will be measured by much more severe criteria.

The technological development of the East European countries cannot be reduced to a recapitulation of the history of the highly developed countries with a blind repetition of all their mistakes. With the opening of the East European countries, an immense market has been opened, but even more important is the surge of great human potential with a strong will to assert itself. In these new movements, energy and coal will certainly play a very important part.

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"CANADIAN COAL EXPORT FUTURE"

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ABSTRACT

The world coal market has become an increasingly competitive and challenging place and like other coal producing countries, Canada must adapt to changes in the market-place. In international steam coal markets where major growth is occurring, Canadian producers must meet the challenge of their competitors whose coal deposits are closer to tide-water ports. This paper discusses Canada's coal industry and its export prospects.

INTRODUCTION

Although coal resources are widely distributed around the world, and are substantial in magnitude in many regions, coal quality and resource economics make it necessary to trade coal internationally. Trade occurs even between countries that have their own domestic coal resources. However, unlike the trade for coking coal, international trade in steam coal is a relatively recent development, only taking off after the 1973 oil crisis. Within a span of little more than a decade, international trade in steam coal has tripled and surpassed that of coking coal. World Coal Trade is shown in Table 1, and as can be seen, seaborne steam coal passed that for coking coal in 1988, and continues to be the major growth market. Coking coal markets on the other hand, have flattened out and remain on a plateau of around 145 million tonnes per year.

TABLE 1

WORLD COAL TRADE 1973 - 1988 (Million Tonnes)

Year	TOTAL WORLD COAL TRADE	COKING COAL		STEAM COAL	
		Total	Seaborne	Total	Seaborne
1973	177.1	117.7	87.0	59.4	19.0
-	-	-	-	-	-
1979	232.5	127.8	104.0	104.7	53.0
1980	256.2	138.7	114.0	117.5	74.0
1981	271.3	144.9	122.0	126.4	86.0
1982	269.2	139.6	120.0	129.6	89.0
1983	266.0	135.3	112.0	130.7	87.6
1984	304.7	155.8	131.6	148.9	103.6
1985	335.8	165.0	140.7	170.8	133.1
1986	336.1	161.0	137.3	175.1	138.2
1987	340.9	164.4	141.9	176.5	141.1
1988	345.3	165.9	144.6	179.4	147.0

Note: "Seaborne" trade excludes overland, barge and lake deliveries.
Source: Chase Manhattan Bank

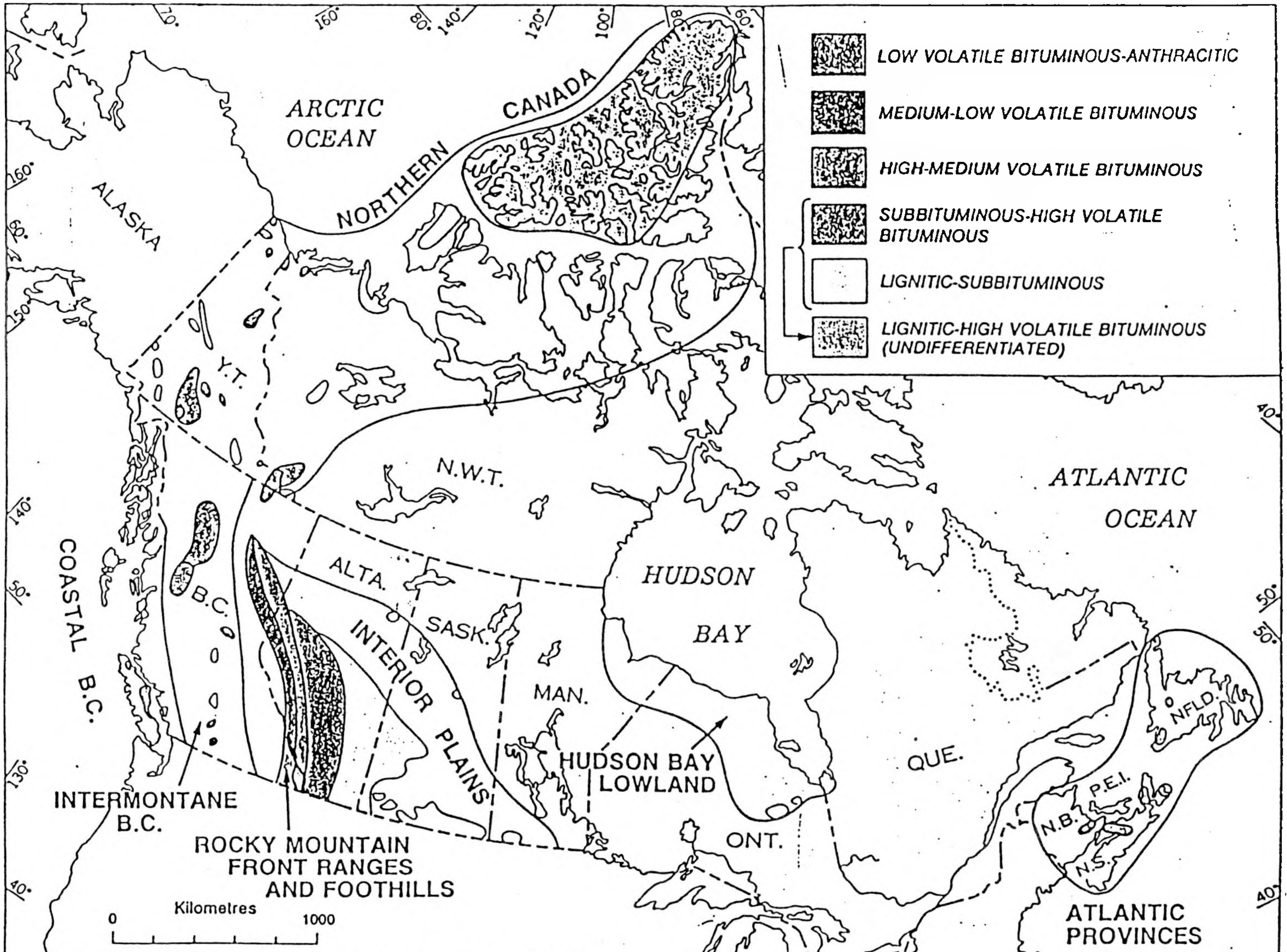
"Coal by wire", is a phrase coined to identify the link between coal and electricity in order to publicize coal's role in electricity markets. As a marketing slogan it is appropriate, because electricity is the world's largest energy market. Electricity demand has trebled over the last twenty years in the Western World, and continues to increase faster than both total energy use and overall economic growth. It is no coincidence therefore to find that today's largest market for coal, is that for power generation. This market represents the best prospects for coal's export future.

CANADA'S RESOURCE BASE

Canada is richly blessed with abundant energy resources and its coal deposits are huge by any measure. We possess world class mining and transportation capabilities and must find ways to utilize these facilities to our economic and social advantage. The economic importance of coal to Canada, is reflected in its significant contribution to supplying primary energy, employment, and revenue from its export to the rapidly expanding markets in the Pacific Rim region. However, at the present time, while Canada is a major supplier of metallurgical coal in the international market, its role in international steam coal trade is very minor.

Principal coal deposits and the principal Canadian coal mines are shown in Figures 1 and 2 respectively. Coal is the most abundant energy resource in Canada and vast reserves lie in the Province of Alberta. That Province's enormous energy resources include coal, bitumen and synthetic crude, natural gas, and conventional oil. Coal is Alberta's most abundant energy resource accounting for over 70% of the developable reserves. However, in terms of percentage of reserves consumed on an annual basis, coal is the most under-utilized energy resource. At current rates of consumption, Alberta's coal reserves will last some 900 years, as opposed to 9 years for conventional oil, 20 years for natural gas, and 200 years for heavy oil and bitumen. This situation is largely responsible for the lack of urgency in Canada, to pursue the adoption of new energy options, and new technologies. Seemingly it is believed by the country's energy planners that Canada has no immediate need for the use of many of today's advanced coal technologies.

As will be seen from Figure 1, sub-bituminous coal comprises the bulk of our reserves, and Figure 2 illustrates how the Canadian coal industry is centred around Western Canada. The bituminous coals found in Alberta and British Columbia are largely metallurgical coals which are mined for export out of the two main West Coast coal ports; Roberts Bank and Prince Rupert. However, some 98% of the coal resource in Alberta is of the sub-bituminous rank. This coal can be recovered using inexpensive surface mining methods; but unfortunately its relatively low heat value limits the distance over which it can be transported and remain an economically viable energy source. These sub-bituminous coals constitute a large energy pool which at present can only be economically utilized within a limited geographical area. In effect, their utilization is confined to mine mouth generation of electricity. While Canada is not among the top ten coal



Source: Coal Resources of Canada, G.G. Smith, Geological Survey of Canada, 1989.

FIGURE 1 - DISTRIBUTION OF COAL IN CANADA.

MINE	OPERATOR	OWNER
Balmer	Westar Mining Ltd	Westar Mining Ltd.
Bienfait	Bienfait Coal Co. Ltd	Luscar Ltd.
Boundary Dam	Manitoba & Saskatchewan Coal (1984) Ltd	Luscar Ltd.
Bullmoose	Bullmoose Operating Corporation	Tech Bullmoose Coal Inc. (51%)
Coal Mountain	Byron Creek Collieries	Esso Resources Canada Limited
Coal Valley	Luscar-Sterco (1977) Ltd.	Luscar Ltd. (75%)
Costello	Prairie Coal Ltd.	Manalta Coal Ltd.
Fording River	Fording Coal Limited	Fording Coal Limited
Greenhills	Westar Mining Ltd	Westar Mining Ltd.
Gregg River	Gregg River Resources Ltd	Manalta Coal Ltd.
Highvale	Manalta Coal Ltd	TransAlta Utilities Corporation
Line Creek	Crows Nest Resources Limited	Crows Nest Resources Limited
Lingan	Cape Breton Development Corporation	Cape Breton Development Corporation

MINE	OPERATOR	OWNER
Luscar	Cardinal River Coals Ltd.	Luscar Ltd. & Consolidation Coal Company of Canada
Montgomery	Manalta Coal Ltd.	Manalta Coal Ltd.
Obed	Obed Mountain Coal Company Limited	Unocal Canada Limited and Norcen Energy Company Limited
Paintearth	Forestburg Collieries (1984) Ltd.	Luscar Ltd.
Phalen	Cape Breton Development Corporation	Cape Breton Development Corporation
Poplar River	Prairie Coal Ltd.	Manalta Coal Ltd.
Prince	Cape Breton Development Corporation	Cape Breton Development Corporation
Quintette	Quintette Coal Ltd.	Denison Mines Limited (50%)
Smoky River	Smoky River Coal Limited	Smoky River Holdings Ltd.
Utility	Prairie Coal Ltd.	Saskatchewan Power Corporation
Vesta	Manalta Coal Ltd.	Alberta Power Limited
Whitewood	Fording Coal Limited	TransAlta Utilities Corporation

FIGURE 2 - PRINCIPAL CANADIAN COAL MINES

producing countries, it does figure in the top ten coal exporting and coal importing countries. Table 2 shows these main coal indicators.

TABLE 2

1987 MAIN COAL INDICATORS (Million Tonnes)

Production		Exports		Imports	
China	925.0	Australia	102.0	Japan	92.5
US	831.6	US	71.1	S. Korea	21.8
USSR	758.4	S. Africa	42.6	Italy	19.7
Poland	193.0	Poland	31.0	France	14.6
W. Germany	191.2	USSR	27.1	Canada	14.3
India	187.2	Canada	26.7	Taiwan	13.4
S. Africa	176.5	China	13.1	Netherlands	12.6
Australia	152.1	Columbia	9.6	Denmark	12.0
UK	104.4	W. Germany	6.4	Belg/Lux	9.8
Yugoslavia	72.3	UK	2.3	UK	9.8

Source: International Coal Report (1988)

The anomaly of Canada having significant levels of both coal exports and imports is due to transportation economics which favour utilization of Eastern U.S. coals in Central Canada; over Western Canadian coals. The long distances involved between the mines in Western Canada and industrial users in Central Canada make transportation costs, prohibitive.

Canada's export coal trade is essentially low/medium volatile bituminous coal, serving metallurgical markets in the Pacific Rim region. Canada's imports on the other hand comprises high volatile bituminous coal for the power station market in Ontario.

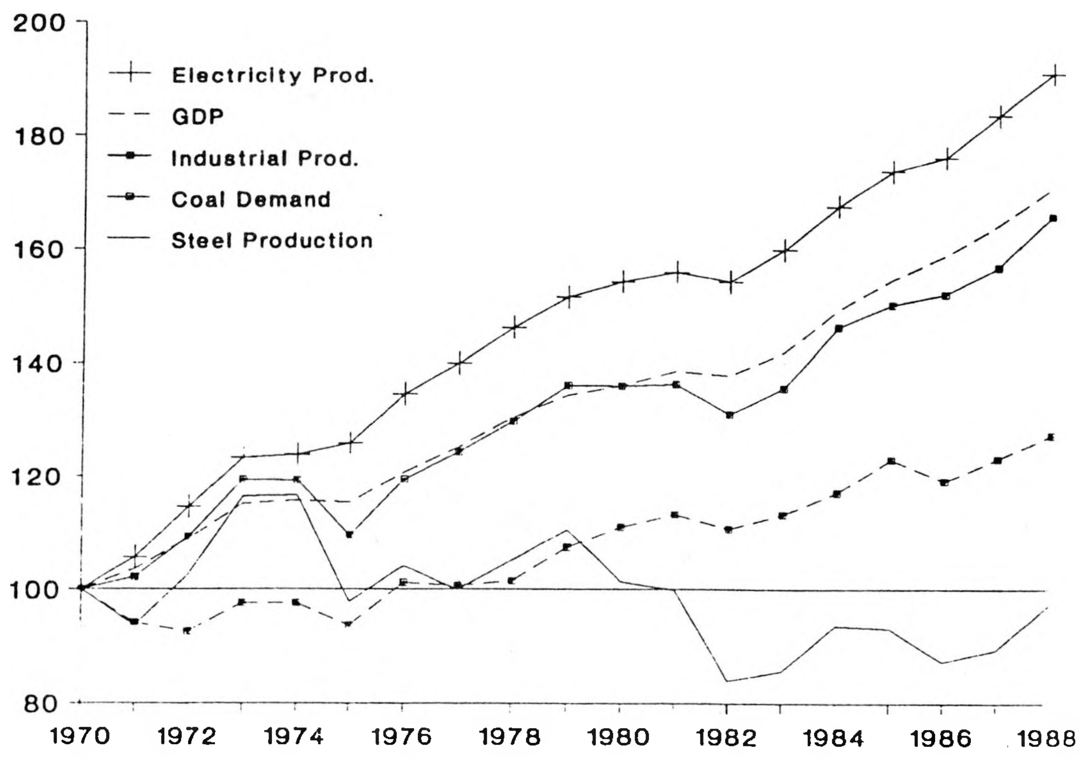
Canada's coal industry, centered primarily in Western Canada, is based on supplying mine mouth power stations in Alberta and Saskatchewan, and exporting large quantities of coking coal into international markets. There is a small struggling trade in international thermal coal which, as presently organized, seems unlikely to grow despite the fact that world demand for thermal coals is growing rapidly. Canadian thermal coals are hampered by high transportation costs, and mediocre quality which makes them marginally competitive with other sources around the world. It is worth remembering that in the late 1960's the Japanese steel industry initiated the Canadian coking coal trade by offering major supply contracts which led to the development of a number of large surface mines, port developments, and most importantly the introduction of large efficient unit trains to reduce transportation costs. In a similar way the future of Canada's thermal coal exports will need the same radical approach to improving competitiveness in a world filled with many good quality coal reserves, located much nearer to tide water than Western Canada's reserves.

HISTORICAL MARKET PERSPECTIVE

In the late 1960's there was a prevailing perception that thermal coal had passed its heyday as an industrial fuel and as a fuel for large electricity generating stations. Ready availability of cheap oil provided the base fuel in most of these applications, and many existing coal-fired plants were converted to oil. There was very little seaborne trade for thermal coal; local production essentially met all thermal coal demand. Utilities were contemplating nuclear power with great anticipation in the belief it offered the prospect of cheap electricity. In any event a number of factors combined to constrain the growth of nuclear power, indeed many jurisdictions prevented the installation of nuclear power stations totally. Oil prices kept going up, and oil users believed the price escalation would never be halted. By the late 1970's the eyes of all industrialists turned to coal and a coal boom started which has not only continued to this day, but is predicted will continue into the next century. This is the general background to the growth in international trade for thermal coal in the 1980's. The "new" aspect of this surge in coal's fortunes has been the demand for imported, mostly seaborne coal.

OECD coal demand and economic activity between 1970 and 1988 is illustrated in Figure 3. A continuance of this scenario is the basis for the future outlook.

Figure 3. OECD Coal Demand and Economic Activity, 1970-1988
(1970 = 100)



Source: *OECD Main Economic Indicators*, OECD Steel Committee and *IEA/OECD Energy Balances*

FUTURE COAL EXPORT PROSPECTS

Canada can expect to maintain its present level of international trade in metallurgical coal. For many reasons, there is unlikely to be any significant increase in metallurgical coal demand for steel production purposes. Statistics show that world demand has now levelled off and continues to remain fairly static. In contrast with this, thermal coal demand is projected to grow rapidly. Figure 4 illustrates world seaborne coal trade to the year 2005. As can be seen, steam coal trade is expected to double its present level. According to the IEA "1989 Coal Information", growth in free world thermal coal imports is expected to be approximately 6% per annum. The main regions where major growth is forecast to occur, is Western Europe, and Japan/Far East

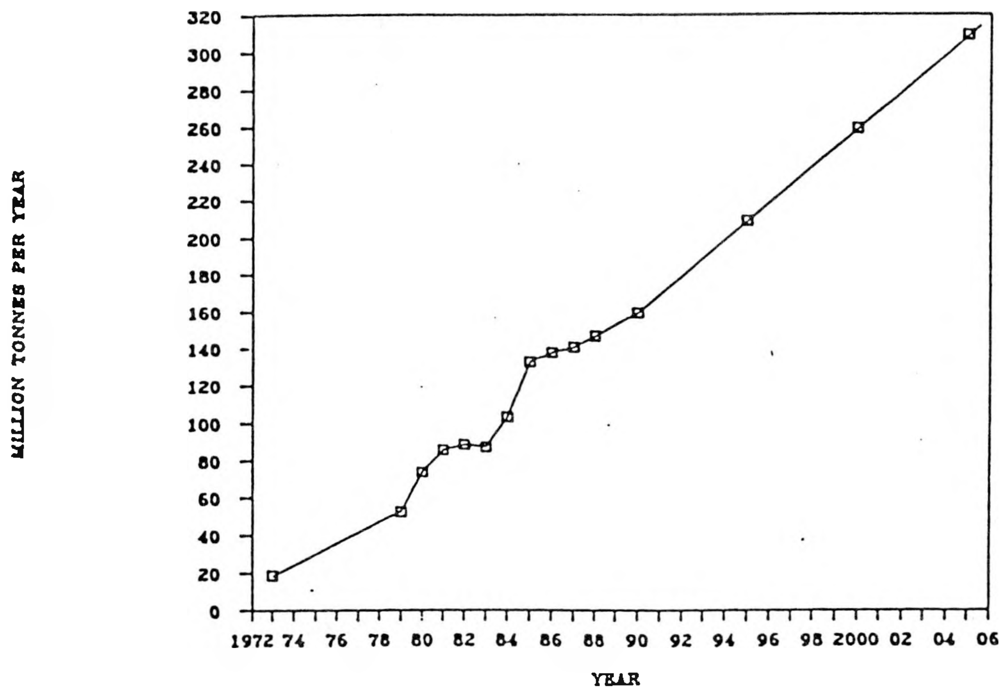


FIGURE 4 - WORLD SEABORNE STEAM COAL IMPORTS

SOURCE: CHASE MANHATTON BANK

The international market for thermal coal has developed very quickly with demand for coal arising almost overnight. Based on this rapidly rising demand, confidence in future forecasts has been promoted as a result of the current construction program for new electricity power generating plants. This energy sector represents a comparatively stable demand for coal in the long term, and given the lead times for new plants, and the sizeable capital commitments they represent, the utilities will probably place coal supply contracts in advance of their actual needs. This should be a stabilizing factor for new mine developments as well.

In Canada, the situation has been less than dynamic in terms of the domestic market. Thermal coal exports have been relatively insignificant when set against world coal movements. The reason for this can be found in Canada's slow acceptance of advanced coal technologies that allow sub-bituminous coals to be upgraded and made economically attractive. This aspect is discussed in the next section. To emphasize the importance of this subject however, it is worth noting that Canada like other resource rich countries such as Australia, and the USA, is falling behind in the industrial application of many of today's advanced coal technologies. Canada's future coal export prospects in international thermal trade, will depend in large measure on how quickly this situation can be rectified.

Uncertainties surrounding economic and political factors will also affect the export prospects for thermal coal in international markets. For instance, the relative movement of national currencies, particularly those of producing countries, namely Australia, South Africa and Canada affect trade. Exchange rates in terms of the US dollar, which is the currency most often used to value coal in the market place, have a major impact on competitiveness.

Political acts such as government to government deals (e.g. Japan and China) can have an effect in international markets. Significant tonnages of coal can preferentially enter the market under these circumstances. Another key factor that has to be borne in mind, is the spectre of crude oil prices falling through the floor. If this were to happen, thermal coal markets would again become vulnerable to competition from heavy fuel oil priced at say ten dollars per barrel. However, widespread use of fuel oil for future utility and industrial purposes is inconsistent with the reality of long term hydrocarbon supplies and therefore it is not a sustainable proposition.

Temporary oversupply situations should not be construed as a long-term problem. Such circumstances do and will occur, but they are a short term problem only. If new mines are developed in a timely way around the world, and if the most economical mines are to come on-stream first, new Canadian coal mines should be developed in the 1990's. This should ensure that Canadian thermal coal exports grow, and allow Canada to play a bigger role in the Pacific Rim and other world markets. In today's environmentally sensitive climate, Canada's abundant low sulphur, low cost coal has the potential to compete economically, while being in compliance with the new strict emission control standards. From Canada's perspective; based on resource base and mining expertise, we should be able to gain a fair share of the expanding world trade in thermal coal. Major consumers will continue to place some reliance on diversified supply, and with their good record of reliability, Canada's coal producers can look forward with some confidence that they will participate in this new trade. Figure 4 illustrates the growth trend that is forecast for World Seaborne Imports.

Although Canada is a major exporter of coking coal, it does not play any significant role in international steam coal markets. Unfortunately, Canada's coking coal is low/medium volatile, and unlike high volatile coking coal it is not readily accepted in thermal markets. Because of this situation, Canada's future thermal coal exports will be based on exploiting its vast reserves of sub-bituminous coal. To that end, current state-of-the-art upgrading techniques will have to be employed to improve their economic merits. In terms of their technical merits, they have considerable advantages over many bituminous coals. From a utilization point of view, they ignite easily, burn fast and because they are highly reactive, good combustion efficiencies are achieved with maximum carbon burn-out.

NEW TECHNOLOGIES

During the 1970's, two phenomena had profound effects on the technology of coal utilization. The more sudden event was the OPEC initiated international oil crisis which brought about coal's rebirth as a primary source of energy. For the first time, serious efforts were made to exploit the enormous reserves of low rank coal which had until then been restricted to local use. Because of sudden increases in oil prices and concern over its availability, it became urgent to achieve new and better ways to use this abundant low-rank coal. More or less concurrently with these abrupt changes in the price and supply position of oil, came the gradually increasing momentum of the environmental movement. As a result of both these forces, it became important to find methods for burning and using coal more cleanly.

Most of the world's present thermal coal trade is for bituminous coal, and three basic approaches have been taken to allow this to be burned cleanly. They include clean coal technology, advanced combustion techniques, and flue gas desulphurization.

Clean coal technology is coal preparation related, and can range from simple washing to deep cleaning. These coal preparation techniques employ beneficiation processes to remove or reduce impurities such as ash and sulphur in the "as-mined" coal. This current state-of-the-art clean coal technology is now well established. When coupled with new advanced drying methods, these new technologies allow sub-bituminous coals to be upgraded. Thus the high moisture levels and attendant low heating values of these low-rank coals need no longer be an economic barrier to their off-site use. These new technologies must be adopted by the Canadian coal industry if Canada is to be successful in its quest to gain a share of the expanding international coal trade.

Advanced combustion techniques have been developed to minimize the formation of free sulphur dioxide and adjust combustion conditions to avoid or at least reduce the formation of oxides of nitrogen; a major precursor of acid rain. The application of clean coal technology makes an important contribution in effecting improved combustion. Having pioneered several advanced combustion techniques, Canada has considerable experience in this aspect of coal utilization. The industrial application of these new techniques in Canada should promote confidence in the minds of coal buyers, that environmental considerations are an integral part of quality control by Canadian coal producers.

An increasing concern worldwide for the environment has drawn attention in particular to the problem of acid rain. Increasing public concern and the need to meet either current or more stringent future emission regulations has prompted the development of various emission reducing technologies. The technology currently available to reduce sulphur and nitrous oxides from coal burning power plants, is "scrubbers". Having to incorporate this flue gas desulpurization technology, greatly adds to the cost of producing power, and there are many research programs underway which are investigating various alternatives. One of the more encouraging developments in this field, is the LNS Burner which promises to reduce both nitrous oxides and sulphur dioxide created from the combustion of coal, to near zero. As previously mentioned, clean coal technology makes an important contribution in minimizing emission problems.

Various new coal utilization technologies currently being employed by importing countries in the international thermal coal market place, include; coal-water-fuels, micronized coal, fluid-bed combustors, and slagging combustors. In the light of these developments it is essential that coal producers be aware that the successful utilization of thermal coal is dependant on two closely inter-related factors; the physico-chemical properties of the coal, and the operational characteristics of the combustion system in which the coal is to be burned. It is therefore necessary for Canadian coal producers to be well informed on current technologies in order to match each coal with its utilization needs. This is of particular importance where a new mine is being developed, or; where a market is being targeted for substituting coals in an existing combustion system.

CONCLUSIONS

The rapid growth of international trade in thermal coal, offers Canada an opportunity to increase its coal exports. However, if Canada is to be successful in its efforts to gain a share of this expanding market, it will need to adopt the same radical approach that was employed to initiate its entry into the international trade in metallurgical coal. This could be achieved by the economic exploitation of Alberta's vast resources of sub-bituminous coal which will require adopting new advanced technologies that are now available for upgrading these low rank coals.

"THE FUTURE OF COAL IN SOUTHEAST ASIA"

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THE FUTURE OF COAL IN SOUTHEAST ASIA

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ABSTRACT

The economic growth of the Pacific region has led to increased energy consumption which is mostly dependent on oil resources. As these resources are limited, it is considered necessary to take steps to reduce dependence on oil. One of the energy resources to be developed in accordance with the energy diversification is coal, of which Indonesia has extensive deposits.

ASEAN coal resources amount to 36.8 billion tons, 86.9% (31.9 billion tons) of which are in Indonesia, 6.3% in Thailand, 5.4% in the Philippines and 1.4% in Malaysia. Mostly the type of coal consists of lignite, subbituminous coal and the rest is small amounts of (semi)-anthracitic coal. Coal is utilized in large quantities in the ASEAN countries for power generation, then for the cement industry, and small industries.

The potential demand for coal in ASEAN, excluding Singapore, will be 97.51 million tons in the year 2000, a large increase from 21.99 million tons in 1990. The coal production in ASEAN is 20.34 million tons in 1989, this is expected to rise to 91.35 million tons in 2000, excluding Malaysia, whose production figures for 2000 are unavailable. Similarly, the coal demand of East Asian countries (NICs and Japan), which amounts to 184.6 million tons in 1990, is expected to rise to 250.6 million tons in 2000.

Coal exports from the Pacific countries comprising USA, Canada, Australia, and the People's Republic of China in 1990 amount to 220.7 million tons, which is sufficient to meet the total demands of East Asia and ASEAN in 1990, amounting to 206.59 million tons. The export capacity will be 253.3 million tons in 1995 and 296.0 million tons in 2000. This quantity will presumably be insufficient to cover the demands of the East Asian and ASEAN countries amounting to 264.75 million tons and 348.11 million tons.

Coal constitutes an alternative energy resource to petroleum, and can act as a bridge to future nonconventional energy use. However, the use of coal as a solid fuel on a large scale will increase pressure for environmental carrying capacity, so it will be necessary to develop "clean coal" technology such as carbonization, gasification and liquefaction, not only for industrial fuel or as oil and gas synthetic fuel but also to decrease the environmental impact and to facilitate handling.

PREFACE

It gives me great pleasure to present a paper on "The Future of Coal in Southeast Asia" at this distinguished Symposium on the Opportunities in the SynFuels Industry on 27-29 August 1990.

It is our belief that the Asia-Pacific region will be the centre of the future development of industry, trade, and modern technology. This belief is based on the abundant natural resources, as well as the industriousness and dynamism of the people of this region. Indeed, in the last decade, the Asia-Pacific region has achieved a remarkable economic growth. The energy sector is also one of the important prime movers for this development. In this regard the topic of this timely Symposium is indeed well grounded.

In my presentation I will try to describe the coal development in the Asia-Pacific region in Southeast Asia in particular; the past, the present, and prospects for the future.

I hope that this brief resume will be beneficial to the symposium.

Bandung, 15 August 1990

INTRODUCTION

The Pacific region covers developed countries such as the United States of America, Canada, Japan, and the New Industrialized Countries (NICs) such as South Korea, Taiwan, Hong Kong, and Singapore, as well as developing countries like ASEAN countries and the People's Republic of China. It has achieved a phenomenal economic growth, although several of the regions are at present in various economic difficulties due to recent world developments, such as the political changes in Eastern Europe, and the strained situation in the Middle East, which harbor the largest oil reserves in the world.

The economic growth of the Pacific region has brought about a perceptable increase in energy demand which, at the moment, is mostly met by oil resources. However, oil reserves can not guarantee a continuous, adequate energy supply. It is considered necessary to take steps to reduce dependence on oil as a source of energy.

Coal, having been in use for a very long time, is one of the obvious alternatives to reduce dependence on oil. The technology for utilizing coal is well established. In addition, the large quantity of coal resources in the Asia-Pacific region comprises 51% of the world's coal reserves (NEDO, 1989).

COAL RESOURCES

ASEAN coal reserves have been estimated at 36.8 billion tons, of which Indonesia possesses 31.9 billion tons (86.9%), Malaysia 1.4%, Thailand 6.3%, and the Philippines 5.4%. Mostly, the type of coal consists of lignite, subbituminous coal, and the rest is a small quantity of (semi)-anthracitic coal. Coal utilization in ASEAN countries is mainly for electric power generation, then for the cement industry, and small industries.

Indonesia

The total coal resources of Indonesia amount to 31.9 billion tons, of which 22.9 billion tons or 62.35% of the total resources are found in Sumatera, succeeded by Kalimantan with an estimated 8.8 billion tons. The location of coal deposits is shown in Figure 2.1, while the quantity of the resources can be seen in Table 2.1. However, the figures in Table 2.1 are tentative and subject to change as the resources are still being explored.

From the known coal resources, the proven reserve is 4.2 billion tons, while the indicated and inferred reserves are 13.27 billion tons. The quality of Indonesian coal varies from lignite, subbituminous to anthracite (Table 2.2). Thus, if the coal reserves of Indonesia are to be compared with the reserves of other ASEAN countries, the Indonesian coal reserves are the largest.

Thailand

The coal resource of Thailand is considered to be of relatively lower quality and catagorized as lignite. The resources amount to 2.3 billion tons from which approximately 70% are deposited in the Mae Moh Basin in the northern part of the country, exploited by the Electricity Generating Authority of Thailand (EGAT). The economic reserves are estimated to amount to between 800 and 950 million tons of which 614 million tons are deposited in Mae Moh.

Philippines

The coal resources of the Phillippines are spread widely in all of the islands. At the end of 1989, the coal resource potentials were estimated to amount to 1.98 billion tons of which the proven reserves were 291 million tons. The mineable deposits are situated in Mindoro and Panay, of which 30% is in Cagayan Valley in the northern part of Luzon, and 11% is in the eastern part of Mindanao. The remaining 15% is spread through Cebu, Samar, Mindoro, Negros, Polillo, Batan, and Catanduanes. The quality of coal is classified as lignite, subbituminous, and bituminous coal (Table 2.2).

Malaysia

The coal resources of Malaysia are known from the Malaysia Gulf, Sarawak and Sabah. Among those three areas, Sarawak contains the biggest resources, then followed by Sabah. The Malaysia Gulf only contains Batu Arang deposits located about 46 km north of Kuala Lumpur with 32 million tons, of which 16 million tons are to be mined. The quality of Malaysian coal reserves varies from lignite to anthracite while the proven reserves are presumably 27.8 million tons, and the estimated reserves are 494.9 million tons, about 522.7 million tons in total. The coal quality is from lignitic to bituminous coal (Table 2.2).

COAL UTILIZATION

Indonesia

Coal in Indonesia has been used mainly for steam power electricity generating plants, then cement industries, small-scale industries, smelting and chemical industries. The coal production in 1989 reached 8.7 million tons, of which 5.66 million tons were consumed by the steam power electricity generating plants, the cement industries, smelting industries and other industries.

The coal utilization in the future is expected to rise in quantity in line with the national policy of energy diversification. For example, in 1989 the electricity power generating plants in Indonesia consumed 3.86 million tons of coal. In the year 2000 it is projected that they will be using between 15.40 million tons (lower projection) and 28.90 million tons (higher projection). The cement industry's 1989 production capacity was 17.41 million tons, which will be increased to reach 25.89 million tons in 2000, when these industries will be utilizing 3.23 million tons of coal. In addition to the large quantities of coal used by the steam power electricity generating plants and the cement industries, the oil industry is also expected to be consuming coal for the exploitation (secondary recovery) of Duri-Riau oil reserve. Besides, based on surveys carried out in cooperation between the Mineral Technology Development Centre and Japan International Cooperation Agency, the prospect of coal for small-scale industries and rural households in Indonesia will be bright. This is indicated by the possible substitution of noncoal fuels by coal. According to the survey, the energy used by small-scale industries amounted to 5.47 million TCE in 1985, of which 4.7 million TCE could be substituted by coal (86%). The energy needed by these industries will increase to 8.15 million TCE in the year 2000 and 86% of this might be obtained from coal. Meanwhile, for rural households the energy demand in 1985 was 21.42 million TCE and in 2000 this will rise to 22.75 million TCE, which might also be obtained from coal. Another coal use, which is at present in process, is to fuel the petrochemical industries.

Thailand

Coal in this country has mainly been used for electricity power generating plants, cement industries, boiler using industries (pulp and paper, food processing, etc.). Domestic coal consumption is expected to increase from 7.6 million tons in 1988 to approximately 24 million tons in 1995 and then to reach 38 million tons by the year 2000. Most of this will be used for the electricity power generating plants.

Philippines

Coal in the Philippines is mostly utilized for electricity power generating plants and cement industries. In 1989 the power plants consumed 62% of the total coal consumption amounting to 2.3 million tons increase 14.8 million tons in 2000, while the cement industries used 36% and the rest was distributed to other industries, including an alcohol distillery in Negros Island, a fertilizer plant in Leyte and a copper smelter in Leyte.

Malaysia

Malaysia is presently at a starting position for developing coal resources. In order to advance in the development of coal resources, the urgent issues which must be addressed are as follows:

- The position of developing coal domestically and the establishment of a policy for advancing coal development according to the four energy strategies,
- The positive utilization of domestically produced coal in domestic coal-demanding industries (i.e., cement and electric power) and the search for a new demand for coal,
- The opening up of the coal market in neighboring countries including the ASEAN member countries,
- Improvement of the parts of the infrastructure (i.e., roads, harbors, etc.) which are related to coal development.

ASEAN

The production and domestic demand for coal of ASEAN countries is shown in Tables 3.1 and 3.2. Indonesia has bright prospects for coal export either to ASEAN countries or to other countries.

From Table 3.3, based on the population of the countries mentioned above, the per capita coal consumption in Indonesia is estimated to lie at the lowest rank (0.03 tons), while that in Thailand is at the first rank (0.14 tons).

Of the ASEAN countries, Indonesia possesses the largest population, the largest quantity of coal deposits, but the lowest per capita coal consumption. Clearly, therefore, it is possible for Indonesia to develop her coal utilization for domestic consumption. Therefore, coal can become an alternative fuel for small-scale industries and rural households but should be accompanied by clean technology.

In addition, Indonesia is able to become the second largest coal supplier after Australia to the other ASEAN countries.

POLICIES, STRATEGIES, AND PROGRAMS

Since the oil crisis in 1973, a number of countries have experienced economic fluctuations, caused by their heavy dependence on petroleum. Since then, ideas have emerged on energy stability and the need for diversification of energy resources. One of the energy resources to be developed in accordance with the energy diversification policy is coal, which is present in great quantities.

Indonesia

Indonesia as an oil exporting country is certainly not affected by the oil crisis. Yet, a long-term program for the future is being considered because her rapidly growing population will need adequate amounts of energy. This is obvious from the relationship between the increase of GDP and the increase of energy utilization. Due to the enhancement of domestic energy demands, in which petroleum is a dominant energy supplier, there is great concern that the income from petroleum exports may decrease as a result.

Petroleum, being a nonrenewable fossil fuel, will surely run out if it is highly exploited continuously. However, energy supply must be kept stable for the purpose of generating effective economic development. Therefore, this kind of problem should be taken into the national energy policies as early as possible. In this regard, the targets of the national policies of Indonesia are as follows:

The management of petroleum resources with focus mainly on the export demand. Domestic energy requirements will be met by developing alternative nonpetroleum resources.

The policy on domestic energy consumption needs to be directed towards the utilization of existing nonoil energy resources such as natural gas, geothermal power, hydropower and coal, with attention paid to distribution.

Considering the important role of energy in national development, the energy supply should be guaranteed for continuity, adequate quantity, quality, and affordability. In an effort to reach those goals, it is necessary to impose policies which can be classified as follows:

- Intensification
- Diversification
- Conservation
- Indexation

Intensification of inventorizing is necessary based on balanced investment pattern to increase the amount of measured reserves which can provide energy, particularly those areas with high potential for the present and future markets, such as natural oil and gas, coal, geothermal, and other renewable energy resources.

Conservation is, in terms of efficient and rational energy resource utilization, based on a cross-generation schedule.

Diversification is needed to prevent the national income and energy utilization depending on only a few energy commodities, and to satisfy the demand for energy cross-sectorally as well as cross-regionally.

Indexation is optimization of available local energy utilization based on economic efficiency and effectiveness criteria.

The government program to develop backward industries concerned with coal is concerned mainly with steam electricity generating plants and the cement industry. The State-owned electricity company has a plan to develop power generating plants for the long term as shown in Figure 4.1. In Java, by the year 2000 it will reach 16,235 MW, of which about 11,100 MW will be coal steam electricity generating plants. Outside Java, it will reach 6,180 MW of which 827 MW will use coal as fuel.

In fiscal year 1989 the installed generating capacity of Indonesia was about 9,008 MW, of which 1,730 MW, or 19.0%, was from coal steam electricity generating plants. This is dramatically changing because of government policy to push up coal utilization in the power plants from 19.0% to 45.93% or from 1,730 MW (the year 1990) to 11,927 MW (installed capacity in the year 2000).

In the cement industry in the year 1989, the estimated coal consumption was about 1.78 million tons. By the year 2000 this will be about 3.23 million tons (as shown in Figure 4.2). Efforts are also underway to replace noncoal energy resources by coal in small industries.

Malaysia

First of all, the energy policies of Malaysia set on petroleum as the main point. The policy on petroleum started in full scale in July 1974 when the Petroleum Development Act (PDA) was imposed. This energy is the main exported commodity in the world, followed by natural gas. Nevertheless, Malaysia has started using coal for its steam power electricity generating plants and the Malaysian Government has made a decision that all cement industries should be fueled by coal.

The major thrust of the policy was energy diversification based on the four-fuel strategy, namely oil, hydro, gas, and coal, and aimed at ensuring reliability and security of supplies while reducing the dependence on oil in energy consumption. The objectives were:

- Supply objective: to provide the nation with adequate and secure energy supplies by reducing dependence on oil and by developing and utilizing alternative sources of energy (Ministry of Energy, 1982). A four-fuel energy strategy based on oil, hydro, gas, and coal has been formulated towards diversifying their energy base as well as guaranteeing assured energy supplies for continued growth.

- Utilization measures aimed at efficient utilization of energy.

- Environment: the achievement of the above two objectives was not to be at the expense of the environment.

Further, the National Depletion Policy, introduced on June 1, 1980, restricted the production of crude oil to 1.75 percent of oil initially in place for major fields. Energy conservation is mainly directed at oil. Electricity tariff rates were structured to reduce wastage. Also, the government decided to impose heavier road tax for cars exceeding 1500 cc. Fiscal measures such as expenditure incurred on plant and accelerated depreciation allowance. Effective from 1982, firms were permitted to generate power for their own use from industrial wastes.

Thailand

After the second energy crisis in 1979, the Thai Government decided to reduce its big dependence on imported energy through developing domestic energy resources such as hydropower, natural gas, and crude oil. These efforts succeeded by decreasing the dependence on imported energy from 90% in 1979 to approximately 55% in 1987.

As a result of the energy policies, the domestic coal production increased from 1.5 million tons in 1980 to 7 million tons in 1988; the stable growth rate of 34% per year during the last five years was considered spectacular. The first stage to increase coal production was to rapidly increase domestic coal consumption in the electric power sector. The total consumption in this sector showed an increase from 0.9 million tons in 1980 to 3.8 million tons in 1985 and 6.4 million tons in 1988.

Programs which will be carried out are to make projections of coal demand and coal production. Domestic coal is used in the power sector, cement industry, boiler-using industries and the tobacco-curing industry.

The power sector was the earliest large-scale user of domestic coal and presently accounts for 83% of total consumption. Of about 7,000 MW total production capacity of the Electricity Generating Authority of Thailand (EGAT), 865 MW is generated using domestic coal, accounting for nearly 20% of total electricity generation.

To meet the rapidly growing electricity demand (13.5% in 1987, 15.6% in 1988, and a forecast of 12% per annum for 1987-1991, 9% per annum for 1992-1996, and 7% per annum for 1997-2000), EGAT is planning to expand its generating capacity to 17,400 MW by the year 2000. Of the approximately 10,400 MW of additional capacity it intends to develop, 6,300 MW should be coal fired.

The cement industry comprises three large companies: Siam Cement Co., Siam City Cement Co., and Jalaprathan Cement Co. Following the surge in cement production, the energy requirements of the cement industry have grown at a rate of more than 20% per annum during the last two years and are projected to grow at an average rate of 7% per annum until 1995 and 6% per annum thereafter. Along with this rapid growth, cement companies are adding the technical capability to use domestic coal for up to 95% of the energy needs of their major plants. As a result, Siam City Cement's plant is already using 95% domestic coal and Siam Cement Company is increasing the capability of using domestic coal in its Saraburi plants from 44% in 1988 to 95% in 1990. With these conversions and the projected growth in cement production, the industry's demand for domestic coal is expected to increase to 1.9 mtpa by 1990, 2.8 mtpa by 1995 and about 3.4 mtpa by 2000.

Industrial boilers offer a significant potential for coal use but only certain sizes, types, and locations. There are currently some 4,000 industrial boilers in Thailand, most of them using heavy oil. Coal use totals some 200,000 tons per annum mainly in the food processing and pulp paper industries. To forecast future coal demand, growth in energy use in each region was assumed to correspond to the weighted average growth rates of four selected industries: food, textiles, pulp and paper, and chemical, and 25% market penetration of domestic coal. This resulted in an estimate of some 800,000 tons of coal consumption by industrial boilers in the year 2000.

Tobacco curing barns have been encouraged to substitute coal for wood in the curing process. Coal demand is expected to taper off and will probably not exceed 100,000 tons per year by the year 2000. As a result from the projection as above, consumption of domestic coal from all sectors is expected to increase from an estimated 7.6 million tons in 1988 to about 24 million tons in 1995 and to 38 million tons by the year 2000, with power generating continuing to dominate.

Philippines

The Office of Energy Affairs (OEA) has prepared the Philippines medium term energy plan (1988-1992), the plan has three main objectives as follows:

- To guarantee the energy preparation in the domestic market with profitable prices.
- To promote the wise and efficient consumption of energy resources.
- To implement both objectives above by keeping the environmental impact at a minimum.

To achieve those three objectives, the OEA has had direction for running the policies:

- Promotion of energy self-reliance.
- Rationalization of energy prices to reflect true cost of production and distribution.
- Encouragement of energy conservation measures to promote efficiency.
- Participation of private sector in energy projects.
- Maintenance of environmental and safety measures for energy projects.

Consistent with the overall objective of promoting energy self-reliance, the following are the future thrusts of the Philippine Coal Development Program (PCDP) for the short and medium term (up to 1992):

- to maximize the production of coal of such quality that can be used by existing users (i.e., Cebu, Batan, Lalat, etc.)
- to promote the use of low-rank coals by blending with high-quality imported coal or upgrading by washing or other coal preparation techniques.

For the long term (beyond 1992), the thrusts are:

- To maximize the use of low-rank coals by ensuring that new coal-fired facilities are designed to use low-rank coals, development of sub-bituminous coals that can be viably transported to shore-based coal-fired facilities in Luzon (i.e., Isabela, Cagayan, Surigao, etc.).
- To firm further long-term market for Philippines coal by further expansion of coal-fired facilities even if initial coal requirements are to be imported.

Philippines coal production is projected to increase from 1.3 million tons in 1989 to 2.6 million tons in 1994. In the same period, however, coal demand is projected to increase from 2.3 million tons in 1989 to 14.8 million tons in 2000. Thus, for the foreseeable future, the Philippines will remain a net coal importer.

PROBLEMS AND POSSIBLE SOLUTIONS

Indonesia

Several problems of Indonesian coal are as follows:

- Coal as an energy alternative needs to be ranked as a strategic project due to its numerous constraints.
- In line with the general policy in the energy sector, an energy diversification which is mainly supported by coal, could have an invertable surplus impact, which can be advantageous to national economic growth.
- Developing transportation facilities in Indonesia is a particular problem because it is necessary to build an extensive network of infrastructures to connect the nation's numerous islands, many of which are still relatively isolated.
- In the program of coal exports, a national mineral trader, who has a function to trade and keep on track with the international mineral trade, should be established.
- In the case of regional economic development, the simulation of coal commodity distribution will depict the geographical path which the same cost or price of coal in order to of minimize economic discrepancies to determine the price of coal.

For Indonesia, coal has been acknowledged at the national level so that it is given full attention by the government both for development and utilization. However, for both development and utilization, many problems have been found in the field, for example, problems caused by inadequate infrastructure. These include the limited capacity of train transportation and loading ports. One of the solutions is to apply the slurry technology. And the People's Republic of China is currently building the technology called "coal-water slurry pipeline" for a distance of 602 km, which is expected to be accomplished by 1993. The slurry technology is considered more effective and is one of the modern transportation methods. This also requires less investment and is quicker than building railways, so it should be considered for application in Indonesia.

Because Indonesian coal varies in quality, it is necessary to have coal blending centres, in order to supply those industries which require a constant quality of coal.

It is expected that Indonesia might produce sufficient coal to exceed domestic demands and thus help overcome the shortage of ASEAN coal supply.

Thailand

Thailand's coal problems include the following:

- The economy of Thailand had a rapid growth from 4.5% GDP in 1986 to 8.4% in 1987 and 11% in 1988, which has resulted in an average growth of 13% per year on the energy demand and 18% per year in coal consumption. Meanwhile, the international price and the shipping costs of exported coal have increased more than 80% during the period 1987-1988 so that hopes of stable coal prices have faded.

- In industrial sectors, particularly in the cement industries, a guarantee was given for a long-term supply, which doubled 1985's figure of 0.6 million tons to become 1.3 million tons in 1988. So the industrial sectors had both the desire and capacity to consume more coal until the domestic coal resources cannot fulfill the demand. The gap between the demand and the domestic supply will grow fast to reach 600,000 tons per year in 1990 and 1 million tons per year in 1992.

Malaysia

This country has enough energy resource potentials including coal. It has been decided that the development of new cement industries as well as steam power electricity generating plants should be on the basis of coal utilization. This year Malaysia is to import coal from Indonesia for the needs of the Electricity Power Authority Malaysia. Thus, the coal potentials of Malaysia have not yet been developed properly for its domestic consumption.

Philippines

The need for energy will be expected to increase while coal resources are scattered throughout the archipelago with quality only good for steaming purposes and has not been developed well all over the country. It is necessary to provide various economic incentives to a company who would go into coal development and/or convert their oil-burning facilities to coal to support the diversification of energy resources. In addition to that, the coal from other countries is needed to fulfill the excess demand of coal.

FUTURE PROSPECT

The potential demand for coal in ASEAN, excluding Singapore as shown in Table 3.2, will be 97.51 million tons in the year 2000, a large increase from 21.99 million tons in 1990. The coal production in ASEAN is 20.34 million tons in 1989, this is expected to rise to 91.35 million tons in the year 2000, excluding Malaysia whose production figure for 2000 are unavailable (Table 3.1). Similarly, the coal demand of East Asian countries (NICs and Japan), which amount to 184.6 million tons in 1990, is expected to rise to 250.6 million tons in 2000.

From these two tables (Table 3.1 and 3.2) it can be seen that the ASEAN countries will be self-sufficient in coal until 1995, and that the surplus is to be exported in particular to neighboring NICs and Japan, to the amount of approximately 2 million tons per year. The quantity is incommensurate with the huge potential demand.

In 2000 the coal demand of ASEAN countries will be 97.51 million tons, which is greater than the total production capacity of 91.35 million tons. Therefore, there will be a surplus demand in the ASEAN countries for about 6 million tons per year. In addition, there will also be an increasing coal demand from the East Asian countries for 250.6 million tons.

Coal exports from the Pacific countries comprising USA, Canada, Australia, and the People's Republic of China in 1990 amount to 220.7 million tons (Table 6.1), which is sufficient to meet the total demands of East Asia and ASEAN in 1990 amounting to 206.59 million tons. While the estimated future export capacity will be 253.3 million tons in 1995 and 296.0 million in 2000, this quantity will be insufficient to meet the demands of the East Asian countries and the ASEAN countries, amounting to 264.75 million tons and 348.11 million tons.

The future configuration of coal flow in the Asia-Pacific region indicates that Indonesia will have opportunities to export her coal surplus to supply the market in Japan and NICs countries due to the shortage of coal in the Pacific region (Figure 6.1), while the estimated future regional coal flow in the year 2000 as shown in Table 6.2 and Figure 6.2.

However, the utilization of coal as a bridge between current conventional energy sources and future nonconventional energy sources must as soon as possible be in the form of synfuel because of the environmental protection requirement, if coal is to be an acceptable substitute for petroleum. In the era of nonconventional energy coal utilization will decrease and be replaced by the use of new energy sources, i.e., wind, solar, nuclear, etc. (see Figures 6.3 and 6.4). The environmental aspect will be addressed by the use of a "built-in" system which incorporates the environmental input factor into energy planning and decision-making; where the environmental cost is covered by earmarked funds out of the flexible funds as part of the total (surplus) funds.

Moreover, the potential ASEAN coal utilization in the future, as a source of energy as well as nonenergy, could be based on the concept of national cross-sectorals, regionals, and across-regional development to gain its benefits as an accelerator to support global economic growth. The application of this fundamental concept requires supporting systems as innovators, such as information systems, clean coal technology and manpower development in line with firm policies in the energy and industrial sectors (see Figure 6.5). This concept is in line with the process of transforming any natural resource into a source of economic potential and finally into a form of social capital which can improve people's lives (see Figure 6.6).

CONCLUDING REMARKS

The Asia-Pacific region indicates a good economic growth, although several countries are in various states of economic fluctuation due to recent world developments, such as the political changes in East Europe and the increased tension in the Middle East. This situation has affected energy supply, especially oil. The majority of Asia-Pacific countries are dependent on oil resources.

Coal resources which occur in the Asia-Pacific region are large, about 51% of the world's coal resources (NEDO, 1989). These coal resources could constitute an alternative energy to reduce the dependence on petroleum. Moreover, the technology for coal utilization has been known since long ago. The main use of coal as an energy source in this region is for electric power generation.

The ASEAN countries will be self-sufficient in coal until the year 1995. The coal demand in the Newly Industrialized Countries (NICs) and Japan constitutes a great market opportunity for coal producers in ASEAN countries. The ASEAN countries' geographic location is more favorable compared to the other Pacific countries like the United States, Canada, and Australia (except China which also has a great market opportunity, though the domestic demand in this country is large). The Indonesian interest is to have the opportunity to utilize her coal optimally, both to help ASEAN become self-sufficient as well as to share in the coal market in the Pacific Region, particularly in ASEAN countries, NICs, and Japan.

To fulfill the coal demand that increases continuously, integrated handling systems are needed among the countries of the Asia-Pacific region, such as a coal flow system to guarantee continuity of supply to meet the coal demand in that region.

Coal constitutes alternative energy to petroleum, and can act as a bridge to future nonconventional energy use. However, the use of coal as a solid fuel on a large scale will increase pressure for environmental carrying capacity, so that it is essential to develop "clean coal" technology such as carbonization, gasification and liquefaction, not only for industrial fuels or as oil and gas synthetic fuels, but also to decrease the environmental impact and to facilitate handling.

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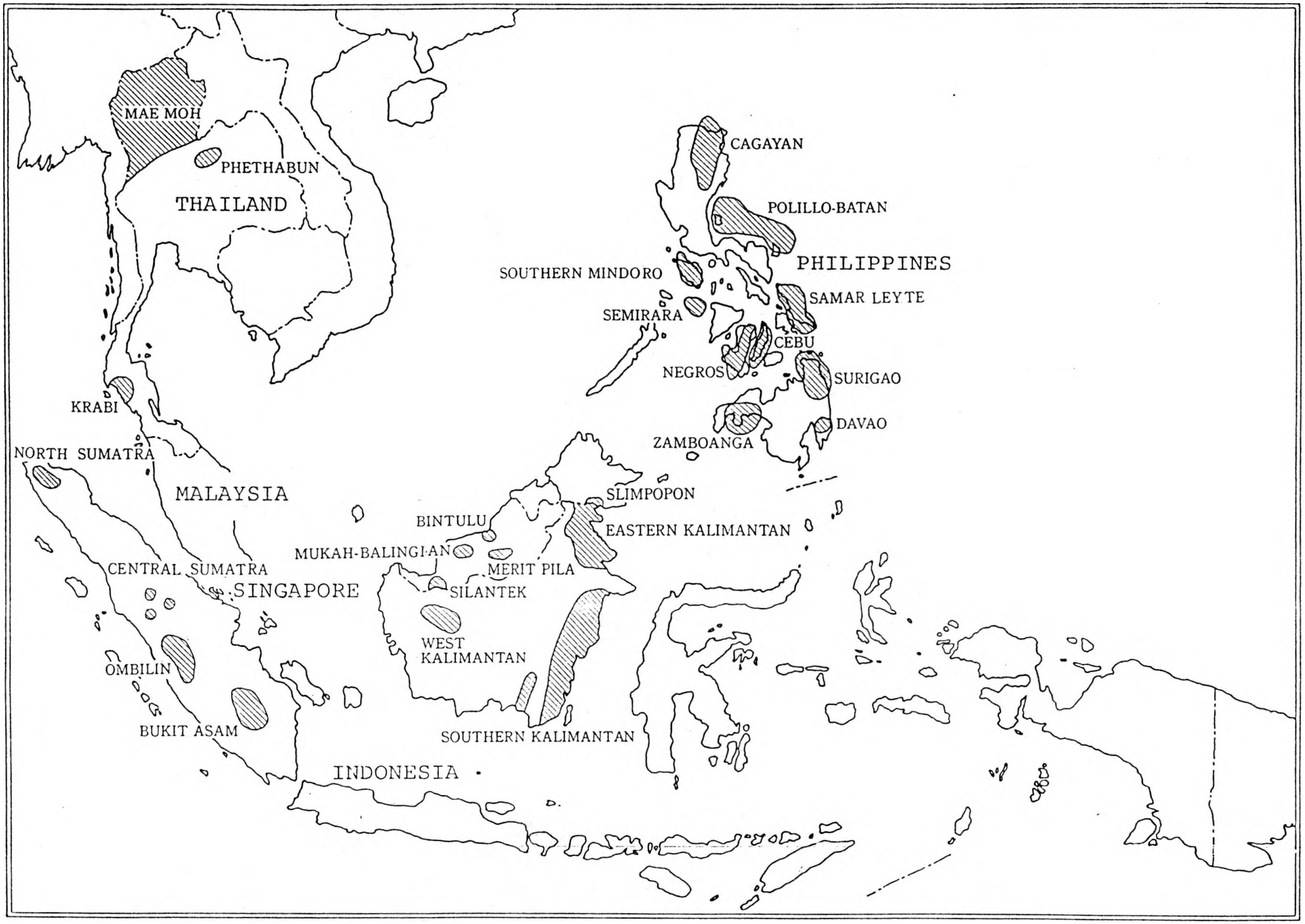
FIGURE 2.1

COAL BASINS IN ASEAN REGION



Source : NEDO, IEE JAPAN

TABLE 2.1

RESERVES AND RESOURCES OF COAL IN SOUTHEAST ASIA

COUNTRY	LOCATION	MEASURED	INFERRED & INDICATED	HYPOTETHIC	TOTAL
INDONESIA	1. NORTH SUMATERA	-	1,272,000	428,000	1,700,000
	2. CENTRAL SUMATERA	590,918	1,261,340	700,000	2,482,258
	3. SOUTH SUMATERA	1,763,294	3,800,270	13,162,000	18,725,564
	4. BENGKULU	2,334	40.079	-	42,413
	SUMATERA	2,286,546	6,373,689	14,290,000	22,950,235
	1. EAST KALIMANTAN	1,058,523	3,924,814	-	4,983,337
	2. SOUTH KALIMANTAN	932,618	2,623,186	-	3,555,804
	3. WEST KALIMANTAN	-	-	102,900	102,900
	4. CENTRAL KALIMANTAN	-	240,000	-	240,000
	KALIMANTAN	1,991,141	6,788,000	102,900	8,882,041
	1. WEST JAWA	4,376	15,390	19,054	38,820
	2. EAST JAWA	-	7,455	755	8,210
	J A W A	4,376	22,845	19,809	47,030
	SULAWESI	-	89,062	-	89,062
	IRIAN JAYA	-	4,000	-	4,000
	T O T A L	4,282,063	13,277,596	14,412,709	31,972,368
PHILIPPINES	1. SEMIRARA	129,300	29,760	550,000	709,060
	2. CAGAYAN VALLEY	88,340	53,180	336,000	477,520
	3. MINDARO	2,400	1,400	100,000	103,800
	4. POLILLO - BATAN - CATAN DUANES	5,670	4,440	17,000	27,110
	5. QUEZON	50	-	2,000	2,050
	6. NEGROS	1,050	1,060	4,500	6,610
	7. NOTHERN CEBU	1,040	370	75,000	76,410
	8. SOUTHERN CEBU	3,320	2.380	50,000	55,700
	9. CENTRAL CEBU	1,420	150	40,000	41,570
	10. BOHOL	530	740	-	1,270
	11. DAVAO	130	-	100,000	100,130
	12. SURIGAO	31,080	23,380	209,000	263,460
	13. ZAMBOANGA	20,310	7,400	45,000	72,710
	14. SAMAR	6,350	4,450	27,000	37,800
	15. MASBATE	170	-	2,500	2,670
	T O T A L	291,160	128,710	1,588,000	1,977,870
THAILAND	1. MAE MOH	614,000	-	1,491,500	2,105,500
	2. SIN PUN	23,000	-	65,170	88,170
	3. KRABI	20,000	-	120,70	140,700
	T O T A L	657,000	-	1,677,370	2,334,370
MALAYSIA	SELANGOR				
	1. BATU ARANG	16,000	-	33,000	49,000
	SERAWAK				
	2. SILANTEK	7,000	-	50,000	57,000
	3. MERIT PILA	-	-	250,000	250,000
	4. BALINGAN	-	-	120,000	120,000
	5. BINTULU	-	-	20,000	20,000
	SABAH				
	6. LABUAN	-	-	8,900	8,900
	7. SILIMPOPON	4,800	-	13,000	17,800
	T O T A L	27,800	-	494,900	522,700
A S E A N		5,258,023	13,406,306	18,142,979	36,807,308

SOURCE :
- DEPT. OF MINES AND ENERGY, INDONESIA, APRIL 1990.
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TABLE 2.2

CHEMICAL ANALYSIS OF COAL IN SOUTHEAST ASIA
(PROXIMATE ANALYSIS)

COUNTRY	PROXIMATE ANALYSIS						REMARK
	MOISTURE (%)	A S H (%)	VOLATILE MATTER (%)	FIXED CARBON (%)	SULPHUR (%)	HEAT VALUE (K. Cal/Kg)	
INDONESIA							
- Lignite	8.00-14.75	1.20-28.2	33.70-49.90	34.80-52.00	0.10-5.37	4900-7125	North Sumatera, Central Sumatera, South Sumatera, East Kalimantan
- Sub bituminous	8.00-14.75	3.00-25.6	25.30-45.25	30.20-60.00	0.49-3.00	5336-6800	Sulawesi, South Sumatera
- Bituminous	6.00-14.75	1.05-28.20	28.34-49.90	30.90-52.00	0.10-5.37	4484-7125	West Sumatera, South Sumatera, East Kalimantan, South Kalimantan
- Anthracite	8.00-13.31	4.15-8.05	39.70-45.25	40.84-51.00	0.49-6.80	5800-6800	South Sumatera
MALAYSIA							
- Lignite	10.30-48.90	2.40-13.80	36.70-53.00	30.70-53.00	0.11-2.53	5140-7110	Merit Pila, Balingan
- Sub bituminous	2.00-8.80	4.50-9.20	42.00-45.80	43.10-44.70	1.40-2.50	6000-8500	Labuan, Silimpapan
- Bituminous	3.30-4.80	2.20-6.70	39.20-43.30	48.80-54.60	1.30-2.90	7110-7540	Bintulu
- Bituminous - Anthracite	1.60-5.20	6.40-15.20	5.30-25.00	61.60-80.20	0.20-0.70	6950-7700	Silantek
PHILIPPINES							
- Lignite - Sub bituminous	4.00-18.00	2.00-35.00	20.00-55.00	25.00-45.00	0.50-3.20	3780-6110	Cagayan, Darao, Masbate, Semirara
- Sub bituminous	6.00-19.00	2.00-13.00	32.00-53.00	34.00-47.00	1.50-4.40	4170-6280	Batan, Samar, Negros, Sungai Mindaro
- Sub bituminous - bituminous	3.00-14.00	1.00-13.00	30.00-48.00	36.00-48.00	0.30-1.30	5060-7170	Polillo, Cebu
- Bituminous	2.00-14.00	5.00-22.00	22.00-40.00	20.00-67.00	0.40-38.00	5720-7280	Cataduanes, Suriaggo, Zambanga
THAILAND/MUANGTHAI							
- Lignite	4.60-30.00	6.20-21.00	20.30-32.00	37.60-40.50	1.50-9.70	1527-5022	Mae Tit, Jaekon, Li, Krabi
- Lignite - Sub bituminous	30.00-35.00	10.00-28.00	20.00	13.00-26.00	0.80-15.00	2500-3000	Maemoh
- Bituminous - Anthracite	7.75	1.06	39.50	51.70	0.71	82.75	Mae Tuen

SOURCE : - DEPT. OF MINES AND ENERGY, INDONESIA, APRIL 1990
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TABLE 3.1

COAL PRODUCTION IN ASEAN COUNTRIES

(Million tons)

COUNTRY	1989	1990	1995	2000
Philippines	1.34	1.68	2.60	3.28
Malaysia	1.79	2.02	3.04	N/A
Thailad	8.51	9.83	24.06	38.07
Indonesia	8.70	10.65	24.00	50.00
Total	20.34	24.18	53.70	91.35

N/A : DATA NOT AVAILABLE

SOURCE : ESCAP SERIES ON COAL VOLUME 3, UNITED NATIONS.

TABLE 3.2

COAL DEMAND POTENTIAL IN JAPAN, NICs & ASEAN

(Million tons)

COUNTRY	1990	1995	2000
ASEAN			
Philippines	2.97	6.79	14.82
Malaysia	1.94	2.80	5.30
Thailand	10.47	24.11	38.36
Indonesia	6.61	17.79	39.03
Sub total	21.99	51.45	97.51
NICs			
South Korea	37.00	41.50	52.00
Taiwan	20.10	24.20	27.40
Hongkong	9.50	15.10	20.70
Singapore	–	2.50	4.50
Sub total	66.60	83.30	104.60
J a p a n	118.00	130.00	146.00
T o t a l	206.59	264.75	348.11

SOURCE : ESCAP SERIES ON COAL VOLUME 3,
UNITED NATIONS.

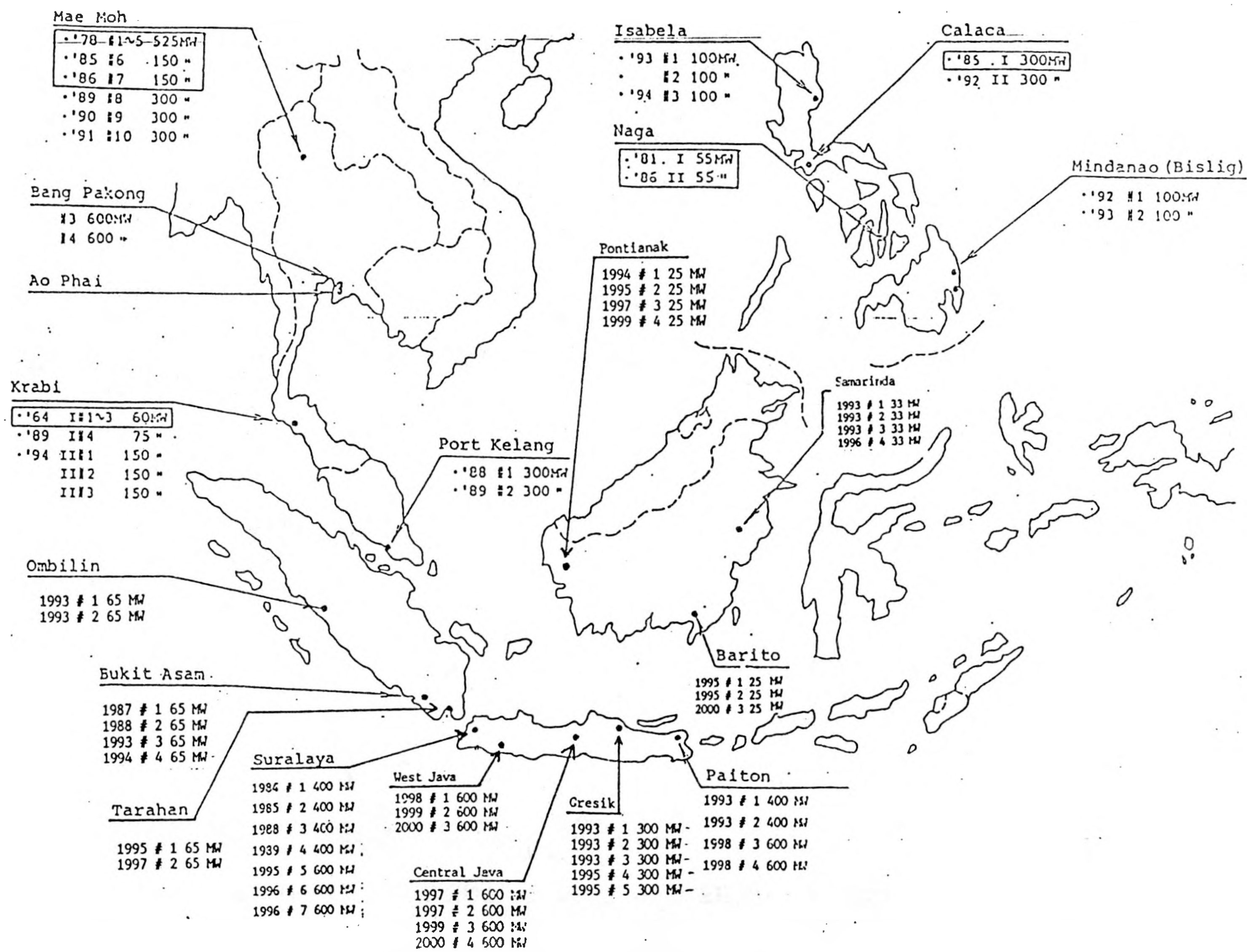
TABEL 3.3

PER CAPITA CONSUMPTION OF COAL

COUNTRIES	COAL CONSUMPTION (MILLION TONS)	POPULATION (MILLION)	PER CAPITA CONSUMPTION (TONS)
CHINA (1985)	806.00	1,041.00	0.77
USA (1985)	685.00	238.80	2.87
USSR (1985)	551.00	227.60	2.42
JAPAN (1985)	110.00	120.60	0.91
U.K (1985)	102.00	56.50	1.80
AUSTRALIA (1985)	39.00	15.80	2.47
INDONESIA (1985	1.50	162.00	0.01
(1987)	3.00	170.00	0.02
(1989)	5.66	179.10	0.03
THAILAND (1987)	7.29	53.60	0.14
MALAYSIA (1986)	-	16.11	-
(1987)	-	16.57	-
PHILIPPINES (1986	-	56.00	-
(1987	-	57.36	-
(1988	2.30	-	-

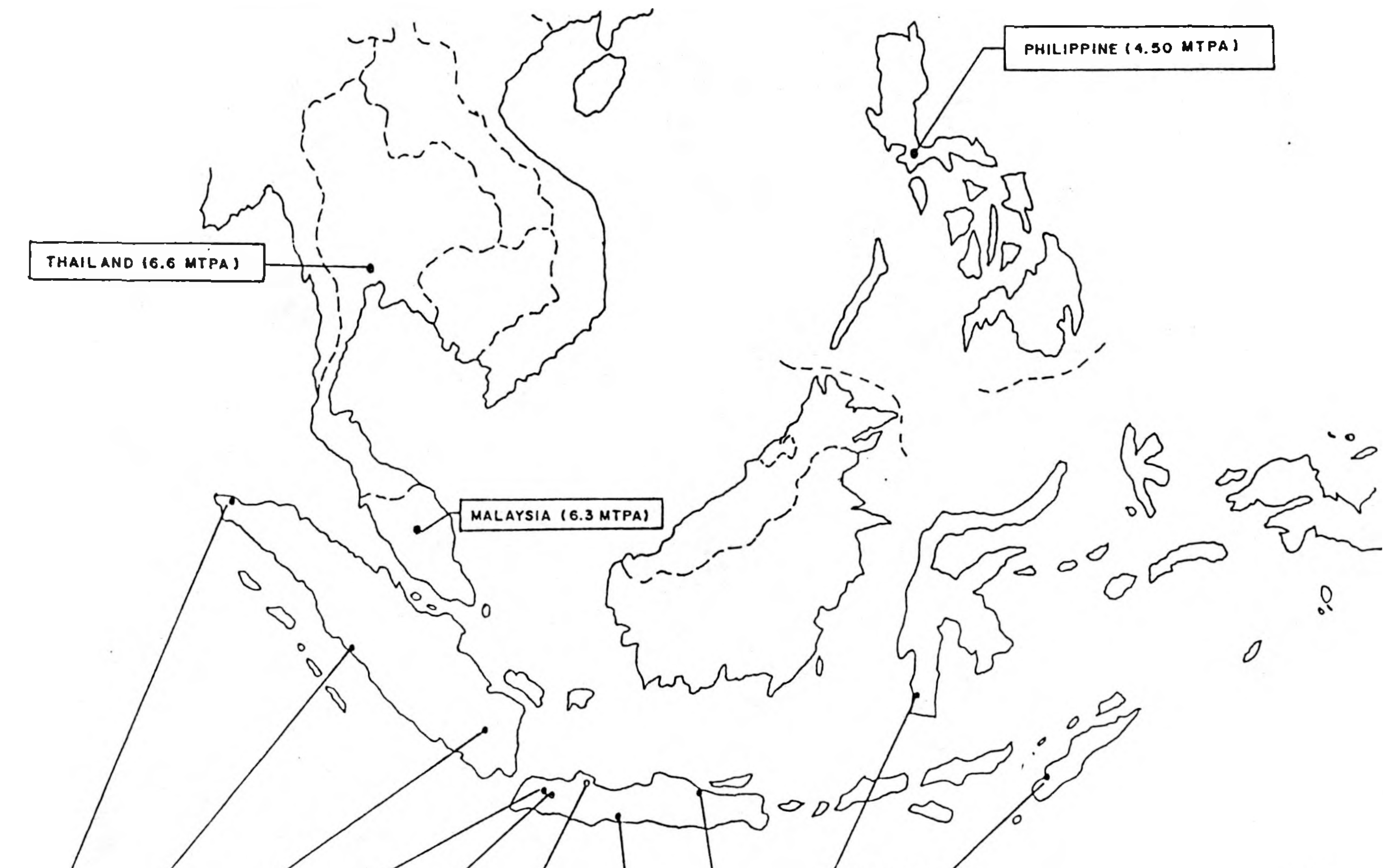
SOURCE : - JAPAN 1986 AN INTERNATIONAL COMPARISON, KEIZAI KOHO CENTER, (JAPAN INSTITUTE FOR SOCIAL AND ECONOMIC AFFAIR), 1986.
- NEDO, COAL IN ASIA - PACIFIC VOL. 2 No.1, QUARTERLY REPORT, JANUARY 1990.
- SOELISTIJO, U.W, PRAWOTO HENDRO, "APO - RSI SEMINAR ON ENERGY SECTOR AND ECONOMIC DEV'T" LAPORAN PERJALANAN DINAS, MINISTRY OF MINES & ENERGY, 1987.
- KNI-WEC, HASIL LOKAKARYA ENERGI, JAKARTA, 9 - 10 AGUSTUS 1988.

FIGURE 4.1 COAL-FIRED POWER PLANTS IN ASEAN REGION UP TO 2000



Source : - NEDO, IEE, JAPAN
- Dept. of Mines & Energy, Indonesia

FIGURE 4.2 CEMENT PLANT IN ASEAN REGION



(1988 MTPA)

ANDALAS	PADANG	BATURAJA	INDOCEMENT	CIBINONG	CIREBON	NUSANTARA	GRESIK	TONASA	KUPANG
1.00	2.13	0.50	7.50	1.50	1.20	0.75	1.50	1.21	0.12

MTPA

TOTAL INDONESIA	
17.41 →	Year 1988
25.89 →	2000

TABLE 6.1

POTENTIAL OF COAL EXPORT FROM THE PACIFIC REGION

(Million tons)

COUNTRY	1990	1995	2000
Australia	155.00	176.00	210.00
China	20.70	27.30	36.00
West USA	5.00	10.00	10.00
Canada	40.00	40.00	40.00
T o t a l	220.70	253.30	296.00

SOURCE : ESCAP SERIES ON COAL VOLUME 3,
UNITED NATIONS.

TABLE 6.2

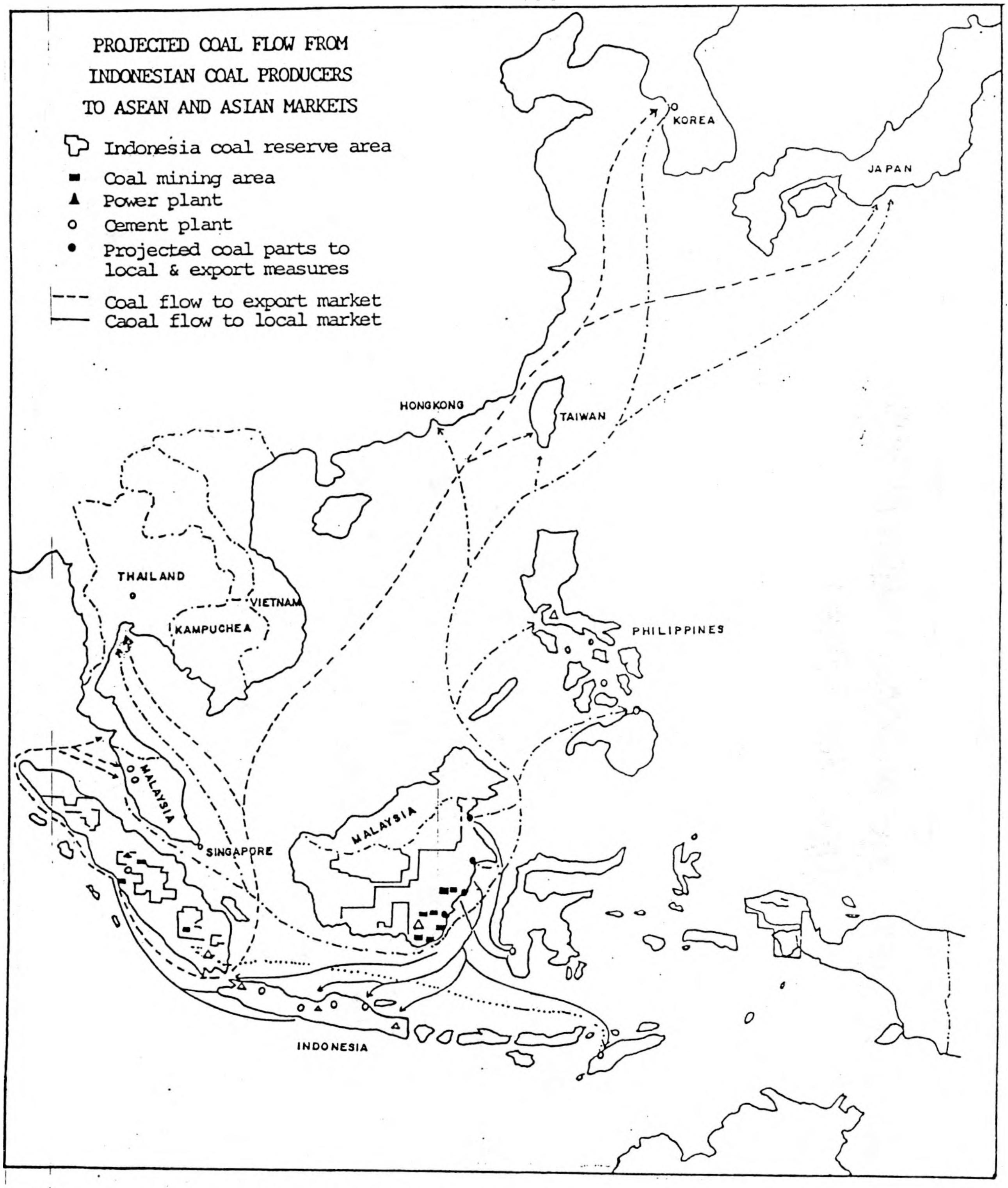
PACIFIC COAL FLOW IN 2000

(In Million Tons)

SUPPLIER \ USER		ASEAN: INDONESIA	ASEAN: PHILIPPINES	ASEAN: MALAYSIA	ASEAN: THAILAND	NICs: SINGAPORE	NICs: HONG KONG	NICs: KOREA	NICs: TAIWAN	JAPAN	TOTAL
AUSTRALIA	LOW	-	0.2	2.0	0.5	-	2.5	12.0	8.5	47.4	73.1
	HIGH	-	1.5	3.0	5.0	1.5	10.0	11.0	8.7	67.4	108.1
CANADA	LOW	-	-	-	-	-	-	4.0	4.5	16.0	24.5
	HIGH	-	-	-	-	-	-	6.5	4.5	20.0	31.0
U S A	LOW	-	-	-	-	-	-	-	1.0	16.0	17.0
	HIGH	-	1.0	-	-	-	-	4.0	2.5	20.0	27.5
C H I N A	LOW	-	-	-	0.4	-	5.5	4.0	-	14.2	24.1
	HIGH	-	-	-	3.0	-	6.0	6.0	-	15.7	30.7
OTHERS	LOW	-	-	3.5	-	0.2	2.5	11.0	9.7	21.9	48.8
	HIGH	-	-	7.5	5.0	3.5	7.0	11.0	11.3	19.9	65.2
T O T A L	LOW	-	0.2	5.5	0.9	0.2	10.5	31.0	23.7	115.5	187.5
	HIGH	-	2.5	10.5	13.0	5.0	23.0	38.5	27.0	143.0	262.5

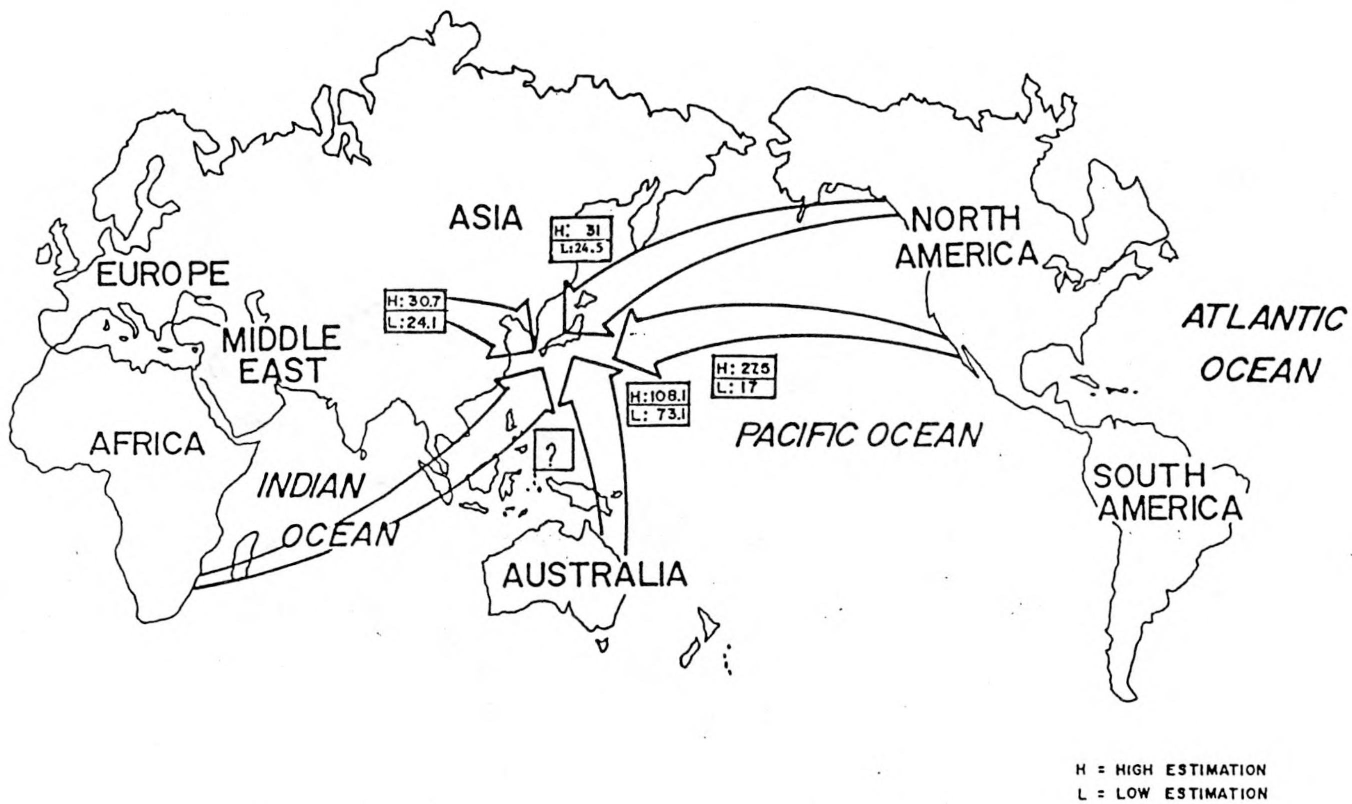
SOURCE : ESCAP Series On Coal, Volume 3, UNITED NATIONS.

FIGURE 6.1



Source : Departement of Mines and Energy, Indonesia

FIGURE 6.2 **PACIFIC BASIN COAL TRADE IN 2000 (MILLION TONS)**



Source : ESCAP Series on coal, Volume 3, United Nations

FIGURE 6.3

TRANSITION PERIOD OF PRIMARY ENERGY COMMODITY UTILIZATION

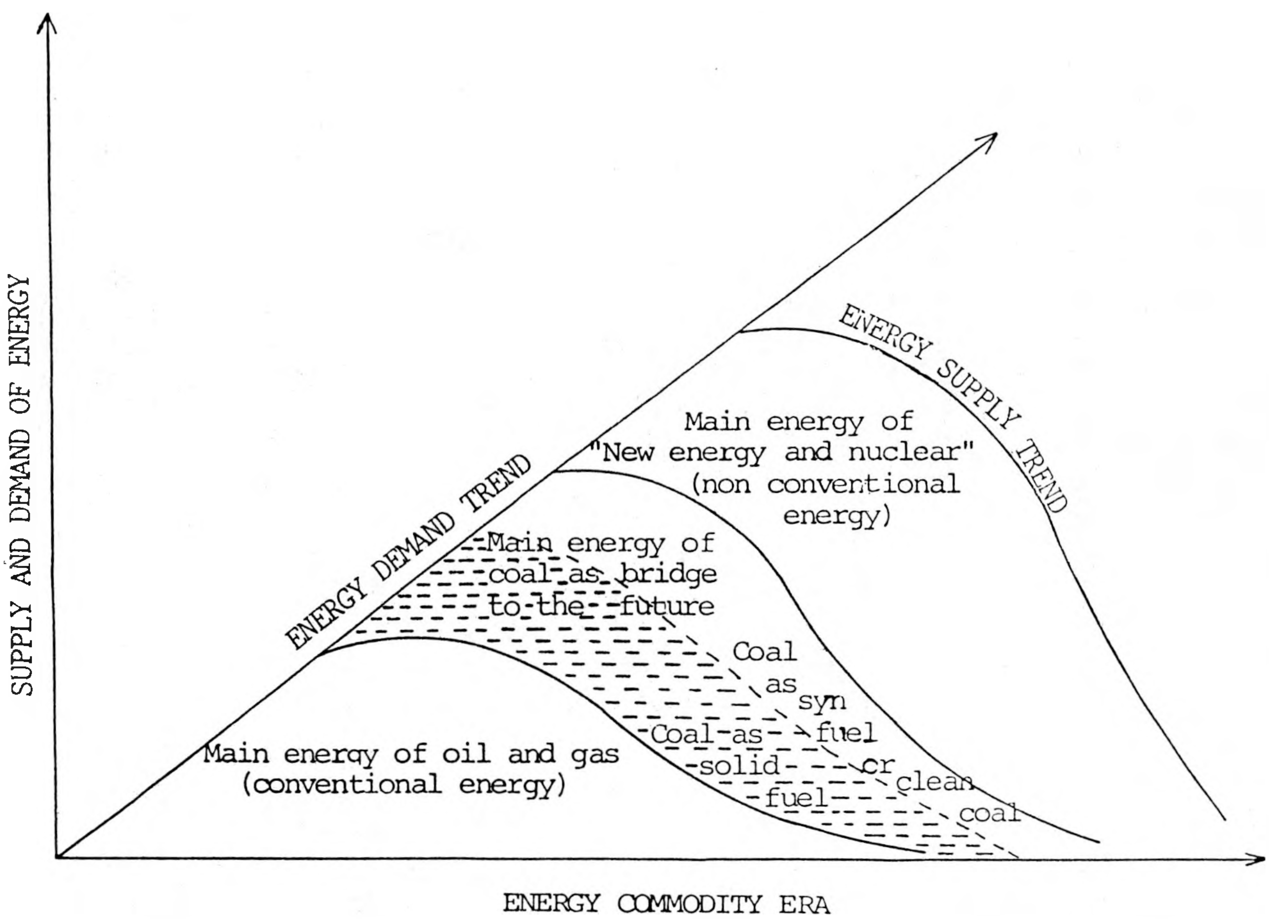


FIGURE 6.4

COAL UTILIZATION TECHNOLOGY FOR PETRO CHEMICAL INDUSTRY

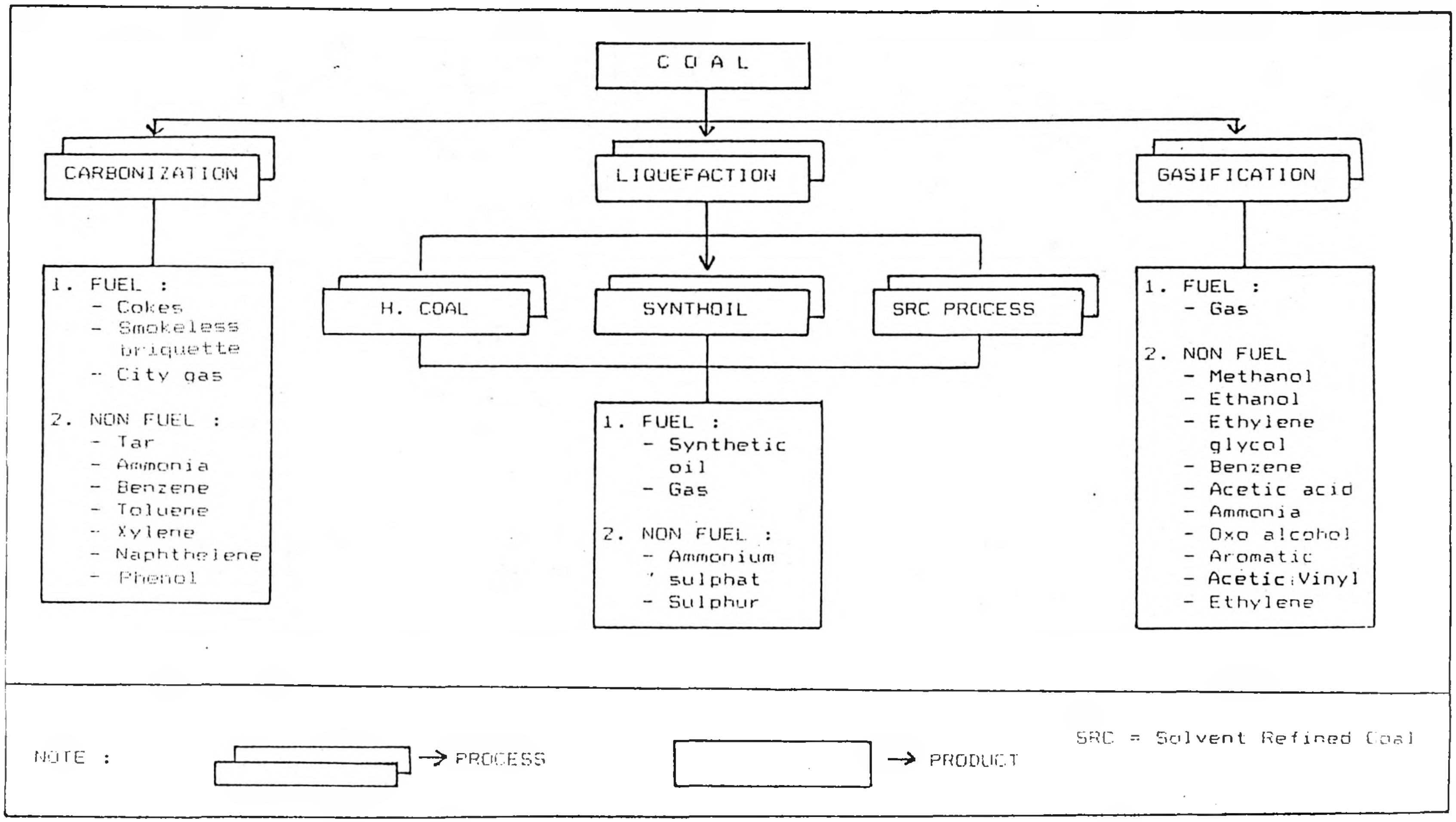


FIGURE 6.5 MOTIVATION OF ASEAN COAL UTILIZATION

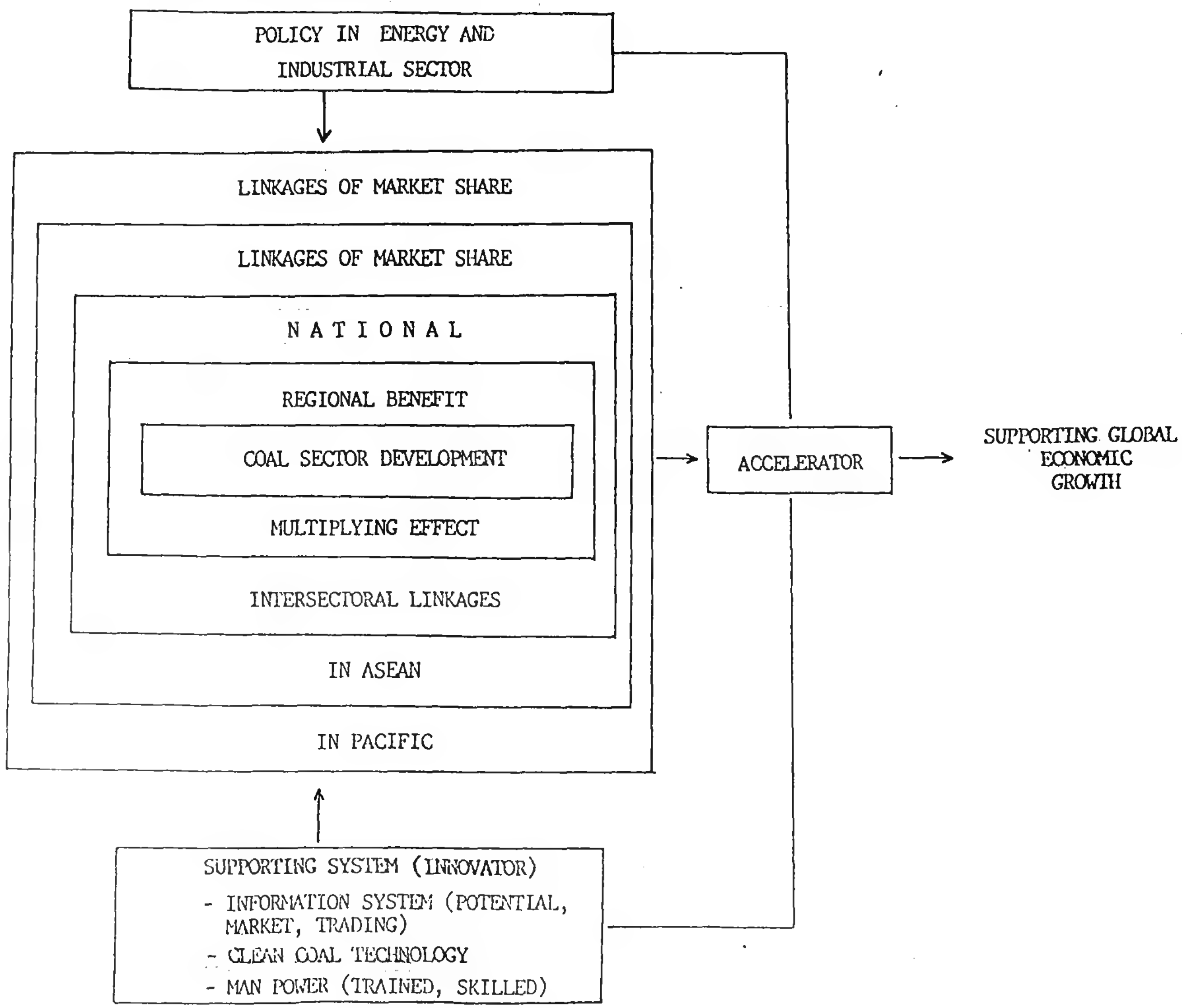
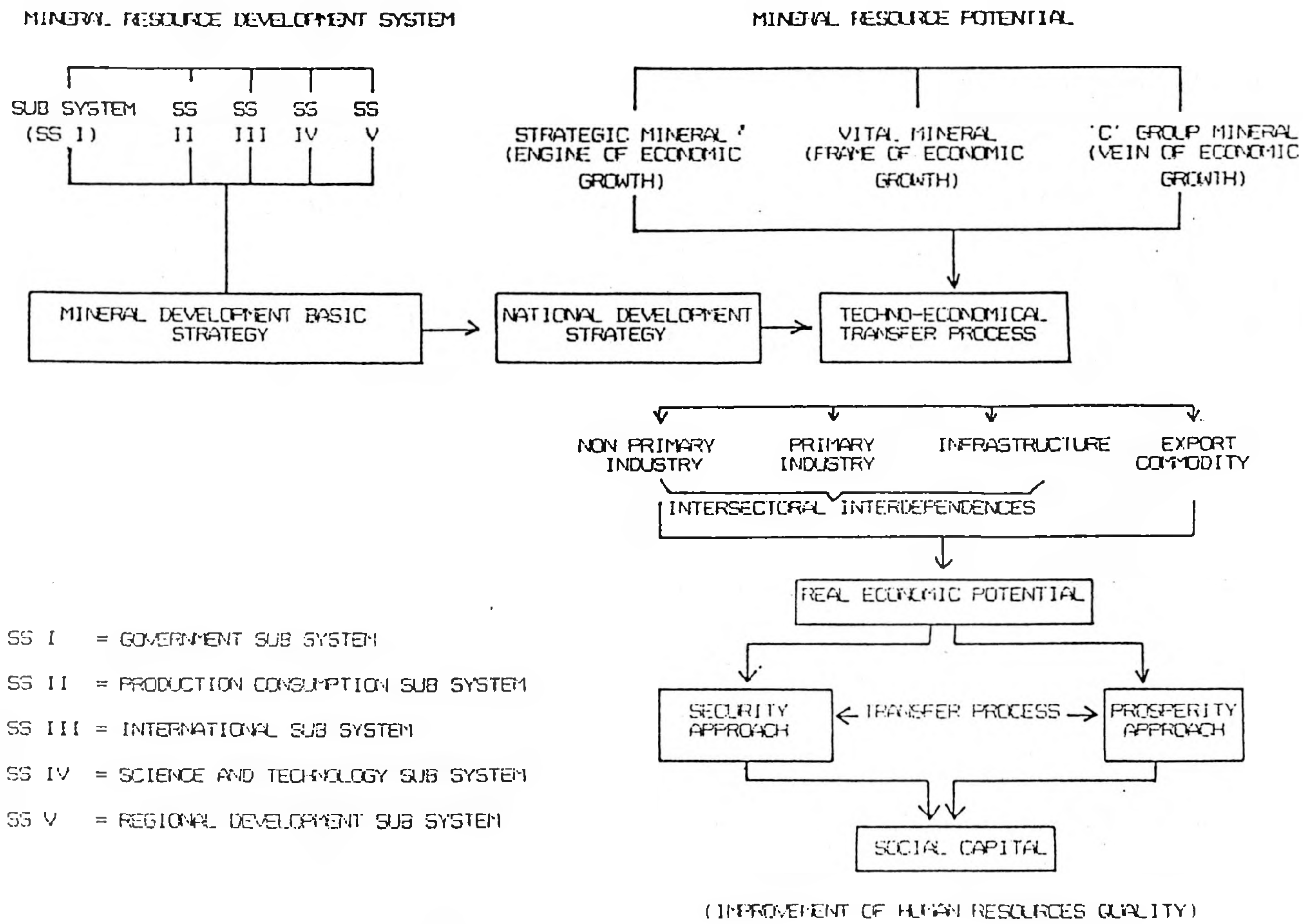


FIGURE 6.6 LINKAGES BETWEEN MINERAL RESOURCE DEVELOPMENT SYSTEM AND TRANSFER PROCESS OF MINERAL RESOURCES



(IMPROVEMENT OF HUMAN RESOURCES QUALITY)

"AUSTRALIAN COALS IN THE DOMESTIC AND INTERNATIONAL ENERGY SCENES, THE PRESENT AND FUTURE -- AN OVERVIEW"

By: Dr. R. (Bob) A. Durie
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AUSTRALIAN COALS IN THE DOMESTIC AND INTERNATIONAL ENERGY SCENES, THE PRESENT AND FUTURE - AN OVERVIEW

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ABSTRACT

The paper briefly reviews the Australian coal scene and examines the reasons wny Australia has become the leading seaborne exporters of both metallurgical and steam coals. Matters addressed include the resource base, its location and nature, production, domestic usage, exports, ports and destinations as well as the technology base and the nature of the R & D support for the mining, preparation industry and coal uses.

Brown coals do not feature directly in the export scene but are important in the Australian energy scene. These coals are addressed separately as appropriate and investigations of these as potential preferred feedstock for conversion to liquid fuels receives brief comment.

Projections of the future world demand for imported coal and of Australia's share in supplying this are presented and discussed. Despite the concerns for the contributions coal use makes to the input of greenhouse gases to the atmosphere the projections for future growth in coal demand, especially steam coal, are optimistic. The implications of the greenhouse issue to the coal industry and the challenges and opportunities these present are briefly addressed in concluding the paper.

INTRODUCTION

Australia, since 1984, has been the leading seaborne exporter of coal to the world markets, displacing the USA. Coal is now one of Australia's major export commodities in terms of dollar value. In recognition of this prominent role of Australian coal in the world coal scene and in the Australian economy the organizers of this conference have invited me to prepare and present a paper which provides an overview of the current

Australian coal scene and addresses the future market prospects for Australian coals. In doing this I include the brown (lignites) as well as the black (bituminous and sub-bituminous) coals since the former coals are of prime concern to North Dakota.

In the limited space allocated the following aspects are addressed briefly in the Australian context - the coal resource base, coal production, domestic coal use, coal exports, the role of technology in the coal industry and coal related research and development. Against this background the paper concludes with a discussion of projections and comments on future markets for Australian coals, with particular regard to the future demands for energy and the implications of growing concerns for the impact of fossil fuel use on the environment and of new technology.

COAL RESOURCES

Distribution, Quantities and Rank

The distribution of Australia's black and brown coal resources are shown in Fig. 1 and current estimates of the amounts of the black (Department of Primary Industry and Energy 1989) and brown coal (Stanley, 1986) resources are summarized in Tables 1 and 2 respectively.

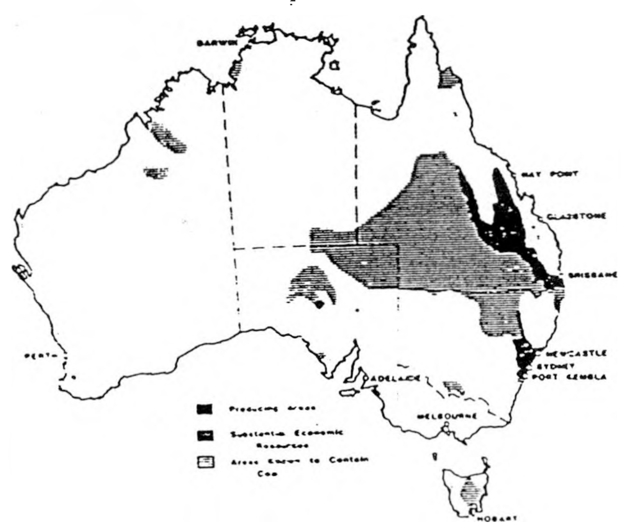

FIGURE 1 - AUSTRALIAN BLACK COAL RESOURCES

Table 1 includes only coals in New South Wales and Queensland. Black coals also occur in Western Australia (864 Mt), South Australia (3410 Mt) and Tasmania (530 Mt) (Joint Coal Board, 1986) but these resources do not feature in the export trade although some are used locally.

Black Coal

The main black coal producing areas are situated along the eastern (Pacific) seaboard. The total resources here (Table 1) are estimated to be 69,489 Mt with 48% in New South Wales and 52% in Queensland. Overall 41% of these resources are considered to be potentially accessible by surface

TABLE 1

AUSTRALIAN BLACK COAL RESOURCES*
(million tonnes)

	Open Cut	Underground	Total
New South Wales	13,929	19,507	33,436 (48%)
Queensland	14,375	21,678	36,053 (52%)
Total	28,304 (~41%)	41,185 (59%)	69,489 (100%) (100%)

*Measured plus indicated, i.e. based on bore cores at 1 km and 2 km intervals respectively.

mining techniques since they occur within 200 m of the surface in seams greater than 0.3 m thick and at an overburden to coal ratio no greater than 10:1. The resources considered amenable to underground mining include only coals with less than 35% ash yield in seams at least 1.5 m thick within 600 m of the surface.

These black coal resources cover a wide range of ranks and petrographic type encompassing low to medium volatile through to high volatile thermal and coking coals in both New South Wales and Queensland as well as some sub-bituminous coals and semi-anthracites. The coals are predominantly Permian in age with the sub-bituminous coals being Triassic or Jurassic (Mesozoic).

Recent information (World Energy Conference, 1989) indicates that, with respect to recoverable black coal resources, those of Australia represent 4% of the world total and correspond to 25% of the USA total.

Brown Coal

Australia's brown coal resources occur in Victoria, South Australia and Western Australia with those of Victoria dominating. The total in-situ reserves in Victoria which occur within 300 m of the surface (Table 2) are estimated to be 207,973 M tonnes of which 158,026 M tonnes (75%) occur in the Latrobe Valley Depression to the east of Melbourne. (Available information indicates that the total resources in all the other States amount to about 6000 M tonnes with none being currently mined). The total measured plus indicated reserves in Victoria, i.e. those yielding no more than 10% ash (dry basis) in seams not less than 3 m thick within 300 m of the surface and having an overburden to coal ratio no higher than 2:1, are estimated to be 96,300 M tonnes of which 86,200 M tonnes (89%) occur in the Latrobe Valley where coal seams average 137 m (450 feet) in thickness over an area of 4636 hectares (179 square miles), under very shallow overburden cover.

It is interesting to compare, on an equivalent basis, the brown coal resources of the Gippsland Basin in Victoria with those of the Fort Union Basin in the USA which underlies portions of Montana, North Dakota and South

Dakota. The latter is considered to be the largest coal basin in the world (US Dept. of Interior, 1980). The total identified coal resources in the Fort Union Basin, down to 300 m in seams exceeding 2.5 feet (0.76 m) in thickness is 465,000 M tonnes. This is far greater than the equipment for the Gippsland Basin down to 300 m which is 134,874 M tonnes. With regard to the reserves regarded as "strippable", however, those of the Gippsland Basin (96,300 M tonnes) exceed considerably those of the Fort Union Basin (26,300 M tonnes). The World Energy Conference (1989) figures for proved recoverable reserves of lignites (brown coals) indicate that the Australian brown coals represent 11% of the world's total whereas those of North America (Canada plus USA) amount to 6%.

TABLE 2

VICTORIAN BROWN COAL RESOURCES
(million tonnes)

		Resources	(%)	Reserves*
Gippsland Basin - Latrobe Valley	(90)	158,026		
- Other		14,848		
	(100)	172,874	(83)	96,300
Murray Basin		19,599		
Otway Basin		15,500		
Total		207,973	(100)	

*Includes only coal with 10% ash yield maximum in seams not less than 3 m thick with less than 300 m of overburden, and an overburden to coal ratio no more than 2:1.

The Latrobe Valley brown coals are of low rank having high moisture contents in the range 60 to 66% in situ. The ash yields, however, are very low being typically less than 3.5% (dry basis) and frequently less than 1% in some locations.

COAL PRODUCTION

Black Coal

The raw black coal production in Australia (Table 3) increased from 52.3 M tonnes in 1970 to 93.6 M tonnes in 1980 to 158 M tonnes in 1985 and 171 M tonnes in 1988. The corresponding saleable coal production was 45.2, 76.5, 129.4 and 141 M tonnes respectively for 1970, 1980, 1985 and 1988 as a consequence of the washing of all the metallurgical coal production and virtually of all the coal destined for export. (Joint Coal Board, 1989; Queensland Coal Board, 1989).

In 1988 almost 69% of the saleable black coal production was from open cut mines (Table 4). In Queensland, however, the corresponding figure was

94.3%. Queensland's sealeable production exceeded that of NSW for the first time in 1988, i.e. 68.6 compared with 65.7 M tonnes.

TABLE 3

RAW AND SALEABLE BLACK COAL PRODUCTION 1970 TO 1988
(million tonnes)

	1970	1980	1985	1988
Raw Coal - NSW	35.9	50.7	75.0	78.3
- Queensland	13.2	37.8	76.7	86.2
- Other*	3.2	5.1	6.3	6.8
- Total	52.3	93.6	158.0	171
Saleable Coal - NSW	31.7	42.7	62.3	65.7
- Queensland	10.5	28.8	61.0	68.6
- Other*	3.0	5.0	6.1	6.7
- Total	45.2	76.5	129.4	141.0
	(86.4)**	(81.7)	(81.9)	(82.4)

*South Australia, Tasmania and Western Australia
**Saleable coal production as percentage of raw coal production

TABLE 4

SALEABLE BLACK COAL PRODUCTION IN 1988 - BY STATE AND MINING TECHNIQUE
(million tonnes)

	Open Cut	Underground	Total
N.S.W.	26.7	39.1	65.8
Queensland	64.7	3.9	68.6
Other	5.5	-	6.6
Total Australian	96.9	43.0	141.0

The coal produced in 1988 was obtained from 68 mines in New South Wales, 51 underground and 17 open cut, and 37 mines in Queensland, 11 underground and 26 open cut. This represents an overall reduction from 89 mines in NSW and 52 in Queensland in 1985 reflecting the closure of 17 underground 4 open cut mines in NSW and of 12 underground and 3 open cut mines in Queensland. These closures all involved old low capacity, high cost mines. The 25 largest mines have annual raw coal production capacities in the range 1.7 to 6.6 M tonnes per year, with all but two at the lower capacity being open cut mines. These 25 mines, 9 in NSW, 14 in Queensland, 1 in South Australia, and 1 in Western Australia, together, accounted for 75% of the total production in 1986.

Brown Coal

Brown coal production mainly from three large open cut mines in the Latrobe Valley, Victoria increased from 21 M tonnes in 1970 to 31 M tonnes in 1980, then to 37 M tonnes in 1985 and 42 M tonnes in 1988 (State Electricity Commission of Victoria, 1988).

CONSUMPTION

Black Coal

The consumption of black coal in Australia (Table 5) increased from 25.1 M tonnes in 1970 to 36.4 M tonnes in 1980, 41.9 M tonnes in 1985 and 48.3 M tonnes in 1988. This represented 55%, 47%, 32% and 34% respectively of the total saleable coal production (Table 3) with the balance being exported.

TABLE 5

CONSUMPTION OF BLACK COAL IN AUSTRALIA, 1980 TO 1988
(million tonnes)

	1970	1980	1985	1988
Electricity generation	12.8	24.6	30.7	35.6
Iron and steel	7.9	8.2	6.3	7.6
Foundry coke	0.54	0.84	0.36	0.50
Cement industry	0.85	0.90	1.0	0.75
Alumina refining		1.2	1.5	1.8
Other	3.0	1.2	1.9	2.1
Total	25.1	36.4	41.9	48.3
(%)*	(56)	(47.6)	(32.4)	(34.2)

*percentage of saleable production

Electricity generation provides the major domestic market for black coal with the iron and steel industry being the second largest user. These two activities accounted for 67% and 22% respectively of the domestic consumption in 1980 and 74% and 16% respectively in 1988, i.e. 90% of the domestic consumption. Most of the steady annual increase in domestic demand is accounted for by the electricity industry.

Brown Coal

In Victoria 95% of the brown coal produced in 1988 was used to generate 84% of the electricity used in the State (Higgins, 1989). Most of the remainder was used to produce binderless briquettes (813,000 M tonnes). The latter are used as fuel in industry and homes (73%), as feedstock for lump char production (18%) and the remainder (9%) is exported.

EXPORTS

Black Coal

The export of Australian black coals (Table 6), exclusively from New South Wales and Queensland, increased from 18.3 M tonnes in 1970 to 99.6 M tonnes in 1988. In 1970 metallurgical (coking) coals accounted for 92% of the coal exported and 45% of the total saleable production. By 1988 metallurgical coal exports, although showing a 70% increase over those in 1970, accounted for only 56% of the exports due to a rapid increase in the exports of steam coals from a low figure of 1.4 million tonnes in 1970 to 43.6 million tonnes in 1988.

TABLE 6

AUSTRALIAN BLACK COAL EXPORTS, 1970 TO 1988
(million tonnes)

State	Type	1970	1980	1985	1988
NSW	Metallurgical	10.0	14.7	16.8	16.9
	Steam	1.3	8.2	23.9	25.0
Queensland	Metallurgical	6.9	19.2	32.9	39.1
	Steam	0.1	0.7	14.2	18.6
Australia	Metallurgical	16.9	33.9	49.7	56.0
	Steam	1.4	8.9	38.1	43.6
	Total	18.3	42.8	87.9	99.6
	(%)*	(40.5)	(55.9)	(67.9)	70.6)

*Percentage of saleable production

The rapid increase in the export demand for steam coal which commenced in the late 1970's has been a consequence of the OPEC oil embargoes and the associated marked increases in oil prices in 1973 and 1979 which led to a renewed interest in coal as an energy source.

Other interesting facts on the Australian coal scene are indicated by Table 6 and a comparison with Table 5. Firstly, coal exports have exceeded domestic coal consumption since 1976 and currently account for about 70% of the saleable coal production. This shows that the major proportion of installed coal production capacity is dedicated to serving the export market. This places Australia in a unique position relative to other coal exporting countries where coal exports represent a minor part of the annual production, i.e. seaborne coal exports (Table 7) represent 7.9%, 24.0%, 16.5% and 53.8% for the USA, South Africa, Poland and Canada respectively in 1988.

TABLE 7

COMPARISON OF BLACK COAL PRODUCTION AND SEABORNE EXPORTS FOR MAJOR COAL EXPORTING COUNTRIES IN 1988
(million tonnes)

Country [a]	Production	Exports Metallurgical	Exports Steam	Exports Total	(%)
Australia	141.0	56.0	43.6	99.6	(70.6)
USA*	863	49.0	19.0	68.0	(7.9)
S. Africa [b]	177.6	1.5	41.1	42.6	(24.0)
Poland**	193	11.0	21.1	32.1	(16.5)
Canada*	58.5	27.4	4.1	31.5	(53.8)
China	975	<2	<14	15.0	

*Seaborne exports only - USA also exported 16.3 M tonnes of coal to Canada in 1988 (6.3 M tonnes metallurgical and 10.0 M tonnes steam). This effectively reduces Canada's coal exports relative to black coal availability to 42.1%.
** Total exports including seaborne - about 50% to Western World

Source (a) Depart of Primary Industry and Energy (Australia), 1989
(b) South African Coal Report, Issue 1.2, April 1990

Secondly, metallurgical coal exports still represent 56% of the total black coal export but Queensland has displaced NSW as the major supplier of metallurgical coal (since 1972) supplying 66% of the exports in 1988. Steam coal exports have increased dramatically (since 1974) with New South Wales supplying 63% of the total.

Internationally, Australia now leads in the seaborne exports of both metallurgical and steam coals (Table 7). In 1988 Australia supplied 34.8% of the World seaborne trade in metallurgical coal which was 161 M tonnes compared with 30.4% for the USA. For steam coal Australia supplied 30% of the total World seaborne trade of 145 million tonnes compared with 28.3% for South Africa and 13.1% for the USA (DPIE, 1989).

Ports

As mentioned above Australia's major black coal resources, and hence the coal mines are situated along the eastern seaboard, in New South Wales and Queensland. The coal is presently transported to a nearby port by rail over distances that range from 20 km to 320 km. NSW is serviced by 3 coal ports and Queensland by 4. The current total annual port capacity is 148.5 M tonnes, 62.5 M tonnes in NSW and 86 M tonnes in Queensland. At NSW ports the maximum size of vessels that can be handled ranges from 60,000 DWT to 180,000 DWT. At Queensland ports the maximum size varies from 65,000 to 220,000 DWT.

Destinations

Any consideration of Australia's coal exports is incomplete without mention of the destination. In 1988 NSW and Queensland exported coal to 20 and 28 countries respectively in Asia, Europe and elsewhere, Japan is, by far, the leading customer for both metallurgical and steam coals accounting for 43% and 51% respectively of the total Australian exports (Table 8), supplying 69% and 41% respectively of Japan's imports.

TABLE 8

DESTINATIONS OF AUSTRALIA'S COAL EXPORTS 1988
(million tonnes)

Region	Metallurgical	Steam	Total
Japan	27.9	22.9	50.8
Other SE Asia[a]	7.3	10.5	17.8
Other Asia[b]	5.0	2.6	7.6
Europe[c]	11.7	6.6	18.3
Other Countries[d]	4.1	1.0	5.1
Total	56.0	43.6	99.6

(a) Hong Kong, Indonesia, S. Korea, Malaysia, Philippines, Taiwan, Vietnam
(b) India, Israel, Pakistan, Turkey
(c) 10 countries
(d) Brazil, New Caledonia, United States

Brown Coal

Brown coals because of their high moisture content as mined, virtually two thirds, and high propensity to heating leading to spontaneous combustion during drying and when dry, are not amenable to transport over even relatively short distances. However, as briquettes, Latrobe Valley (Yallourn seam) brown coal has been successfully exported on a modest scale i.e. 75,000 tonnes in 1987/88 mainly for use as a domestic fuel in the importing countries.

REASONS FOR AUSTRALIA'S PROMINENCE AS A BLACK COAL EXPORTER

A number of factors have contributed to Australia featuring prominently as an exporter of both metallurgical and thermal coals from the early 1960's eventually displacing the USA as the leading exporter of seaborne coal in 1984. These are:

1) The extensive coal resource base close to ports, in thick seams close to the surface which includes a wide range of coal types suitable for use as metallurgical and thermal coals.

2) The application of the latest coal mining technology to the mechanisation of existing underground mines and in new underground and open cut mines established to service the export market.

3) The proximity of Australia to its initial and largest customer, Japan.

4) The policy of using the latest coal preparation technology to wash all metallurgical coal and virtually all export thermal coal. This aided by product blending affects both close quality control and quality assurance to enable all shipments against a contract to meet the required specification. About 75% of the coal produced in NSW is washed. The corresponding figure for Queensland is 90%.

5) The low sulphur content and the high ash fusion temperatures of most Australian black coals.

6) The perceived political and economic stability of Australia.

A key factor that stimulated the early interest of the Japanese Steel Mills, at a time when Japan as a nation decided on a complete modernization of their iron and steel industry, using the then best available technology worldwide (a decision that laid the basis for the current economic dominance of modern Japan), was the existence of an extensive and growing knowledge base on the chemical and physical characteristics of Australian coals. This was initiated in 1947 by CSIRO (then CSIR) and the CSIRO reports were studied in detail by the Japanese and some were even translated from cover to cover into Japanese.

With the renewed interest in coal as an energy source that resulted from the OPEC initiatives relating to oil prices and supply in 1973 and 1979 Australia was well poised to supply thermal coal into overseas markets as well as metallurgical coals.

It has not all been easy for the Australian coal industry, however, and in recent years much of the industry has operated at a loss while at the same time the exports of metallurgical and thermal coals continued to expand. The factors that have contributed to this have been, on the one hand, the fall in oil prices as OPEC has struggled to increase its share of the world oil market which provides a marker for setting the price of coal as a fuel and, on the other hand increases in the FOB costs of coal beyond the direct control of the coal industry. The latter have included:- unrealistic front end government charges in the form of royalties and levies, and for the provision of infrastructure services (rail transport, and port); the high cost of capital and the effect on capital requirements of the prolonged delays involved in processing through many government bodies environmental impact studies etc to obtain permission to start a new mine; restrictive work practices, together with a multitude of unions and consequent demarcation problems, which resulted in expensive items of equipment lying idle for much of each week; unrealistic wage bonus and penalty, and employment demands by the unions, with stoppages to win these demands, many of which were stimulated by the moves of mine owners to introduce new technology to increase productivity and efficiency hence to reduce costs. It has taken the downturn in the profitability of the industry and the closing of a number of high cost mines (36 since 1986 - see above) for unions, government and coal industry management to recognize the need to work together if Australia is to maintain and improve its competitive position as an international supplier of high quality coal. Over the past year significant changes in work practices etc have been negotiated which have helped increase productivity and reduce costs. This trend together with increases in the prices being received for metallurgical and steam coals is helping the industry to begin to move into profitability.

RESEARCH AND DEVELOPMENT AND NEW TECHNOLOGY FOR THE COAL INDUSTRY

The Australian coal industry has been progressive in applying, adapting to local conditions as required, coal mining and coal preparation technology developed overseas. In addition the industry has been backed by wide ranging coal related research and development (R&D) activities essentially commencing with the establishment by CSIRO (then CSIR) in 1947 the Coal Research Section (which has now become, after many changes, the present Division of Coal and Energy Technology) to undertake a systematic study of the physical and chemical characteristics of both Australia's black and brown coal resources. The subsequent development of coal R&D in Australia with regard to the establishment of industry government and academic laboratories, and to the topics addressed and the circumstances influencing changes in emphasis from time to time makes an interesting story in itself, but not for now.

Interest in coal and hence support for coal research reached a low ebb in the late 1960's as elsewhere when oil supplies were abundant and cheap and with oil being a more convenient fuel to transport, store and use. This all changed in the mid to late 1970's due to the OPEC initiatives which focussed the attention of the Western World on their heavy dependence on oil as an energy source and on oil from OPEC members in the politically unstable Middle East. This renewed interest in coal as an energy source both directly where it can be so used and as a feedstock for the production of gaseous and liquid fuels. Australia was no exception here. Although fortunate in having the electricity industry firmly based on coal (61% of the coal produced used to generate over 80% of the electricity needed the major energy demand sector (51% of total energy needs in 1973) was for oil with over half of the latter being fuel for transport. At the time Australia was about 65% self sufficient with respect to crude oil but indigenous oil reserves represented, in energy terms, less than 1% of Australia's fossil fuel energy resources (excluding oil shale) whereas coal represented over 97%.

In recognition of the significant existing dependence on imported oil, and the prospect that in the absence of any significant new oil discoveries self sufficiency is projected to be down to ~36% by 2000 (ABARE 1989), the Federal Government in 1977 implemented a levy of 5 cents/tonne on all saleable coal produced in the country to establish a Coal R&D Trust Fund and created the National Energy Research, Development and Demonstration Council (NERDDC). The latter was charged with the responsibility of funding R&D relevant to the realization of the Government's energy policy which was to maintain and increase Australia's self sufficiency in all forms of energy. The initiatives taken were directed to replacing oil by coal directly whenever practical, increasing the efficiency of energy use in all forms, the production of liquid and gaseous fuels from coals and other feedstocks and increasing the use of renewable energy sources, all in a manner that was environmentally responsible. NERDDC was charged with the responsibility of allocating funds derived from the Coal Research Trust Fund Levy together with energy research funds provided by the Government.

The initial emphasis was on Australia's energy needs but later research to help the export of Australian coals was included on the basis that overseas revenue earned in the export of energy as coal could offset the cost of importing energy as oil. In the coal area NERDDC has supported research in coal mining and preparation technology, and coal utilization including an extensive program related to the production of oil from coal, as well as research directed to improving the knowledge of the nature of coals as an important national resource. The ready availability of crude oil at relatively low cost in recent years, however, has lulled the sense of urgency and, as elsewhere, interest in coal conversion has waned, at least for the time being.

Although the NERDD program has made a significant contribution to advancing the science and technology of Australian coals the Federal Government, as part of its policy to replace the present government research funding organizations by industry based R & D Boards, is in the process of replacing the NERDD Council by an Energy R & D Corporation and a Coal R & D Corporation. There are, however, some problems relating to the latter than remain to be resolved with the coal industry.

Brown Coal

With regard to the theme and venue of the present conference and the differences between black and brown coals the latter require special comments on technology transfer and R & D in Australia. Firstly, it is of interest to recall that in 1956 the Gas and Fuel Corporation successfully commissioned and operated a brown coal gasification plant based on Lurgi high pressure steam-oxygen gasifiers to supply town gas to Melbourne. The brown coal was supplied to the gasifiers as briquettes (180,000 tonnes per year). Further expansion was planned but the discovery of natural gas resulted in the gasification plant being closed down in 1969 (Higgins, Allardice and Perry, 1988).

A more recent activity has been the Japanese financed Brown Coal Liquefaction (Victoria) Pty Ltd (BCLV) project. This project involved the construction and operation of a pilot plant at Morwell, Victoria for converting 50 tonnes per day (dry basis) of brown coal in a two stage process to naphthene and middle distillate (Higgins, Allardice and Perry, 1988). The project which has involved an expenditure in excess of A$700 million (US$540 million) including over A$500 million (US$390 million) in capital coals is scheduled to conclude in September 1990. The decision to construct this plant was based on the previously proven reactivity of Victorian brown coals, their low ash yield, and the extent of the resource. The technical feasibility has been established by the current oil supply and economic considerations do not justify a move to a commercial plant at this stage.

The extensive brown coal resources of Victoria are seen by the State Government as providing major opportunities to contribute to the economic development of the State. To this end the Coal Corporation of Victoria was established in 1985 to initiate, facilitate and co-ordinate brown coal based developments, other than for electricity generation. It is recognized by the Coal Corporation that these opportunities depend primarily on the production of value-added products using new and improved technologies. Thus considerable importance is being placed on R & D in the Corporations own Laboratories, in tertiary institutions and in CSIRO, with current emphasis on activated carbons, ion exchange materials, humic acids and agricultural applications. However, the opportunity for enhancement of the value of brown coals as a fuel is not being overlooked (Higgins, Allardice and Perry, 1988).

Before leaving the subject of technology and R & D in the Australian coal industry the advanced technology involved in the mining of very thick brown coal seams under low overburdens, the reverse of the German situation, as well as for the efficient combustion in power station boilers of a fuel which contains over 60% water needs brief mention. The State Electricity Commission of Victoria have 4960 Mwe installed generating capacity involving the use of brown coal fired boilers up to 500 Mw in size. These operations and the future development of brown coal based electric power generation in the State are backed by their own Herman Research Laboratories.

FUTURE MARKETS FOR AUSTRALIAN COALS

It remains to consider the future prospects for Australian coals. In doing this the black and brown coals need to be considered separately in the context of the domestic and export markets.

Black Coal

The first point to be made is that the coal resource base is of such a size and quality as to pose no constraint on a significant increase in production over the foreseeable future.

Recent forecasts (DPIE, 1990) suggest a continued strong growth in black coal demand in the domestic market from 48.3 M tonnes in 1988 to 60.8 M tonnes in 1995 with steam coals representing 90% of the projected 26% increase, i.e. predominantly for the electricity sector (Table 9).

Three recent forecasts of the demand for imported coals by the major coal importing countries out to 1995 and 2000 are summarized in Table 10 (DPIE, 1989; IEA 1989; and ABARE 1990). The DPIE forecast is for a 33% increase over 1988 in the World demand for imported coal to 403 M tonnes in 1995. Australia's exports are forecast to increase by 48% over the same period to 148 M tonnes in 1995 which would represent a further gain in Australia's share of the market from 33% in 1988 to 36% in 1995. Steam coals represents the major portion of the forecast increase in both the world coal exports and Australia's exports, Japan's share of Australia's coal exports is forecast to increase to almost 62% in 1995 compared with 51% in 1988.

TABLE 9

FORECAST DOMESTIC CONSUMPTION OF AUSTRALIAN BLACK COALS 1995
(million tonnes)

	1988	1995
Metallurgical	5.0	9.2
Steam	40.3	51.6
	48.3	60.8
Total Exports	99.6	137.0
Total Production	147.9	197.8

DPIE, 1989

TABLE 10

FORECASTS OF WORLD IMPORTS OF BLACK COAL
AND AUSTRALIAN EXPORTS
(million tonnes)

SOURCES:*	DPIE (1989)		IEA (1989)		ABARE (1990)	
	1988	1995	1995	2000	1995	2000
Australian Exports:						
Metallurgical	56.0	64.0	69	68	73	75
Steam	43.6	83.9	57	78	68	97
Total	94.6	147.9	126	146	141	172
World Imports:						
Metallurgical	162.4	172.4	165	169	171	181
Steam	140.8	230.4	210	285	236	345
	303.2	402.8	375	454	407	526

*DPIE - Department of Primary Industries and Energy (Australia)
IEA - International Energy Agency
ABARE - Australian Bureau of Agricultural and Resource Economics

The IEA forecasts are more conservative out to 1995 for the world coal import requirements but a figure of 454 M tonnes is forecast for year 2000 with Australia's contribution at 146 M tonnes remaining at 33%. This spread reflects differences in the basis of the forecasts but either way significant increases in the demand for Australian black coals are anticipated.

ABARE have made an estimate of the impact of the progressive removal of the heavy coal producer subsidies paid in European countries and Japan (e.g. US$91 in the German Federal Republic, US$96 in Belgium and US$93 in Japan in 1987) on the local coal industry and hence the world demand for imported coal and Australia's share as an exporter. Using the IEA 1989 forecasts as base the world import requirements was predicted to increase by 199 M tonnes to 526 M tonnes in 2000 and Australia's exports by 31 M tonnes to 172 M tonnes or 33% of the total.

Brown Coals

There are no readily available forecasts for brown coal markets, since these do not feature significantly in the export trade. Expansion in demand and hence production will largely be tied to increases in demand for electricity. However, as current research initiatives mature it can be anticipated that increasing amounts of brown coal will be processed into value added products such as activated carbons, ion exchange materials, soil conditioners and fertilizers and to assist in the immobilization of undesirable components on gaseous and liquid effluents.

There are no immediate prospects for the commercial production of gaseous or liquid fuels from brown coals in Australia. However, as the availability for non OPEC oil declines, as it surely will, and oil prices increase significantly it should become economically feasible and strategically necessary to establish a significant synfuel industry in Australia. On the basis of the extensive work done to date on the conversion of Australian coals it seems likely that the initial focus will be on Victorian brown coals.

Environmental Implications

The above forecasts on future markets have been made in the presence of the present emotive concerns about the impact of fossil fuel use on the environment, particularly with regard to carbon dioxide input into the environment and its predicted contribution to global warming and climate changes. Also amongst the fossil fuels coal is seen to be a higher contributor of CO_2 to the atmosphere per unit of energy produced than oil or natural gas.

Although the actual impact of a continuing increase of CO_2 in the atmosphere remains a subject of debate the public and media attention to the matter increases the risk that governments could prematurely move to legislate economic penalties on energy use that could cause economic chaos with little or no impact on the global scene. It is therefore prudent that the coal industry addresses the problem and be seen to be concerned, despite the uncertainties. It makes both environmental and economic sense to undertake R & D to improve the efficiency of coal use to maximize useable energy production while minimizing CO_2 emission. Synfuel production could well have an important role here. Coal is well placed relative to other fossil fuels with respect to the potential for affecting significant control of CO_2 emission because most of it is used in large amounts at central plants rather than being distributed to a multitude of users.

CONCLUDING COMMENTS

Australia has become the major seaborne exporter of both metallurgical and steam coal. The import demand for coal is expected to continue to increase into the foreseeable future with the emphasis on steam coals and it is anticipated that Australia will retain a dominant position as exporter.

Coal is a significant contributor to Australia's own energy requirements being the major fuel for electricity generation. This situation is expected to continue as the demand for electricity increases. However, Australia is unique amongst the major coal exporters since most of the coal production capacity has been established to service export markets.

R & D has contributed significantly to the technological advancement in coal mining, preparation and use in Australia and elsewhere. There remains much scope for further advances to decrease production costs, enhance quality and to increase efficiency in use as well as developing new uses. This applies to both black and brown coals.

The coal industry worldwide operates in a continuing environment of challenge and opportunity. Through the 1980's the world energy scene has been focussed on the limited and rapidly declining reserves of oil and gas and the urgent need to maximize the use of coal because of its relatively high abudance and wide distribution. At the same time the need to protect the environment from sulphur and nitrogen oxides emissions was recognized. this stimulated worldwide interest in the production of clean solid, liquid and gaseous fuels from coals to either produce a clean fuel for use in electricity generation from high sulphur coals (as in the USA) or to supplement indigeneous gas or liquid fuel supplies (as in Australia and the USA).

A combination of the delayed economic impact of the OPEC actions in the 1970's and the effect of initiatives taken as a result of these actions created a situation where the availability of oil and its cost was such as to allay concern for the need for conservation of liquid and gaseous fuels and interest in synfuels from coals (and other feedstocks) declined. However, this situation can only be transient.

Now another challenge arises - that relating to an enhanced greenhouse effect due to build up of carbon dioxide in the atmosphere. In the rush to address this issue the need for conservation of liquid and gaseous fuels has been lost as oil and gas are being promoted as preferential fuels to coal in relation to greenhouse gas emissions as CO_2. As mentioned in the previous section however coal offers its own advantages which the industry should be quick to promote.

ACKNOWLEDGEMENTS

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"PROSPECTS AND CONSTRAINTS IN THE USE OF COAL IN ITALY"

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PROSPECTS AND CONSTRAINTS IN THE USE OF COAL IN ITALY

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ABSTRACT

Italy is heavily dependent on energy imports (80% of energy consumption) and on oil in particular.

To better balance our energy mix, we plan to double in ten years our coal imports and consumption.

An analysis is given on the reasons of our past scarce coal use and on the actions to be taken in the future to reach our goal.

HYDROCARBONS DEPENDENCE

The chronic and unusual, among industrialized countries, Italian dependence on hydrocarbons characterizes our energy scene.

As shown in tab. 1, in spite of two serious energy crises, our reliance on hydrocarbons has remained substantially stable. In addition, the most part of energy (80%) is imported; in particular we import 100% of coal and 90% of oil.

This fact is underlined by the Italian energy trade balance (17500 billion lire) which, even in a period of low prices, is comparatively high.

This situation points out the vulnerability of our energy supply and calls for a more balanced energy mix.

SCARCE COAL USE

The various sources contribute differently to the deficit. Coal, while representing 10% of the energy imports, accounts for only 7% of the trade deficit.

Given this situation, coal should expand its role, at least where its use is more suitable.

This target has been clear for a long time, by now, but it is difficult to pursue.

In fact, coal utilization increase has not been up to expectations. Tab. 2 shows the coal consumption in 1989. The increase is mainly due to the thermoelectric sector and to the cement industry, and it is linked, to a large extent, to existing power stations and industrial plants designed for, or easily retrofitted to, coal. Little, if any, have contributed new power stations or industrial boilers specifically designed for coal usage. As shown in fig. 1, only 20% of electricity produced from fuels is produced from coal, another 20% from NG, the remaining from fuel oil.

Nevertheless Italy, as indicated by the New Energy Plan, is still committed to increase its coal use. By the year 2000 Italy should double present coal consumption and increase coal share from 10 to 16% (fig. 2).

We aim at that target, but in order to achieve it, we have, first, to understand why the coal use grew so slowly in the last 15 years and how we can overcome past difficulties.

In tab. 3 there are some possible answers to the first question.

Slow turnover

A slow turnover of the power stations and of the industrial boilers was certainly a factor, but probably not the most significant.

As a matter of fact industry has put off construction of new thermal plants (fig. 3) as a consequence of the industrial restructuring and/or of energy saving programs.

Logistic problems

They regard coal ports and, more generally, coal distribution.
Tab. 4 shows the handling capability of our coal ports, along with the maximum tonnage allowed for the carriers.

The present situation is inadequate both from the point of view of the transportation cost, decreasing with the size of the carriers, and from the point of view of the unloading and stockpiling capability.

Moreover, the ability to distribute coal in the mainland is quite modest. Especially the railways are unable to transport large quantities of coal; consequently the present logistics are able to supply only those users who are close to the coal ports.

Environmental problems

The public opinion regards coal use as having an environmental impact higher than other sources, although, for some aspects, coal is intrinsically less pollutant than high sulphur fuel oil.

Public acceptance

In Italy a coal tradition does not exist. Our lack of familiarity with coal use is one of the main reasons for the strong public opposition.

Lack of demonstration projects

For this reason was not possible to prove that coal can comply with the environmental standards to a level equal or better than competing fuels. In Italy only one medium size power station is equipped with a spray scrubber, which is not the most efficient technology to abate SO_2 emissions; no power station is fitted with a denitrification system.

The insufficient demonstration of clean coal technologies, compounded with the unfamiliarity of the public opinion with coal, adds fuel to hostility towards new plants.

This vicious circle has to be broken.

ACTIONS TO BE TAKEN

With this background, in order to increase coal acceptance and actually develop coal utilization, the following steps should be carried out:

- demonstration of technologies which comply with strict environmental limits;
- debottlenecking of the logistic system, by relying on technologies able to handle coal easily and in a manner similar to liquid fuels;
- development of technologies suitable to retrofit existing, oil designed plants;
- issuing of regulations able to promote coal use in new plants or, at least, calling for a design compatible with future coal use (multifuel power stations and boiler).

Only if we succeed in implementing a consistent and integrated action plan, along these lines, we will be able to effectively tackle the problem of energy diversification, and coal use, in our country.

On all these topics there are some activities; in particular we mention the more advanced projects.

Sulcis coal exploitation

In the near future will start the exploitation of the Sulcis coal in Sardinia.

This coal, due to high sulphur content (roughly 7%), needs an environmentally suitable technology.

For this reason ENEL will install a desulphurization plant on Sulcis 720 MWe power plant and will probably built an IGCC plant.

New technologies

ENI's companies and ENEL are actively involved in R&D on new technologies.

In particular Snamprogetti (ENI group) built a 256 km coal-water pipeline in USSR and retrofitted a 670 t steam/h boiler at the arrival power station in Novosibirsk; still Snamprogetti is building a 500.000 t/y BCWF (beneficiated coal water fuel) plant in Sardinia.

ENEL (still considering CWF uneconomic in the present Italian situation) tested 4000 t of CWF in a power plant and successfully studied a new dual burner to very shortly switch from fuel oil to CWF and vice versa.

Finally, ENEL is building a 150 MWe CFBC plant and Snamprogetti will build an air-cooled PFBC 3.5 MWe pilot plant.

Environment

On this topic, in addition to the before-mentioned activities, we point out the Enitricerche beneficiation process, the Snamprogetti-Topsoe process to remove NOx and SOx from combustion gases, and the ENEL activities on sorbent direct injection and on denitrification and desulphurization of gases.

TABLE 1

ITALY'S PRIMARY ENERGY CONSUMPTION ('89)

	SOLID FUELS	OIL	NATURAL GAS	ELECTRICITY	TOTAL
MTOE	14.6	93.7	37.0	16.0	161.3
%	9.1	58.1	22.9	9.9	100.0

TABLE 2

ITALY'S COAL CONSUMPTION ('89)

	STEELMAKING	ELECTRICITY	INDUSTRY	TOTAL
MTOE	6.7	6.1	0.7	13.5
%	49.6	45.2	5.2	100.0

TABLE 3

CONSTRAINTS TO COAL EXPANSION

- SLOW TURNOVER OF THE POWER STATIONS AND OF THE INDUSTRIAL BOILERS
- LOGISTIC PROBLEMS IN THE COAL PORTS AND MORE GENERALLY IN COAL DISTRIBUTION
- ENVIRONMENTAL PROBLEMS
- PUBLIC ACCEPTANCE
- LACK OF DEMONSTRATION PROJECTS FOR NEW TECHNOLOGIES

TABLE 4

MAIN STEAM COAL PORTS IN ITALY

PORT	DWT	DRAFT m	UNLOADING RATE t/h
BRINDISI	60000	13	1500
GENOVA	50000	12	300
GIOIA TAURO	80000	14	4500
FUSINA	25000	9	2000
LA SPEZIA	65000	12.5	1100
MARGHERA	40000	10.5	250
MONFALCONE	10000	8	800
PORTO VESME	15000	8.5	450
SAVONA	40000	9.7	1500
TRIESTE	150000	17.5	1800
VADO LIGURE	50000	12.5	800

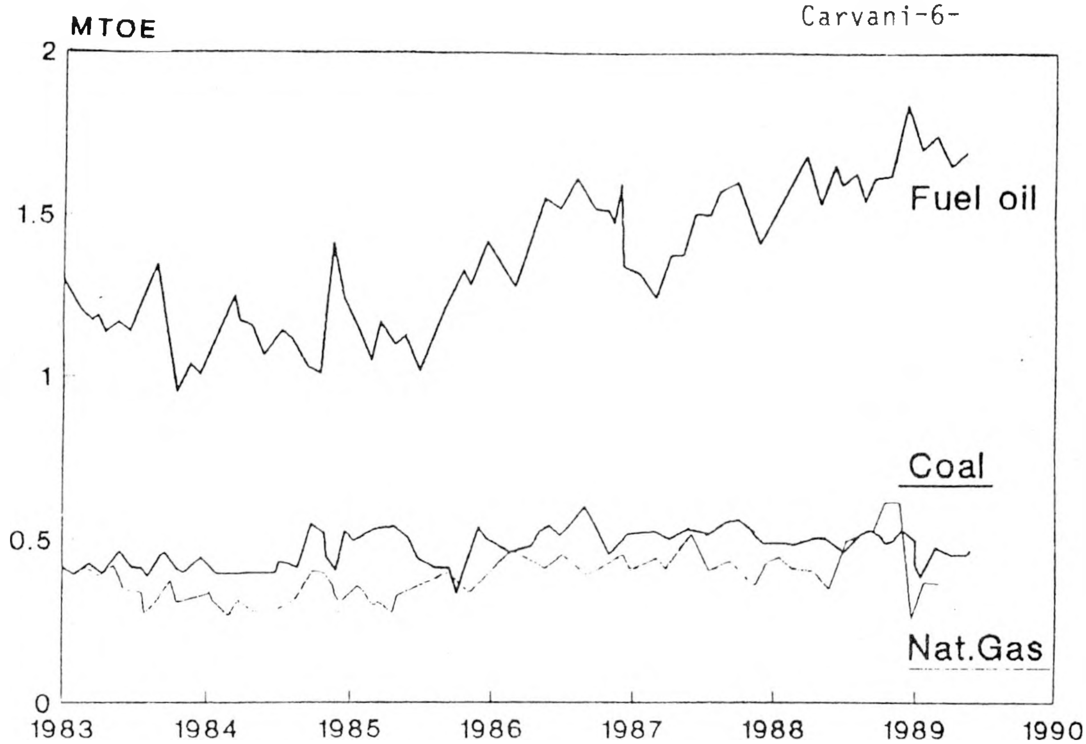

FIGURE 1: FUEL DEMAND DISTRIBUTION FOR THERMOELECTRIC PRODUCTION (MONTHLY BASIS)

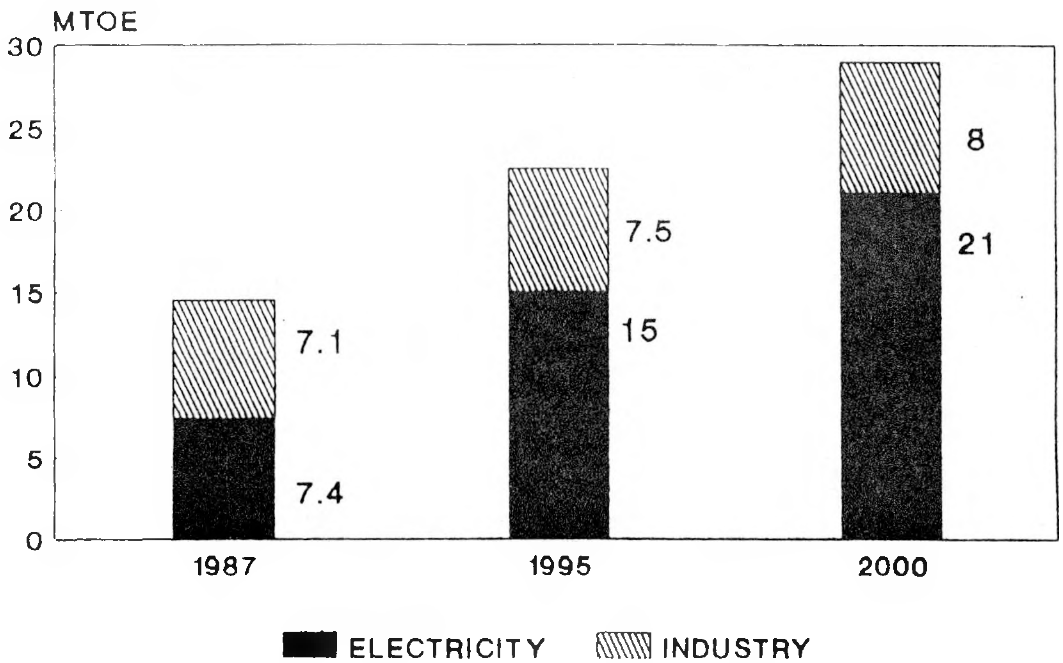

FIGURE 2: FUTURE COAL CONSUMPTION AS INDICATED BY NATIONAL ENERGY PLAN

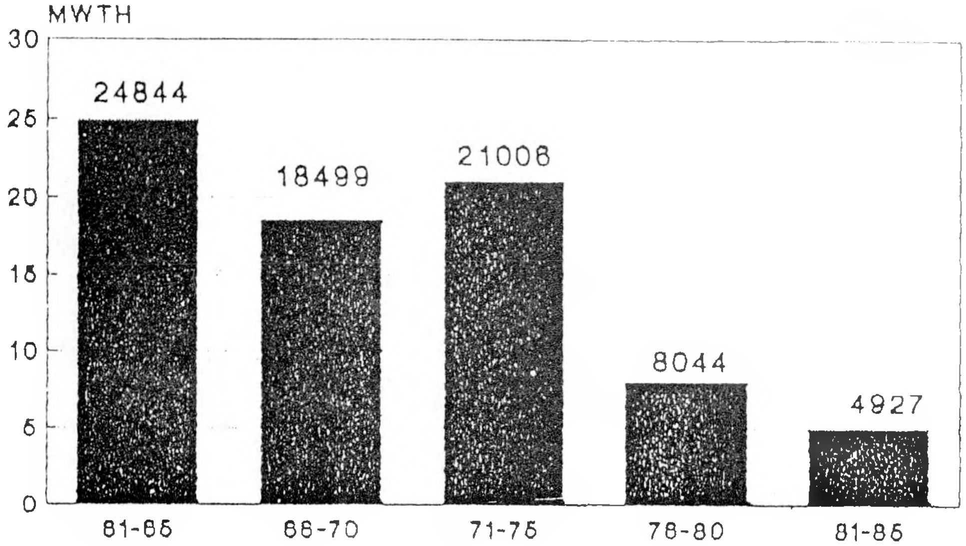

FIGURE 3: NEW THERMAL PLANTS

"U.S. COAL EXPORT OPPORTUNITIES"

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U.S. COAL EXPORT OPPORTUNITIES

Good afternoon ladies and gentlemen. It is indeed an honor for me to speak at the SynOps '90 Conference on behalf of Mobil Mining and Minerals Company, a division of Mobil Oil Corporation. I have been asked to talk to you today about the export opportunities for U.S. coal.

As you know, ever since U.S. steam coal exports surged and then suddenly collapsed in the early 1980S, U.S. suppliers have been looking forward to a major and long lasting rebound in the steam coal export market. Strong growth opportunities always seem to be just around the corner, but for one reason or another expectations haven't been realized. Is the United States now on the verge of significantly expanding its export market share or are we destined to remain a swing supplier that simply fills the gap when supplies from lower cost export sources are tight?

Realistically, one cannot address this question without first examining the outlook for internationally traded steam coals. I have opted to focus my discussion on steam coal trade and omit the metallurgical coal arena since most industry analysts believe that steam coal will represent most, if not all, of the growth in international coal trade. Met coal demand is not expected to change materially in the future - despite a projected increase in crude steel production - due to advances in steel making technology which will lower the consumption of coke needed per unit of steel production.

Exhibit 1 shows three published forecasts for world seaborne trade in steam coal which are considered representative of the prevailing industry outlook. One forecast is by the U.S. Energy Information Administration (EIA), an independent agency within the Department of Energy. A second is by Wharton Econometric Forecasting Associates (WEFA), a U.S. and U.K. based consulting firm involved in energy forecasting. The third is by the Australian Bureau of Agricultural and Resource Economics (ABARE), a research organization associated with the government. As you can see, all the forecasts are quite bullish about the prospects for growth in international steam coal trade. The EIA is at the top end of the range of projections forecasting that seaborne steam coal trade will more than double from 160 million tons in 1989 to almost 330 million tons in 2000. ABARE is on the lower end with a forecast of roughly 285 million tons in 2000, while WEFA is in the mid-stream of these industry projections. Mobil's outlook for international steam coal trade generally tracks WEFA'S.

As noted in Exhibit 2, all of these published forecasts are projecting that growth in steam coal trade will be strong in both the European/ Mediterranean region and Asia, with these two markets accounting for essentially all of the rise in trade between 1989 and 2000. To put the growth projections in perspective, actual 1989 imports to the two areas are shown on the right side of the exhibit. For presentation purposes, the small volume of imports to the Americas and various miscellaneous destinations has been included in the European/Mediterranean figures.

While both European and Asian steam coal imports are expected to increase substantially, the underlying factors driving the growth are different in each region. In Western Europe, most of the expansion in coal imports is expected to result from declining domestic production as countries such as West Germany, the United Kingdom, Spain and Poland close high cost, inefficient mines in response to the phase out of government subsidies and support programs. A contributing factor in some of the mine closures, such as those in Spain, will be environmental compliance programs to meet tightening European Community targets on power plant emissions of sulfur dioxide and particulates. Only a small fraction of the projected growth in European steam coal imports relates to building new coal-fired capacity. This is because most of the European countries, except for a few in the southern tier, don't anticipate a need for major new baseload generation capacity until after 2000 due to current large reserve margins and modest rates of growth in electricity demand.

In contrast to Europe, growth in Asian steam coal trade is being driven principally by market fundamentals. The key factor is strong electricity demand which is spurring the addition of substantial new coal-fired generation capacity. However, growth of new coal-fired capacity also is being aided by slowing nuclear programs in Japan, South Korea and Taiwan, where there is rising public opposition to new nuclear capacity. The net result is that Japanese utilities, which are projecting load growth of about 3% per year, plan to add 15 gigawatts (GW) of new coal-fired capacity over the remainder of the decade. South Korea, with forecast electricity growth of approximately 7% annually expects to build 9 GW of new coal-fired capacity. And Taiwan, which also is projecting electricity demand growth of almost 7% per annum is planning to install 8 GW of additional coal-fired capacity. Since, most of the Asian countries, particularly the developed ones, have small coal reserves and declining domestic production, essentially all of the growth in utility coal demand will translate to increased steam coal imports.

It is obvious from Exhibit 2 that each of the forecasters has a somewhat different perception of regional growth prospects. The EIA is the most bullish on steam coal imports to Europe, while WEFA has the most optimistic view of Asian growth potential. In our opinion, a projection of strong import growth for Asia is on much firmer ground than that for Europe. Much of the Asian demand growth is predicated on new coal-fired capacity which is already under construction, principally in Japan, South Korea, Taiwan and Hong Kong. In contrast, import growth prospects in Europe are highly uncertain because they are dependent on the pace at which domestic coal industries are allowed to down size and the extent to which coal imports, rather than natural gas, replace domestic production. While the U.K. government's plan to privatize the British coal industry has been at its own initiative, pressure to dismantle the West German coal support system emanates from the European Community. The prevailing view is that the Germans will eventually comply, but the process of removing the subsidies is likely to be highly contested and take much longer than anyone anticipates. Keep in mind that West Germany employs 90,000 people in underground mines, many of which are non-competitive without subsidies. As a result, the government has a major political and social issue with which to deal.

Beyond the question of how quickly the domestic coal industries are allowed to scale down, there is the issue of the degree to which steam coal imports are substituted for domestic production. Given the availability of natural gas supplies from the North Sea, the Netherlands, the Soviet Union and Algeria, coupled with the high level of environmental concern in Europe regarding sulfur dioxide emissions and global climate change, it remains questionable whether steam coal imports will actually penetrate Europe to the levels anticipated by the various forecasters. Political changes in Eastern Europe and the Soviet Union may also have a significant effect on international steam coal trade, but it's really too early to assess the implications. One recent development that potentially could lead to a sizable expansion of coal use is the unstable situation that has manifested itself in the Middle East. It's too soon to tell, but this episode may spur the developed countries of Europe, Asia and North America to renew and reinforce efforts to further reduce reliance on imported oil. Should this occur, coal could again be a big winner as it was in the 1970s.

With this perspective on the outlook for and factors affecting steam coal trade, I'd now like to address the subject of my presentation - U.S. coal export opportunities. Exhibit 3 shows the same regional growth projections we just looked at, but superimposes on them each forecasters' outlook for growth in U.S. steam coal exports. The upper portion of each bar represents the anticipated U.S. market share. All the forecasts project a hefty increase in U.S. steam coal exports to the European/Mediterranean region over the 1989-2000 period, ranging from 20-45 million tons. However, in Asia, only a minimal rise in U.S. exports is projected from current levels. The scenario which creates the favorable prospects for U.S. coal in the European/Mediterranean market is depicted in Exhibit 4.

- First, growth in South African, Colombian and Venezuelan exports, the most competitive coals available to Europe, is limited by various infrastructure constraints or higher net back prospects in other markets (e.g. South African coal to Asia).

- Second, growth in Australian exports to Europe peak out by the mid 1990s as forecasted increases in marine transportation rates favor maximizing shipments to Asia.
- And lastly, Polish steam coal exports decrease over time due to the elimination of government subsidies.

Based on this scenario, the United States, although a higher cost supplier, becomes the chief beneficiary because it can provide the necessary production and has the needed infrastructure to satisfy Europe's shortfall. This scenario demonstrates the underlying vulnerability of U.S. steam coal exports to Europe. Unfortunately, according to the EIA and other sources, the U.S. is expected to remain the high cost supplier to Europe. As such, to the extent the assumed supply/transportation constraints for competing suppliers don't materialize or import needs don't grow as rapidly as anticipated, U.S. steam coal exports may well be lower than these three forecasters are projecting. On the other hand, United States domestic producers may find it attractive to sell surplus production into the export market on an incremental basis since, unlike other exporters, the U.S. doesn't have an export-dedicated industry. One other factor that could negatively affect U.S. exports to the European/Mediterranean region is the imminent passage of a tougher Clean Air Act, which is expected to substantially increase the demand for eastern low sulfur coals in U.S. power plants. The overall impact of the new legislation could be to limit the U.S. role in the steam coal export market unless international prices firm markedly.

Now let's turn to the Asian steam coal import scenario which generally assumes a continuation of current supply trends. As shown in Exhibit 5, Australia is expected to remain the dominant supplier, while other low cost suppliers such as South Africa, China and an emerging exporter, Indonesia, capture the bulk of the remaining market. U.S. coal supplies, mainly from the Rockies and Central Appalachia, are forecast to continue playing a minimal role in this market due to the mines' long distance from tidewater and their higher FOB mine costs.

In our view, we believe there is significant upside potential in U.S. steam coal export volumes to Asia, particularly after 1995. This potential lies in the use of subbituminous coals from the Powder River Basin (PRB) by Asian electric utilities. As many of you know, a few trial shipments of PRB coal already have been purchased by Asian utilities. In 1988, Taiwan Power successfully tested 60,000 tons of coal bought from Mobil's Caballo Rojo Mine. More recently, two Japanese electric utilities evaluated PRB coal purchased from one of our competitors and, we understand, arrangements are being made for another test shipment.

From our standpoint, PRB coals can be competitive today with Australian coals in the Japanese, Korean and Taiwanese markets on a delivered, heating value basis. Asian utilities recognize this cost competitiveness but have been reluctant to use the coal principally because of its lower heating value which could potentially derate their boilers. We, at Mobil, are convinced that this reluctance will be overcome during the next several years as Pacific Rim power companies increasingly observe more and more Eastern U.S. utilities successfully using blends of PRB and bituminous coals in boilers designed for bituminous coals.

Once PRB coals are considered acceptable by Asian utilities, we expect to see them being moved into the Asian utility market on a regular basis. Initially, the market will be restricted to blend applications of perhaps a few million tons per year. Longer term, however, new and larger opportunities for PRB coals are expected to materialize as Asian utilities begin to build more advanced boilers that can handle a wider range of coal qualities, including subbituminous.

Despite the views of many cynics, we believe subbituminous Powder River Basin coals will eventually play a role in the Asian steam coal market. The basin's huge surface minable reserves, enormous supply capability, very low production costs and non-union work force, coupled with the coal's very low sulfur and ash makes the Powder River Basin coal attractive to many utilities, including those in Asia and perhaps parts of Europe as well. As some of you may know, the Spanish state electricity company, ENDESA, is currently testing Powder River Basin coal in boilers designed for domestic lignite. Use of Powder River Basin coal is being considered as a way to extend the life span of Spain's high sulfur lignite mines, as well as to comply with tightening European Community regulations on sulfur dioxide emissions from power plants. If the ENDESA test is successful, a long-term market of several million tons per year could materialize.

Ultimately, the extent of the PRB's penetration of overseas coal markets will be dependent on the railroads' willingness to price their services competitively. Their current demonstrated aggressiveness in seeking new coal business in Asia and Europe would suggest they have strategic interests in participating with PRB producers in this growing market.

Well, I hope my presentation has raised some thought-provoking issues and enlightened you somewhat on the challenges and opportunities facing U.S. producers in moving our coal overseas. We, at Mobil, are prepared to accept the challenge because we are convinced Asia will become a significant market for Western U.S. coal exports.

This concludes my remarks. Thank you very much.

Exhibit 1

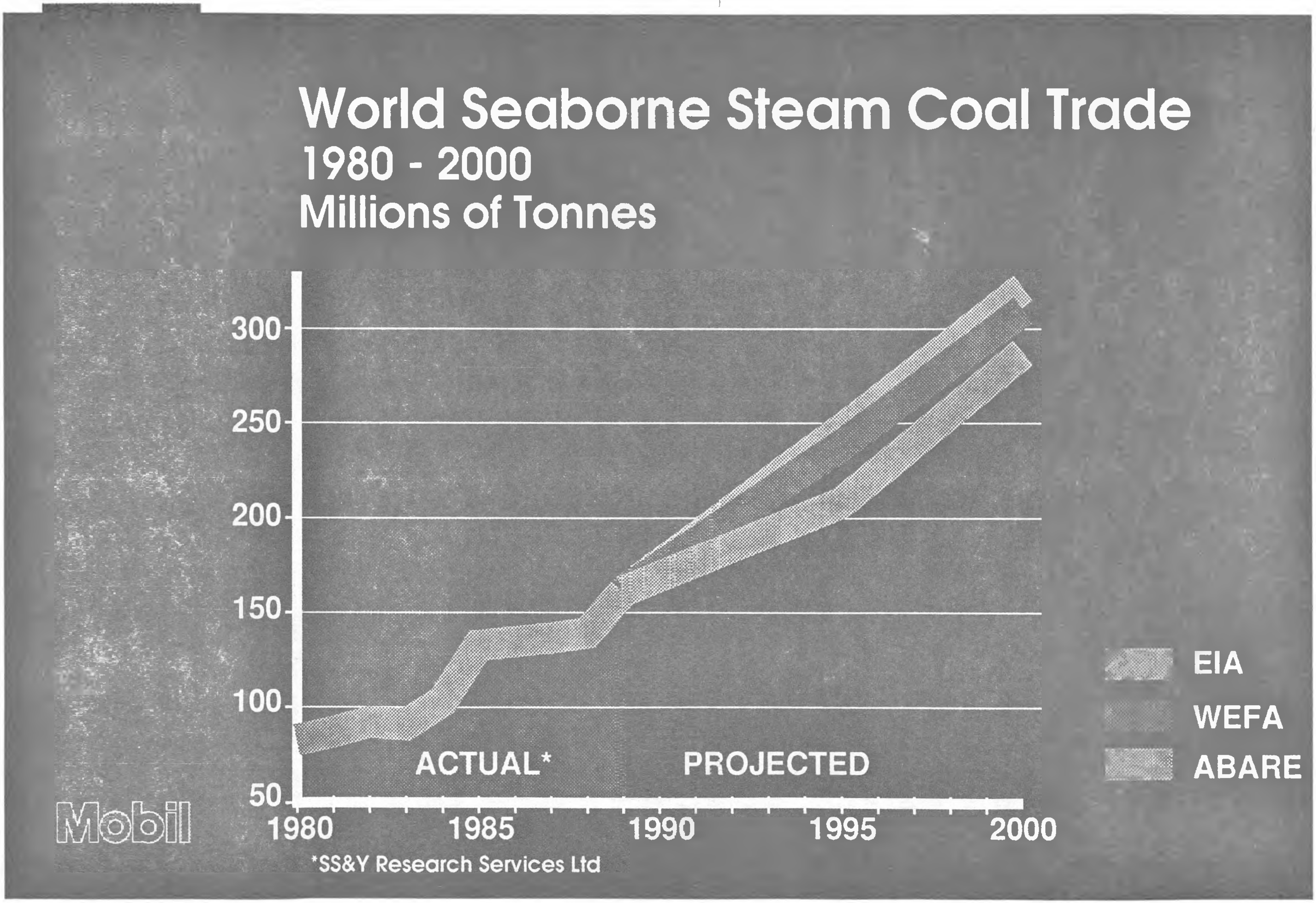
World Seaborne Steam Coal Trade
1980 - 2000
Millions of Tonnes
300
250
200
150
100
50
1980
1985
1990
1995
2000
ACTUAL*
PROJECTED
EIA
WEFA
ABARE
Mobil
*SS&Y Research Services Ltd

Exhibit 2

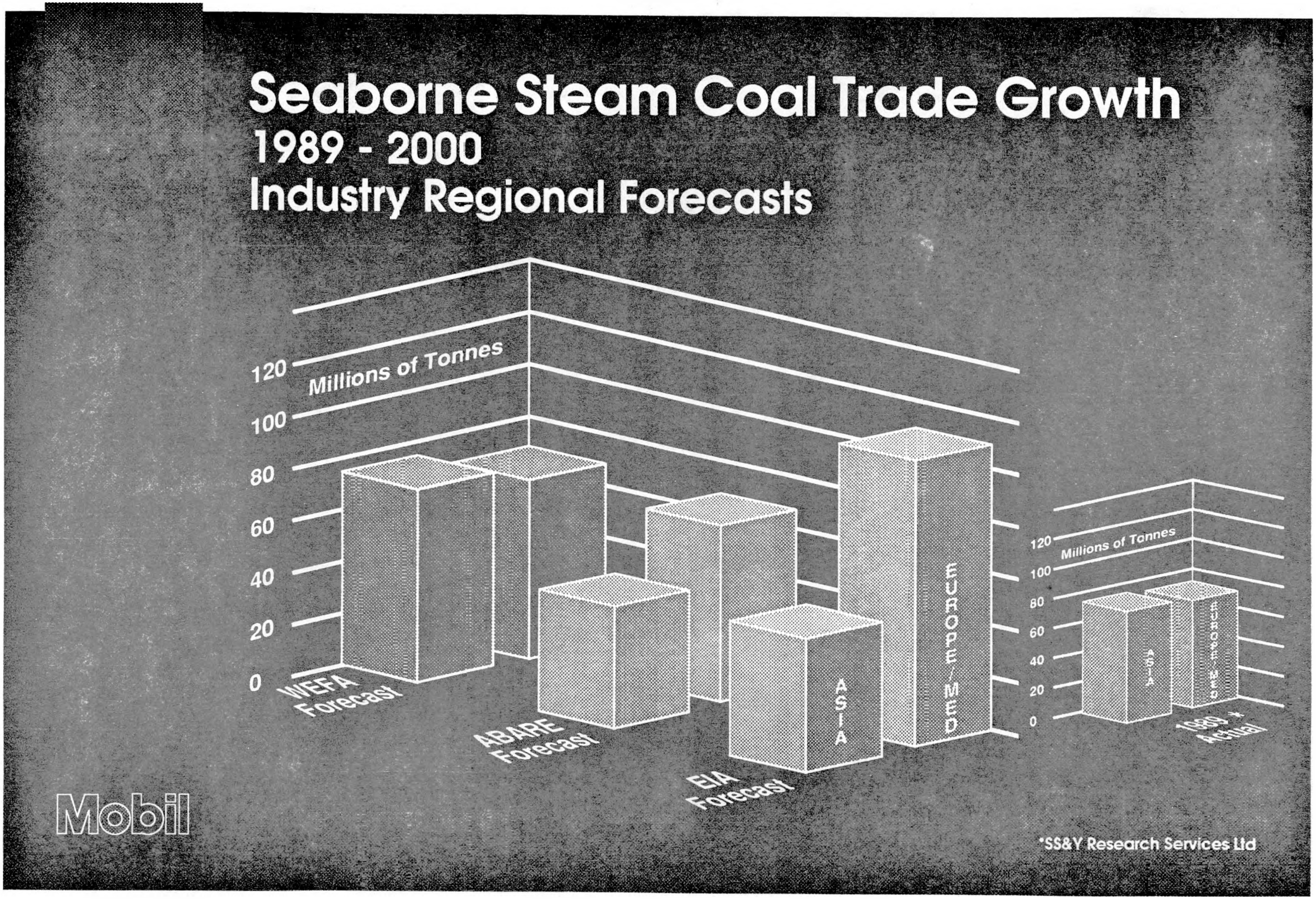

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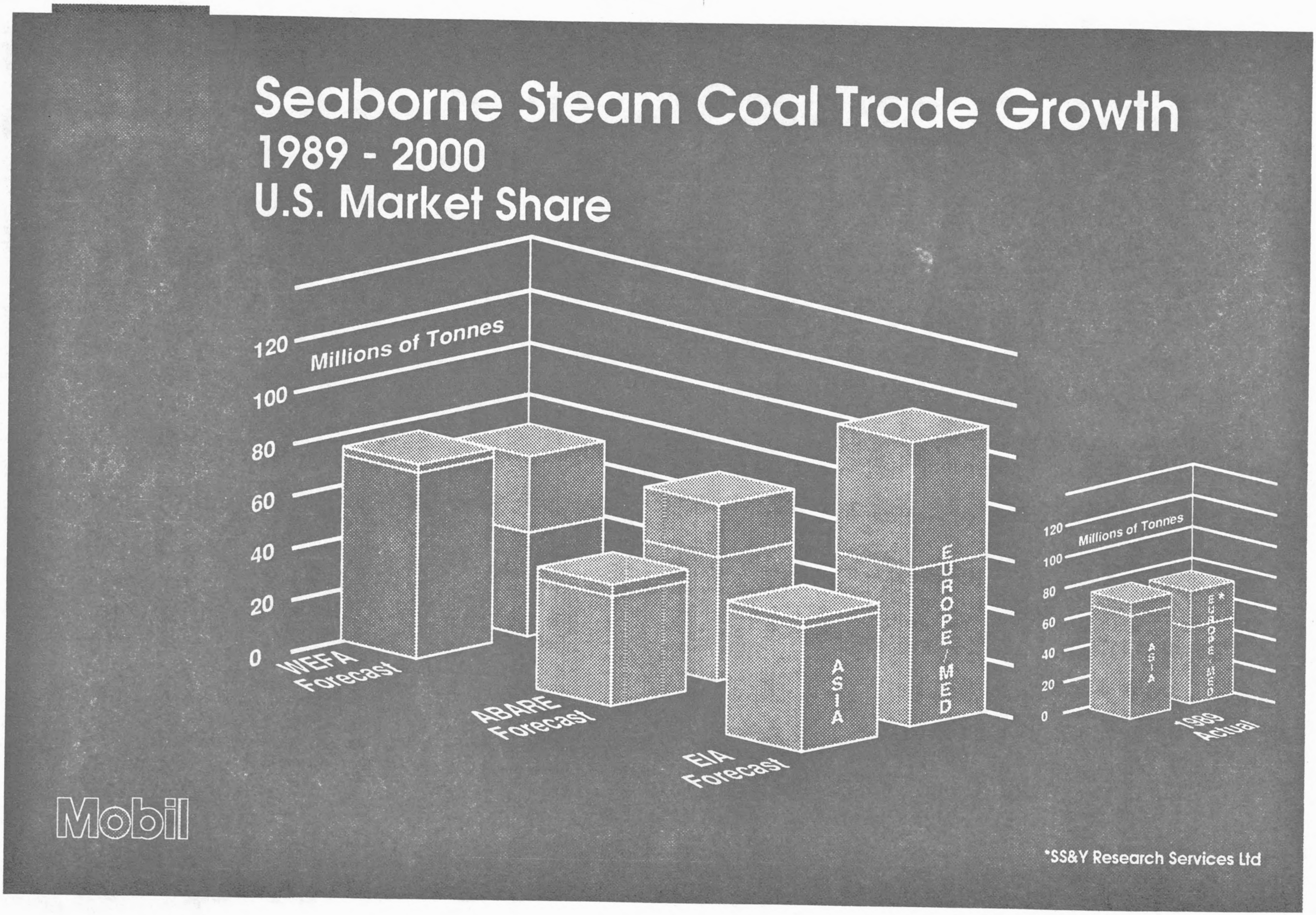
Exhibit 3


Seaborne Steam Coal Trade Growth
1989 - 2000
U.S. Market Share
Millions of Tonnes
0
20
40
60
80
100
120
WEFA Forecast
ABARE Forecast
EIA Forecast
ASIA
EUROPE / MED
Millions of Tonnes
0
20
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60
80
100
120
ASIA
EUROPE / MED *
1989 Actual
Mobil
*SS&Y Research Services Ltd

Exhibit 4

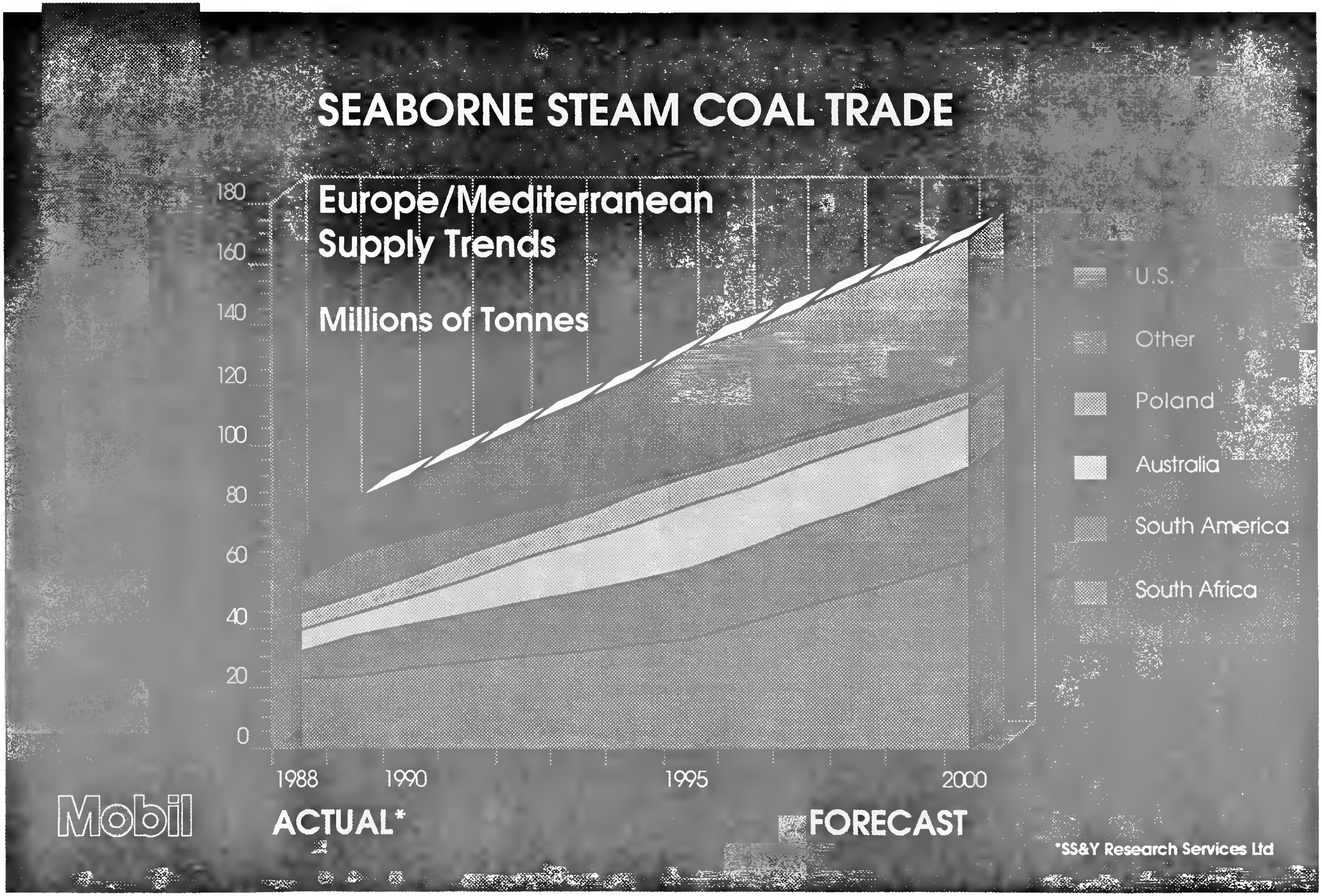
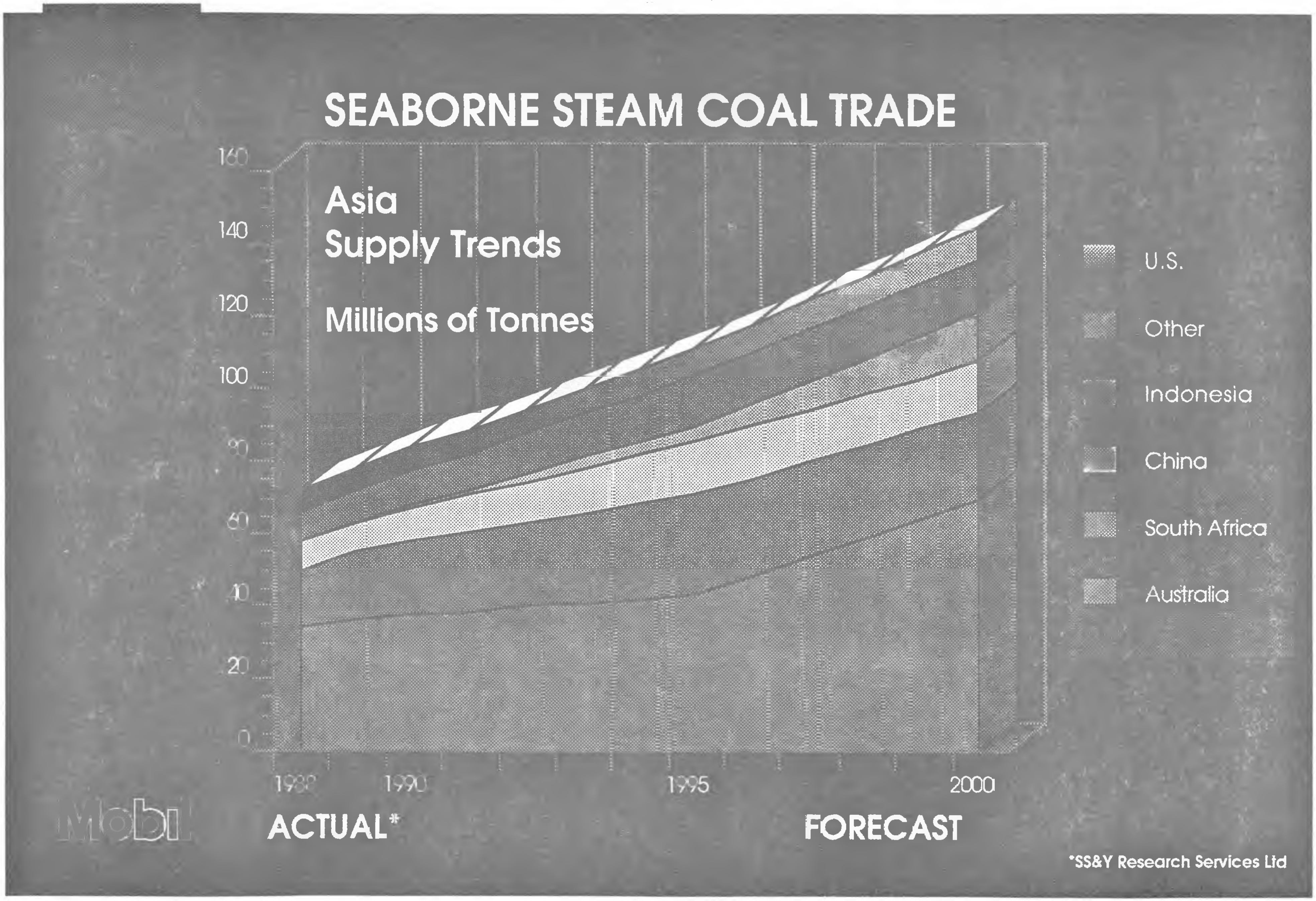

SEABORNE STEAM COAL TRADE
Europe/Mediterranean
Supply Trends
Millions of Tonnes
180
160
140
120
100
80
60
40
20
0
1988
1990
1995
2000
U.S.
Other
Poland
Australia
South America
South Africa
Mobil
ACTUAL*
FORECAST
*SS&Y Research Services Ltd

Exhibit 5


SEABORNE STEAM COAL TRADE
Asia
Supply Trends
Millions of Tonnes
160
140
120
100
80
60
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20
0
1990
1995
2000
U.S.
Other
Indonesia
China
South Africa
Australia
ACTUAL*
FORECAST
*SS&Y Research Services Ltd

ALTERNATE COAL PRODUCTS

Session Chair: **Dr. Michael L. Jones**
Energy & Environmental Research Center, UND
Grand Forks, North Dakota

1. "A Comparative Techno-Economic Analysis of Coprocessing, Direct Coal Liquefaction and Resid Upgrading"

   by: Dr. David Gray
   Principal Engineer
   MITRE Corporation
   McLean, Virginia

2. "Update on the Synfuels Industry in the Republic of South Africa"

   by: Mr. Jan H. Fourie
   General Manager
   Sasol Limited
   Johannesburg, Republic of South Africa

Session Chair: **Dr. Frank W. Beaver**
Energy & Environmental Research Center, UND
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3. "Global Perspectives: Trends and Issues"

   by: Dr. Everett A. Sondreal
   Senior Technical Advisor
   Energy & Environmental Research Center
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"A COMPARATIVE TECHNO-ECONOMIC ANALYSIS OF COPROCESSING, DIRECT COAL LIQUEFACTION AND RESID UPGRADING"

By: Dr. David Gray
Principal Engineer
MITRE Corporation
McLean, Virginia

A COMPARATIVE TECHNO-ECONOMIC ANALYSIS OF COPROCESSING, DIRECT COAL LIQUEFACTION AND RESID UPGRADING

by
David Gray, Glen Tomlinson and Abdel ElSawy
The MITRE Corporation, McLean, VA

ABSTRACT

This report documents a study of the developmental status and future potential of coal/oil coprocessing technology. It provides a techno-economic analysis of coprocessing as it compares to other alternative technologies of resid upgrading and coal liquefaction, and presents a comparative technical and economic analysis of coal liquefaction using the HRI catalytic two-stage liquefaction (CTSL) process, the HRI two-stage coprocessing technology, and resid upgrading using the H-Oil process. The conclusion is that coprocessing could be a transitional technology between resid upgrading and coal liquefaction, and would be economically more favorable than coal liquefaction until crude oil prices climb to around 40 $/bbl.

BACKGROUND

The U.S. Department of Energy (DOE) has been supporting several development efforts to demonstrate the technical and economic feasibility of coprocessing. As part of this effort, they requested that MITRE undertake a comparative economic analysis to identify economic conditions favorable to coprocessing.

This paper reports on the results of this techno-economic analysis performed to assess the relative economic potential of the coprocessing of coal and petroleum resid compared to the other alternative technologies of resid upgrading alone and coal liquefaction. All three of these technologies can use ebullated-bed reactors to accomplish the conversion of coal, coal-derived resid, and petroleum resid.

Two of the successful, commercially proven resid hydrocracking technologies use ebullating-bed reactors. These are the H-Oil[1] and LC-Fining[2] processes. Both of these essentially similar technologies use high-pressure ebullating-bed reactors and hydrotreating catalysts. Feed oil and hydrogen gas enter the reactors at the bottom, and the upflow velocity expands the catalyst bed into a state of ebullation. The bed expansion is controlled by an internal recycle oil pump. H-Oil process installations are located at the Texaco refinery in Convent, Louisiana, and in Kuwait and Mexico. Husky Oil Operations is currently designing an H-Oil unit in Canada to upgrade Lloydminster and Cold Lake heavy oils. LC-Fining units are located at the Amoco refinery in Texas City, and at Syncrude Canada's bitumen upgrading plant in Alberta.

These ebullating-bed reactors are also the key components in several technologies for the direct liquefaction of coal. Lummus-Crest used LC-Finer reactors as the second-stage, together with a short-contact-time thermal first-stage in their Integrated Two-Stage Liquefaction (ITSL) process.[3] At the Wilsonville coal liquefaction test facility, H-Oil reactors are used for both first- and second-stages in the Close-Coupled ITSL process.[4] Hydrocarbon Research Incorporated (HRI) uses two close-coupled H-Oil reactors in their Catalytic Two-Stage Liquefaction (CTSL) process.[5] Two of the current development efforts in coprocessing also utilize the ebullated-bed reactor. The Lummus-Crest coprocessing concept[6] uses LC-Finers, and the coprocessing technology being developed by HRI[7] uses H-Oil reactors and the same configuration as used for direct coal liquefaction.

There are several incentives for the development of coprocessing technologies. Since coprocessing upgrades both resid and coal simultaneously, it represents an intermediate technology to produce high-value distillate from poor-quality and low-cost feedstocks. The major plant components needed for coprocessing are commercial because of the availability of ebullated-bed reactors. There is also some evidence that coal may facilitate heavy petroleum resid upgrading. It has been suggested that heavy metals from the resid may preferentially deposit onto the coal ash rather than onto the catalyst.[8]

DATA SOURCES USED IN ANALYSIS

For coprocessing, this analysis uses data provided by HRI from their process demonstration run Phase 2, Bench Run No. 1.[7] These data were obtained during continuous bench-unit operations using Ohio 5/6 coal and Cold Lake resid as feedstocks. Subsequent to this bench-scale run at a nominal throughput rate of about 50 pounds of coal per day, HRI has conducted tests using these bench-scale conditions at the 3-ton-per-day level using their process development unit (PDU). Since the PDU data were not available, the bench-scale test results were used as the basis for scale-up in the MITRE analysis.

Experimental data on the HRI CTSL coal liquefaction process were also obtained from continuous bench-unit operations. The run selected for this analysis was Run 227-32 that used Illinois #6 Burning Star coal as feedstock.[5]

For the resid-only upgrading case, experimental data were obtained from a forty-one day demonstration run on Cold Lake resid that was performed by HRI in their 30-barrel per day H-Oil process development unit.[1] During this run high conversions of resid to distillate were achieved by using vacuum bottoms recycle. This demonstration run was conducted by HRI for the Alberta Oil Sands Technology Research Authority (AOSTRA).

METHODOLOGY

This comparative analysis was accomplished by developing computerized models that simulate conceptual commercial-scale plants.[9] Performances of the technologies were estimated from the experimental results cited above. The conceptual plants were all scaled to produce 100,000 barrels per day of liquid products. The models calculate feedstock requirements, plant fuel, hydrogen and energy needs, and final product yields and selectivities. The raw products are of differing quality and are hydrotreated in the model to produce distillates of common quality so that fair comparison is possible.

The computer model includes all of the unit processing steps necessary to convert the feedstocks to final products. In the coal liquefaction case, this includes coal handling and preparation, coal liquefaction, product recovery, hydrogen purification, solids/liquids separation, hydrogen production via coal gasification, and all the associated off-sites. For the coprocessing case, the model is very similar and includes coal and resid preparation, coprocessing, product recovery, hydrogen purification and vacuum distillation, hydrogen production via coal gasification, and associated off-sites. In the resid-only case, the model includes the H-Oil reactor section, product recovery, hydrogen purification, hydrogen production via coal gasification or steam reforming of natural gas, and associated off-sites.

In addition to performing energy and material balances, the models estimate the total installed cost of the conceptual plants, the total capital requirements, the operating costs, and the required selling prices of raw and hydrotreated products. Product prices are calculated from a discounted cash-flow analysis for a specified set of financial parameters.

Three cases are considered in this analysis. For case 1, the direct coal liquefaction case, figure 1 shows a schematic of the overall materials flow for the CTSL technology. The flows are based on 100 pounds of moisture-free Illinois #6 coal as fresh feed. Solids/liquids separation is accomplished using the ROSE-SR critical solvent deashing (CSD) process. Case 2, coprocessing, is shown schematically in figure 2. Flows are based on 50 pounds of moisture-free Ohio 5/6 coal and 50 pounds of Cold Lake resid to give a total input of 100 pounds of fresh feed. Solids/liquids separation is accomplished using vacuum distillation. Case 3, resid only upgrading, is shown in figure 3. Flows are based on 100 pounds of Cold Lake heavy oil. No deashing process is needed, but vacuum distillation is required to separate unconverted bottoms for recycle.

RESULTS OF ANALYSIS

Table 1 shows a summary of the feedstocks and products for conceptual commercial plants based on the data sources described above. The commercial plants are sized to produce 100,000

TABLE 1

CONCEPTUAL COMMERCIAL PLANT FEED AND PRODUCT SUMMARY (PLANTS SCALED TO PRODUCE 100,000 BPSD OF RAW PRODUCT)

	Coal Liquefaction HRI CTSL		Coprocessing HRI		Resid Upgrading Only H-OIL	
Feedstocks						
Coal to Liquefaction TPD(AR)	27,322		11,536		0	
Coal to Steam Plant	2,669		1,461		793	
Coal to Hydrogen Production	9,540		4,369		1,853	
Total Coal to Plant	39,531		17,365		2,646	
Oil to Upgrading TPD	0		10,406		17,206	
Oil to Upgrading BPD	0		57,973		95,200	
Products	TPD	BPD	TPD	BPD	TPD	BPD
Naphtha	5,076	36,118	3,454	25,247	3,149	24,395
Middle Distillate	8,575	53,495	8,135	52,442	6,505	43,187
Heavy Distillate	1,856	10,387	3,724	22,311	5,231	32,418
Total Raw Product	15,507	100,000	15,313	100,000	14,885	100,000
Hydrotreated Product	15,430	106,850	15,107	104,614	14,672	101,611
Gasoline	14,786	114,330	14,477	111,937	14,060	108,724

barrels per stream day (BPSD) of raw distillate. In the CTSL plant, coal is required for liquefaction, steam generation, and gasification to produce process hydrogen. This is also the situation for the coprocessing plant, but here 58,000 BPD of Cold Lake resid is also processed in the coprocessing reactors. In the resid-only plant, coal is used for plant steam and for gasification to produce hydrogen. Coal gasification in this case is comparable to the other two cases that use coal for hydrogen production.

In order to compare the different quality products from the different processes, the MITRE model simulates the hydrotreatment of the raw products to a common hydrotreated product. The costs of performing this hydrotreatment and of converting the hydrotreated product to gasoline are also computed in the model. From these costs an equivalent crude value is obtained. Equivalent Crude is defined as the price a refiner can afford to pay for crude oil that would allow him to produce gasoline for the same price as synthetic gasoline. Thus the differential between the equivalent crude and the raw product price is a measure of the added value of the synthetic crude to the refiner.

Table 2 shows a summary of the economic data for conceptual commercial plants based on the three technologies. Construction costs are broken down by plant area, and the total capital costs are

TABLE 2

CONCEPTUAL COMMERCIAL PLANT ECONOMIC SUMMARY

	Coal Liquefaction HRI CTSL	Coprocessing HRI	Resid Upgrading Only H-OIL
CAPITAL AND OPERATING COSTS			
Plant Construction Cost ($1000)			
Liquefaction	1,286,594	924,358	662,932
Solids Removal	172,224	0	0
Hydrogen Production	757,083	485,608	280,493
Balance of Plant	534,949	364,581	247,623
Total Construction Cost	2,750,850	1,774,546	1,191,048
Total Capital	4,358,360	2,941,057	2,098,213
Operating Costs ($1000/yr)			
Coal (22.70 $/ton)	296,130	130,084	19,820
Oil (16 $/Bbl resid)	0	306,097	502,703
Other Operating	371,923	265,873	203,546
By-product Credit	110,472	89,460	36,178
Hydrotreating	127,326	95,020	44,421
Total Net Operating Costs	684,907	707,614	734,311
PRODUCT COSTS $/Bbl			
Raw Product	38.95	33.45	31.52
Hydrotreated Product	40.07	34.72	32.35
Gasoline	42.69	37.81	35.75
Equivalent Crude	32.90	28.24	26.27

given. Operating costs include the cost of coal feedstock at $1/MMBtu (22.70$/ton) and of resid at 16$/barrel. Table 3 shows the economic assumptions used in calculating the annual revenue requirement from which the required selling prices of the products are calculated. These required selling prices are shown at the bottom of table 2 for raw product, hydrotreated product, and gasoline. The equivalent crude value is also shown, which is calculated from the gasoline price, assuming a $6/barrel refiner's margin.

TABLE 3

ECONOMIC ASSUMPTIONS USED FOR ALL ANALYSES

Equity	25 percent
Project Life	25 years
Tax Life	16 years
Income Tax Rate	34 percent
Price Escalation*	0
O and M Escalations	0
Fuel Escalation	0
General Inflation	3 percent
Return on Equity	15 percent
Interest on Debt	8 percent
Construction Period	5 years

*Escalation defined as inflation over and above general inflation.

In order to investigate the favorable economic conditions for coprocessing, a series of sensitivity analyses were performed to determine the impact of feedstock costs on the required selling prices for these three technologies. Figure 4 shows the results of such an analysis for various costs of resid, assuming that the value of product gas is equal to resid on a thermal basis. Raw product selling prices are shown, and coal cost is assumed to increase at half the rate of resid on a thermal basis. This shows that coprocessing would be the preferred, lowest-cost technology for a range of resid costs from 21 to 28$/bbl. Above 28$/bbl, CTSL becomes economically preferred and below 21$/bbl, resid upgrading would be cheaper.

There is obviously a relationship between resid cost and crude oil price. This relationship does change with oil price, but historically the ratio of resid to crude cost is usually in the range from 0.66 to 0.9.

Figure 5 shows a plot of equivalent crude against crude oil price, assuming that resid value is 2/3 that of crude. The parity line for resid equal to 2/3 crude oil price is also shown for reference. The economically attractive regime is that area to the right of the parity line. With resid at 2/3 oil price, coprocessing is economically favorable for oil prices greater than 30$/bbl. Coprocessing appears to be economically favored compared to direct coal liquefaction and resid upgrading for crude oil prices between 33 and 42 $/bbl.

In conclusion, this analysis has shown that the economic window of opportunity for coprocessing occurs at resid, raw product, gasoline and crude oil prices of potential commercial interest. Coprocessing could be a transitional technology between resid upgrading and coal liquefaction, and would be economically more favorable than coal liquefaction until crude prices climb to around 40 $/bbl.

ACKNOWLEDGEMENT

This work was supported at the MITRE Corporation by Sandia National Laboratories under contract to the U.S. Department of Energy (DE-AC04-76DP00789).

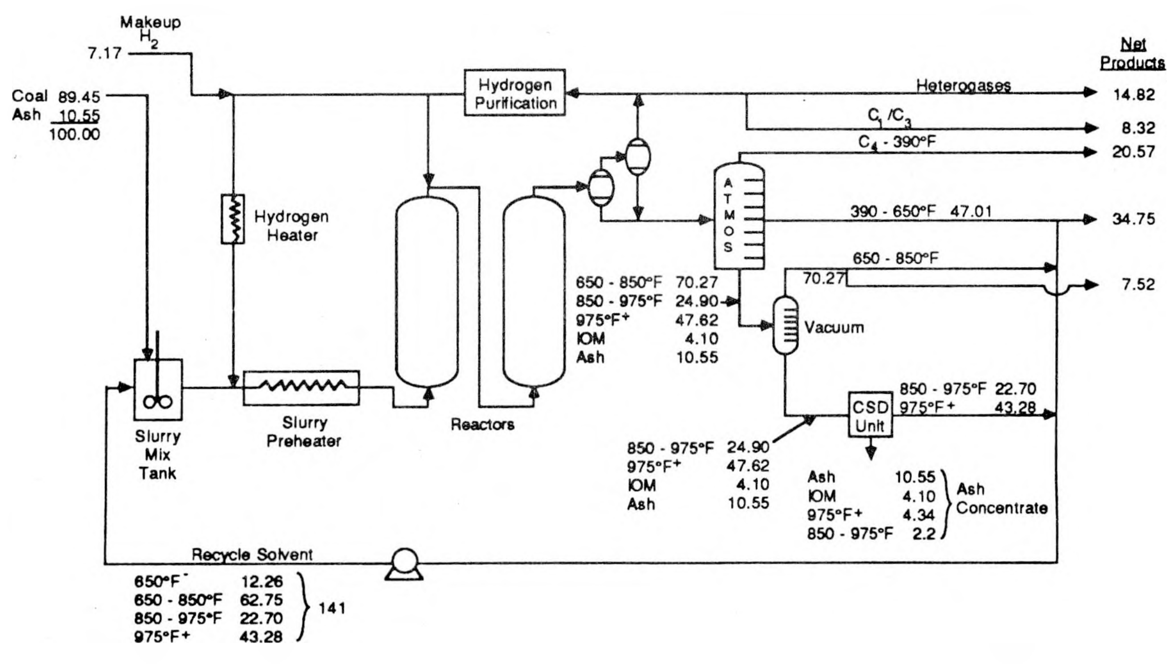

FIGURE 1 - HRI CTSL OPERATIONS--ILLINOIS NO. 6 BURNING STAR BENCH RUN 227 - 32/24

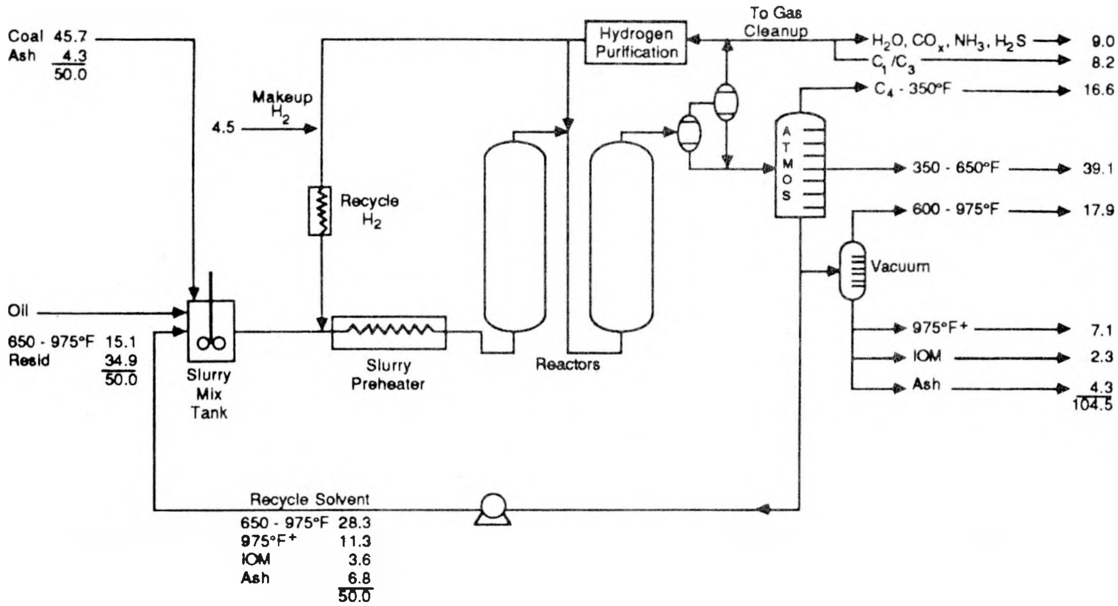

FIGURE 2 - HRI COPROCESSING CASE--PHASE 2 BENCH RUN 1/25

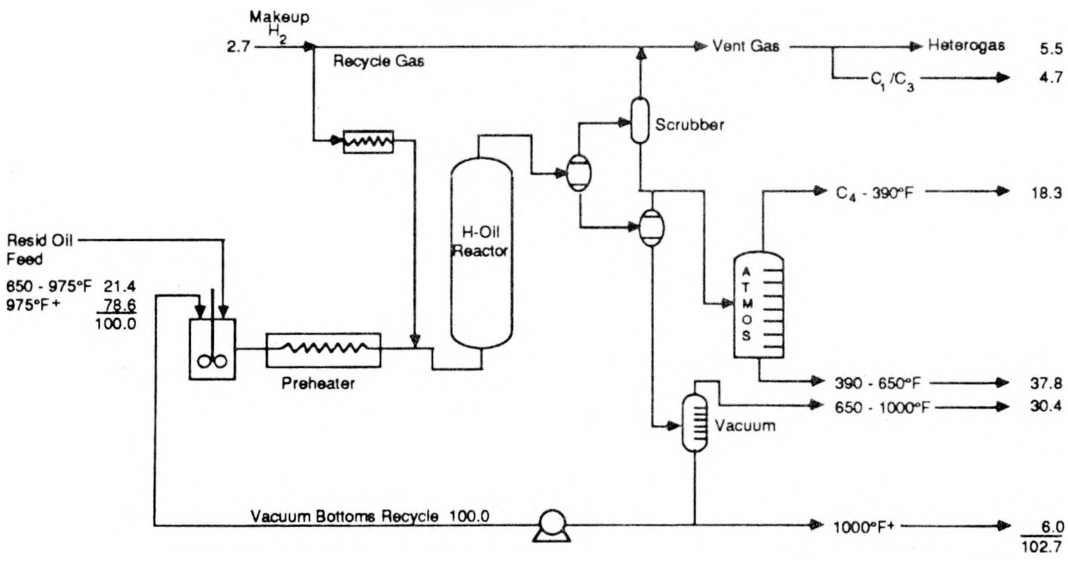

FIGURE 3 - RESID UPGRADING ONLY CASE H-OIL

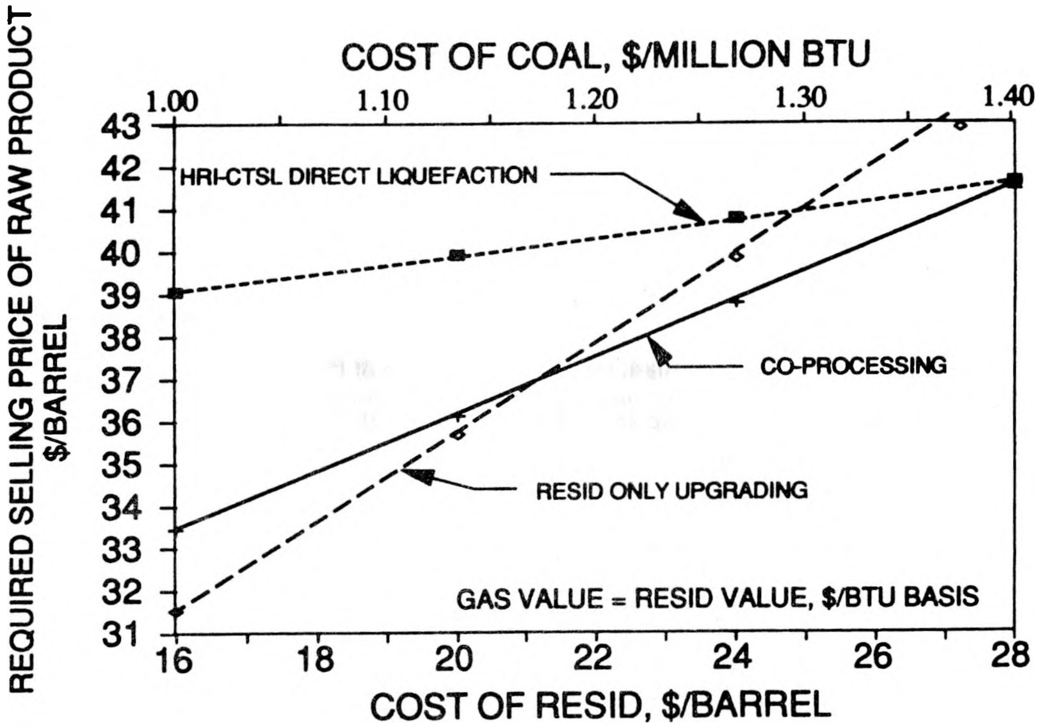

FIGURE 4 - REQUIRED SELLING PRICE OF RAW PRODUCTS VS RESID COST AND COAL COST

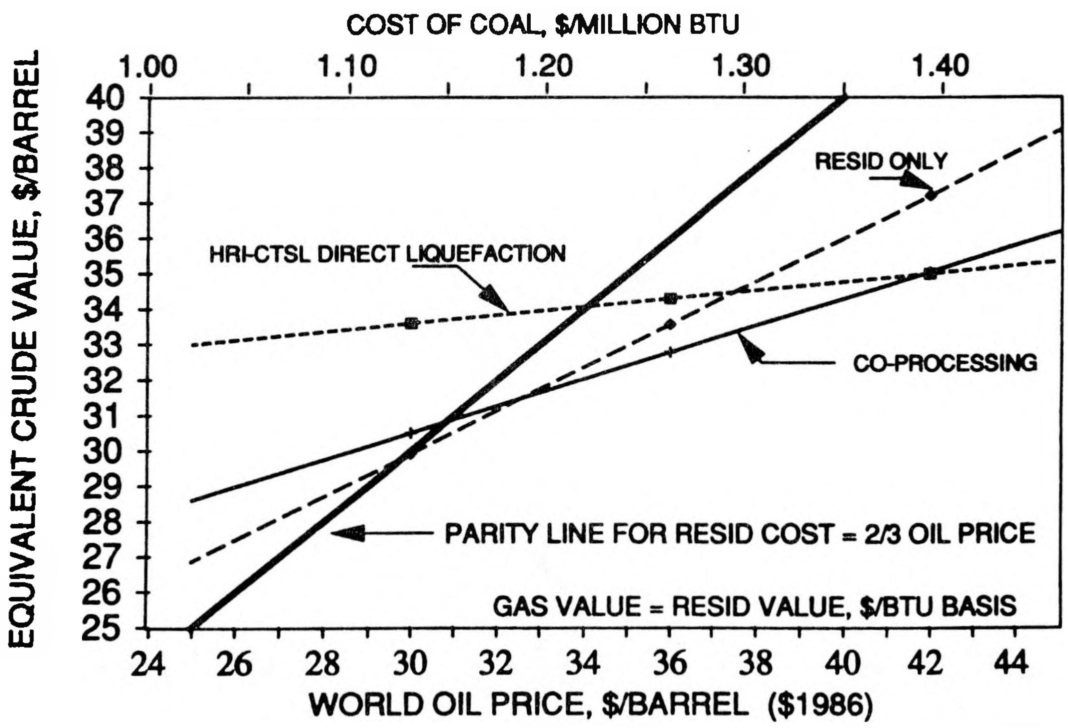

FIGURE 5 - EQUIVALENT CRUDE VALUE VS CRUDE OIL PRICE (RESID = 2/3 CRUDE)

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"UPDATE ON THE SYNFUELS INDUSTRY IN THE REPUBLIC OF SOUTH AFRICA"

By: Mr. Jan H. Fourie
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UPDATE ON THE SYNFUELS INDUSTRY IN THE REPUBLIC OF SOUTH AFRICA

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ABSTRACT

This paper deals with the developments in the Synfuels technology at Sasol since the commissioning of the Sasol Two and Sasol Three plants in 1982. The specific areas covered are coal gasification, synthesis plants and the development of modern high technology reactors to reduce capital and maintenance costs of future Synfuel plants.

Emphasis is further placed on the coproduction of chemicals in Synfuel plants to increase profitability. An important aspect namely that the fuels from the Sasol Synthol process can meet the new specifications for reformulated gasoline are also dealt with in the paper.

Introduction

When synfuel technology or the production of synfuels is discussed, South Africa is invariably mentioned together with Sasol. Sasol ventured into synthetic fuels during the 50's and expanded its production capacity many times over following the energy crisis during the 70's, thereby producing a significant percentage of South Africa's total liquid fuel consumption. Until recently Sasol remained the only company in South Africa involved in the production of synthetic automotive fuels.

In 1988 the South African government approved a new project, this time for the production of synthetic fuels from offshore natural gas. Although Sasol synthesis technology is involved, Sasol decided not to participate in the project. It was Gencor, a South African mining house, which obtained a 30% option in the project. The other shareholders are the Central Energy Fund (with a 50% participation) and the Industrial Development Corportion or IDC (with a 20% participation). Gencor also accepted responsibility for project management and the subsequent operation of the Synfuels complex known as Mossgas. The name is based on the town "Mossel Bay", where the onshore synthesis plant is being built. Gencor Limited was established in 1980 after the merger of two leading South African mining houses, General Mining and Finance Corporation and Union Corporation, both founded at the end of the last century.

The history of the synfuels industry in South Africa has clearly shown that in isolation the production of synfuels from coal cannot compete with crude oil. This leaves, as I said earlier, two alternatives. To drop production of synfuels altogether and rely, exclusively on imported crude oil or to maintain a limited synfuels activity supported by oil refining and chemicals production. In South Africa the second alternative was chosen and I believe correctly so. Although crude oil is freely and cheaply available now, this commodity will not be available forever. It is therefore important that an atmosphere be maintained conducive to the development of alternative fuels processes. In South Africa we improved on the conventional Fischer Tropsch route, but extensive work has also been done on the direct liquifaction of coal. Elsewhere in the world development work is concentrating on hydrogen and/or electricity as an automotive fuel and no doubt there are other routes to replace the present conventional liquid fuels.

The successful commissioning of the two Sasol plants in Secunda during 1980 and 1982 is by now well known. In this paper the history of these mammoth projects and the lessons learnt, will be left aside and the focus will be on developments at Sasol since the Sasol Two and Sasol Three plants were designed and commissioned. The changing strategy towards a greater emphasis on products other than gasoline and diesel fuel will also be dealt with.

The progress of development and commercialisation of processes at Sasol should be seen against the background of the choice of processes for the original Sasol One plant in the early 1950's. Pioneering work was, amongst others, done regarding the Lurgi, Phenosolvan and Rectisol processes. The two Fischer-Tropsch reactor types, namely the circulating fluidized bed (Synthol process) and the fixed bed (Arge process) were developed to commercialisation for the first time. With perseverance and hard work the processes in Sasol One were improved up to the point where reliability and performance reached levels acceptable in the petrochemical industry.

In the process selection for Sasol Two and Sasol Three only commercially proven processes were selected. This was a major factor in the smooth commissioning of the plants and it contributed to the fact that the plants were completed and commissioned on schedule and within budget.

Over the years process optimization and improvement in equipment design continued. The competitiveness of the Sasol Operations has been maintained and improved due to continued increases in plant throughputs and productivity improvements. Many of these are incremental in nature and do not attract particular attention. However, in an environment where local inflation has been running at about 15% p.a. for several years, and the revenue from synfuels is coupled to the international crude oil price, special efforts were required to maintain profits.

Sasol employs 33 000 workers and it has 28 000 private shareholders. In 1989 US Dollar value, the replacement cost of the Sasol Two and Sasol Three plants was some 12 000 million US Dollars. The annual turnover of the Sasol group came to 1,3 million US Dollars during the previous financial year. The attributable after tax profit was 180 million US Dollars.

Gasification

The original 9 Lurgi gasifiers at Sasol One have a diameter of 3,7m and were designed for 26 000 m^3n/h raw gas. They were scaled up to 3,8m and improved during the 1970's and altogether eighty of these units were installed at Sasol Two and Sasol Three. In 1981 a 4,7m diameter prototype Lurgi gasifier was commissioned at Sasol One and this unit has been available for large scale application since 1982. This gasifier produces between 90 000 and 100 000 m^3n/h raw gas, which is about 70% more than the installed capacity of the Secunda gasifiers. The development regarding gasifiers also covered aspects such as coal and ash locks, coal, gas and ash distribution, steam and oxygen feed and the automation of gasifier control.

Synthol Fischer-Tropsch synthesis

Parallel to developments in catalyst formulation and the combined optimisation of process conditions and catalyst characteristics, a separate reactor development project was tackled in 1981. The traditional Synthol reactors are using the circulating fluidized bed (CFB) concept. By its nature the circulation of catalyst requires significant amounts of energy and special precautions had to be taken to take care of the erosive properties of the iron based catalyst. The concept of a "fixed fluidized bed" (FFB), i.e. a traditional fluidized bed without external catalyst circulation was very attractive. Starting from pilot plant work and progressing through semi-commercial scale, a full commercial scale reactor using the fixed fluidized bed concept has been commissioned in March 1989 at Sasol One. It was built as a parallel unit to one of the three Sasol One Synthol reactors and it has a nominal capacity equal to that particular reactor. The commissioning of the reactor went very smoothly, and it is meeting, and in some aspects surpassing, design expectations.

Besides the obvious advantage of a much simpler and thus cheaper construction and a lower linear gas velocity, the fixed fluidized bed (FFB) reactor has much lower operating costs and maintenance is expected to be significantly cheaper than the circulating fluidized bed reactors. It is expected that the capital cost of a Synthesis plant based on the FFB reactors in stead of the CFB reactors could be as much as 60% lower.

The commercial scale fixed fluidized bed reactor still uses cyclones to separate the product gas and entrained catalyst as is the case with the circulating fluidized bed reactors. Semicommercial scale tests are under way to prove the suitability of sintered metallic filters instead of cyclones. The successful commercialisation of this technology drastically reduces the complexity of down stream processing and would lead to much better thermal efficiencies since the present quench system could be eliminated.

On-line catalyst addition and withdrawal provides the basis for considerably extended on stream times.

The fixed fluidized bed reactor provides significant cost advantages for any new large scale Fischer-Tropsch plants and thus further improves the competitiveness of Sasol technology for the production of fuels or chemicals from gas or coal.

Fixed bed Fischer-Tropsch sythesis

At Sasol One five fixed bed Fischer-Tropsch reactors were built in the 1950's. In 1987 a sixth reactor was commissioned successfully. The older reactors operate at about 25 bar, whereas the sixth reactor can operate up to 45 bar. It has similar dimensions to the older units, but throughput is higher in proportion to the pressure. Results obtained have been highly satisfactory. Product properties also meet the stringent wax specifications and catalyst life (time on stream) is similar to that of lower pressure runs. The conversion and selectivities were as predicted by the computer model developed in house.

Slurry Bed Fischer-Tropsch

Similar advantages to that described above for the fixed fluidized bed reactor are in principle possible for slurry bed operation. This includes very good temperature control as well as good heat and mass transfer. Pilot scale work confirmed the possibility of getting high conversions and desirable selectivities in slurry beds. The semicommercial reactor used to commercialise the fixed fluidized bed reactor will now be converted to a slurry bed reactor. One of the crucial steps to be tested is the catalyst separation from the final wax products. Laboratory scale testing provided results that indicate that a suitable economical technique can be developed.

If the slurry reactor development is successful, it will mean that Sasol will have four reactor systems available for Fischer-Tropsch applications. It is anticipated that the fixed fluidized bed will be the most generally applicable system for the production of a combination of gasoline, diesel fuel and chemicals. The slurry bed reactor will probably be more suitable for diesel fuel and wax products.

Chemicals

Currently Sasol markets in excess of 100 different products. These can be categorised as follows:

Fuels	(gasoline, diesel fuel, industrial gas, fuel oils etc.)
Solvents	(aromatics, alcohols, acetone, methyl ethyl ketone etc.)
Waxes	(ranging from soft to very hard and including special products such as oxidized and crystallized waxes)

Nitrogenous products	(ammonia, a full spectrum of fertilizers as well as porous ammonium nitrate for mining explosives).
Coal co-products	(creosotes, phenol, cresylic acids, pitch etc.)
Polymers	(a Polypropylene plant came on stream in February 1990)
Explosives	(a wide range of mining explosives)
Chemicals	(ethylene, propylene, paraffins, sulphur etc.)

The main benefit of the Sasol Synthol process in olefin production is the fact that olefins have only to be recovered from the Synthol products which is a much cheaper process than the olefins from a naphtha cracker.

Further recent expansions to Sasol's activities include the erection of a fertilizer plant, an explosives plant, solvent purification and blending facilities and phenol purification facilities. These are examples how the profitability of Sasol is being increased by expanding on the basis of existing competitive advantages.

Ethylene production at Secunda amounts to 315 000 t.p.a.

A 120 000 tons per annum polypropylene plant was commissioned during February 1990 at Secunda. Associated with this plant is a 150 000 tons per annum propylene recovery plant. The polypropylene is aimed at replacing imported polypropylene and additionally a substantial quantity will be exported.

Further opportunities are developed based on co-products from the Sasol processes, and also from downstream derivatives of some of these products. Areas for which such opportunities are evaluated, include speciality solvents, cresylic acid derivatives, annode and electrode coke, speciality olefins and derivatives, aldehyde derivatives, wood preservatives and speciality waxes.

In 1987 the capacity of the tar acid refining plant was doubled and since further process improvements were made, a minimum phenol purity of 99,8% can be achieved consistantly. This coal based phenol is now successfully competing with synthetic phenol in international markets.

Technology

The South African Mossgas enterprise, employing Sasol Synthol technology to convert off-shore natural gas into liquid fuels, entered into a licensing agreement with Sasol. This covered the Synthol process (circulating fluidized bed) and associated processes. Technical assistance with the design of the on-shore facilities and commissioning assistance were also provided by Sasol. The plant is now under construction. This was an excellent opportunity to extend the application of Sasol technology to a natural gas feed, which opens the way for similar plants elsewhere in the world where gas is available.

For further process developments Sasol has the benefit of having its Reasearch and Development facilities within the Sasol One plant perimeter. The scaling up of processes to prototypes can be accommodated within Sasol One, where adequate infrastructure is available. The quantities of product streams are such that the risk of large scale testing is clearly much less than at Secunda, but the scale is adequate to prove commercial viability and to determine operating costs reliably.

Environmental Aspects

Representatives from the coal industry are fully aware of the environmental aspects of coal use. Coal as an energy source is increasingly being labelled as a dirty and environmentally unacceptable. Problems ranging from acid rain to the greenhouse effect are being ascribed to coal. These problems are all related to coal in its use as a feed for power generation and I do not want to take sides in this argument.

However, the problems of coal in a boiler are largely eliminated when considering a coal to synfuels plant. The sulphur is not converted to Sulphur dioxide (SO_2) which is difficult and expensive to remove from flue gas, but is gasified to Hydrogen Sulphide (H_2S) which can be recovered as sulphur.

Nitrogen oxides which can add to the acid rain/photochemical smog problem are not formed in a gasifier, but rather nitrogen in the coal is recovered as ammonia, a valuable and useful raw material. In addition the ash in the coal is recovered in a coarse form which has very little chance of ever polluting the air.

Optimal use and re-use of water is a clear requirement in South Africa, where droughts occur sporadically and rivers have limited capacities both regarding the supply of water and their potential to dilute effluents. Significant progress was made at Sasol Two and Sasol Three to recycle various grades of water to the extent that a Zero Effluent plant is achieved.

A cooling tower system using the stripped gas liquor from the gasification plant was developed to commercial operation at Sasol. This technology was subsequently transferred to the Great Plains plant in North Dakota. Recently the co-use of stripped gas liquor and Fischer-Tropsch reaction water in a cooling water system was also successfully piloted.

The development of an anaerobic digestion plant for the treatment of industrial effluent was a significant step forward to have a robust effluent treatment system which has both a wide range tolerance for the spectrum of organic components of the feed streams and it can withstand concentration shocks in the feed very well. This process was successfully piloted to degrade the Fischer-Tropsch acids in the reaction water. It has not been scaled up to full commercial size at Secunda, since consideration is now given to two other options, namely bioprotein production and acid extraction. The process will however be used at Mossgas.

Coal gasification and Fischer-Tropsch Synthesis plants can be built and operated today, as shown by the Sasol Two and Sasol Three plants, in an environmentally acceptable way.

In addition it is not generally known, but the primary fuels produced by Sasol at Secunda are amongst the most environmentally acceptable in the world. The gasoline that is produced has zero sulphur content, is low in aromatics and the level of oxygenates means a relatively high octane number. It has also been proved that an oxygenate containing fuel, as a result of the lower combustion temperature results in a generally lower level of reactive exhaust constituents.

The blending of synthetic gasoline with alcohols (ethanol as well as higher fuel alcohols) presented a particular challenge to Sasol. The physical properties of such blends can, by using known refining technology and blending techniques, be tailored to meet typical international standards. The addition of a whole range of additives in most automotive fuels constitute a cost element which deserves particular attention. Sasol erected very sophisticated Research and Development facilities to optimise and characterise fuel additives. Whereas carburettor corrosion with alcohol containing gasoline occurs with certain alloys used for carburettors, Sasol has now developed its own package of additives to the point where a formal guarantee is issued to clients who used Sasol fuel.

The diesel fuel is a zero sulphur fuel with a high cetane number and a paraffin content that will result in a lower particulate emission level than any normal refinery fuel.

The fuels from Secunda could with a minimum of refinery modification be able to meet the specifications for the new reformulated gasoline and diesel fuels presently being proposed in the USA as the specifications for the new reformulated gasoline and diesel fuels presently being proposed in the USA as the specifications for the year 2000 and beyond.

Conclusion

The theme of this conference is "Opportunities in the Synfuels Industry". The experience at Sasol has shown that synfuels industry is and should be an ongoing one. Even after 35 years in production, there is an ever increasing number of projects being taken through laboratory and pilot scale operation to commercial implementation. The key to success lies in selecting the winning products from a range of possibilities, to be able to build on specific sustainable competitive advantages and to market the products at prices and with a quality that ensure competitiveness.

The improvements in Sasol and its associated technologies have contributed to significant improvements in the synfuel process economics by reducing operating and capital costs and by increasing plant throughputs and reducing maintenance time. This has kept Sasol technology up to date and confirmed a position to compete economically not only in the traditional gasoline and diesel fuel sectors, but also increasingly in the chemicals field. This technology is equally well suited to coal or lignite gasification as to natural gas based plants.

I believe I have also shown that coal, when used to produce a combination of synfuels and chemicals as is done today at Sasols One, Two and Three is, in essence the feedstock to a Coal Refinery. The Coal Refinery offers opportunities for the production of by-product and co-product chemicals and for the establishment of a chemical industry based on the unique raw materials. In addition the fuels produced in such a Coal Refinery can easily be formulated to meet or exceed the most stringent specifications for environmentally friendly fuels which can be expected in the future.

/mc919

"GLOBAL PERSPECTIVES: TRENDS AND ISSUES"

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ENERGY POLICY ANALYSIS
July 20, 1990

"conditions leading to crisis events in energy supply during the 1970s are again developing as we enter the 1990s..."

- *Sustained Growth*
- *Low Inflation*
- *Accelerating Energy Demand*
- *Passive Energy Policy*
- *Active Environmental Policy*

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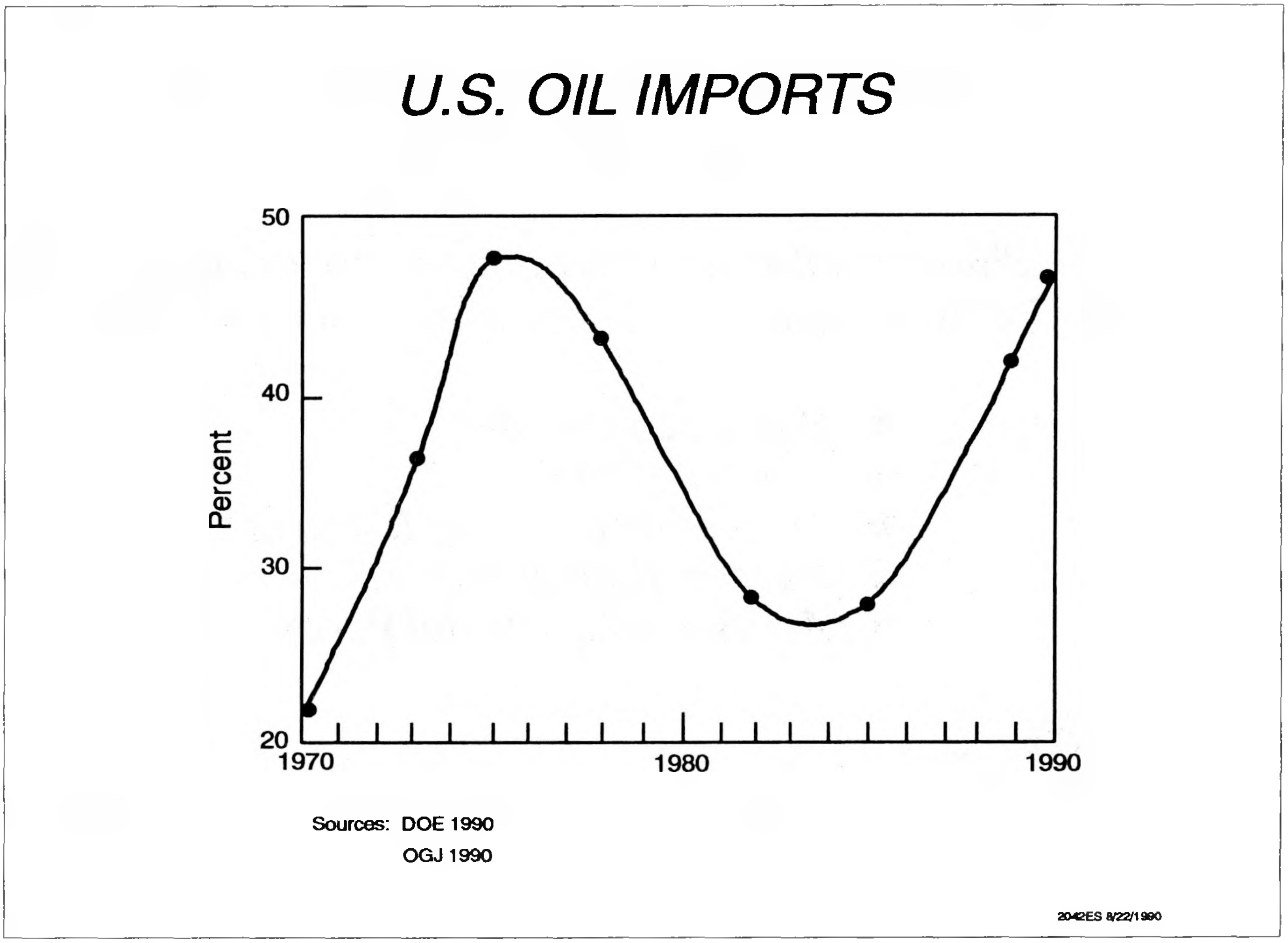
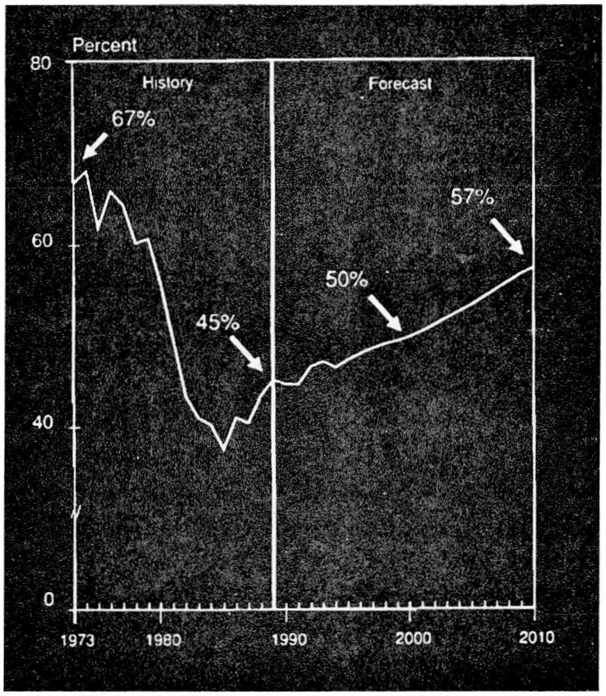
1977ES.IMA 8/24/1990


U.S. OIL IMPORTS
50
40
30
20
Percent
1970
1980
1990
Sources: DOE 1990
OGJ 1990
2042ES 8/22/1990

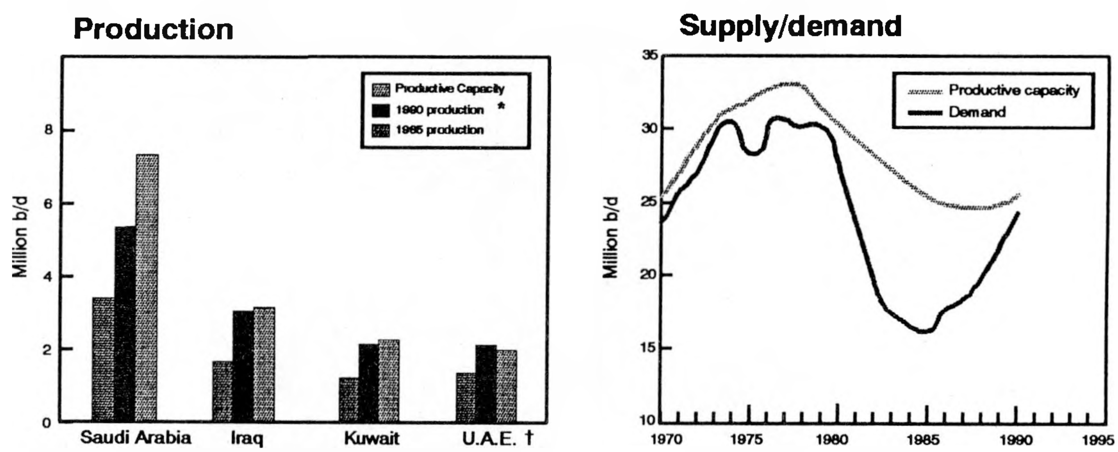
OPEC IN WORLD OIL MARKETS



Source: DOE 1990

2043es.ima 8/22/1990

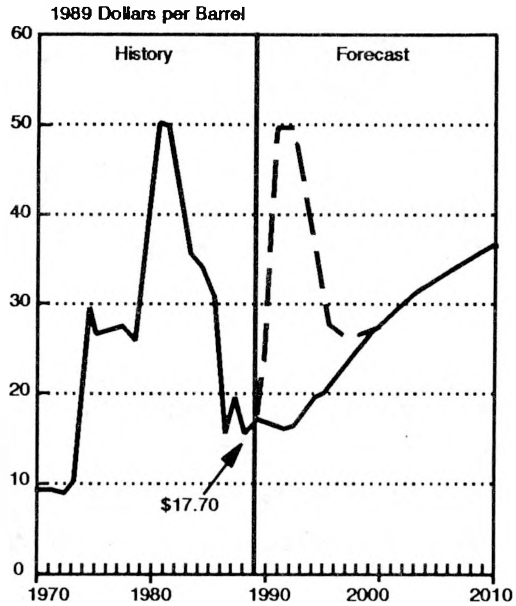
SUPPLY AND DEMAND FOR OPEC OIL



* Average through July. † Produced earlier in the year at a level not sustainable in the long term.
Source: OGJ, Aug. 13, 1990

1826ES.IMA 8/24/1990

OIL PRICE RISE SCENARIOS



Source: DOE 1990

2047ES.IMA 8/23/1990

ENERGY MARKETS ARE CYCLICALLY UNSTABLE

- *Accelerating energy demand is periodically constrained by resource availability and producing capacity.*
- *Resources enter the market at widely differing costs, forcing marginal oil producing capacity from U.S. stripper wells costing $25/Bbl to compete with Saudi Arabian crude costing $1/Bbl.*
- *The concentration of low-cost oil supply in OPEC results in monopolistic pricing whenever world demand approaches production capacity. Response to energy supply shortfalls have built-in time lags which cause major interruptions in supply to affect prices for about 5 years.*

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1978ee 8/22/1990

ENERGY MARKETS... (cont.)

- *A small energy shortfall has a disproportionately large effect on price in the short term, which also allows a small increment of reserve capacity to stabilize the market.*

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Environmental
Research
Center

1986ea 8/23/1990

NATIONAL ENERGY POLICY

The underlying role of government energy policy is to enable and restrain energy markets to protect public interests.

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1987es 8/23/1990

FOSSIL ENERGY RESERVES

Resource	10^9 Bbl Oil Equivalent	World Reserves, Principal Reserves,%	U.S. Reserves, %
Oil	990	OPEC 60%	4%
Gas	650	USSR 40% OPEC 30%	5%
Coal	3300	US 29% USSR 26% Europe 18% China 11% Australia 7% S. Africa 6%	29%

Source DOE 1989

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CONSENSUS GOALS

- *Strict Protection of Health, Safety and the Environment*
- *Secure Energy Supply*
- *Stewardship of Scarce Domestic Resources*
- *Efficiency and Conservation in Energy Use*

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Research
Center

1979se 8/22/1990

HISTORY OF U.S. ENERGY SUPPLY POLICY

The U.S. response to instabilities in energy supply over the past two decades has varied between two extremes, neither of which alone has proven effective.

1970s - "Project Independence"

1980s - Return to Reliance on Market Forces

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ELEMENTS OF A SUSTAINABLE U.S. ENERGY SUPPLY STRATEGY

- *Energy markets are global--U.S. energy independence is not a viable option.*

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ELEMENTS OF A SUSTAINABLE U.S. ENERGY SUPPLY STRATEGY (cont.)

- *Management of inherent instability in price and supply of oil is possible based on reduced dependence on oil and incentives for reserve producing capacity, including measures for:*

  - *conservation*
  - *improved efficiency*
  - *long-term fuel switching*
  - *regional supply agreements*
  - *a dynamic strategic oil reserve*
  - *a two-tier domestic market providing incentives for reserve*

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ELEMENTS OF A SUSTAINABLE U.S. ENERGY SUPPLY STRATEGY (cont.)

- *Increased reliance on domestic coal and natural gas can be fostered by means that are economically and environmentally sound*

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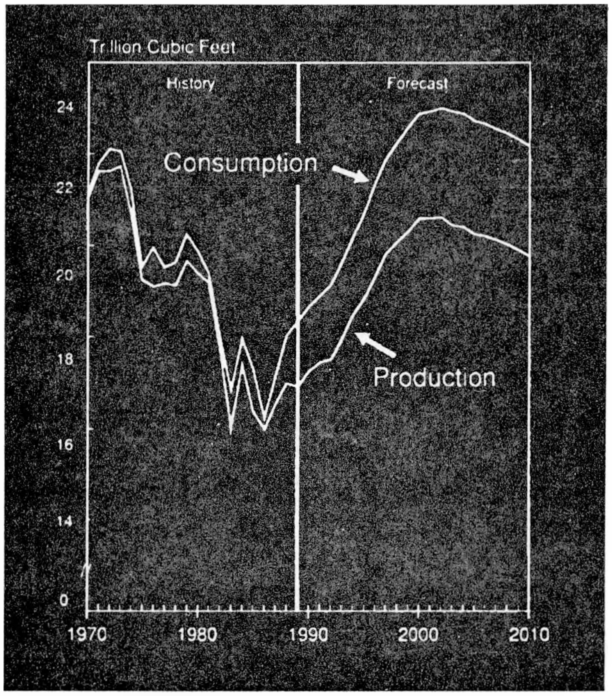
GROWTH IN U.S. GAS MARKETS

U.S. RESERVES-1000TCF



Source: DOE 1990

2044es.ima 8/22/1990

ELEMENTS OF A SUSTAINABLE U.S. ENERGY SUPPLY STRATEGY (cont.)

- *Measures for Gas:*
  - *gas price deregulation by 1993 as scheduled*
  - *open access to gas markets*
  - *broadened gas markets, e.g. natural gas fueled vehicles*
  - *increased use of gas by electric utilities under long-term contracts*
  - *improved efficiency in gas use based on turbine, combined fuel cell technologies, e.g. turbines, combined-cycle systems, fuel cells*
  - *liquid fuels from natural gas, e.g. methane*

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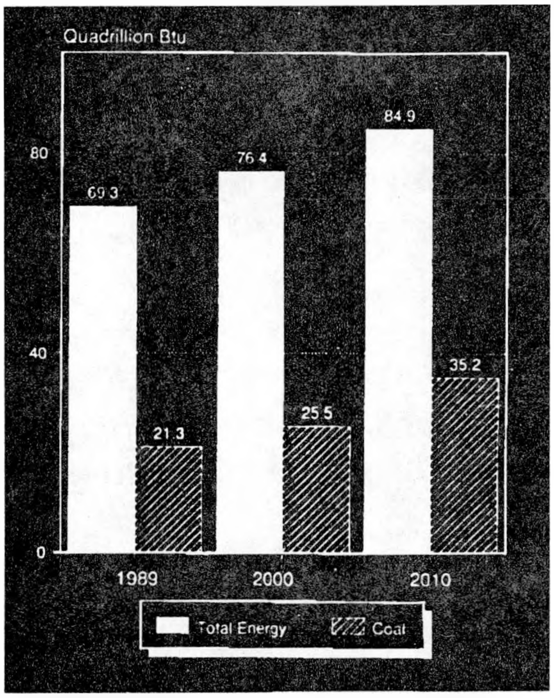
2000ee 8/24/1990

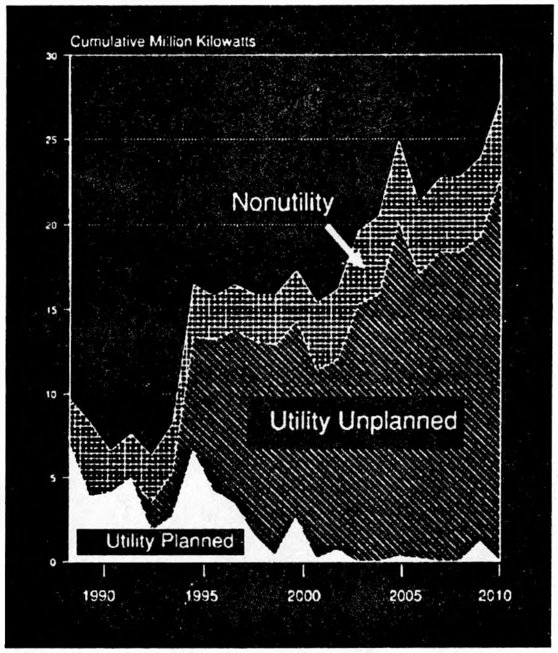
COAL'S SHARE OF TOTAL U.S. ENERGY PRODUCTION



Source: DOE 1990

2045es.ima 8/23/1990

MAJOR ADDITIONS IN U.S. ELECTRICAL CAPACITY REQUIRED BEYOND THE MID-1990'S



Source: DOE 1990

2046es.ima 8/23/1990

ELEMENTS OF A SUSTAINABLE U.S. ENERGY SUPPLY STRATEGY

- *Measures for coal:*

  - renewed support for large synfuel projects,

    - e.g. coal-water fuels at \$12/Bbl oil equivalent
    - underground coal gasification at \$30-\$40/Bbl
    - synfuel liquids include methanol at \$30-\$60/Bbl

  - a sustained clean coal program for all coal ranks and regions

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ELEMENTS OF A SUSTAINABLE U.S. ENERGY SUPPLY STRATEGY (cont.)

- Measures for coal (cont.):
  - regulatory reform affecting coal use in areas of:
    - the Abandoned Mine Reclamation Act
    - eminent domain for coal slurry pipelines
    - review of the Staggers Rail Shipment Act
    - independent power producers
  - support for coal exports from the Western U.S. and Alaska
    - quality standards
    - preparation methods
    - transportation infrastructures

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ELEMENTS OF A SUSTAINABLE U.S. ENERGY SUPPLY STRATEGY (cont.)

- *Measures for coal (cont.):*
  - *expanded coal R&D focused on:*
    - *coal preparation*
    - *efficient combustion and heat engine technologies*
    - *fuel cells*
    - *integrated emissions controls*
    - *strategic fuels for military environmental applications*
    - *coal refinery concepts for co-producing char, oil and gas*

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NEEDED ENVIRONMENTAL INITIATIVES

- A high level federal mandate to assess the impact of global warming at the earliest possible time
- Clean Air Ammendments providing
  - SO_2 and NO_x emissions control based on the full potential of the best available technology
  - a market driven approach to compliance
  - freedom of choice on fuel and technology
  - repeal of the 1977 percentage SO_2 reduction requirements
  - plant averaging
  - flexibility for retrofit, repowering and clean-coal demonstration projects
  - extension of compliance to 2005 for high-efficiency technologies

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1996es.IMA 8/24/1990

COMMERCIAL OPPORTUNITIES FOR COAL

Session Chair: **Dr. Frank W. Beaver**
Energy & Environmental Research Center, UND
Grand Forks, North Dakota

1. "Beneficiation by Oil Agglomeration of Center North Dakota Lignite"

   by: Mr. George R. Nehls, P.E.
   Research Engineer
   Minnesota Power Company
   Duluth, Minnesota

2. "Use of Oil Shale Waste in a Circulating Fluid Bed Boiler"

   by: Mr. Roger E. Moore
   Consultant
   Occidental Oil Shale, Inc.
   Steamboat Springs, Colorado

3. "Review and Update of the Coal Fired Diesel Engine"

   by: Mr. Martin J. Hapeman
   Chief Engineer
   General Electric Company
   Erie, Pennsylvania

4. "Fluid Bed Operations to Date"

   by: Mr. Duane Steen
   Station Manager, Heskett Station
   Montana Dakota Utilities Company
   Bismarck, North Dakota

Session Chair: **Dr. Warrack G. Willson**
Energy & Environmental Research Center, UND
Grand Forks, North Dakota

5. "The Technologies of the Clean Coal Technology Demonstration Program"

   by: Dr. C. Lowell Miller
   Associate Deputy Assistant Secretary
   Office of Clean Coal Technology
   Office of Fossil Energy
   U.S. Department of Energy
   Washington, D.C.

6. "Healy Clean Coal Project"

by: Dr. John Sims
Vice President
Usibelli Coal Mine, Inc.
Fairbanks, Alaska

7. "Coal Gasification Combined Cycle Power Generation Enhancement with Methanol"

by: Mr. Kent E. Janssen
Vice President and Chief Operating Officer
Dakota Gasification Company
Bismarck, North Dakota

"BENEFICIATION BY OIL AGGLOMERATION OF CENTER NORTH DAKOTA LIGNITE"

By: Mr. George R. Nehls, P.E.
Research Engineer
Minnesota Power Company
Duluth, Minnesota

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BENEFICIATION BY OIL AGGLOMERATION OF CENTER NORTH DAKOTA LIGNITE

By:
Ron Timpe, Todd Potas, Ray DeWall & Mark Musich
Energy and Environmental Research Center
Grand Forks, North Dakota

George R. Nehls, P.E.
Minnesota Power
Duluth, Minnesota

Introduction

Utilization of North Dakota lignitic coals has been primarily restricted to mine-mouth power generation of electricity. In a few cases, past and present, it has been economical to transport lignites moderate distances via rail. However, high moisture, dustiness, spontaneous combustion, and competition from Wyoming and Montana subbituminous coals have reduced the demand for North Dakota lignites in these markets.

Most attempts to promote the export of North Dakota lignite, by reducing moisture and enhancing the energy content, have used evaporative drying which accelerates the dusting and spontaneous combustion problems. An additional detriment is that the excellent reactivity of the raw lignite may be severely reduced by oxidation, if gaseous thermal drying is used. In addition, and perhaps most importantly, these drying processes do not significantly reduce the moisture-free sulfur or ash levels in the coal products. This is a concern because of the adverse environmental effects of acid rain generated from fossil fuel emissions. Lignite can be marketed as a premium quality fuel if a beneficiation process is developed which economically reduces moisture, preserves coal reactivity, reduces sulfur and ash, and enhances stability during handling. Oil agglomeration is a developing technology that holds promise for achieving these objectives, while leaving the coal product in a manageable, exportable form for dry rail transportation.

This paper describes bench-scale testing of an oil agglomeration technique developed at the University of North Dakota Energy and Environmental Research Center (EERC) for both raw and hot-water dried (HWD) Center North Dakota lignite. The Center lignite mine is owned and operated by BNI, Inc., a wholly owned subsidiary of Minnesota Power, Inc. This project was funded on a joint venture basis between Minnesota Power and the Department of Energy (DOE) Morgantown Energy Technology Center (METC). DOE contracting officer representative (COR) for the project is Ms. Jacqueline Balzarini, Pittsburgh Energy Technology Center.

Objectives

The primary purpose of the oil agglomeration testing was to assess the recovery of hot-water dried coal fines, as an easily transportable, nondecrepitating fuel agglomerate. The fines would be produced during hot-water drying of lump coal in Minnesota Power/BNI's Enhanced Lignite (ELFUEL) process. The agglomerated coal fines would be transported and combusted with a lump ELFUEL HWD product, as proposed by Minnesota Power, for Round Three of the DOE Clean Coal Technology Program (1). While recovering the HWD fines, it was proposed that the oil agglomeration would clean the fines by reducing sulfur and ash levels. As a secondary objective, the raw Center lignite was tested by the EERC agglomeration process to assess ash reduction, dewatering potential, and sulfur reduction via pyrite removal (2).

Experimental Procedure

Hot-Water Drying

Center lignite coal fines were HWD at 280°, 290°, 300°, 310° and 320°C, in a 7.6 liter, externally heated autoclave for a residence time of 15 minutes. The details of hot-water drying have been reported earlier (3). The feed for the testing consisted of -3.35 mm (6 mesh) x 0" coal to simulate the fines produced by the ELFUEL process. The slurry charge consisted of 2000 gms of coal and 2000 gms of deionized water, and heat-up to the desired temperature was approximately two hours. The HWD products and the raw Center lignite were analyzed for proximate and ultimate composition, heating value, sulfur forms, and equilibrium moisture values. In addition, the raw coal and the 310°C-HWD sample were analyzed by XRFA to determine the mineral elements in the ash. The filtrate from HWD was analyzed to determine the concentration of dissolved mineral elements.

Oil Agglomeration

Oil agglomeration of the raw and hot-water-dried (HWD) BNI lignite was achieved with only minor modifications to the procedure used for agglomerating other lignites (4). Table A shows the experimental matrix test conditions used on the -30 mesh (595 um x 0 um) raw and -6 mesh HWD coal samples. Acid strength, oil volume, acid-coal mixing speed, high-speed mixing times, and oil-coal mixing speed were the process variables used to select optimum conditions for agglomerating the coal. Agglomerates were formed in 21 of the 30 tests performed. Nine tests on raw Center lignite, and twelve tests on the HWD samples prepared at five different temperatures, produced agglomerates. In the other nine tests agglomerates over 30 mesh size were not formed.

Results

Hot-Water Drying

Analyses for the raw and HWD Center lignite, and the process water (filtrate) are presented in Table B. The major improvements to the coal were a reduction in ash and sulfur contents, and an increase in heating value due to hot-water drying. Increased HWD temperatures lowered the equilibrium moistures and increased the heating values, but did not result in lower ash levels. The ash reduction from HWD was near 25% for all tests. In addition, sulfur contents were reduced by 22% to 32% during hot-water drying, with a slight increase in the removal as the HWD temperature increased from 280°C to 320°C.

Comparison of the XRFA analyses of the raw coal and the 310°C product indicated that the iron, sulfur, and sodium contents were reduced significantly. The decrease in iron and sulfur were a result of pyrite reduction. Sodium, as well as other soluble cations, bound to carboxyl groups in the coal, was liberated during decarboxylation. As a result of the removal of these elements, silicon, aluminum, and calcium were concentrated. Concentration of silicon and aluminum will most likely increase the ash fusion temperature, and reduce ash fouling during combustion. Calcium concentration increases the Ca/S molar ratio from 0.93 to 1.17, consequently, increasing the potential calcium-sulfur capture during combustion.

TABLE A

RANGE OF EXPERIMENTAL AGGLOMERATION CONDITIONS
FOR RAW AND HWD CENTER LIGNITE

Test No.	Coal Type R(Raw) H(HWD)	Acid Conc. (wt%)	Oil Vol. (mls)	Acid Mix Speed (rpm)	Oil Mix Speed (rpm)
02	R	6.2	50	550	550
03	R	6.2	60	550	550
04	R	6.2	50	5500	1000
08	R	3.1	40	5500	800
09	R	1.5	40	5500	800
10	R	1.5	50	5500	800
18	R	0.75	50	5500	600
19	R	0.75	50	5500	1000
21	R	0.75	45	5500	1000
16	H @280°	1.5	40	5500	1200
17	H @280°	1.5	35	5500	550
20	H @290°	1.5	35	5500	800
22	H @290°	1.5	30	5500	800
23	H @300°	1.5	30	5500	800
24	H @310°	1.5	30	5500	800
25	H @320°	1.5	30	5500	800
26	H @320°	1.5	30	5500	550
27	H @310°	1.5	30	5500	550
28	H @300°	1.5	30	5500	550
29	H @290°	1.5	30	5500	550
30	H @280°	1.5	30	5500	550

* Acid Mix Time for all tests was 30 minutes
** Oil Mix Time for all tests was 10 minutes

TABLE B

RAW & HWD BNI LIGNITE
(Moisture Free Basis)

	Raw	280°C	290°C	300°C	310°C	320°C
PROXIMATE ANALYSIS, wt%						
Volatile Matter	42.23	38.80	38.76	38.85	37.77	37.40
Fixed Carbon	45.80	51.35	51.15	51.41	52.02	52.06
Ash	11.97	9.85	10.09	10.24	10.21	10.54
ULTIMATE ANALYSIS, wt%						
Hydrogen	3.93	4.06	4.33	3.88	3.86	3.95
Carbon	63.60	68.28	68.70	69.10	70.16	69.53
Nitrogen	1.04	1.11	1.14	1.14	1.15	1.14
Sulfur	1.33	1.08	1.15	1.16	1.05	1.14
Oxygen*	18.10	15.60	14.57	14.46	13.55	13.67
Ash	11.97	9.85	10.09	10.24	10.21	10.54
ASH, wt%						
Silica, SiO_2	9.4				25.5	
Al. Oxide, Al_2O_3	2.4				12.0	
Fe. Oxide, Fe_2O_3	20.1				8.8	
Titan. Oxide, TiO_2	0.5				1.0	
Phosph. Pentoxide, P_2O_5	1.7				1.3	
Calcium Oxide, CaO	18.5				21.3	
Magnesium Oxide, MgO	5.0				6.7	
Sodium Oxide, Na_2O	9.4				1.3	
Potassium Oxide, K_2O	0.1				0.5	
Sulfur Trioxide, SO_3	33.0				21.5	
HEATING VALUE, Btu/lb	10,690	11,470	11,540	11,800	11,850	11,900
SULFUR FORMS,** wt%						
Organic	0.62	0.75	0.74	0.73	0.79	0.67
Pyritic	0.53	0.34	0.38	0.46	0.23	0.41
Sulfate	0.09	0.02	0.03	0.02	0.05	0.04
Total	1.24	1.10	1.15	1.21	1.07	1.13
EQUIL. MOIST, wt%						
(Three-Day)	36	23	20	22	20	20
(Six-Day)***				18	19	16
FILTRATE, ppm						
Silicon		59	75	68	66	62
Aluminum		<0	<0	<0	<0	<0
Iron		<0	<0	<0	<0	<0
Phosphorus		<2	3	<2	<2	<2
Calcium		320	253	297	444	439
Magnesium		703	627	403	237	250
Sodium		1826	2338	2420	2446	2474
Potassium		45	57	63	64	68

* Oxygen determined by difference.
** Duplicate analyses by independent laboratory.
***Six day values were necessary to allow wet samples more time to come to equilibrium moisture.

The dry solids and Btu recoveries, plus ash and sulfur reductions, are listed in Table C, for the five HWD temperatures (5). The Btu recoveries decreased from 97% to only 93%, while dry solids recovery decreased from 91 to 84 wt%, as the temperature was increased from 280° to 320°C. The high Btu/solids ratio indicated that the majority of the dry solids were lost to decarboxylation, while heat content was lost during volatile matter reduction.

The reduction in sulfur content represented a reduction in theoretical SO_2 emissions. Table C also lists the estimated SO_2 emissions for the raw coal and the HWD products. These worst-case numbers were determined based on the assumption that the total sulfur will be converted to SO_2 during combustion. The total possible emission for the raw coal is 2.49 lb SO_2/MM Btu, and the lowest total emission after HWD is 1.77 lb SO_2/MM Btu. Hot-water drying can reduce sulfur emissions, but the compliance emission ceiling of 1.2 lb SO_2/MM Btu has not been met for this specific coal sample. It should be pointed out that the sulfur levels of the sample of raw Center lignite used in this study were higher than the mine average of around 1.0 wt% (6). In addition, the actual emissions will likely be lower than these worst-case calculated values, because sulfur can be captured by inherent alkali minerals, mainly calcium and sodium. The high sulfur trioxide and calcium oxide levels in the HWD coal ash, as indicated in Table B, represent potential sulfur capture during combustion. The actual sulfur emissions and ash sulfur retention can only be determined by combustion testing.

Raw Coal Agglomeration

Table D shows the TGA modified proximate analyses of the raw coal, and the agglomerates formed under the test conditions described above. An example of the raw data obtained from this analysis is shown in Figure 1. In this analytical procedure, the first weight change occurs over the range ~25-110°C, and is termed "H_2O & Light Oil," since Karl Fischer water determination typically finds <5% moisture, whereas the thermogravimetric weight loss over this temperature range is >5% in all cases except that of the distilled agglomerates. "Oil" is assumed to be the agglomerating oil adhered to the coal, and is volatilized over the temperature range ~110-250°C. "Volatiles" is assumed to originate from the coal being agglomerated. This fraction is removed over the range ~250-900°C. "Combustible residue" can be compared to fixed carbon of the ASTM 271 proximate analysis. With the addition of air to the sample chamber at ~900°C, this fraction burns off, and "Ash" is the oxidized inorganic residue remaining. The "moisture-oil-free" (MOF) value for ash was calculated to provide the ash content of the agglomerates, for comparison with moisture-free BNI lignite. Although not a primary objective, ash removal from the raw coal on a moisture-oil-free basis ranged from 40% to 75%. The ash removal from the raw coal as a result of the process appeared to be a function of acid concentration, except in two cases. Test No. 08 was the only test with 3.1% acid, so it is not known whether the low ash is characteristic of the acid concentration; however, Test No. 18 was much lower in ash than the other two tests run with the same acid concentration of 0.75%, indicating that the other test conditions were also factors to be considered for optimization.

Table D shows the agglomerate yields for raw and hot water-dried BNI lignite, and, in conjunction with the ash removal discussed above, gives an indication of the effectiveness of the process. The agglomerate yield is reported in grams of air-dried agglomerates obtained from 50 grams of coal. The agglomerate recovery is best represented as a ratio of the combustible residue content (fixed carbon of agglomerates = FC_a) in the agglomerate and the combustible residue content of the raw coal (FC_c). The fixed carbon content of the coal was assumed to be relatively unchanged by the agglomeration process. From Figure 2 (which shows the ratio as a function of the agglomerate weight recovered, and gives the test number for each point), it can be seen that raw coal test numbers 04, 10, 18, and 19 were most successful on the basis of FC_a recovery. Moisture and ash were both reduced by design of the process and, with the adsorption, absorption and recovery of the oil, significant volatiles content changes were also expected. The moisture reduction that occurred as a result of agglomeration was substantial. Although the Karl Fischer moisture analysis was not performed on every product, sufficient numbers were tested to indicate that the behavior of the process regarding moisture reduction was not different from that of previous tests with other lignites, where moisture levels, as determined by the Karl Fisher method, were routinely reduced to less than 5%.

TABLE C

ANALYSIS OF RAW AND HWD BNI COALS

Drying Temperature, °C	Raw	280	290	300	310	320
Solids Recovery, %		90.8	89.3	86.9	85.5	83.5
Btu Recovery, %		97.4	96.4	95.9	94.8	92.9
Ash Reduction, %		25.6	24.8	25.6	27.4	26.3
Sulfur Reduction, %		26.6	22.4	24.3	32.2	28.4
Sulfur Emission, lb $SO_2/10^6$ Btu	2.49	1.88	1.99	1.97	1.77	1.92

TGA proximate analyses of three fines from the agglomerating process are also shown in Table D. As in the agglomerates, the ash content of the fines was reduced, but over a narrower range, 45-60%. In many agglomeration experiments, the fines appeared to be agglomerates. However, they are small enough to pass the 30 mesh (595 um) product screen.

Hot-Water-Dried Coal Agglomeration

Agglomeration testing of the HWD coal was accomplished with the same mechanical methodology as the raw coal, but with fewer variables. When agglomerating the HWD coal, only oil volume and oil mixing speed were process variables, all others were held constant. The recoveries were similar to those of the raw coal agglomerates, as shown in Table D. Generally, coal dried at the lower temperatures gave agglomerates with the lower moisture-oil free ash values. The ash content of all HWD agglomerated samples remained high relative to agglomerates of the raw coal.

TABLE D

RAW AND HWD CENTER LIGNITE AGGLOMERATE TGA PROXIMATE ANALYSES

SAMPLE NO.	WT% H20*/LT OIL	OIL	VOLATILES	FIXED CARBON	ASH AR	ASH MOF	YIELD FC_a/FC_c
Coal(ASTM)	34.3	---	27.7	30.1	7.86	11.96	--
Coal(TGA)	33.4	3.2	25.7	31.9	5.80	9.16	--
Coal(TGA)	33.9	3.0	25.6	31.7	5.73	9.09	--
02	22.5	18.4	26.3	31.1	1.65	2.79	0.91
03	27.1	21.3	23.2	27.1	1.29	2.50	1.02
04	21.4	23.3	24.7	29.3	1.27	2.30	1.12
08	21.3	18.7	27.0	31.5	1.51	2.52	0.77
09	18.5	18.5	27.7	33.3	2.11	3.35	0.78
10	18.4	23.0	25.8	30.4	2.42	4.13	1.14
18	20.6	22.9	25.4	29.9	1.21	2.14	1.10
19	18.3	20.0	26.9	31.5	3.31	5.37	1.14
21	18.6	20.8	26.7	30.9	3.02	4.98	1.07
16	19.6	13.3	26.0	37.0	4.08	6.08	1.11
17	17.3	13.0	27.5	38.0	4.16	5.97	1.09
20	13.9	12.2	27.9	41.3	4.79	6.48	1.12
22	16.0	10.8	27.3	40.9	5.10	6.96	1.08
23	15.8	9.8	26.9	42.0	5.61	7.53	1.13
24	13.8	9.0	27.5	44.1	5.67	7.34	1.28
25	11.0	8.0	28.6	46.4	5.93	7.33	1.16
26	13.1	8.7	27.2	44.8	6.09	7.79	1.15
27	15.4	10.0	26.4	42.7	5.63	7.54	1.28
28	13.6	10.8	27.4	42.7	5.51	7.29	1.13
29	9.2	10.4	30.5	44.7	5.09	6.33	0.26
30	15.0	12.2	27.9	40.2	4.76	6.53	0.99
02#	12.0	15.3	32.9	37.2	2.64	3.63	--
03#	19.9	16.4	28.1	33.0	2.64	4.15	--
04#	7.5	14.9	35.1	38.5	4.01	5.17	--

* Average moisture levels for agglomerates of raw coal 2.85% and for that of HWD coal was 4.31%.
\# Fines from agglomeration process.

From Figure 2 (which also shows the fixed carbon ratio as a function of the agglomerate weight recovered for the hot-water dried samples), it can be seen that HWD coal test numbers 16, 24, and 27 were most successful on the basis of FC_a recovery. Test number 16 involved more oil than the other HWD tests, and 24 and 27 were the only tests in which the feed was dried at 310°C. Other factors were held constant for the HWD coal agglomeration tests.

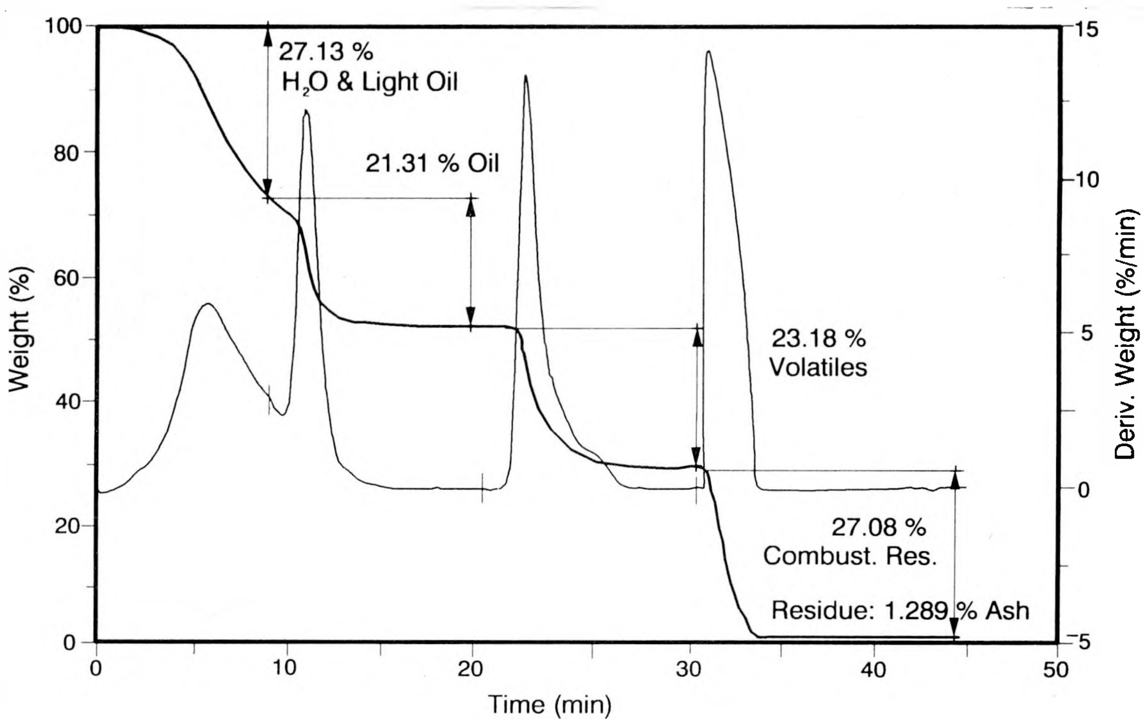

Figure 1. TGA THERMOGRAM OF AGGLOMERATES FROM RAW CENTER LIGNITE, TEST NO. 10.

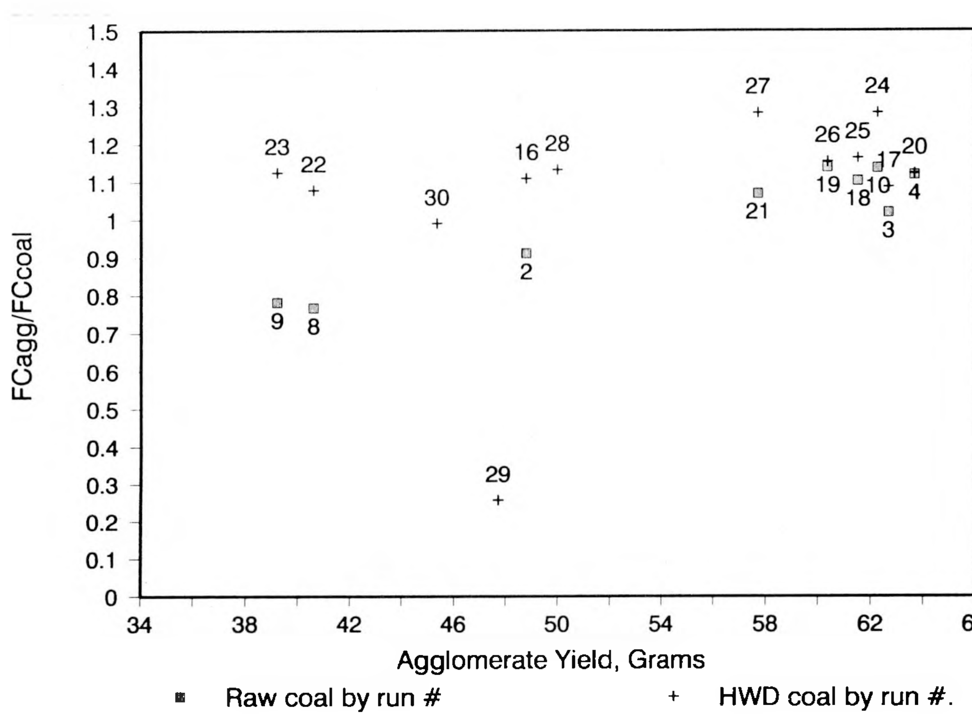

Figure 2. FIXED CARBON RATIO VS. OF AGGLOMERATE WEIGHT RECOVERED FOR AGGLOMERATES FROM BOTH RAW & HWD CENTER LIGNITE.

TABLE E

ULTIMATE AND HEATING VALUE ANALYSIS ON SELECTED TEST SAMPLES
OF BNI LIGNITE AGGLOMERATES

Test No.	04	10 Before Distillation	10 After Distillation
Ultimate Analysis wt%			
Carbon	70.2	70.5	69.6
Hydrogen	5.9	5.8	5.0
Nitrogen	1.0	0.8	1.1
Sulfur	0.7	0.8	1.1
Oxygen(by difference)	20.9	20.0	19.6
Ash	1.3	2.1	3.6
Heating Value Btu/lb	12,600	12,560	12,120
Ash Reduction, % (from raw coal)	89	77	70
Sulfur Reduction, % (from raw coal)	46	38	15
Sulfur Emmission, lb $SO_2/10^6$ Btu	1.11	1.27	1.80

Oil Recovery

Test 10 involved conditions which were nearly optimum for all defined objectives of this study. Using this method, approximately 200 grams of agglomerates were prepared for further analyses. Besides TGA proximate analysis; ASTM ultimate analysis, calorific value, oil recovery, and Hardgrove grindability were carried out on this sample. The ASTM ultimate and calorific value are shown in Table E. The hydrogen content of the agglomerates decreased after oil removal by heating, while the nitrogen and sulfur content, on a weight percent basis in the oil recovery residue, was increased over that of the original agglomerates. The heating value of the agglomerates was >12,000 Btu/lb, as compared with 10,700 Btu/lb for the moisture-free coal, and those from which the excess oil had been removed had only slightly less heating value (i.e., 3.5%) on a Btu/lb basis than the original agglomerate. In addition, the projected total sulfur emissions for these three agglomerates are also shown in Table E. The levels are below or near compliance for the agglomerates, which include recoverable oil. A slight increase in ash, and a significant increase in sulfur, occurred after oil removal to the agglomerates for sample MPOA-10. This caused the calculated total emissions to go above the 1.2 lbs SO_2/MM Btu for this sample. As mentioned previously, these calculations make no accounting for the sulfur capture potential of calcium in the ash, which has been concentrated as a result of the cleaning to the coal.

Oil recovery from the agglomerates at ambient pressure, at temperatures of ambient to 140°C, to 180°C, and to 200°C, resulted in removal of most of the oil from the agglomerates in a recyclable form. The hardness of the agglomerates following oil recovery, was greater than that prior to recovery, and the agglomerates maintained their roughly spherical geometry. The process did not result in agglomerate break-up but instead, it resulted in harder agglomerates, while reducing the oil content by 50%-90+%, as analyzed by TGA. Material closures for the process, shown in Table F were 92%, 87%, and 98% for the heat treatment carried out at 140°, 180° and 200°C, respectively. The improved closure at the highest temperature was due to the use of an additional cold-trap and the improved efficiency of the trap design for this test.

TABLE F

OIL RECOVERY AT THREE TEMPERATURES FROM BNI OIL AGGLOMERATES

	140°C	180°C	200°C
AGG, G	15.80	16.60	50.0
OIL, G*	3.00	3.30	16.4
OIL, G#	----	----	1.0
RESID, G	11.50	11.20	31.6
TOTAL, G	14.50	14.50	49.0
MATERIAL CLOSURE, %	91.80	87.40	98.0

* oil recovered at 0°C using water-ice bath

\# oil recovered at -78°C using isopropanol-dry ice bath

Figure 3 shows the oil, volatiles, and fixed carbon for the raw coal and the agglomerates, prepared according to the method used in MPOA-10, before oil recovery and after oil recovery at each of the three temperatures, 140°, 180° and 200°C. TGA proximate of the residues of the lower two temperatures indicated that recovery at 140°C removed approximately one-half of the oil, whereas two-thirds of the oil was removed at 180°C. The analysis of agglomerates after 200°C showed an oil content on a moisture-free basis that was only slightly greater than that of the raw coal, and significantly less (5 to 8-fold, depending on what value is used for moisture in calculating moisture-free agglomerates) than that of the agglomerates before the treatment, indicating that the potential for oil recovery for re-use is excellent. Removal of excess oil also contributes to improved handling characteristics, including less odor and reduced oiliness.

Hardgrove Grindability

A commercially important characteristic of the agglomerates is their ability to maintain structural integrity during transportation and storage. The test of hardness adapted for this study was an extended Hardgrove

Grindability Index (HGI). The HGI of a coal sample is defined according to ASTM Method D-409 as:

$$HGI = 13 + 6.93W$$

Where W is the weight of material passing a 74 um sieve, determined as the difference of 50 grams of starting material, minus the weight retained on the sieve.

The standard coals used for the test have a size range from 16 to 30 mesh (1,180 microns by 600 microns), which easily applied to the agglomerates because of their bottom size of 30 mesh. Figure 4 is the HGI curve determined for the standard coals, as indicated by the line, and for the raw coal and selected agglomerate samples, indicated by symbols. The standard values are determined by the amount of coal that passes through a 200 mesh (75 microns) screen versus the designation for the standard sample. The highest standard used has an HGI of 102, so a linear regression was performed in order to obtain higher agglomerate values than those for the standard coals.

The hardness of the agglomerates was not affected greatly by removal of the excess oil, as indicated by their HGI values. Although the agglomerates are somewhat softer than the coals for which the test was designed, the ASTM test did give a basis for determining the relative hardness of the samples. MPOA samples 04, 10, and 27 fell on the calibration curve which was prepared from indices of raw coals of measured hardness. The other samples listed occurred on the extrapolated portion of the HGI curve. The HGI of 04, 10, and 27 would imply that these agglomerates may be physically handled in a manner similar to the raw coal during transportation and utilization.

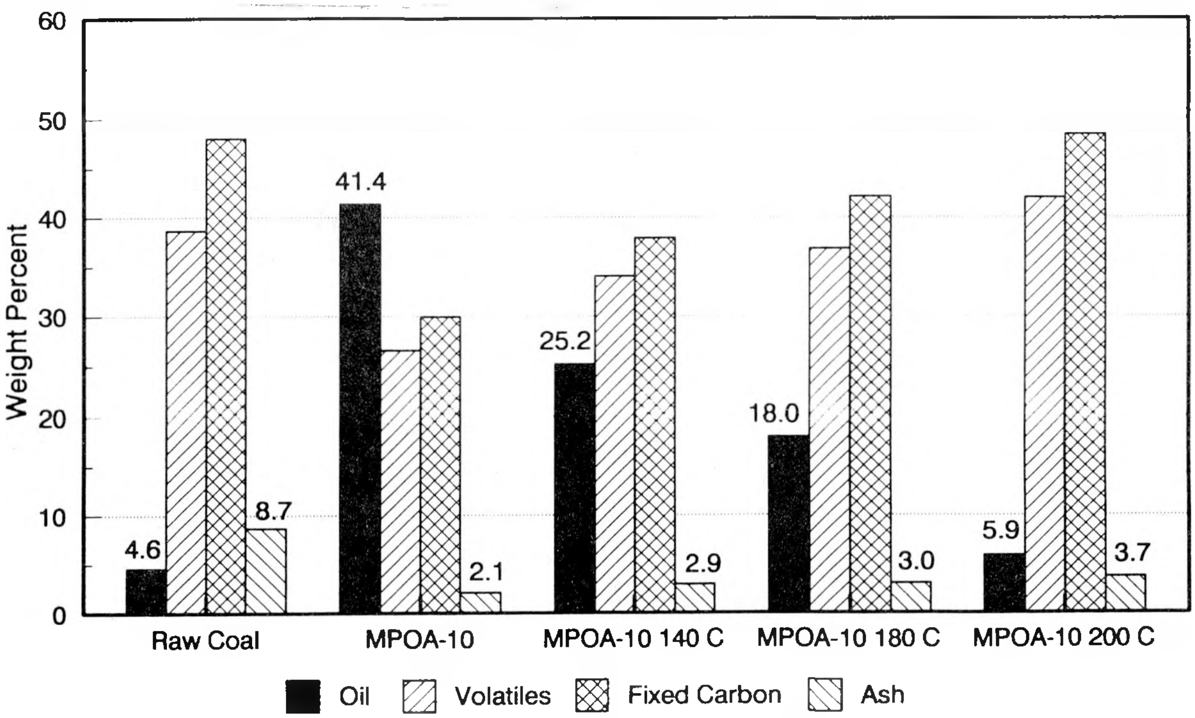

Figure 3. TGA PROXIMATE ANALYSES COMPARISON FOR RAW CENTER LIGNITE, RAW COAL AGGLOMERATES AND RAW COAL AGGLOMERATES AFTER OIL RECOVERY.

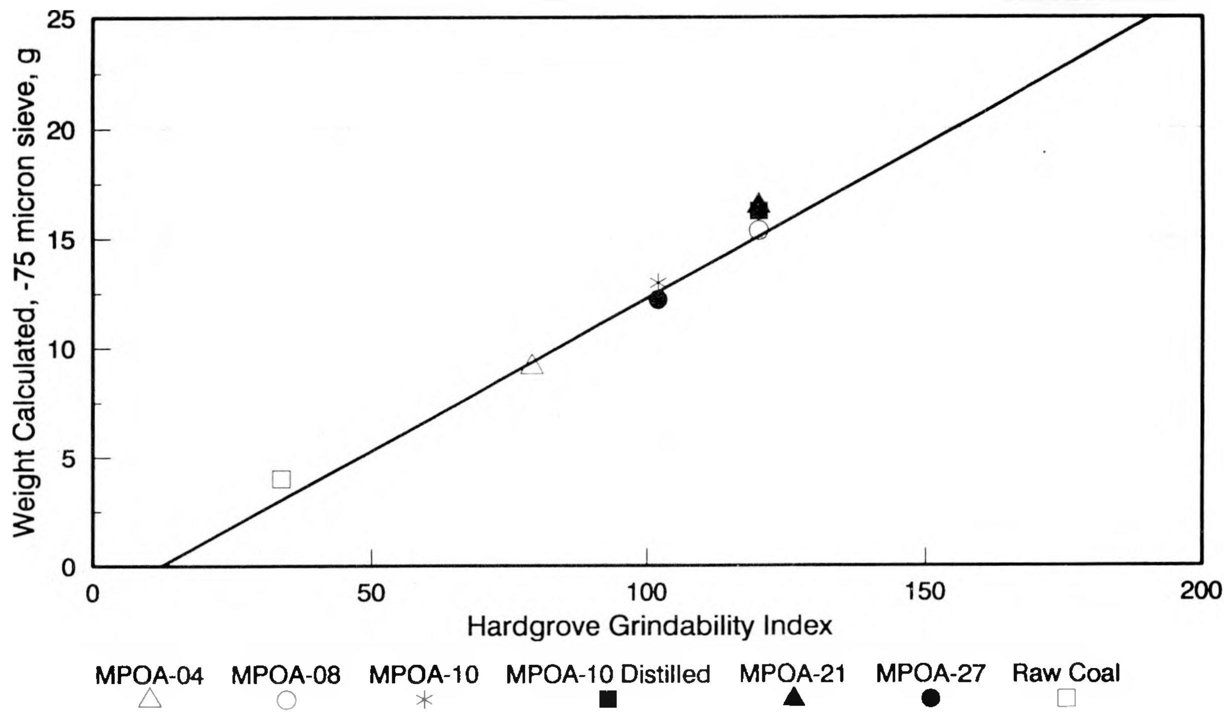

Figure 4. HARDGROVE GRINDABILITY INDEX VALUES FOR RAW CENTER LIGNITE AND CENTER LIGNITE AGGLOMERATES.

Conclusions

- o Raw and HWD Center lignite, of -6 mesh, can be easily and quantitatively agglomerated by parameter modification of the EERC oil agglomeration technique.

- o Moisture in the Center agglomerates can be reduced by as much as 95% from the raw coal after oil agglomeration.

- o Although only a secondary effort was made in this study to reduce sulfur and ash content of the coal, the data indicates that over 40% sulfur and 80% ash reduction in the Center lignite is inherent to the agglomeration process.

- o The oil content of the BNI agglomerates can be reduced to as little as 3% by heating, and the oil removed has the potential to be recycled to greatly reduce processing costs.

- o The BNI agglomerates can be prepared with a hardness comparable to soft coals, which should permit transportation and handling by conventional means.

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"USE OF OIL SHALE WASTE IN A CIRCULATING FLUID BED BOILER"

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USE OF OIL SHALE WASTE IN A CIRCULATING FLUID BED BOILER

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STEAMBOAT SPRINGS, COLORADO

ABSTRACT

Oil shale produced during development mining of Occidental Oil Shale, Inc.'s modified in situ (MIS) retorts may be processed by an aboveground retort, or can be burned to produce steam and power in a circulating fluidized bed (CFB) boiler. The calcium-based minerals in the shale provide efficient sulfur capture capacity during combustion in the CFB boiler. The burning of shale, alone and in combination with H_2S-laden low Btu gas from MIS retorting and coal, has been recently demonstrated in two boiler manufacturers' pilot plants. The pilot plant tests showed extremely high sulfur capture, high combustion efficiency, and low emission levels of NO_x, carbon monoxide and hydrocarbons. As a result of these tests, both boiler manufacturers would design, build, and guarantee a commercial facility burning the shale plant waste streams.

BACKGROUND

Oil shale is a fine-grained sedimentary rock which contains an organic material known as kerogen. When the rock is heated the kerogen decomposes to oil and gas and leaves residual carbon on the mineral matrix. The quality or grade varies in layers in the deposits. The United States deposits are wide spread with the most extensive being the Devonian-Mississippian black shale of the Appalachian area and the Green River formation of Utah, Wyoming and Colorado. The Piceance Creek basin in Colorado contains the richest and thickest deposit of oil shale. The recoverable reserves of western oil shale are estimated at one thousand (1,000) billion barrels.

The immense size of the resource continues to stimulate national interest in its commercialization. During the past 70 years, billions of dollars have been spent in pursuit of oil shale commercialization. Efforts have been cyclic because of swings in world oil prices and prevailing political views. During the late 1970's and early 1980's, a number of major firms prepared to build commercial-scale projects. Ultimately, only Unocal constructed a 10,000 barrel per day facility utilizing their retorting technology. The plant has reached 70% capacity some six (6) years after start up.

Occidental Oil Shale, Inc. (OOSI) has been active in the development of oil shale for nearly 20 years. A versatile technology was developed known as Modified-In-Situ (MIS) processing which mines out a small portion of the shale and retorts the remaining shale in the ground. In the 1970's and 1980's, OOSI conducted programs that verified the technical viability of the technology in full scale retorts. It remains to be demonstrated that the technology can be replicated on a continuous commercial basis.

Both Unocal and MIS retorting technologies produce shale fines that are not usable in proven retorting technologies. In addition, MIS processing and some other retorting processes generate a low Btu gas laden with H_2S gas which must be utilized in an environmentally sound manner. The circulating fluid bed boiler technology, which has been commercialized so successfully in the past 10 years with coal, coal wastes, wood, and other low grade fuels, appeared ideal to handle all the waste fuel streams. Bench scale testing by various investigators held out great promise for the technology. Therefore, by integrating a CFB boiler into a project with a retorting process, useful energy in the form of steam and electric power could be recovered from the waste streams generated by oil shale processing. However, this approach had never been tested by a boiler manufacturer or demonstrated commercially.

Therefore, industry is still left with limited technology options for responding to the need to commercialize production from Western oil shales. A logical response to this dilemma is to conduct engineering-scale proof-of-concept demonstrations to provide technologies which will be ready for commercialization after the year 2000.

OOSI has pursued that option at the urging of State and local government officials. During fiscal year 1990, the U.S. Department of Energy, State of Colorado, Rio Blanco County and OOSI entered into a cooperative agreement to determine the feasibility of a proof-of-concept test facility. The tasks to be accomplished in 1990 were firming up design and cost information for the plant and mine, preparing marketing plans for oil and electricity, determining financing requirements, reviewing of the many permits required, and finally testing of the combustion of oil shale in a large CFB pilot plant.

The results of the testing of oil shale and other fuels conducted as the first step of this Colorado Tract C-b demonstration oil shale project are discussed in the remainder of this paper.

FUEL STREAMS

The project is being designed to incorporate three fuels in the CFB boiler: oil shale, mined out during the development of the MIS retorts; low Btu MIS gas, produced during the retorting process; and, supplemental coal, readily available in the area, to provide additional Btu's to generate the amount of steam and power planned for the project. The demonstration project will provide process steam requirements and up to 50 megawatts of power for internal use and external sales. Engineering studies for a commercial facility of 25,000 Barrels/Day envision integrating MIS and aboveground retorting technologies and using a CFB boiler to burn shale fines, low Btu gas and other waste streams.

Oil shale at the C-b tract in the horizons that will be mined for the MIS retorting process varies in grade from under 20 gallons per ton (GPT) to over 40 GPT. This corresponds to a range of 2000 to 4000 Btu/pound in higher heating value. The analysis of the expected grade of shale mined for the project is shown in Table 1. The shale is about 15% organic matter, 30% carbonate minerals such as dolomite and calcite, and 55% inert minerals. The calcium compounds were expected to provide the sulfur capture in the CFB boiler. In the current design, the shale represents about 47% of the energy to the CFB boiler and contain 45% of the sulfur.

The low Btu MIS gas stream is laden with H_2S from the shale retorting and contains about 70 Btu/SCF. This represents about 23% of the Btu's in the boiler design and 51% of the sulfur load. The composition of the average gas is shown in Table 2.

Supplemental coal is available from several operating coal mines within trucking distance of the C-b site. Coal represents the remaining 30% of the Btu's into the boiler and introduces about 4% of the sulfur. Table 3 shows analyses of two typical coals. Each was used in pilot plant tests.

In addition, small waste streams, such as sour water stripper overheads rich in ammonia, may also be combusted in the CFB boiler in the demonstration project.

THE PILOT PLANTS

The first test series was run at Tampella-Keeler's facility in Williamsport, PA. The second test series was run at Pyropower's pilot plant in San Diego, CA.

The Tampella Keeler test facility is the largest CFB pilot unit in the U.S. It is rated at about 10 MM Btu/hr fired load. It is about 3 feet in internal diameter and is the same height as commercial units (70 feet). Waste heat recovery and a baghouse for dust emission control are included. During the testing that covered one and a half weeks, 100 tons of oil shale and 10 tons of coal were burned. In order to simulate MIS gas, recycled flue gas spiked with natural gas and H_2S was injected into the boiler.

The Pyropower pilot plant is rated at 2 MM Btu/hr fired load. It is about 16-inches by 16-inches in inside dimension and about 30 feet high. Waste heat recovery, baghouse for dust emission control and backup sulfur scrubbing facilities are included. During the testing which covered about two weeks, 20 tons of oil shale and 5 tons of coal were burned. MIS gas was simulated with recycled flue gas spiked with propane and H_2S.

A matrix of steady state cases was run in each pilot plant to investigate the affects of temperature, load, mixes of fuel and partial load design conditions. Based on the results of the Tampella-Keeler test, the range of the Pyropower tests was expanded to get a larger variation in sulfur capture.

COMBUSTION BEHAVIOR

The three fuels burned intensely and very efficiently in both pilot plants. Carbon utilization was over 99% in all runs. The main fuel, oil shale, proved very reactive due partly to its high volatiles content. On introduction into the bed, much of the organic matter promptly devolatilizes. The loss of volatiles and decomposition of the calcite and dolomite, results in a highly porous and fragile particle which tends to decrepitate into fines. As a result, though the size of the shale was below 1/4 inch at Tampella-Keeler and below 3/4 inch at Pyropower, much of the combusted solid ended up as fly ash recovered in the baghouse. A smaller stream, typically less than 20% of the ash, was withdrawn as bottom ash.

SULFUR CAPTURE

Various investigators have shown in bench scale tests that Western oil shale could be an effective absorbent for sulfur dioxide in a fluid bed boiler. One of the major objectives of the pilot tests was to verify that low sulfur emission limits could be achieved. The data are to be used to obtain permits for the facility from the State regulators and to allow the manufacturers to provide accurate cost estimates and guarantee plant performance. Due to feed restrictions at the Tampella Keeler plant, two mixtures of shale and coal, and shale only were burned. Simulated MIS gas could be added at any time. Figure 1 shows the sulfur dioxide (SO_2) in the stack gas for all the runs at various temperatures. Over 95% sulfur capture was achieved by the minerals inherent in the shale ash. The sulfur capture efficiency decreased with increasing temperature and fell off rapidly above 1600 F.

The shale ash contains about 30% calcite and dolomite (mostly the latter) which represents a calcium to sulfur ratio of 3.0 at normal conditions. However, the shale appears to be more effective than typical limestone. Other tests achieved very high sulfur reductions at Ca/S molar ratios that are well below those expected when coal is burned with limestone as the sorbent. This is due primarily to the phenomena, noted above, in which the shale particles break down into many fines affording a high amount of reactive surface for the SO_2.

The tests at the Pyropower unit gave generally similar results to those observed at Tampella Keeler. The dependence on temperature was similar. During these tests, the proportions of fuels were varied to achieve different Ca/S ratios. The results are shown in Table 4. They confirm the high sulfur capture and the high sorbent efficiency of the combusted shale ash.

NO_x EMISSIONS

Shale is a high nitrogen fuel and on this basis one would expect high nitrogen oxide emissions. Burning shale alone did result in elevated levels of NO_x emissions which would require some control technology. Burning shale in combination with low Btu gas and with coal resulted in acceptable emission levels. Due to the unique characteristics of the shale we noted behavior that is not typical of normal coal/limestone results in a CFB boiler. As the bed temperature decreased, the NO_x in the flue gas actually increased.

The experimental data from Tampella Keeler is shown in Figure 2. The data clearly show the increasing NO_x level with decreasing temperature. The effect of secondary air injection, within the limits of the experimental conditions, was not significant.

We cannot offer any plausible explanation for the temperature dependence of the NO_x levels. The sulfation level of the sorbent has a strong influence on NO_x. For example, introducing H_2S with oil shale alone brought down the NO_x promptly to below 200 ppmv. Further, when the amount of H_2S was doubled, there was an additional drop in NO_x. However, the higher NO_x level measured at the lower temperature cannot be explained along these lines, since sulfur capture was more effective at the lower temperature. Hence, at these lower temperatures, there was less free lime, more sulfate, and comparatively less H_2S. The rationale for the observed temperature dependence must therefore be sought in other parameters and mechanisms.

During the Pyropower tests, more emphasis was given to the study of NO_x and its control. Table 5 summarizes the emission data from these tests. Again the same temperature dependency as observed.

Ammonia injection into the outlet of the CFB boiler is a NO_x control technology. Table 6 shows that the emissions can be controlled when shale is burned alone. Test 11 simulated injection of an ammonia stream produced during the MIS retorting. The ammonia is recovered from the MIS gas wash water in a sour water stripper. This ammonia waste stream was injected it into the bottom bed and cyclone outlet at various ratios. Injecting 100% into the bottom of the bed lowers NO_x somewhat; injecting it all to the top of cyclone results in the lowest NO_x emission level. As Table 7 shows this represents a high molar ratio of NH_3 to NO_x: 8 versus 3 normally used for control. However, the ammonia is a small waste stream from which anhydrous ammonia can not be economically recovered for the demonstration project.

Shale, alone or in combination with other low quality fuels, can be burned and achieve low NO_x emission levels by using standard ammonia injection or by using the sour water ammonia produced during the shale retorting.

ASH CHARACTERISTICS

The characteristic of the ash which contributes to it being an effective sulfur capture agent is the fine particle size after combustion. As noted before, in both test units over 80% of the ash was recovered as fly ash in the baghouse. The baghouses at both test units showed no problem in handling the heavy loading of fly ash or in blowing the ash from the bags.

The quantity and particle size of shale ash did require that precautions be taken in the waste heat recovery sections of the two pilot plants. The fine ash did build up on the heat transfer surfaces in the waste heat boilers and the economizers.

The Tampella Keeler plant has a soot blower in the economizer but not in the waste heat boiler. During the run, baghouse inlet temperatures increased and were controlled initially by blowing the economizer. Eventually, the waste heat boiler outlet temperature became too high for the economizer to cool, forcing a shut down to clean out the waste heat boiler. An air lance was fabricated to blow the waste heat boiler during the remainder of the runs. The dust adhered to the tubes but was easily blown off by the soot blower and air lance.

The Pyropower plant has soot blowers in their waste heat boiler/economizer exchanger. A similar buildup was noted by temperature changes in the exchangers. Soot blowing effectively controlled the buildup. In a normal 10 hour burn with coal and limestone, soot is blown at the beginning and end. With shale/coal/low Btu gas, soot was blown every 2 to 4 hours; and, with shale alone, soot had to be blown every 20-30 minutes.

Both manufacturers feel that soot blowing will control the dust buildup on the heat transfer tubes. The units will be conservatively designed for proper tube spacing, soot blowers, and baghouse capacity.

The fly ash from the pilot plant tests has been tested using the EPA TCLP method and found to have no leachable heavy metals or organics. Thus the ash can be handled as a non-hazardous material. The large quantity of fly ash looks like brown cement. Tests are currently underway to determine the material's properties as a cement additive, roadbase enhancer and waste stabilizer. Preliminary results are encouraging.

CONCLUSIONS

A test program has been completed at two CFB boiler manufacturers' pilot plants. The results demonstrate that oil shale alone and in combination with other fuels can be burned efficiently in an environmental acceptable manner. The CFB boiler technology will allow OOSI to burn mined shale wastes and low Btu gas from its MIS processing in a commercially proven technology and produce steam and power. The combustion can be accomplished in an environmentally acceptable manner with very low emissions without the addition of limestone to the CFB or the use of flue gas desulfurization technology. The waste ash stream is non-hazardous and may eventually find uses as building materials.

ACKNOWLEDGEMENTS

The testing described in this paper was jointly sponsored under a cooperative agreement between OOSI, the U.S. Department of Energy, the State of Colorado, and Rio Blanco County.

TABLE 1

SHALE ANALYSIS

COMPOSITION	
Ultimate Analysis	
As Received, wt%	
Carbon	17.74
Hydrogen	1.80
Nitrogen	0.34
Sulfur	0.99
Oxygen	9.97
Ash	68.13
Moisture	1.03
	100.00
Dolomite (MgCa(CO3)2)	20.15
Calcite (CaCO3)	7.75
Grade, Gallons/ton	27
Heating Value, Btu/Lb.	2799
Pounds of Sulfur/MM Btu	3.54

TABLE 2

MIS RETORT OFFGAS ANALYSIS

COMPOSITION	
Volume %	
Hydrogen	8.5
Nitrogen	53.9
Oxygen	0.1
Carbon Monoxide	2.9
Carbon Dioxide	29.1
Methane	1.3
C2's	0.4
C3's	0.2
C4's	0.1
C5+	0.15
Ammonia	0.15
Hydrogen Sulfide	0.75
Other Sulfur	0.0002
Water	2.5
	100.00
Heating Value, Btu/Scf	70
Pounds of Sulfur/MM Btu	9.1

TABLE 3

COAL ANALYSES

	COLOWYO Meeker	Powderhorn Palisade
Proximate Analysis		
As Received, wt%		
Moisture	15.86	9.50
Ash	4.94	10.00
Volatile Matter	32.82	33.50
Fixed Carbon	46.37	47.00
	100.00	100.00
Btu/Lb	10710	11500
Ultimate Analyses		
Dry Basis, wt%		
Carbon	72.12	73.50
Hydrogen	4.91	4.86
Nitrogen	1.65	1.16
Chlorine	0.02	0.01
Sulfur	0.42	0.67
Ash	5.87	11.05
Oxygen	15.01	8.78
	100.00	100.00
Pounds of Sulfur/MM Btu	0.33	0.53

TABLE 4

PYROPOWER RESULTS
SULFUR DIOXIDE EMISSIONS

DESIGN MIX: 47% SHALE; 23% MIS GAS; AND, 30% COAL ON BTU BASIS

RUN	FEED	TEMPERATURE	Ca/S RATIO	SO2, PPM
1	DESIGN MIX	1600	3.0	16
2	DESIGN MIX	1550	3.0	1
4	DESIGN MIX, LOW LOAD	1470	3.0	1
5	DECREASE SHALE	1550	1.9	25
6	HIGH S MIS GAS	1550	1.6	138
7	SHALE WITH FG RECIRC	1470	6.6	2
9	SHALE WITH S IN RECIRC	1550	3.3	1
11	DESIGN WITH NH3	1530	2.3	3
12	SHALE ALONE	1550	6.7	6

TABLE 5

PYROPOWER RESULTS
NITROGEN OXIDE EMISSIONS

DESIGN MIX: 47% SHALE; 23% MIS GAS; AND, 30% COAL ON BTU BASIS

RUN	FEED	TEMPERATURE	Ca/S RATIO	NOx, PPM
1	DESIGN MIX	1600	3.0	187
2	DESIGN MIX	1550	3.0	222
4	DESIGN MIX, LOW LOAD	1470	3.0	263
5	DECREASE SHALE	1550	1.9	140
6	HIGH S MIS GAS	1550	1.6	148
7	SHALE WITH FG RECIRC	1470	6.6	574
9	SHALE WITH S IN RECIRC	1550	3.3	238
11	DESIGN WITH NH3	1530	2.3	Varied
12	SHALE ALONE	1550	6.7	395

TABLE 6

NO_x EMISSION CONTROL

Burning Shale Alone with Recycle Flue Gas @1500F

NOx ppmv	NH3/NOx Molar Ratio	% NOx Reduction
600	0	0
450	1.1	25
280	2.2	53
200	3.3	67

TABLE 7

NO_x EMISSION CONTROL

Injection Sour Water Ammonia into Bed and Cyclone
NH3/NOx = 8.8

NOx ppmv	% to Cyclone	% NOx Reduction
150	None	None
122	0	19
98	25	35
55	50	63
39	75	74
33	100	78

FIGURE 1 - SULFUR DIOXIDE RESULTS

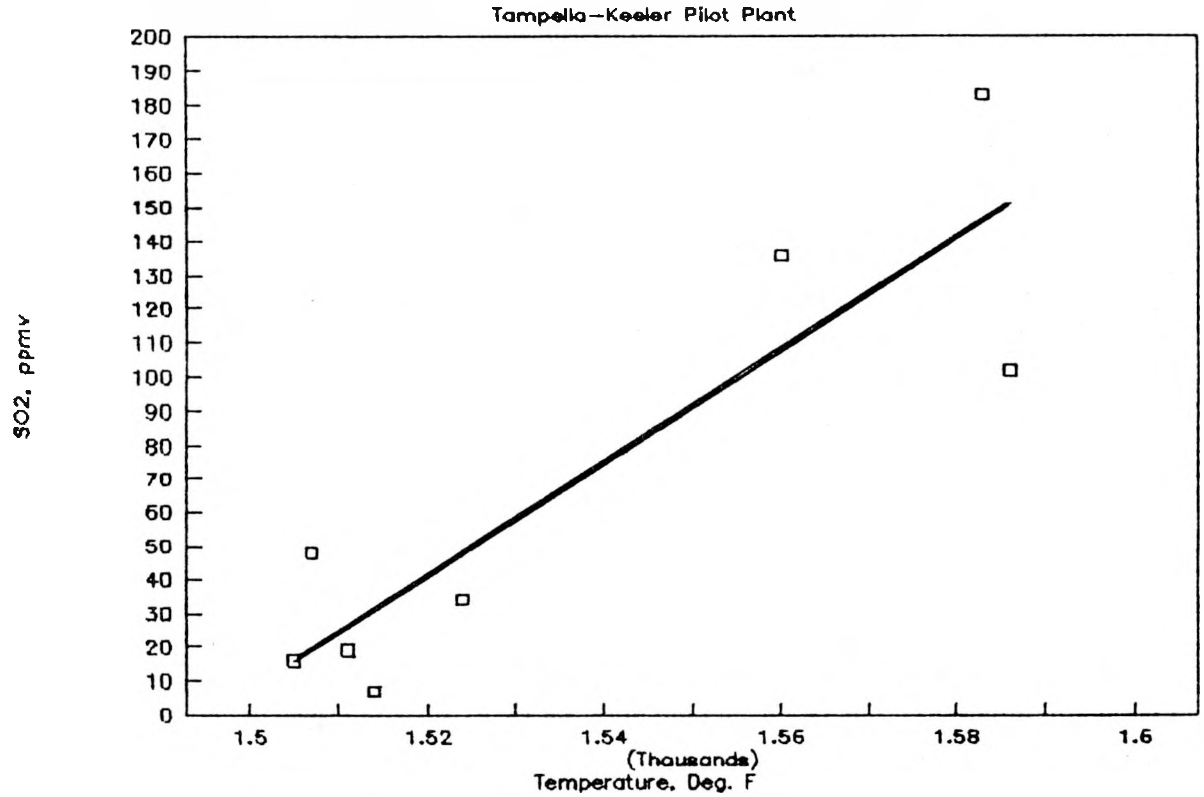
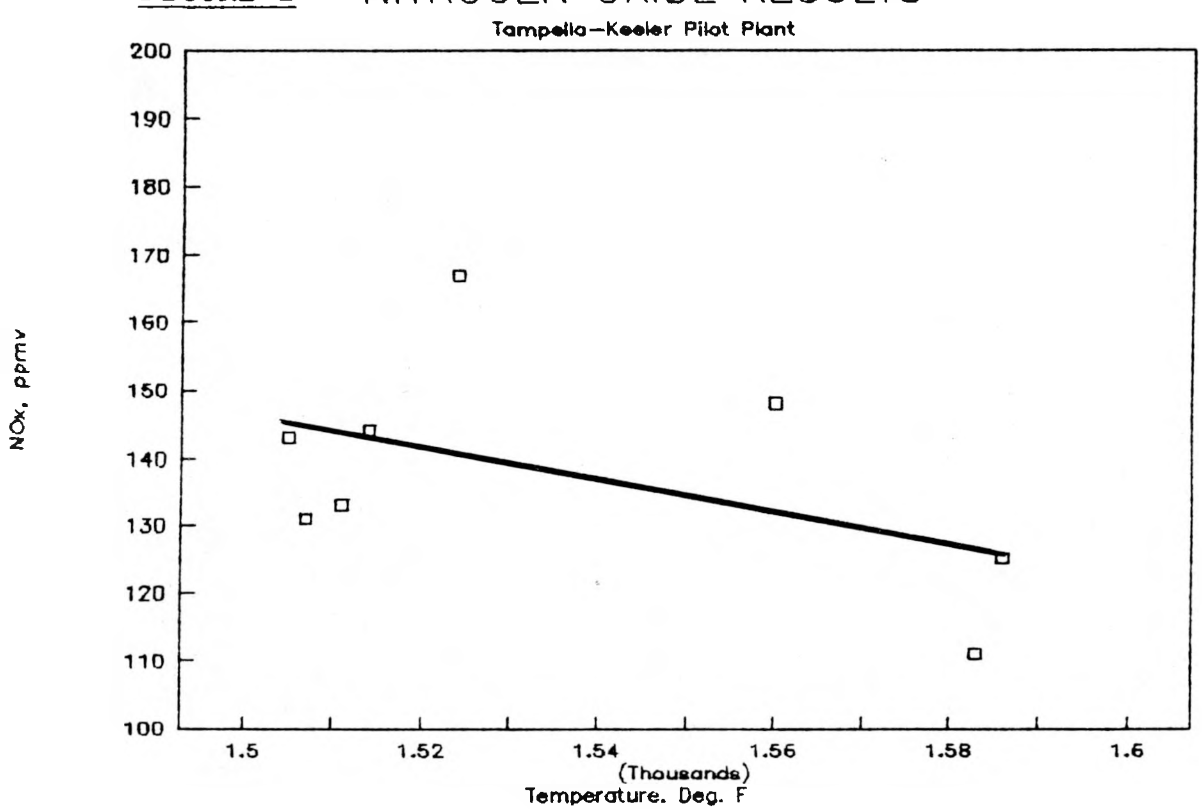


FIGURE 2 - NITROGEN OXIDE RESULTS



"REVIEW AND UPDATE OF THE COAL FIRED DIESEL ENGINE"

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REVIEW AND UPDATE
OF THE
COAL FIRED DIESEL ENGINE

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ABSTRACT

GE Transportation Systems, manufacturer of diesel-electric locomotives, has been pioneering the development of a coal fired diesel engine. The project is the consequence of the 1982 study to find the most effective way to reintroduce coal as a locomotive fuel, to alleviate high fuel costs and unavailability. The project which was initially sponsored by two American railroads has since been funded largely by the U.S. Department of Energy. Feasibility of using a coal water slurry has been demonstrated and preliminary test results for commercial practicality are most encouraging. Engine thermal efficiencies are comparable to oil engines and materials have been identified to withstand the erosive effects of the fuel and its combustion products. The presence of the water in the fuel has a significant effect in controlling NOx emissions, HC and CO emissions are very low and particulates can be controlled with a particulate trap. Economic studies indicate coal slurry fuel is an attractive economic alternative for railroads. A 2200KW engine is scheduled to be installed on a locomotive this year. The success of this project may influence the development of coal burning diesels of this power output and higher for utilities.

INTRODUCTION

The volatility of oil prices and its potential limited availability continue to support the need for alternative fuel sources for America's railroads. The recent environmental concerns have also demanded that any alternative fuel meet stringent emission standards. The outlook for a coal fired diesel engine to satisfy these requirements is promising.

In 1973, the days of the oil crises, U.S. imported oil was about one-third of our domestic production and was rising rapidly. It reached about two-thirds in 1978 and then fell again to the 1973 level.[1] (See Figure 1.) It is on the rise again and domestic supply is falling, such that in 1989 the imported supply was equal to three-fourths the domestic supply. However, because oil prices have become a function of economic growth and exchange rates as well as supply and demand,[2] current low oil prices do not reflect the need for alternative fuels and there is a tendency to ignore the seriousness of the need for alternate fuels.

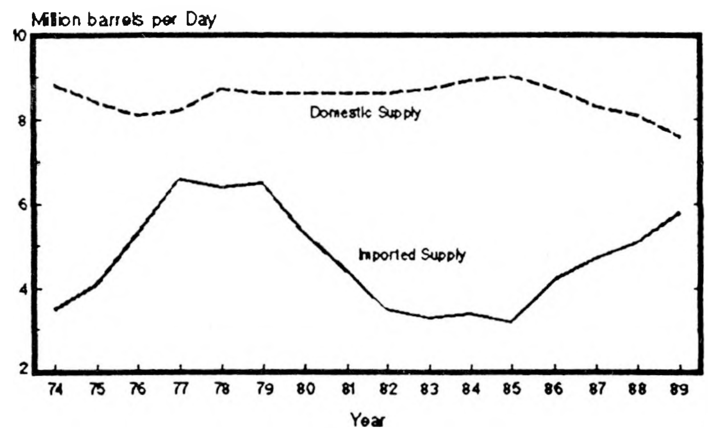

FIGURE 1 - U.S. OIL SUPPLY

There is also a renewed emphasis on environmental issues, especially the latest "panic" concern about global warming.[3] Because coal has little hydrogen content, it will have a somewhat higher CO_2 emissions content per million BTU liberated than other recently popular fuel candidates such as natural gas or methanol.

It is the purpose of this paper to review the development of the coal fueled diesel engine and to postulate its future relative to practicality, economic desirability and environmental acceptance.

BACKGROUND

The idea of using pulverized coal as an engine fuel began in the beginning of this century, mainly in Germany, with the first encouraging results reported by Pawlikowski in the mid-twenties. His work spurred the activities of many developers throughout the war years, but unfortunately most of the development was curtailed at the end of World War II. Most of these engines were developed to burn coal dust, with minor attempts to use coal mixtures, and but one attempt to gasify the coal. During the post war period a few studies in the United States were conducted using dry pulverized coal or coal slurried with oil.[4]

Within the last 15 years, interest was renewed as a result of the oil crises, and development effort sponsored by the U.S. Department of Energy culminated with tests of a single cylinder Sulzer engine operating first with coal-oil slurry fuel and then with coal-water slurry. This engine was a large slow speed diesel engine (120 RPM), with a bore of 760mm and a stroke of 1550 mm. The results of this study were encouraging in that they showed that operation on slurry fuel was feasible.[5] (A fuel slurry is preferred due to the more explosive nature of dry powdered coal and the consequential need for special fuel handling.) However, the tests also pointed out the need for hardware development. More intensive fuel processing developments have also been taking place within the last 15 years. These parallel development efforts encouraged GE Transportation Systems to consider a coal fueled diesel engine for use in a locomotive. However, the locomotive application would necessitate the use of a medium speed engine (1050 RPM) for size and power reasons, and feasibility for this higher speed engine had not been successfully demonstrated using coal-water slurry fuel. Coal-water slurry would have more potential fuel savings than coal-oil slurry, due to the high cost of oil, and a coal loading limit of about 50 percent to prevent high viscosity.

Ignition and combustion feasibility of the fuel within the engine had to be demonstrated, which necessitated developing fuel injection systems. The effects of the fuel on engine durability had to be understood and studies of economic desirability and exhaust emissions had to be undertaken.

THE FUEL

Most of the early GE experimentation was carried out using fuel produced by the OTISCA process. (See Figure 2.) Briefly described, the process first pulverizes the coal, and then comminutes the coal with water in a ball mill to a mean particle size of about 5 microns. (The developments by OTISCA demonstrated the feasibility of fine comminution with reasonable cost. Heretofore, it had been assumed that a process to produce such a fine particle size would be prohibitively expensive.) After grinding, the fuel is mixed with an agglomerate in a high shear mixer. The coal is agglomerated and the mineral matter can now be separated from the fuel agglomerate. The ash is easily separated from the water and the water recycled. The agglomerate is recovered from the fuel by heating and is also recycled. The fuel is then slurried with demineralized water to the desired fuel concentration and any necessary additives are included. The ash content of the final fuel is less than 1.5 percent (dry), and most of the pyritic sulphur is removed. Because it is a mechanical process, organic sulphur is not removed. Fuels made from other processes have also been studied.

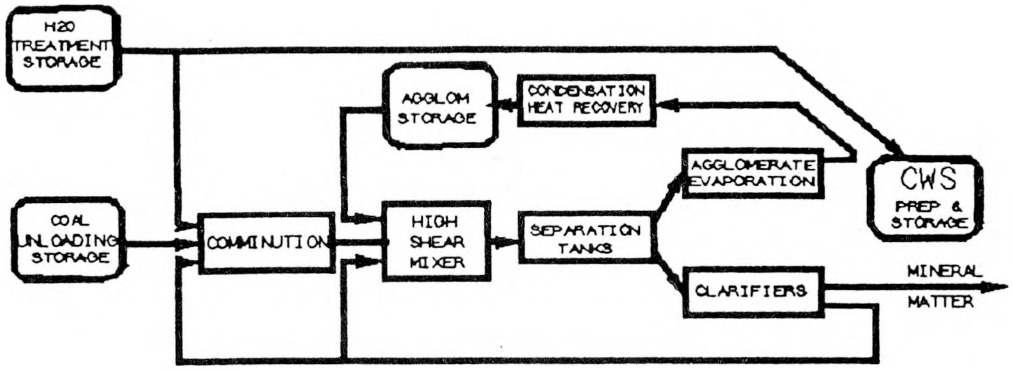

FIGURE 2 - THE OTISCA COAL SLURRY PROCESS

The nominal requirements of the engine grade coal fuel are shown in table I.

Proximate Analysis	
% Ash	1.5 max
% Volatiles	35 to 40
% Fixed Carbon	60 max.
Particle Size	
Mean Diameter (microns)	7 to 10
High Heating Value (MJ/kg)	28 to 34
Sulphur Content	1% max.

TABLE I

NOMINAL ENGINE GRADE COAL SLURRY FUEL REQUIREMENTS

The engine grade fuel cost is composed of three pieces: the cost of the raw coal itself; the fuel processing cost; and the transportation cost. These costs have been estimated for railroad applications[6] and recently reverified.[7] The current estimate of the fuel cost is approximately $3.10 per million BTU, with variations depending upon process plant site location, which affects transportation costs, the source of the raw fuel and the reasonableness of the fuel process business markup.

Results to date of fuels, both bituminous and sub-bituminous which have been processed and successfully burnt in the diesel engine are shown in Table II.

FUEL NO.	FUEL SUPPLIER	STATE, SEAM & TYPE	CLEANING PROCESS	MEAN MICRON SIZE	PROX ANALYSIS (Wt%) VOLI-TILES	FIXED CARBON	ASH	LOWER HEATING VALUE	FUEL SOLID %	BURN OUT %	SFC
1.	OTISCA	KY-BlueGem Bitum	Physical	4.6	39.5	59.8	0.7	33.48	49.0	98.8	8399*
2.	OTISCA	KY-BlueGem Bitum	Physical	4.8	38.8	60.4	0.8	33.48	50.2	98.8	8812
3.	OTISCA	KY-BlueGem Bitum	Physical	3.1	39.5	59.8	0.7	33.48	49.3	98.7	8707
4.	OTISCA	KY-BlueGem Bitum	Physical	3.2	39.3	60.0	0.7	33.48	48.9	99.2	8342
5.	OTISCA	PA-Mariana Bitum	Physical	2.5	36.9	61.4	1.7	33.52	50.9	98.6	8194*
6.	UNDERC	WY-Kemmer Subbit	Chemical	13.9	40.7	56.5	2.8	28.46	48.9	99.3	8564*
7.	UNDERC	Wy-SprgCrk Subbit	Phys+Che	14.7	40.5	57.4	2.1	28.71	52.3	98.9	9064*
8.	UNDERC	Wy-SprgCrk Subbit	Chemical	14.9	40.7	56.5	2.8	28.68	50.3	99.2	8282*
9.	AMAX	KY-Splint Bitum	Physical	8.2	37.3	60.2	3.5	32.80	49.3	97.9	8769

TABLE II

FUEL COMBUSTION RESULTS
(* Average of several test point)

THE ENGINE

Engine development began by separating the task into three phases: combustion development; fuel injection systems; and wear resistance.

Combustion Development:

Combustion of the coal-water fuel began with simulation in a combustion bomb at GE's Corporate Research and Development center. "Single shot" tests were conducted to determine the ignition characteristics of the fuel. These tests with sufficient combustion parameter variation, aided with high speed combustion film photography led to chemical combustion models indicating that not only was coal water slurry combustion possible in a medium speed diesel environment, but that the general character of combustion was similar to oil combustion. Indeed, based on the differences which do occur, and with later experimentation, more understanding of the entire combustion process for coal or oil is being achieved.

Fuel Injection Systems:

Several fuel injection system designs were conceived, and experimental hardware and single cylinder engine testing began. Coal slurry is not only erosive, it tends to clog pumps, injectors, and fuel lines. Figure 3. is a diagram of the first fuel injection system which was successful. This system was characterized by the separation of coal slurry from the high pressure injection pump by the use of an intermediate diaphragm. Circulating fuel oil is used to provide injection pressure, volume and timing via the diaphragm. The coal slurry was prevented from clogging the injection needle by using back pressure on the needle valve. This system led to single cylinder operation of the coal slurry fueled engine at 1050 RPM and at power levels equal to that of an oil fueled engine. (The capacity of the high pressure pump was doubled to accommodate the increased fuel volume due to water.)

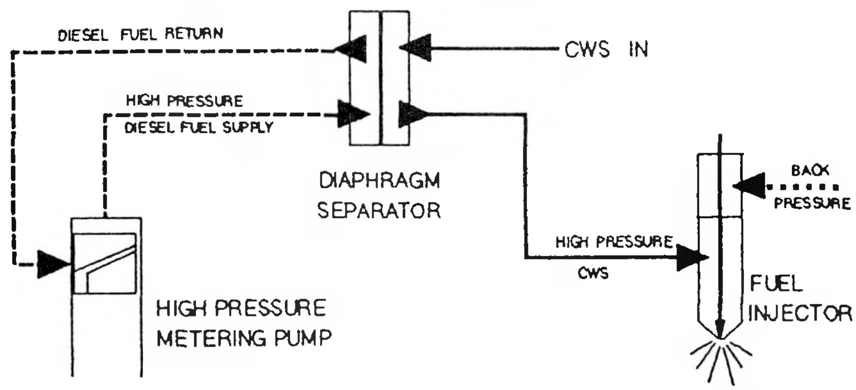

FIGURE 3 - MECHANICAL FUEL INJECTION SYSTEM

The feasibility of operating the coal fired diesel at medium speed (1050 RPM) had been demonstrated but the rapid wear of the injector nozzle holes, less than 5 hours life, underscored the need for a wear resistant development program. Other injection systems were subsequently developed, including electronically actuated accumulator systems.[8] Ironically, it had been presupposed that it might be difficult to obtain such high power levels with coal fuels, but as it evolved, it was found that low power levels were more difficult, necessitating the need for diesel fuel pilot injection at these low power levels. At this stage of the development, a small quantity of diesel fuel (about 3% energy) is used at full power to promote ignition stability, and operation at low pwer levels is on diesel fuel only.

Engine Wear:

Unlike engine designers of the turn of the century, today's designers have a greater repertoire of materials and processes available to them to solve the problems of a coal fired diesel.

Injector tip wear was the most obvious shortcoming of the coal fired diesel, and work to identify harder materials for the nozzle tips was begun. Of all the materials investigated, drilled industrial diamonds which were implanted in the injector tip were found to have the best life. In fact, no appreciable wear has been experienced to date after 60 hours of engine operation and bench scale tests exceeded 1000 hours of equivalent engine operation. The development of these tips is now underway even for use in today's oil diesels.

The wear response of the production nitrided cylinder liner to coal water slurry fuel was about six times higher than when operated with diesel fuel. Research activities on ring and liner coatings have concentrated on determining the plasma spray parameters necessary to deposit a tungsten carbide coating with optimum characteristics to resist the coal-water slurry ash sliding wear. Using a chromium carbide coated top ring, a chromium plated middle ring and a chromium plated cast iron oil ring, liner wear was reduced to only twice that of an oil diesel engine. Top ring wear was also reduced to about twice that for an oil engine by using the tungsten carbide coated top ring. The chromium plated middle ring showed better performance than when operated on oil, and the chromium plated oil ring after limited testing showed no wear at all. The fact that this first attempt to reduce the wear rate using harder materials was so dramatic indicates that the cylinder liner and ring wear problems can be solved with "reasonable advances in material technology".[9]

When the coal fired diesel program began, many other wear problems had been anticipated. Even though only limited durability testing has been done, to date no problems of wear have developed beyond those cited above.

ENVIRONMENTAL CONSIDERATIONS

Unlike the currently popular alternative fuel candidates such as natural gas and methanol, coal-water slurry is a much safer handling fuel. It is non-toxic, and non-flammable because of the high water content. It is truly an ideal fuel for mobile applications in this respect.

Table III, depicts the projected emissions from a coal fired diesel both as a bare engine and an engine with emission controls. A comparison is made with the current production oil engine.

The predictions show that the coal fired diesel with cleanup has every chance to be environmentally acceptable. Test data indicates that the HC's are slightly lower which would seem to be natural since the oil has largely been replaced with coal.

NOx emission of the coal engine is less than half of the oil engine because of the low firing temperature due to the high water content in the fuel.

	OIL DIESEL	BARE COAL DIESEL	CONTROLLED COAL DIESEL
HC	.25	.20	.20
NOx	11.50	4.80	4.80
SOx	.56	2.00	1.00
CO	.75	1.00	1.00
PM	.20	3.00	.30

Diesel fuel sulphur content= 0.5%
Coal slurry sulphur content= 1.0%

Table III

EMISSIONS COMPARISON (gr/HP-hr)

Development is underway to control exhaust particulate emissions. To date, a small scale cyclone was able to collect most of the unburned char particles in the stream, which accounts for about one-half of the particulate emissions. The smaller ash particles (less than 3 microns) passed through the cyclone. Several mesh filters were investigated. Although they were very effective, they clogged easily. Precoating the filter with lime greatly improved the ability of an air pulse to restore filter effectiveness. The high temperature (750 deg F) exhaust degraded the filters and Inconel fabric showed the most stable performance. Because the current program has locomotive application preference, the filtering system must be installed on a locomotive, thus severely limiting possible alternatives. Still, current investigation shows that a system can be designed which renders particulate emission not much greater that current oil engine output. On the other hand, removal of the size constraint which is possible with stationary applications will most likely result in a system which will capture most all of the particulate.

It seemed logical to try to capture oxides of sulphur by premixing CaO sorbent in with the coal-water slurry. For a Ca/S ratio of 2, 25 % of the initial SO_2 was removed as Calcium sulfate (a solid). Not only was the sulphur capture poor, it coated the head liner and valves in less than 8 hours operation.

Another concept of injecting a calcium slurry containing 25% of $Ca(OH)_2$ into the exhaust stream before the turbocharger removed 40% of the SO_2.[10] In addition, bench scale tests showed that CuO granular bed is very effective at capturing SO_2 at engine temperature. It is possible to capture over 90% of the SO_2. Development is under way to establish the best method of using powdered CuO in the actual engine. Thus, a great deal of SO_2 can be removed by post combustion techniques and as with the particulate control, even better results can probably be achieved without space constraints for stationary applications.

The lower hydrogen content of coal as compared to other fuels will result in a higher CO_2 emission content per unit of heat liberated. When comparing the effects of the CO_2 emission with other fuel characteristics, one should consider fuel process manufacturing and distribution requirements and engine efficiencies to determine overall system CO_2 generation. Furthermore, there are other emissions likely to be present in greater quantities in the exhaust of engines using other fuel alternatives. (e.g. formaldehyde when using methanol.) The probable greater dangers from such emissions could outweigh any CO_2 reduction advantages.

ECONOMICS

An economic analysis of the coal fired diesel locomotive has been carried out. The analysis indicates that with diesel fuel costs of $0.85 per gallon ($6.18/million BTU), most railroads could expect an attractive discounted rate of return of more than 20% by switching to coal which includes the incremental capital costs for new locomotives and the necessary changes in railroad fueling infrastructure.[6,7]

Coal costs have historically been independent of the supply, demand and price structure of other fuels and there is an abundant supply. Thus, as oil prices rise, the cost of other non-coal fuel alternatives rise also, limiting their economic advantage.

CLOSURE

The coal fired diesel engine concept is finally a reality. A 12 cylinder medium speed locomotive size engine has been run in a development test at power levels comparable to oil fueled engines. This engine is scheduled to provide locomotive power before the end of this year. Coal-water slurry fuel is non-toxic and safe and fuel savings can amount to as much as 50% over oil fuel. (Diesel fuel costs assumed at $0.85/gallon). Materials are being developed that should make engine wear comparable to present day engines, and the engine emissions control outlook looks favorable.

Interest in the coal engine is waning somewhat because of the current low oil prices. However, coal is an abundant fuel supply and its price has historically been independent of the supply, demand and price structure of other fuels. The coal engine development could lead to reduced dependence on imported oil, especially if further engine development results in coalfueled diesels for on-highway vehicle use. Use of a safe fuel like coal-water slurry for transportation would be most welcome. For stationary applications, the highly efficient diesel engine, burning coal could certainly supplement utility prime mover needs. At some point in the future it seems certain that coal fired diesels will find their way into our economy.

ACKNOWLEDGMENTS

The support of and permission of the U.S. Department of Energy to publish these updated results is gratefully acknowledged. The author also wishes to thank all of the GE coal fuel diesel team and in particular Drs. Bert Hsu and Paul Flynn for their help and support.

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"FLUID BED OPERATIONS TO DATE"

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FLUID BED OPERATIONS TO DATE

By:
Bruce Imsdahl and Duane Steen
Montana-Dakota Utilities Company
Mandan, North Dakota

INTRODUCTION

Good morning ladies and gentleman, it's a pleasure to have this opportunity to speak here at the Syn Ops 90. I first want to express my appreciation to the Energy and Environmental Research Center for the invitation to speak. Also, I want to thank them for the assistance that they provided us during the initial planning, start-up, and operation of the fluid bed unit of which I will be telling you about today.

Montana-Dakota Utilities retrofitted the existing 75 mw stoker fired unit at the R.M. Heskett Station near Mandan, North Dakota, to a 80 mw fluidized bed during the winter of 1986. For those of you that are not familiar with Montana-Dakota Utilities, I would first like to give you a little explanation of our company.

Montana-Dakota Utilities is an investor owned utility that serves a territory encompassing approximately 5% of the continental United States. Our service territory includes communities in the states of North Dakota, South Dakota, Montana, and Wyoming. The R.M. Heskett Station is located approximately in the center of the state of North Dakota. We are a combination utility in that we not only service our communities with electricity, but we also have natural gas service as well.

The R.M. Heskett Station consists of two centrally independent units. The unit on the north side of the station property is unit #1. It was built in 1954, and is a 20 MWe unit. The boiler is a Riley traveling grate stoker fired unit. Unit #2, located on the south, is a 66 MWe unit that was built in 1963. The original boiler was a Riley traveling grate stoker fired unit.

There were a number of reasons for our decision to retrofit unit #2 to a fluid bed. Our expectations were to solve the problems experienced with this unit since it's initial operation. Those expectations were (1) reduction of furnace slagging (2) reduction of convection pass fouling (3) increase boiler availability (4) increase boiler efficiency (5) increase unit capacity.

The design of the fluid bed included the following parameters:

Fluidization velocity: 12 foot per second (3.7 m/s)

Normal bed temperature: 1500 degrees F. (816 degrees C.)

Bed depth: 51 inches (1.3 m)

Overall excess air: 25%

Air heater gas exit temperature: 275 degrees F. (135 degrees C.)

Bed material: Sand

Because time is money, we wanted the retrofit to be completed as quickly as possible with a minimum down time. The fast track schedule was as follows:

Contract award: January, 1986

Begin demolition: October 14th, 1986

Hydrostatic test: February 18th, 1987

First coal fire: April 16th, 1987

First generation: May 10th, 1987

Commercial operation: May 15th, 1987

The steaming conditions as set by the contract, included the following parameters:

Superheat flow: 700,000 pounds per hour

Superheater outlet pressure: 1,300 PSIG

Superheater outlet temperature: 955 degrees F.

Feedwater temperature: 443 degrees F.

Figure one is a side view of the unit prior to the retrofit. So that you are familiar with the design of this unit, I would like to point out the following features. The unit has a traveling grate that travels towards the coal feeders which are located about five feet above the grate. Below the grate is the bottom ash collection system.

This unit is a two drum boiler. The unit has three division walls in the radiant section. It has a multi-clone dust collection system in the gas path after the economizer. There was a Ljungstrom regenerative air heater located just prior to the electrostatic precipitator.

The figure number 2 shows the areas that were changed in the retrofit. Notice that the traveling grate has been removed with the fluid bed section located again just below the coal feeders. The fluid bed consists of a boiling bank and a superheater section. Below the floor of the bed, is the wind box. Below the wind box there are ash collection screw conveyors, located both towards the front and rear of the unit. The in-bed boiling bank is supplied by three new 50% capacity wet stator boiler circulation pumps. The feed for these pumps is from the lower drum. The water flow therefore is through the in-bed surface and up in to the existing three division walls. The retrofit also consisted of a new three pass tubular air heater and a new forced draft fan.

In order to accommodate the fast track schedule, Babcock & Wilcox modularized the construction. The fluid bed was made in three sections or modules. The three sections were manufactured in West Point, Mississippi. They were then loaded on flat bed trailers and hauled north to the R.M. Heskett Station. The lightest module, consisting of part of the boiling bank, weighed 87,000 pounds. The heaviest module consisting of the entire in-bed superheat section weighed 108,000 pounds. The modules were made up of the wind box, floor and their associated headers, and the respective in-bed section.

Upon arrival at the station, the three modules were pushed individually under the boiler, welded together, and lifted up in to position so that the structural steel supporting them, could then be installed.

The firing deck where the stoker feeders are located is essentially unchanged. This frontal area, forty feet long, contained the ten stoker feeders. These feeders were grouped in to four groups to match the division of the wind box. The feeders continue their original design to spread the lignite over the entire twenty five foot depth of the boiler. The top of the in-bed surface, is at the same elevation as the firing deck. The fluid bed uses sand as bed material. Figure number 3 is the analysis of the sand used in our operation. The sand is washed and sized in a pit near Washburn, North Dakota. The sand pit is a glacial deposit. The sand is delivered in trucks on a daily basis. We use approximately sixty to eighty tons of sand material per day.

Our coal is North Dakota lignite. The lignite is delivered by rail from an open pit mine located near Beulah, North Dakota. Figures number 5 and 6 reflect the typical analysis of the lignite, and the size as fired.

Part of the retofit included the installation of a new Bailey Network 90 control system. This control system is a hybrid. To keep the cost of the project down. Those elements in the control system not necessarily part of the fluid bed, remained the original pneumatic control system as installed in 1963. The Net 90 control system included a single operator interface unit, as well as a number of hand auto stations mounted in the existing boiler board.

The graphics capability of the Net 90 system allowed for the creation of a plan view of the bed. The plan view includes twenty four thermocouples identifying temperatures through out the dense bed. The graphics includes the ten feeders, two sand feeders, and indicates the air flow through the eight air ducts supplying the segmented eight bed wind boxes. Although the bed was designed for fifty one inches of bed material, it has been our operational experience that full load can be achieved best with approximately forty eight inches of bed material. The splash zone of the bed material extends some five feet above the top of the in-bed surface. Through out the some twenty thousand operating hours, we have noted that there is very little slag build up within the boiler. This slag build up is very easily removed.

That is not to say however that we have not experienced large agglomerations within the last three years. With the North Dakota lignite being relatively high in sodium, we continuously note small agglomerates or eggs being formed during operation. We have found however, that should foreign material in particular clay, be introduced with the fuel, that large agglomerations can be easily formed predominately during start-ups.

We have however noted that with fresh bed material, the chances of large agglomerate formation is minimized during start-up.

The in-bed boiling bank and superheat section was designed with erosion shields to protect the under side of the lower tube rows. These have since been removed from the superheat section. The erosion shields have been falling off the tubes in the in-bed boiling bank. The erosion shields, due to their higher temperature, have aided in the formation of slag material. Where the erosion shields have fallen off, we have been unable to determine appreciable erosion.

The tube bends in the in-bed surface were protected with refractory covered pin studs. Again, due to the temperature of the refractory, build up of slag material is also evident in these areas. Through out the operation of the unit, the superheat section gradually acquires a coating of calcium sulfate. Figure number 7 shows the plot of steam temperature entering the in-bed surface, as well as steam temperature leaving the in-bed surface. The graph also shows the reduction in steam outlet temperature due to an agglomeration formed in the in-bed superheat section on day 108. On day 36, the unit was shut down and the in-bed surface cleaned after a 2,500 hour run. From this, we project about a 40 degree F. decrease in steam temperature over a four month period.

The results of emission tests ran in November of 1988 are listed in figure number 8. At full load, our opacity is approximately 6%.

The unit's availability is shown in figure number 9. During the months of November and December of 1987, the unit was unavailable due to the failure of the 4,000 horsepower FD fan motor. The outage in June of 1988 was to install additional in-bed boiling bank surface. Since that time, the unit has had an exceedingly good availability. For the year 1989, the unit's availability was 88%. This brief description of our fluid bed and operation to date shows that fluid beds are indeed a viable option for retro-fitting older boilers.

I hope I have shown that fluid beds can be operated with exceedingly good availability. A lot of this is atributable to the persistence of those people involved with this project, not withstanding the determination of the operators and maintenance people involved in day to day operation of our unit. I would encourage you to consider the tour of our unit that is scheduled for the last day of this conference. I think you will find this tour to be very interesting.

Thank you for your attention.

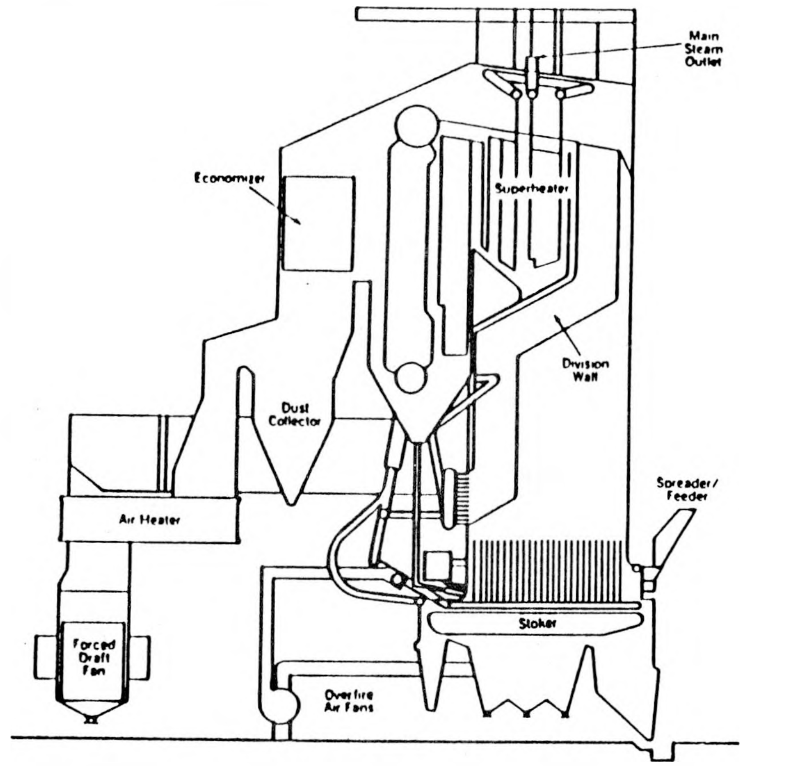


Figure 1 Original Unit 2 - R.M. Heskett Station.

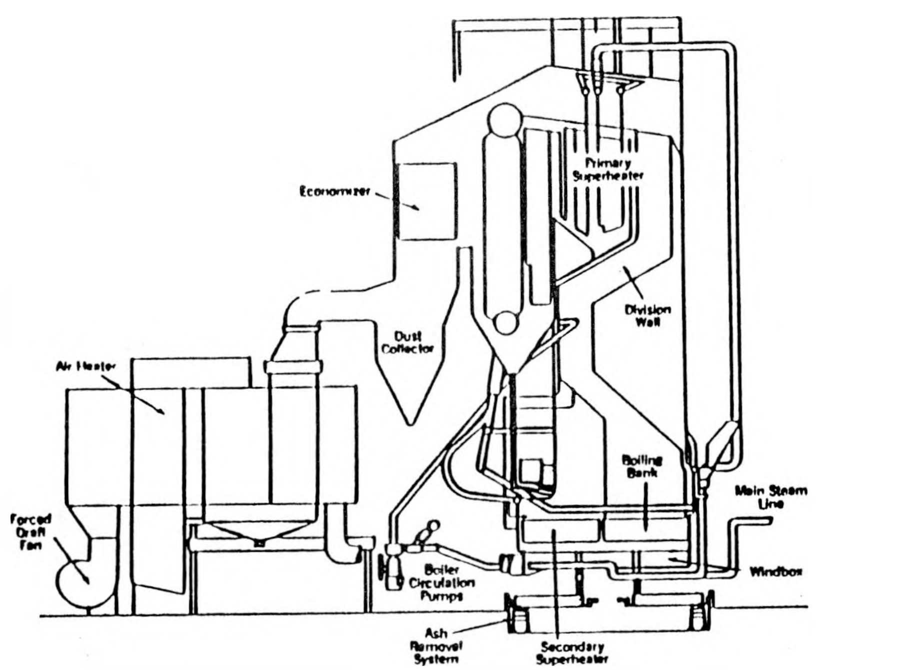


Figure 2 Unit 2 retrofitted with atmospheric fluid bed combustor.

Sample Identification: Geidde Pit - McLean County

Chemical Analysis

% Al_2O_3	8.29
% CaO	12.12
% Fe_2O_3	2.77
% K_2O	1.96
% MgO	4.52
% Na_2O	2.26
% SiO_2	59.40

Fusion Temperature: ASTM D1857-68(1980)

	Reducing Atmosphere	Oxidizing Atmosphere
Initial Deformation	2210 ° F.	2200 ° F.
Softening Temperature	2230 ° F.	2230 ° F.
Hemispherical Temperature	2240 ° F.	2240 ° F.
Fluid Temperature	2285 ° F.	2280 ° F.

Figure 3 R.M. Heskett Station

SAMPLE NUMBER:	#1
LOCATION SAMPLED:	Geidd Pit McLean County, ND
TEST METHOD:	Los Angeles Abrasion Resistance ASTM:C131, Modified Grading "D"
Loss at 100 Revolutions	3.3%
Loss at 500 Revolutions	18.4
Weight of Balls Prior to Test	2505.4 gr.
Weight of Balls After Test	2505.4 gr.

REMARKS: Material as represented by the above test results was tested in accordance with ASTM:C131, Grading "D" (6 balls) modified utilizing the #20 sieve in lieu of the #12 and the loss was determined after 100 and 500 revolutions. The abrasion balls were washed and dried to 104° ± 1°C prior to and after the test with those weights shown above.

Sample was submitted to and received here at the laboratory for test on August 7, 1986.

Figure 4 R.M. Heskett Station

SIZE DISTRIBUTION OF BEULAH LIGNITE AS FIRED AT MDU'S HESKETT STATION

SCREEN	WT. % THROUGH	NORMALIZED WT. % THROUGH
1-1/2"	94.5	100.0
1"	86.0	91.0
3/4"	75.7	80.1
1/2"	63.9	67.6
1/4"	38.9	41.2
#8	19.3	20.4
#20	7.5	7.9
#25	4.7	5.0

Figure 5 R.M. Heskett Station

COAL QUALITY

Proximate Analysis (percent "as-received")

	Average	Expected Range Minimum	Expected Range Maximum
Heat Content (Btu/lb)	6849	6605	7464
Moisture	37.21	31.66	41.32
Ash	7.33	4.34	13.19
Volatile Matter	26.56	24.20	28.63
Fixed Carbon	27.70	24.16	35.79

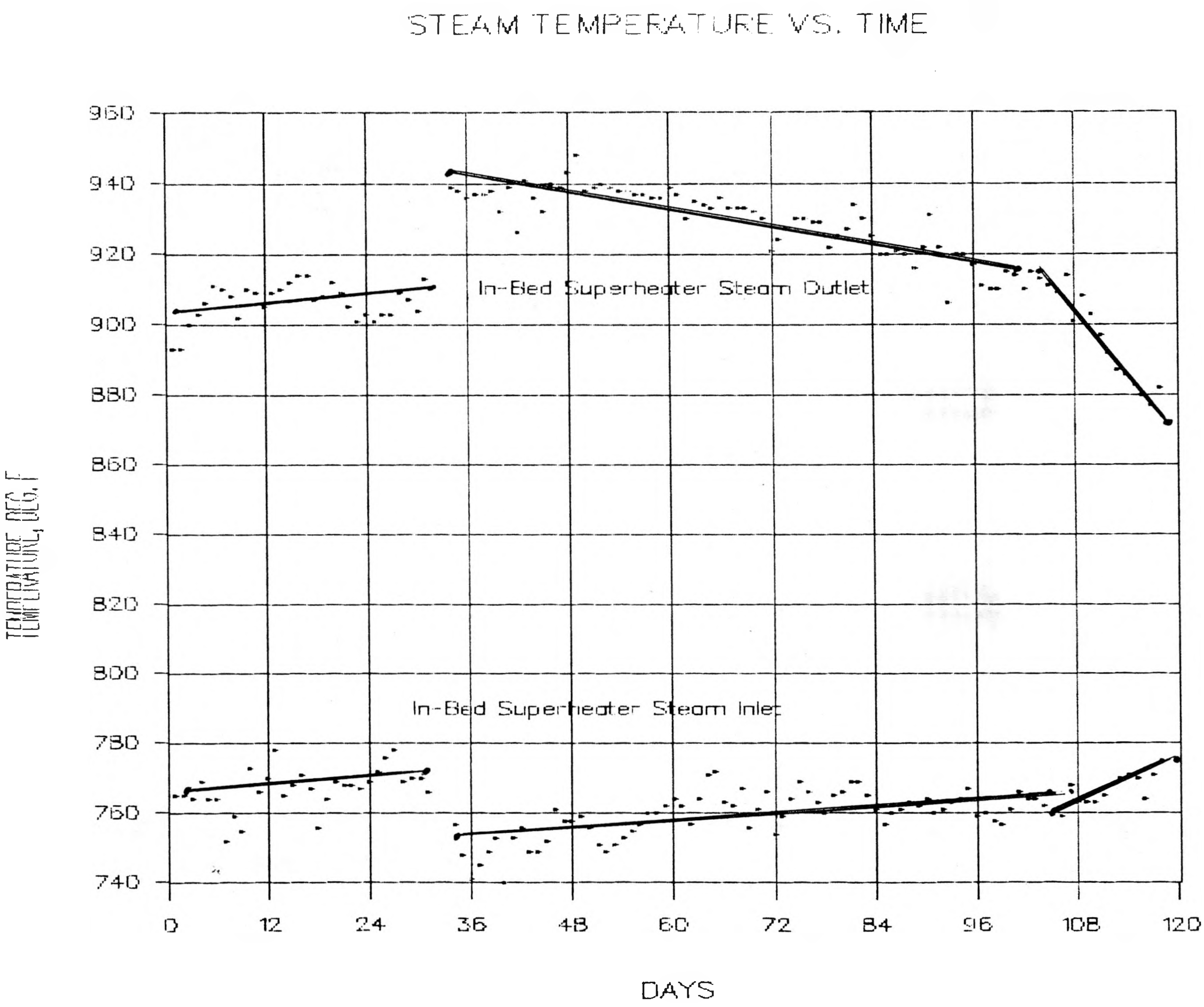
Ultimate Analysis (percent "as-received")

	Average	Expected Range Minimum	Expected Range Maximum
Moisture	38.20	36.59	40.17
Carbon	38.01	33.93	40.25
Hydrogen	7.01	6.28	7.41
Nitrogen	0.52	0.45	0.60
Chlorine	N/A	--	--
Sulfur	0.94	0.36	2.46
Ash	8.26	5.56	11.95
Oxygen	45.19	41.16	51.51

Mineral Analysis of Ash (percent weight, ignited basis)

	Average	Expected Range Minimum	Expected Range Maximum
Phos. Pentoxide, P205	0.46	0.14	1.03
Silicon Oxide, SiO_2	27.69	17.59	38.26
Ferric Oxide, F203	8.32	3.34	16.10
Aluminum Oxide, Al203	11.93	7.40	16.30
Titanium Oxide, TiO_2	0.67	0.45	0.99
Calcium Oxide, CaO	17.08	10.68	23.41
Magnesium Oxide, MgO	5.49	3.79	7.57
Sulfur trioxide, SO_3	19.67	14.34	24.39
Potassium Oxide, K20	0.63	0.39	1.27
Sodium Oxide, NaO_2	6.26	0.51	16.20
Undetermined			

Figure 6 R.M. Heskett Station



F re 7 R.M. Heskett Station

EMISSIONS

Particulate	0.057	$lbs/10^6$ BTU	
SO_2	0.6	$lbs/10^6$ BTU	160 PPM
NO_X	0.33	$lbs/10^6$ BTU	127 PPM

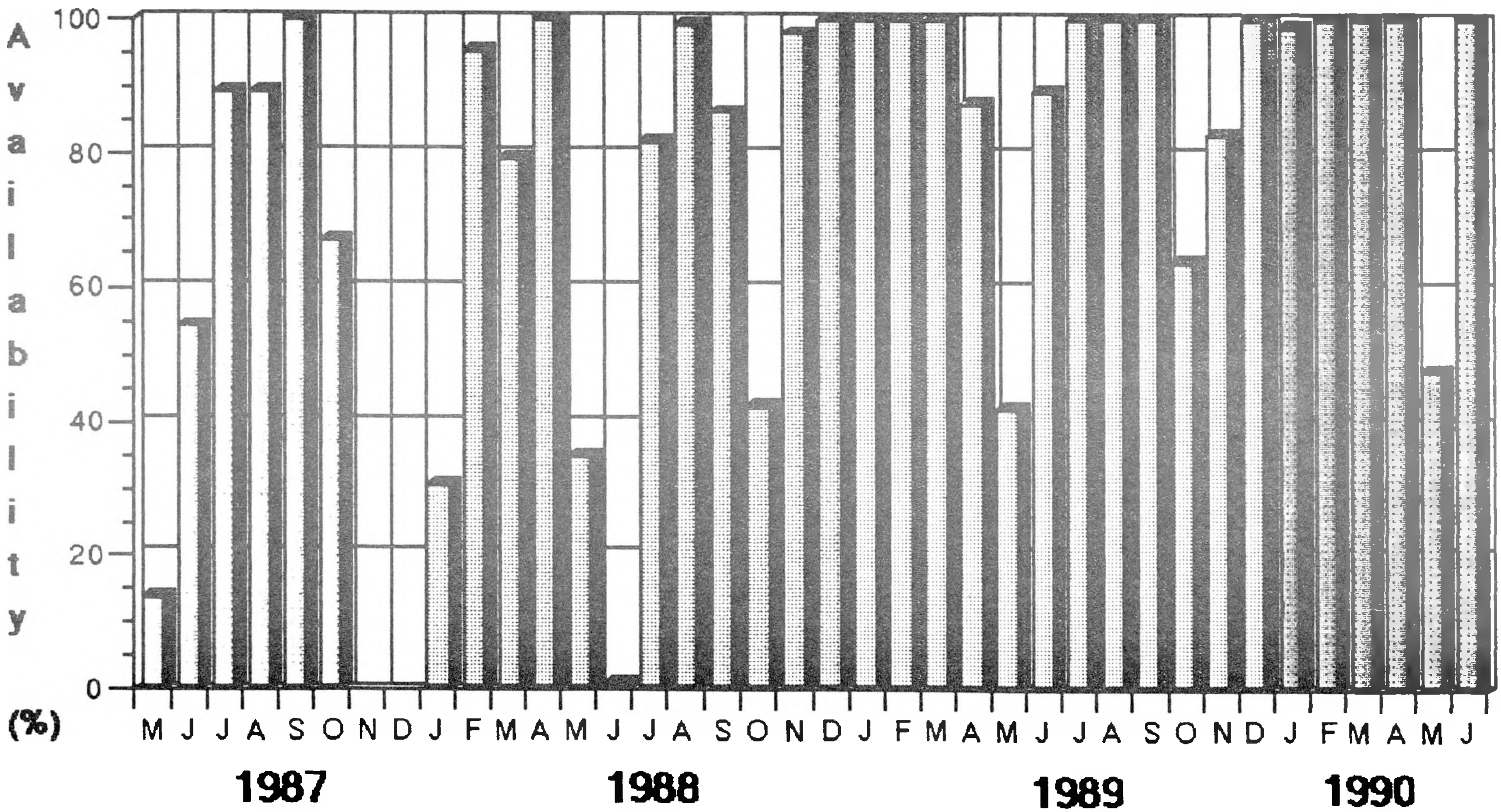
Figure 8 R.M. Heskett Station

Availability - Heskett #2 F.B.C.

May 1987 - June 1990

Availability Factor

(AF=[AH/PH]*100 AH=SH+RH)



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Figu 9 R.M. Heskett Station

"THE TECHNOLOGIES OF THE CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM"

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THE TECHNOLOGY OF THE CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

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Office of Clean Coal Technology
and
George Weth
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Office of Clean Coal Technology

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INTRODUCTION

Good morning ladies and gentlemen it's a pleasure to have this opportunity to speak of the Clean Coal Technology (CCT) Demonstration Program. Today, I would like to give a brief overview of the goals, objectives and current status of the program almost as an introduction and subsequently focus most of our discussion on the technology now in the program.

My goal will be to acquaint you with the progress the program is making in providing a wide range of advanced coal utilization technology options. These options will permit the industrial and utility sectors of the energy marketplace to continue to use coal in an environmentally responsive manner with greater efficiency and at lower overall costs.

THE CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

The program is a government-industry partnership that is demonstrating, at commercial or near commercial scale, a new generation of innovative coal utilization processes. For many technologies, it is the culmination of 15-20 years of research and development effort during which major improvements were made in the environmental and economic performance of these coal-based energy production systems.

As a goal, the program will make available to the energy marketplace a number of advanced, more efficient and environmentally responsive coal utilization technologies. These technologies will reduce or eliminate the economic and environmental impediments that limit the use of coal. We believe that this activity and the resulting processes that will be commercialized are a recognition of the strategic importance of coal as an energy resource.

The program as planned (i.e., Figure 1), currently consists of five phases with a total funding level of $2.747 billion. To date three phases of the program have been implemented by completing three competitive solicitations. The 38 projects, with an estimated total cost of $3.5 billion, that have been selected represent approximately $1.3 billion of federal funding and $2.2 billion of private sector cost sharing.

Of these projects, nineteen have been started under the terms of Cooperative Agreements between the participants and the Government and negotiations are in progress on the remaining nineteen. These negotiations are expected to be completed before the end of this year. Of particular importance to the Department of Energy (DOE) is the level of financial participation by the private sector in these projects. Although the U.S. Congress, in its guidance to the program, requires that such participation be a minimum of 50 percent, the participants are providing over 60 percent of the funds in the Cooperative Agreements signed to date.

The fourth phase of the program has been initiated. Although currently on hold, the next solicitation funded at a level of $600 billion is in the final stages of preparation. After it is released, the industrial participants (IP) will have 120 days to prepare their proposal and the technical evaluation teams will have 120 days to select the new projects.

The program also is benefiting from strong international participation. To date, companies from 10 foreign countries are supporting projects in the program. These countries include: Canada, Denmark, England, Finland, Italy, Japan, Spain, Sweden, West Germany, and Switzerland. These 10 projects will further develop a wide range of technologies that range from new concepts such as the pressurized fluidized-bed combustor from ASEA now ABB Carbon of Sweden to the continued development of an innovative near commercial flue gas scrubber that can operate on high sulfur U.S. coal. We expect that such participation will continue to the mutual benefit of the U.S. and other members of the international community.

WHAT ARE CLEAN COAL TECHNOLOGIES

Turning now from the statistics about the program to an examination of the technologies themselves, the role they play in the coal utilization process and the degree to which they contribute to accomplishing the programmatic goals.

When we speak of CCTs we are referring to advanced coal-based utilization systems that offer significant economic and environmental benefits when used for power generation, pollution control, or the conversion of coal into other alternate energy products.

First, in the area of power generation, the characteristics of the CCTs such as improved thermal efficiencies, modular construction, improved environmental performance, fuel flexibility, repowering capability, etc., will help the power industry accommodate a time of significant change caused by such factors as regulatory reform, aging boilers, uncertain growth in power demand, limited capital resources, and environmental pressures.

Second, the name Clean Coal emphasizes their role in pollution control. In this case, the technologies can directly remove SO_2 and NO_x acid rain precursors and substantially reduce the amount of CO_2 generated when coal is burned. The specific type and amount of pollutants removed will be determined by the particular process used. It should be noted, also, however, that some CCTs (e.g., pressurized fluidized-bed combustion and gasification combined cycle systems) have the ability to remove these pollutants while at the same time increasing the power output of the facility from 50-150 percent.

In the third case, some CCTs can be used to produce coal derived liquids to replace oil and gas in some applications. This capability will permit coal to have a greater role in providing energy to the industrial, commercial, and transportation sectors.

THE TECHNOLOGIES

There are at lease four points in the coal utilization process where innovative technologies might be used either to remove pollutants or to contribute to improved operational efficiencies. These are:

- Before Combustion - By advanced coal cleaning processes generally located at or near the mine mouth; (Figure 2)
- During Combustion - By modifying the combustion process or by injecting pollutant absorbing substances into specifically designed boilers; (Figure 3)
- After Combustion - By using devices that remove the impurities from the flue gases leaving the boiler; (Figure 4)
- Through Conversion - By changing the coal into a fuel gas, synthesis gas or liquid products; (Figure 5)

Of the 38 clean coal projects that have been selected, one or more can be applied at each of these four stages in the coal utilization process. The comparative advantages of these technologies include the following.

ADVANCED COAL CLEANING (PRECOMBUSTION) PROCESSES

In the precombustion stage, conventional coal cleaning, a physical beneficiation process, can reduce CO_2 emissions by 10-13 percent by removing some pyritic sulfur along with a portion of the ash material. Advanced coal cleaning on the other hand removes a significant amount of the sulfur and ash achieving a 30 to 90 percent reduction in SO_2 and essentially upgrading the feedstock. Currently, there are three projects of this type in the CCT Program and they range in size or capability from 115 tons/day to 1200 tons/day. These projects are summarized in Figure 6.

ADVANCED COMBUSTION PROCESSES

Advanced combustion processes include such concepts as control of the combustion process chemistry, advanced burners and innovative repowering technologies. The performance improvements that can be realized through the application of these technologies is best represented by the pressurized fluidized-bed combustion boiler. It captures over 95 percent of the sulfur dioxide, 60-80 percent of the nitrogen oxides, and can increase the power output of the facility by as much as 50 percent when used in a combined cycle application. The technology also is fuel flexible and produces a dry granular waste as opposed to the sludge generated by a state-of-the-art FGD. Projected commercial plant costs are lower than a conventional pulverized coal plant with an FGD system by some $250 to $300 per kilowatt. These systems also are compact and lend themselves to modular construction.

At the present time, the program has four advanced burner development projects for different applications that range in size from 24 tons/day to 840 tons/day coal feed. It also has eight repowering projects that feature: (1) atmospheric and pressurized circulating fluidized-bed technologies, (2) pressurized fluidized-bed combustors, and (3) gasification combined cycle systems. The names of these projects are listed in Figure 7 and Figure 8.

ADVANCED POST COMBUSTION PROCESSES

There are two basic kinds of post combustion cleanup processes: (1) those that achieve moderate emission reductions with relatively minor modifications in the facility and low capital investment, and (2) those that achieve high emission reductions, but also require major modifications to the plant and comparable capital investment.

An example of the first kind is a gas reburn/sorbent injection technology. In this process natural gas is used to displace up to 20 percent of the coal which creates a "staged combustion" for NOx control. A sorbent is injected into the boiler or downstream ductwork to capture the sulfur oxide emissions. This system has a demonstrated capability of reducing SO2 and NOx by about 70 percent and 60 percent, respectively. The capital costs are a function of plant size and gas availability, but have a range of $50-$110 per kilowatt. This cost is considerably less than that of a conventional scrubber. As indicated, this technology removes a significant amount of NOx, has little impact on plant efficiency, and generates a dry solid waste; whereas a conventional scrubber removes no NOx, reduces plant efficiency by about 3 percent and generates a difficult to dispose of sludge.

The other kind of advanced post-combustion cleanup system under development is much the same as a conventional scrubber in approach in that the unit is installed downstream of the boiler. Characteristics of these advanced systems include lower capital costs (approximately half that of a conventional scrubber) higher SO2 removal efficiencies as well as reductions in NOx emissions and in turn these systems generate a saleable byproduct and/or easily disposed of dry waste. Figure 9, 10, and 11 identify the projects of the Program in this category.

<u>CONVERSION PROCESSES</u>

While integrated gasification combined cycle systems are considered repowering technologies, they contain the key components of a coal conversion system. Coal is converted into a fuel/synthesis gas in the gasifier. This gas can be processed downstream of the gasifier to remove essentially all the sulfur while at the same time minimizing the amount of NOx generated. These systems when operated as a combined cycle system (combustion of the fuel gas in a combustion turbine accompanied by heat recovery and use in a steam generator) can increase the power output of a facility by 50-150 percent. The cleaned gas also can be used as a feedstock for a number of conversion processes capable of generating a wide range of liquid products. The modular nature of the gasifier gives the user flexibility in application as it can be sized to meet a wide range of demand.

Projected plant costs are as much as $400-450 per kilowatt less than that required for a conventional PC facility with an FGD system. Efficiencies are in the range of 40 to 48 percent depending upon the application (i.e., repowering or new plant).

Currently, as shown in Figure 12, there are six projects in the program that represent either conversion or industrial processes. These projects are designed to produce a wide range of products from coal in a more economic and environmentally response manner.

THE ROLE OF THE PROJECTS

Even at this stage of the program (i.e., 60 percent complete), the 38 projects will provide a number of operational, economic, and environmental advantages. In summary:

- Clean coal power generation technologies now being demonstrated have the potential to reduce SO_2 emissions from 95-99 percent, achieve NO_x reductions of 80-95 percent, operate with plant conversion efficiencies of 40-48 percent, and achieve continued economic improvements as the third, fourth, and fifth plants are constructed. Furthermore, some of these technologies offer incremental power increases of 50-150 percent, while using the same space requirements of the facility being modified.

- Clean coal technologies address the global warming issue in that they can reduce the emissions of greenhouse gases in two fundamental ways. First, many of the CCTs improve significantly the efficiency of the conversion of coal to useful energy. As a general rule, a 5 percent increase in efficiency equates to a 15 percent decrease in CO_2 emissions. Second, they reduce NO_x emissions which impacts the formation of N_2O, another global warming gas.

- The concept of placing an overall emissions limit (i.e., caps) as part of the Clean Air Bill currently being considered by Congress could indeed require the use of the more efficient CCTs in order to meet these emission caps.

- The program may be the most important incentive for continuing the development of the next generation of more sophisticated and innovative CCTs now in the research and development pipeline. These technologies will permit greater increases in efficiency and further emissions reductions.

SUMMARY

One of the major objectives of the CCT Program as identified in the Joint Envoy's Report on Acid Rain is to develop a suite of technology options for the control of acid rain emissions that would be significantly cheaper, more effective and yet highly efficient. This objective was subsequently expanded in guidance from Congress to include consideration of some processes that could increase the utilization of coal in an environmentally responsive manner. The projects now in the Program, when developed and commercialized, will advance the Program well along the road to achieving these goals.

CLEAN COAL TECHNOLOGY PROGRAM

FUNDING PROFILE

(BASIS: FY 1991 BUDGET REQUEST)

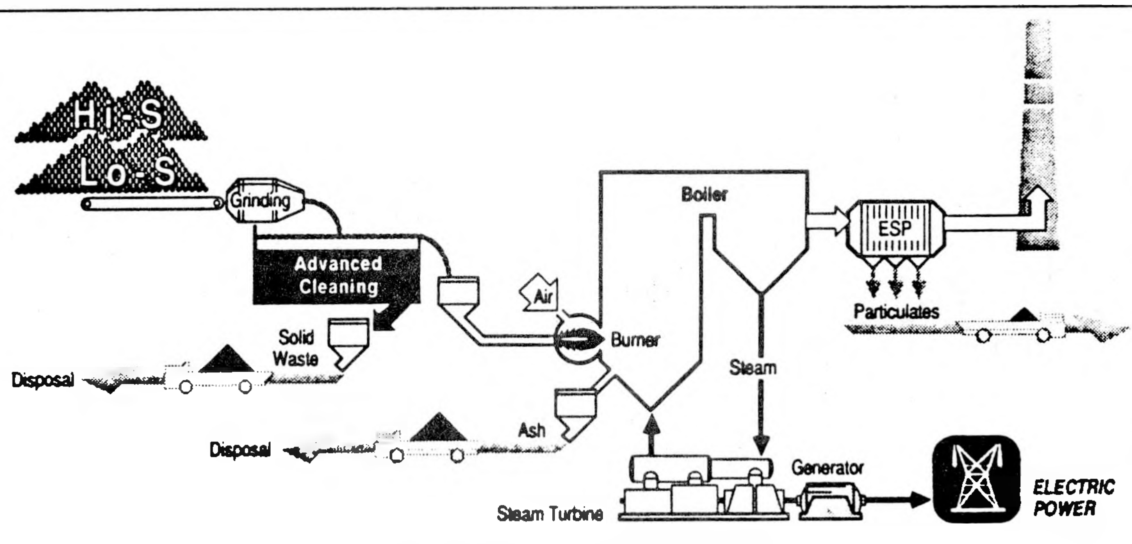
FISCAL YEARS ($ MILLION)

CCT	1986	1987	1988	1989	1990	1991	1992	1993	1994	TOTALS
I	99.4	149.1	149.1							397.6
II			50.0	190.0	135.0	200.0				575.0
III					419.0	156.0				575.0
IV						100.0	250.0	250.0		600.0
V							150.0	225.0	225.0	600.0
TTL:	99.4	149.1	199.1	190.0	554.0	456.0	400.0	475.0	225.0	2747.6

FIGURE 1

Clean Coal Technologies—

Pre-Combustion (Advanced Coal Cleaning)



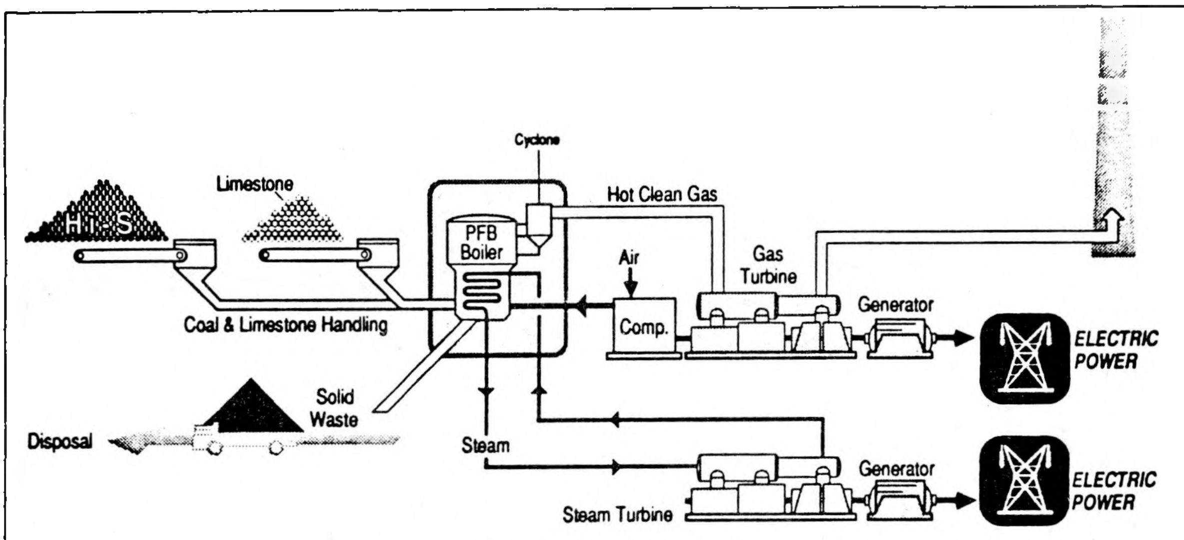
COMPARED WITH CONVENTIONAL TECHNOLOGY*

SO_2 (EMISSION REDUCTION)	NOx (EMISSION REDUCTION)	PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
30–90%	No Change	Small Increase	No Change	Slight Extension	6–21 MILLS/KWH	Additional Fuel Cost Only

* CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

FIGURE 2

Clean Coal Technologies—
Advanced Combustion Processes



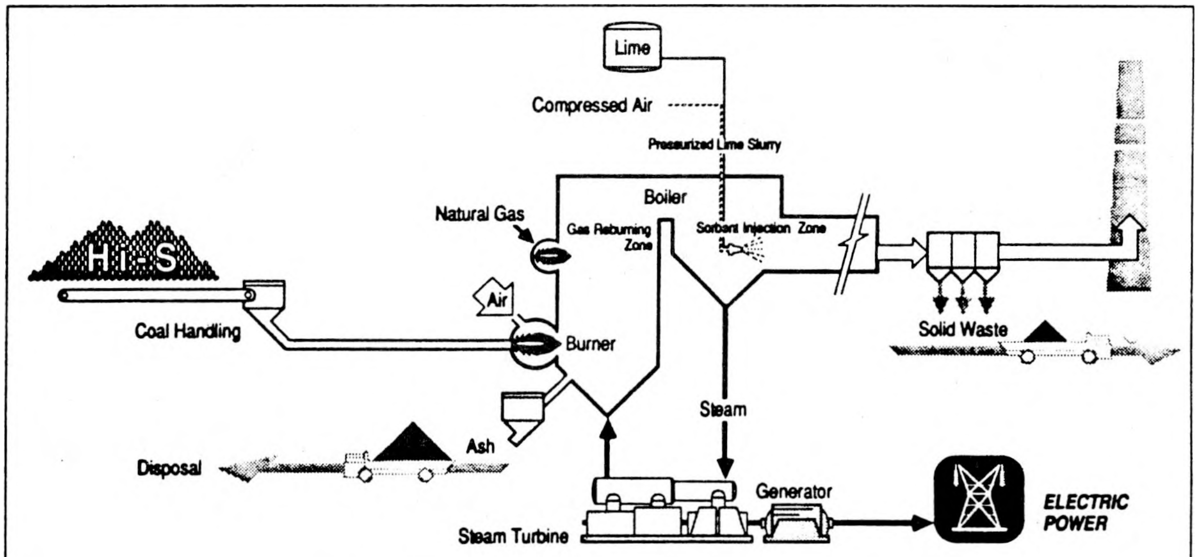
*COMPARED WITH CONVENTIONAL TECHNOLOGY**

SO_2 EMISSION REDUCTION	NOx EMISSION REDUCTION	PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
90–95%	Moderate	Slight Increase	40-50% INCREASE	Moderate Extension	4–6 MILLS/KWH	$800–1,000 PER KW

* CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

FIGURE 3

Clean Coal Technologies—
Advanced Post-Combustion Processes



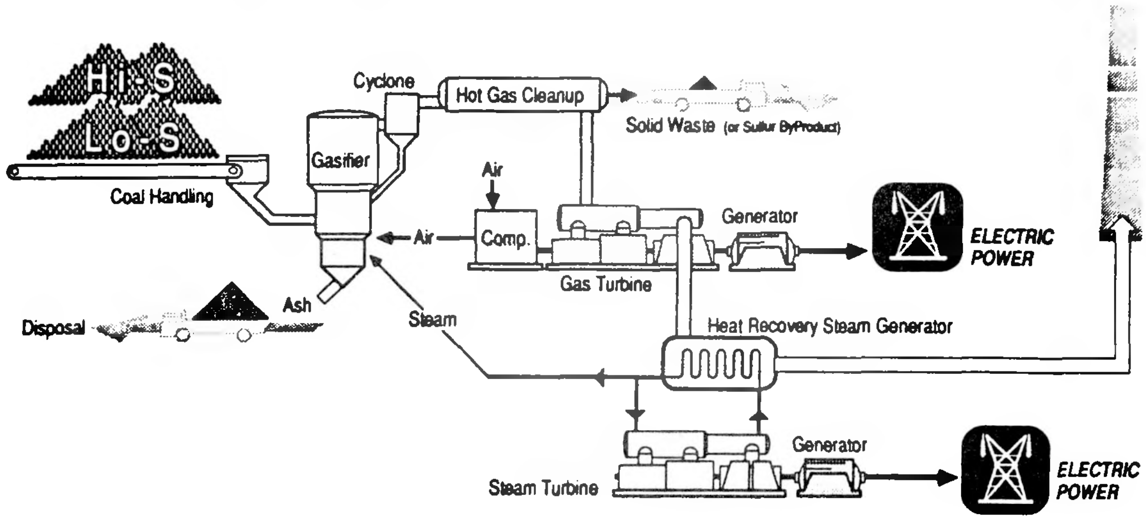
*COMPARED WITH CONVENTIONAL TECHNOLOGY**

SO_2 EMISSION REDUCTION	NOx EMISSION REDUCTION	PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
55–75%	Moderate	Small Decrease	Small Decrease	Slight Extension	2–4 MILLS/KWH Plus Gas Price Factor For Reburning	$50–110 PER KW

* CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

FIGURE 4

Clean Coal Technologies—
Conversion Processes



COMPARED WITH CONVENTIONAL TECHNOLOGY*

SO2 EMISSION	NOx REDUCTION	PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
95–99%	Moderate	Moderate Increase	50-150% INCREASE	Moderate Extension	1–2 MILLS/KWH	$1,100–1,300 PER KW

* CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

FIGURE 5

CLEAN COAL TECHNOLOGY PROGRAM

PRECOMBUSTION TECHNOLOGIES

- **ADVANCED COAL CLEANING AND PROCESSING FACILITY -** 1200 TONS/ DAY
- **CLEAN COAL COMBUSTION TESTING PROJECT -** 480 TONS/ DAY
- **PRODUCTION OF OTISCA COAL SLURRY FUEL -** 115 TONS/ DAY

FIGURE 6

CLEAN COAL TECHNOLOGY PROGRAM

ADVANCED COMBUSTION-BURNER TECHNOLOGIES

- **ADVANCED CYCLONE COMBUSTOR FOR INDUSTRIAL USE -** 24 TONS/DAY
- **ADVANCED SLAGGING COAL COMBUSTOR FOR UTILITIES -** 69 MWe
- **LOW NO_X/SO_2 BURNER RETROFIT FOR UTILITY CYCLONE BOILERS -** 33/MWe
- **COMBUSTION/SLAGGING COMBUSTOR COGENERATION PROJECT -** 840 TONS/DAY

FIGURE 7

CLEAN COAL TECHNOLOGY PROGRAM

ADVANCED COMBUSTION-REPOWERING TECHNOLOGIES

- **NUCLA ATMOSPHERIC CFB COMBUSTOR UILITY PROJECT -** 110 MWe
- **HOPKINS STATION ATMOSPHERIC CFB COMBUSTOR UTILITY PROJECT -** 250 MWe
- **NICHOLS STATION ATMOSPHERIC CFB COMBUSTOR UTILITY PROJECT -** 256 MWe
- **ALMA STATION PRESSURIZED CFB COMBUSTOR COGEN PROJECT -** 40 MWe
- **PHILIP SPORN PRESSURIZED FLUIDIZED BED COMBUSTION PROJECT -** 330 MWe
- **TIDD PRESSURIZED FLUIDIZED BED COMBUSTION PROJECT -** 70 MWe
- **INNOVATIVE CLEAN COAL GASIFICATION REPOWERING PROJECT -** 65 MWe
- **INTEGRATED GASIFICATION COMBINED CYCLE PROJECT -** 120 MWe

FIGURE 8

CLEAN COAL TECHNOLOGY PROGRAM

POST COMBUSTION FLUE GAS CLEANUP - SULFUR CONTROL

• ADVANCED ON-SITE FLUE GAS DESULFURIZATION (FGD) PROCESS -	529 MWe
• APPLICATION OF CHIYODA THOROUGHBRED - 121 FGD PROCESS -	100 MWe
• DEMONSTRATION OF GAS SUSPENSION ABSORPTION FGD DPROCESS -	10 MWe
• DEMONSTRATION OF CONFINED ZONE DISPERSION FGD PROCESS -	-
• DEMONSTRATION OF LIFAC FGD PROCESS -	60 MWe

FIGURE 9

CLEAN COAL TECHNOLOGY PROGRAM

POST COMBUSTION FLUE GAS CLEANUP - NO_X CONTROL

• ADVANCED TANGENTIALLY-FIRED COMBUSTION DEMONSTRATION -	180 MWe
• ADVANCED WALL-FIRED COMBUSTION DEMONSTRATION -	500 MWe
• DEMONSTRATION OF COAL REBURNING IN CYCLONE BOILERS -	100 MWe
• DEMONSTRATION OF SELECTIVE CATALYTIC REDUCTION PROCESS -	75 MWe
• DEMONSTRATION OF LOW NO_X CELL BURNER RETROFIT -	60 MWe
• DEMONSTRATION OF COMBINED GAS REBURNING AND LOW NO_X BURNERS -	

FIGURE 10

CLEAN COAL TECHNOLOGY PROGRAM	
POST COMBUSTION FLUE GAS CLEANUP - COMBINED SO_2 / NO_X CONTROL PROCESSES	
• LIMESTONE INJECTION MULTI-STAGE BURNER PROJECT -	105 MWe
• GAS REBURNING AND SORBENT INJECTION PROJECT -	117 MWe
• DEMONSTRATION OF SOx-NOx-ROx BOX (SNRB) PROCESS -	5 MWe
• COMMERCIAL DEMONSTRATION OF WSA-SNOX TECHNOLOGY -	35 MWe
• NOXSO INNOVATIVE FLUE GAS CLEANUP TECHNOLOGY PROJECT -	65 MWe

FIGURE 11

CLEAN COAL TECHNOLOGY PROGRAM	
INDUSTRIAL / CONVERSION PROCESSES	
• COAL-PETROLEUM COPROCESSING PLANT -	800 TONS/ DAY
• INNOVATIVE COKE OVEN GAS CLEANING SYSTEM -	5,687 TONS/ HR
• RECOVERY SCRUBBER FOR REMOVING SO_2 EMISSIONS -	276 TONS/ DAY
• BLAST FURNACE GRANULATED COAL INJECTION -	7500 TONS METAL/ DAY
• COMMERCIAL LIQUID PHASE METHANOL PROCESS -	500 TONS/ DAY METHANOL
• ENCOAL MILD GASIFICATION DEMONSTRATION PROJECT -	1000 TONS COAL/ DAY

FIGURE 12

"HEALY CLEAN COAL PROJECT"

By: Dr. John Sims
Vice President
Usibelli Coal Mine, Inc.
Fairbanks, Alaska

HEALY CLEAN COAL PROJECT

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INTRODUCTION

The Healy Clean Coal Project (HCCP) will construct a state-of-the-art coal-fired power plant at Healy, Alaska. The power plant will provide 50 megawatts of competitively priced electricity to satisfy increasing demand in the Kenai, Anchorage and Fairbanks corridor known as the railbelt, will demonstrate innovative coal burning technologies, and may provide energy for the future development of a pilot-scale plant to beneficiate high-moisture Alaska coals. The combination of new coal-burning technologies and low-sulfur Alaska coal will result in one of the cleanest coal-burning plants in the world.

In August 1989 the Alaska Industrial Development and Export Authority (AIDEA), a state government corporation, submitted a proposal for the Healy Cogeneration Project (HCP), renamed the Healy Clean Coal Project, to the U.S. Department of Energy (DOE) under DOE's Clean Coal Technology Program. In December 1989 the HCCP proposal was selected from among 48 other projects for grant funding of up to $93.2 million. The grant will finance nearly half of the design, capital and initial operating costs of the HCCP plant.

ALASKA BENEFITS

The Healy Clean Coal Project will draw national and international attention to the demonstration of leading-edge technologies and provide a variety of benefits to the state's economy. The project will employ approximately 200 workers during a two year construction period and create about 50 year-round jobs in Healy once the plant is fully operational. In addition to employment, several other long-term economic benefits will contribute to the future well-being of Alaska's railbelt.

Satisfying Growing Railbelt Energy Needs

The addition of a new, efficient 50 megawatt power plant will provide low-cost power to satisfy increasing regional energy demands. Between 1984 and 1988, kilowatt-hour sales by Golden Valley Electric Association (GVEA), serving the northern part of the railbelt, increased nearly 18 percent. By the mid to late 1990's additional base load generating capacity will be needed. While primarily serving northern customers, the strategically located generating plant would also be available for transmission to the southern railbelt.

Technology for New and Existing Power Plants

The HCCP will demonstrate a clean-burning technology that can be used to retrofit or repower existing power plants in Alaska, the nation, and the Pacific Rim.

Many coal-fired power plants in Alaska and other states will require life extension work within the next 10 to 15 years.

EPA's stringent New Source Performance Standards will be applied to these plants and HCCP technology may be the lowest-cost solution for meeting these standards.

In addition to environmental advantages, the use of HCCP technology to retrofit coal-fired power plants in the Pacific Rim will open new markets for Alaskan coal. Currently, few Pacific Rim plants are designed to use Alaska's ultra-low sulfur, high-moisture, sub-bituminous coal. HCCP technology would allow Alaskan coal to be burned in such plants without the need for extensive boiler modifications.

Packaging the innovative combustion technology with a reliable coal supply from Alaska should present an attractive option to utilities and industrial customers in the Pacific Basin.

Beneficiation of Alaska Coal

A future component of the project concerns the use of process heat from HCCP plant to improve the quality of Alaskan sub-bituminous coal or to produce entirely new fuel products. Alaska sub-bituminous coal has superior environmental qualities compared to coal from virtually all other states and countries. However, its low energy value, due primarily to its high moisture content, makes the coal costly to transport and puts it at an economic disadvantage with international competition. The value and competitiveness of Alaska coal could be increased through drying, gasification, liquefaction or a combination of these processes. The excellent environmental qualities and high energy value of beneficiated Alaska coal would result in a premium fuel for export markets. This component of the project may involve a pilot plant capable of producing sufficient product for bulk market tests but should not be viewed as a commercial scale facility.

Focus on Alaska's Coal Resources

Alaska has enormous resources of coal and could become a major energy supplier to the Pacific Rim. The HCCP project will be a showcase for leading-edge coal-burning technology and will bring national and international attention to Alaska's low-sulfur coal resources. The project will also send a clear signal that Alaska is serious about using new and environmentally superior technologies to utilize the state's enormous natural resources.

CLEAN COAL TECHNOLOGY PROGRAM

The Clean Coal Technology program (CCT) was created by the U.S. Congress in response to concerns about acid rain. The program is administered by the DOE and focuses on the reduction of air pollutants considered to be precursors of acid rain. Five rounds of funding totaling over $2.5 billion have been planned. The first two rounds made $973 million available while the third and current round has $540 million available to support qualifying projects. The $93.2 million granted to HCCP represented approximately 17 percent of the total funding available in round three.

The objectives of the third round are to promote, through demonstration projects, the commercialization of innovative technologies which are capable of significantly reducing emissions of sulfur dioxide and nitrogen oxides in existing coal burning facilities and/or providing for future energy in an environmentally acceptable manner.

The DOE may match up to 50 percent of the costs for the design, construction and initial operation of selected projects. Project owners are responsible for financing the remainder of the cost. Under the terms of the program, AIDEA and DOE must negotiate an agreement during 1990 for the design, construction, demonstration and financing of the HCCP project before federal funding may be awarded.

HEALY CLEAN COAL PROJECT

The Healy Clean Coal Project involves six participants. These include the Alaska Industrial Development and Export Authority (AIDEA), which will own the project and be assisted by the Alaska Energy Authority; Golden Valley Electric Association (GVEA) which will operate, maintain and purchase power from the project; Usibelli Coal Mine, Inc. (UCM) which will supply coal and an alternate site for the project; Stone & Webster Engineering Corporation, which will act as project design and management engineer; TRW Combustion Business Unit, which will provide proprietary combustion technology to the project; and Joy Technologies Inc. which will provide proprietary emission control technology to the project.

The HCCP power plant will use an innovative design integrating advanced combustion, heat recovery, and emission control technologies. The stack emissions from the HCCP plant, including sulfur dioxide and nitrogen oxides, may be lower than any other coal-based power system in the world.

The HCCP plant will use approximately 300,000 tons per year of low-sulfur sub-bituminous coal. The plant will contribute to resource conservation by burning both run-of-mine coal and high-ash waste coal that could not be normally utilized. In the project's demonstration phase, various Alaska coals will be tested and the plant will be made available for testing coal from other states. The plant will be designed to provide process heat to an adjacent pilot coal beneficiation facility that is anticipated in a future phase of the project.

The estimated cost of the project is $192 million. The HCCP was selected for up to $93.2 million of cost-sharing by DOE. Additionally, in the 1990 session, the Alaska legislature appropriated $25 million from the Railbelt Energy Fund for the HCCP project. The balance of the project costs will be secured by AIDEA through the sale of revenue bonds. If available, tax-exempt bond financing will significantly improve the economics of the project.

PARTICIPANTS

Six participants cooperated in the preparation of the HCCP proposal and will participate in the performance of the project.

1. The Alaska Industrial Development and Export Authority (AIDEA) supervised the preparation and submittal of the HCCP proposal to DOE and after selection submitted a financing plan to the state legislature, AIDEA will:
   - be the HCCP project owner and coordinate the functions of the Alaska Energy Authority:
   - issue revenue bonds to finance project costs not covered by federal or state grants.

2. Golden Valley Electric Association (GVEA) will:
   - oversee the project's design and construction;
   - operate and maintain the HCCP power plant;
   - purchase electricity produced by the project;
   - manage the training of operator personnel; and
   - perform power plant start-up activities.
   - provide access to land for plant siting.

3. Usibelli Coal Mine, Inc. (UCM) initiated, oversaw and funded the costs of preparing the HCCP proposal and will:
   - make land owned or leased by UCM available for the alternate siting of the HCCP project;
   - supply coal to HCCP and dispose of plant ash; and
   - review project design and construction activities.

4. Stone and Webster Engineering Corporation acted as consulting engineer and prepared the HCCP proposal under contract to UCM and will:
   - act as design engineer and supply key members to the project management and design team; and
   - provide construction management services to AIDEA.

5. TRW Combustion Business Unit assisted in the preparation of the HCCP proposal and will:
   - provide proprietary combustion technology to the project;
   - participate in the project design; and
   - provide warranties and guarantees covering the design and performance for the TRW scope of supply.

6. Joy Technologies Inc. with its European associate NIRO Atomizer assisted in the preparation of the HCCP proposal and will:
   - provide proprietary technology for sulfur and ash removal;
   - participate in the project design; and

- provide warranties and guarantees covering the design and performance of Joy Technologies equipment.

INNOVATIVE TECHNOLOGIES

Two separate technology envelopes are featured in the HCCP. (Fig. 1) The HCCP will integrate entrained coal combustion (ECC) technology developed by TRW Combustion Business Unit and spray dryer absorber (SDA) technology developed by Joy Technologies Inc. in association with NIRO Atomizer.

Entrained Coal Combustion

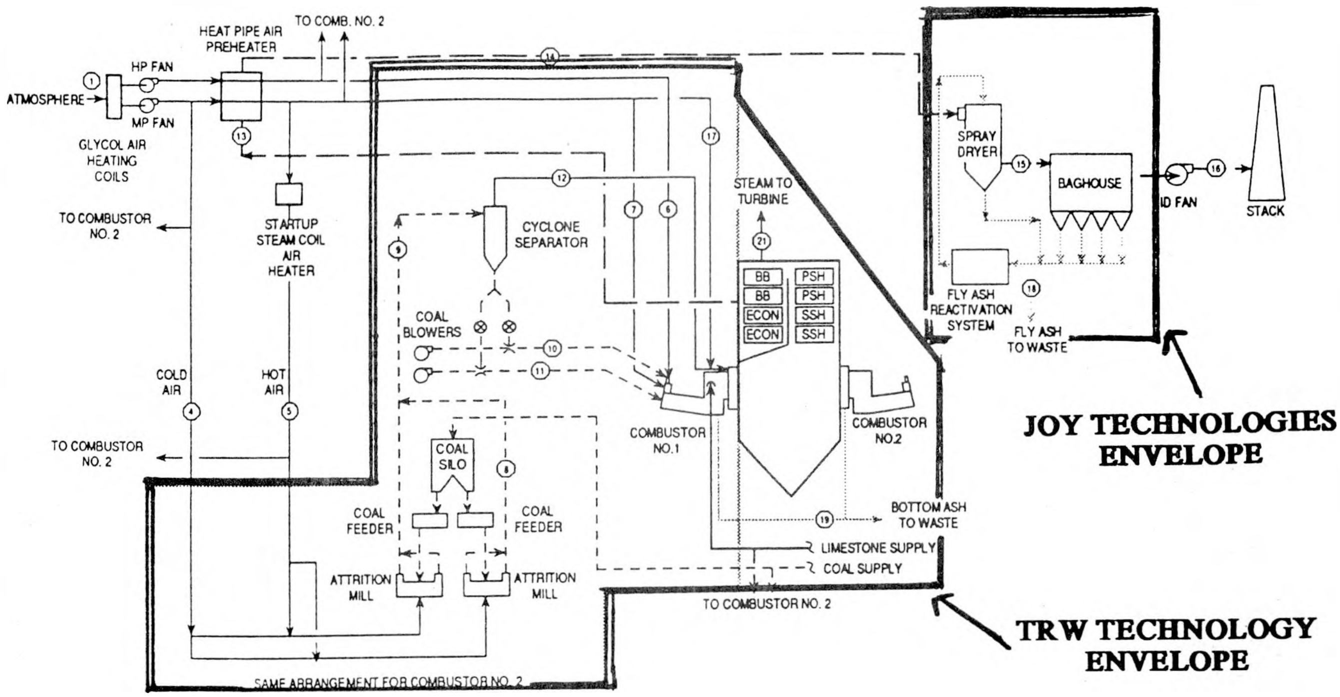
TRW began developing new methods of clean coal combustion in the mid 1970's. The adaptation of advanced rocket propulsion fuel mixing technology, that TRW had created for the Apollo space program, is key to the ECC system. During a twelve year R&D phase, TRW fabricated six different combustors and conducted an exhaustive test program. In 1986 commercialization of the new system began.

The TRW system removes molten ash (slag) during combustion but a unique combustion process distinguishes it from other slagging systems. Pulverized coal is burned in entrained swirling flight under sub-stoichiometric conditions. This is in contrast with cyclone type furnaces in which combustion of granulated coal takes place on the walls of the unit under conditions which tend to exacerbate corrosion problems. In the ECC system combustion takes place away from the walls of the combustor.

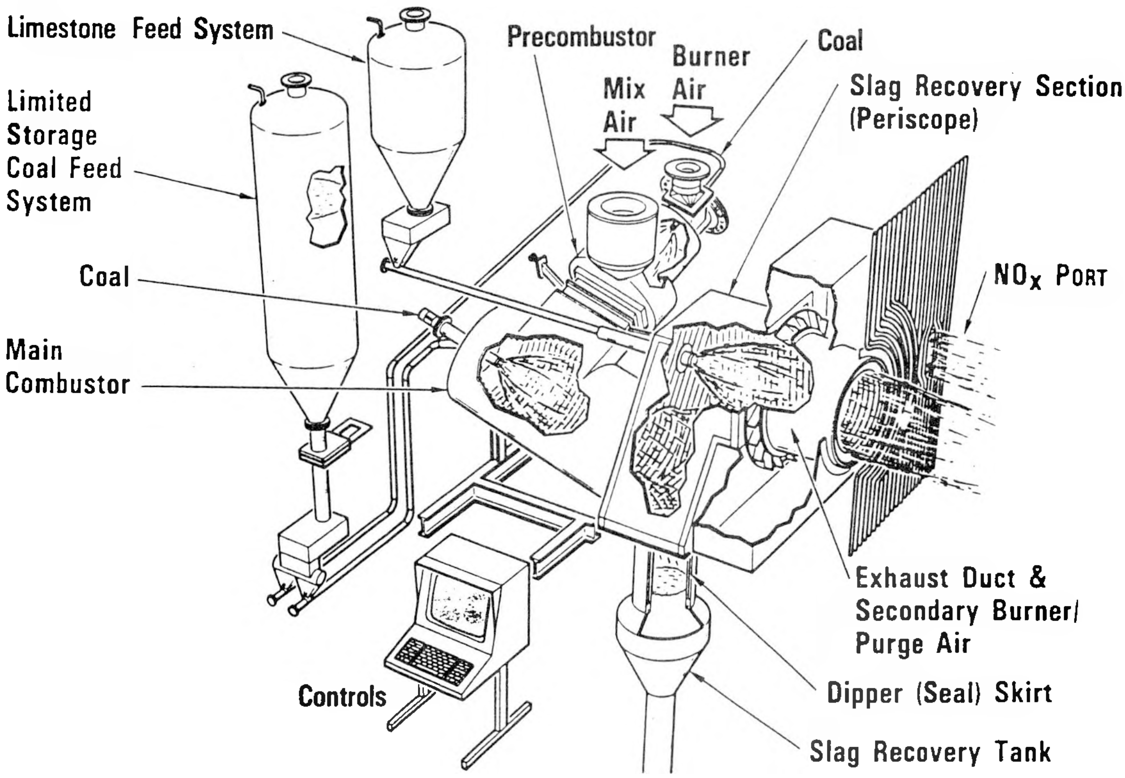
Careful control of combustor stoichiometry in the TRW system promotes lower peak combustion temperatures and the formation of low NO_x levels. Thus are nullified the major failings of cyclonic combustion systems which produce high Nox levels resulting from the combination of high peak temperatures and excess air.

In the ECC system, pulverized coal feed is injected into a precombustion chamber (Fig. 2) where it is entrained in swirling air and partially burned. About 25% of the pulverized coal feed is introduced in this stage which functionally heats the combustion air for the main stage to the high temperatures needed to induce slagging. The balance of the coal feed (+75%) is burned in the second, or main slagging, stage of the combustor at temperatures high enough to melt the ash. Carbon conversion or burn out in the combustor typically exceeds 99.5%.

Additional air is added in the secondary burner where further combustion of hot gases takes place before entering the boiler. Flue gases enter the boiler from the two stage combustion unit at 2800°F. to 3200°F and contain combustible gases CO and H_2. These gases represent the remaining heating value of the original coal feed and are burned in combination



<u>FIGURE 1</u> SCHEMATIC DEPICTION OF THE PROPOSED HCP TECHNOLOGY



<u>FIGURE 2</u> COMBUSTOR SYSTEM COMPONENTS

with overfire air in the boiler.

The molten slag which coats the water-cooled walls of the main stage of the combustor is drained thru the slag recovery system. Removal of more than 80% of the coal ash as slag minimizes boiler maintenance associated with slagging and fouling, promotes thermal efficiency, and should enhance the attractiveness of using ECC technology in retrofit applications.

At the entrance to the boiler, limestone is injected into the combustion stream to react with and provide first stage removal of sulfur dioxide (SO_2). Just as careful control of temperature and air quantities in the two-stage combustion process minimizes NO_x, so the injection of limestone maximizes initial SO_2 removal.

ECC units are relatively compact, have no moving parts, are not prone to excessive wear and corrosion problems and are highly suited to modular construction. All are factors which suggest ease of adaptation in retrofit applications and a potential role, perhaps major role, in virtually all sizes of future greenfield plants.

Spray Dryer Absorber

In addition to sulfur reductions in the ECC system, Joy Technologies' SDA emission control system further reduces sulfur dioxide levels in the flue gases. Lime particles contained in baghouse ash are activated by abrasive removal of the calcium sulfate surface and returned to the SDA system. The recycled ash product, produced by the limestone injected during the combustion stage, is mixed with water and sprayed into the flue gases. Sulfur dioxide reacts with the spray and is removed along with the remaining ash in filter bags. The second-stage removal of sulfur dioxide and the reduced costs of limestone recycling contribute to the environmental and operational efficiencies of the HCCP design.

COAL SPECIFICATIONS

The performance coal for which the boiler is being designed is a 50:50 blend of waste and run-of-mine coal from the Usibelli Coal Mine. The typical analysis for this feed coal is:

Heating value	6960 Btu/lb.
Moisture	25.11%
Ash	16.6%
Volatiles	30.78%
Fixed Carbon	27.51%
Sulfur	0.15%

Preparations for test burns are underway, which will test the performance of Alaskan coals, proposed for long term use, in the HCCP. The coals will be tested, along with Alaskan limestone, at TRW's industrial scale ECC demonstration unit in Euclid, Ohio. Various blends of waste and run-of-mine coal, at various feed rates, will be burned in the ECC and the performance monitored for ash capture in slag, grinding requirements, combustor tuning for NO_x control, first stage SO_2 capture and impact on boiler design. After selection of optimum firing conditions, long duration tests will be used to produce samples of Flash Calcined Material, the lime laden baghouse ash, for testing in Joy/Niro's SDA pilot plant in Denmark.

Foster Wheeler has been selected to fabricate the boiler unit for the HCCP.

THE HCCP SCHEDULE

The HCCP, several months after selection for funding by DOE under round three of the Clean Coal Technology program is on schedule. Agreement with DOE and ratification by Congress should be complete by early in the New Year. Environmental permitting and engineering design and other factors should accommodate a construction schedule beginning in 1992. Construction will span a period of two years to be followed by a one-year demonstration phase. Full commercial operation of the HCCP should be a reality in 1996.

CONCLUSION

Emissions for the HCCP are predicted to be equal or better than any other coal based system and at lower capital costs than competing technologies. The HCCP emission levels should be less than 0.04 lbs/MM Btu for SO_2, less than 0.2 lbs/MM Btu for NO_x and less than 0.01 lbs/MM Btu for particulates. These are levels well below current federal and state requirements.

The HCCP is a project whose time has come. It is a project which I hope will showcase the strength and wisdom of the Clean Coal Technology program.

The author wishes to thank Alaska Industrial Development & Export Authority (AIDEA) for its permission and Charles B. Green and Steve Denton for their contributions to this paper.

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"COAL GASIFICATION COMBINED CYCLE POWER GENERATION ENHANCEMENT WITH METHANOL"

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COAL GASIFICATION COMBINED CYCLE POWER GENERATION ENHANCEMENT WITH METHANOL

As environmental requirements become more stringent and costly, power generating companies will need to increase efficiency and at the same time maintain high environmental standards. A new concept is emerging wherein proven technologies will be combined to create an optimum system. In this concept, combined cycle power generation integrated with the coal gasification process could be greatly enhanced with methanol production.

A combined cycle system represents proven technology provided at relatively low installation costs along with improved efficiency levels compared to more traditional methods. Existing commercial units are being fired with oil or natural gas.

Basic elements of a combined cycle system include a combustion gas turbine, a heat recovery steam generator to recover the gas turbine exhaust energy and a steam turbine to utilize the recovered heat energy in the form of steam to produce additional kilowatts.

Combined cycle is a two stage production of electricity with generation from a gas turbine and a steam turbine. Combining the two power sources improves the efficiency of converting the combustion energy from fossil fuels to electricity.

The combustion energy not converted to power in the gas turbine, the hot turbine exhaust gases, are used to raise steam in a waste heat boiler. This steam then drives a steam turbine which generates additional electricity.

Combined cycle systems use about one-third less fuel to generate the same amount of electricity as that of the conventional steam turbine utility station. The cost of oil and natural gas per unit of heating value is two to three times that of coal, however.

Coal gasification combined cycle (CGCC) combines the technology of using coal in a gas turbine by converting the energy in coal to a fuel gas suitable for a gas turbine by gasifying the coal. Not only does CGCC increase efficiency, but is environmentally superior in the use of coal to generate power. Both sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions are significantly reduced from that of a conventional utility station using flue gas desulfurization technology.

This presentation will demonstrate how methanol production can enhance coal gasification combined cycle power generation. I will also explain Dakota Gasification Company's involvement in commercializing a process that could be used for the methanol as a way of improving the economics of using coal for combined cycle power generation.

The main objective of this joint venture with Air Products is to demonstrate liquid phase methanol (LPMEOH)* technology on a commercial-sized basis. However, an additional benefit would be proving that the technology is ideally suited for a combined cycle plant and, therefore, could greatly improve

* LPMEOH is a trademark of Chem Systems, Inc.

the economics of generating electrical power from coal in a combined cycle plant. The production of methanol is attractive because the coal gasification section can be sized significantly smaller. A large cost savings is realized because the coal gasification equipment makes up a large portion of the capital investment of a coal-fired combined cycle plant.

Because power demand is less during weekends, holidays and nighttime, the average annual production from a typical power plant is only about 75 percent of its capacity. With liquid phase methanol technology, the gasification portion of such plants could be sized to match the average plant load factor. During low load levels, the unneeded gas turbine fuel would be used for the production of methanol. When the electrical loads exceeded the capability of the coal gasification system, methanol would be taken from storage and fired in the gas turbine.

It is estimated that integrated coal gasification combined cycle systems with LPMEOH requires 5 to 15 percent less capital investment and that operating costs are reduced by about 4 mills/kWh.

The merged technologies could offer yet another advantage. Currently, gas turbine peaking systems are fired with natural gas or fuel oil. The stored methanol could be used for fuel, reducing utilities' purchase of costly natural gas or fuel oil.

Abundant United States coal resources is another drawing card for methanol production from coal. The U.S. reserves for coal are much larger than natural gas or oil. Efficient production of energy from coal makes this country less dependent on foreign oil.

Air Products and Chemicals, Inc. (APCI), and Dakota Gasification Company (DGC), through a joint venture, propose to demonstrate the LPMEOH technology under the federal government's Clean Coal funding. The Clean Coal Technology Demonstration Program is a $5 billion national commitment to demonstrate economic and environmentally sound methods for using our nation's most abundant energy resource, coal. The government shares costs up to 50 percent with the private sector. The Clean Coal program requires, however, that the money be repaid to the federal government from the commercialization of the technology.

The three Clean Coal Technology solicitations to date were issued in 1986, 1988 and 1989. We applied to Round Three which has $545 million dollars available to assist in demonstrating technologies in the use of coal in an efficient and an environmentally acceptable manner.

APCI and DGC submitted a proposal to the Department of Energy (DOE) for a commercial-scale demonstration LPMEOH unit. The APCI/DGC proposal was one of 13 projects selected late last year out of 48 competing proposals.

APCI and DGC are equal partners in the projected $214 million project. Costs include construction and four years of operation. Under the proposal, the DOE will contribute $86.9 million to the project which will convert about 7.4 percent of the plant's synthetic natural gas (SNG) to 400 tons of methanol daily.

DGC owns the Great Plains Synfuels Plant near Beulah, North Dakota. The 650 acre plant is the only commercial-scale coal gasification plant in the United States that manufactures a high-Btu SNG. The synfuels plant began operation in the summer of 1984 and produces an average of 148 standard million cubic feet of SNG daily.

Through the proposed methanol project, the Great Plains synfuels plant would increase product diversity. Moreover, the knowledge gained from the demonstration would aid in the commercialization of this technology.

APCI is an international supplier of industrial gases headquartered in Allentown, Pennsylvania. They will install an advanced process for making methanol at the Great Plains plant, a technology which has been extensively tested at their process development facility in LaPorte, Texas.

Improved economics for coal gasification combined cycle is the main reason APCI pursues the demonstration project. This could increase the demand for large air separation plants, which they supply. Moreover, proving the LPMEOH technology on a commercial basis could create a market for their LPMEOH technology and equipment.

By choosing the Great Plains synfuels plant as the demonstration site, APCI and the DOE have chosen an ideal location to prove the LPMEOH technology. According to the proposal, DGC will provide the real estate, the utilities, the raw synthesis gas and the plant infrastructure. By having these services in place and available, the demonstration can be achieved far more economically than a grass-roots project.

The DOE has supported the LPMEOH technology since conception. The process was developed in the mid 1970's by Chem Systems. From 1975 to 1981 APCI conducted bench scale testing. The success of the those tests lead to laboratory testing in 1983. These pilots provided the groundwork for APCI's 7 ton/day demonstration plant in LaPorte, Texas, from 1984 to 1989. This project laid the groundwork for the proposed demonstration using carbon monoxide and hydrogen in synthesis gas available at the Great Plains Synfuels Plant.

Today's commercial methanol production technology is dominated by two processes, one developed by Lurgi and one by Imperial Chemical Industries. Both processes use gas-phase reactors with a zinc-copper catalyst to convert syngas to methanol.

Today methanol is made from methane (natural gas) by a two-step gas-phase conversion process. First, methane is reacted with water and heat to produce a syngas, consisting of carbon monoxide and hydrogen (CH_4 + H_2O --- CO + $3H_2$). This step is called steam reforming. Secondly, the syngas is converted to methanol, using a copper-based catalyst to promote the reaction (CO + $2H_2$ --- CH_3OH). Both steps carry built-in obstacles that cause energy loss and are costly.

The LPMEOH process is believed to be more cost effective than the conventional method. The process differs from gas-phase systems in that the catalyst is suspended as a slurry in an inert hydrocarbon liquid, such as mineral oil. This oil distributes the heat of the reaction throughout the reactor more efficiently than the current technology where these reactions take place in the gaseous state. In both processes, the heat of the reaction generates steam in a heat exchanger.

Another clear advantage, and perhaps the most significant to utilities, is that the liquid-phase can use syngas derived from coal gasification, which has a higher proportion of carbon monoxide than the syngas used by gas-phase reactors. This results in a higher conversion per pass and reduces the volume of recycling, with its associated energy penalty. Furthermore, the process can operate with a higher turn-down-ratio, which is necessary as power production fluctuates due to changes in the needs of the utility's electric system.

Further cost savings are realized in catalyst replacement. Spent catalyst can be pumped from the system and replaced with a fresh slurry on-stream rather than shutting down the reactor to replace the entire catalyst inventory. Production efficiency remains high through the addition of fresh catalyst and because shutdowns are not required for catalyst change.

In the demonstration project, the liquid-phase methanol unit will be integrated into the existing facility at the Great Plains synfuels plant. In the existing facility all of the clean syngas stream from the Rectisol unit is currently sent directly to the methanation system, for conversion to SNG. The proposed unit will be located downstream of the Rectisol unit, prior to methanation, and will process about 28% of the Rectisol outlet stream. The unreacted gas from the liquid phase methanol unit will be sent to the methanation section for conversion to natural gas.

The improved technology of using LPMEOH for converting synthesis gas ($CO + H_2$) to methanol will raise electrical generation operating efficiency and lower production costs. Methanol will be more useful to electric utilities, both as a new fuel option for combustion turbines and as a salable by-product. Another benefit of the liquid product is that it is easier to transport and store.

As part of the demonstration project, the ACUREX Corporation will test the crude methanol produced in the liquid phase methanol process to determine its suitability for boiler, turbine and transportation fuel applications.

The DOE and the joint venture continue negotiations on the methanol project. The original DOE application is for a 500 ton per day, but plans are to reduce the size to a 400 ton per day plant and expand the facility to 560 tons per day during the demonstration period. The proposed reduction in plant size results because of the difficult economics of marketing the plant's production. Not only is this plant a great distance from the U.S. methanol market, but we can anticipate continued strong competition from foreign sources.

Methanol is used as a chemical feedstock in producing a wide variety of products, including formaldehyde, acetic acid and gasoline additives. Methanol is also used directly as a solvent and potentially as an alternative motor fuel.

Methanol is a commodity, so prices are partially influenced by world conditions, making economics difficult to predict as prices fluctuate with the world market.

Most of the large users of methanol either have their manufacturing near ports or water ways, such as the Mississippi or the Ohio River. Production from Great Plains will have to be shipped by rail in competition to both U.S. production, where natural gas is competitively priced, as well as foreign imports.

The future of methanol prices could be affected by legislation as well. Federal and State legislation, both existing and proposed, would increase the requirement of methanol for reformulated gasoline and as an alternative fuel.

Clean Air legislation will modify gasoline composition to improve air quality and reduce human exposure to potentially harmful hydrocarbons. The goal is to target the best fuel composition to reduce emissions, especially those contributing to ground level ozone formation, while maintaining transportation fuel quality.

The Clean Air Bill currently before Congress, which restricts the vapor pressure of gasoline could increase the need for methanol.

Hydrocarbon vapors cause ozone formation. Some hydrocarbons, like butane, are high vapor pressure components, which contributes to atmospheric pollution. By eliminating the high vapor pressure hydrocarbons from the fuel and replacing it with a lower vapor pressure component, such as ethers, the ozone forming characteristics are lowered.

Some industry analysts predict that ethers, including ethyl tertiary butyl ether (ETBE) and methyl tertiary butyl ether (MTBE), will have a major role in new reformulated gasolines. MTBE is produced from methanol, while ETBE is a product of ethanol.

While the large-scale manufacture of methanol from domestic coal could have a positive impact on the United States economy, there currently is a great concern about green house gases and the conversion of coal to methanol resulting in more CO_2 emissions than when produced from natural gas. The use of coal, however, for a larger share of our energy needs would reduce the need for imported oil.

DGC is still evaluating the financial risk of the LPMEOH project. The passage of the Clean Air bill would provide insight on the future requirements of reformulated gasoline, which would have a great impact on this country's requirement for methanol and ethanol.

With project economics difficult to predict, the project is not yet a reality. The future of the methanol market is the key as to whether this technology can be demonstrated at the Great Plains plant on a financially sound basis.

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PLANT STATISTICS

- Produces pipeline quality natural gas (55 billion cubic ft/yr)
- 0.3% of total U.S. consumption
- Construction cost for Phase I ($2.1 billion)
- First production (July 1984)
- DOE ownership (August 1985)
- Dakota Gasification Company (DGC) ownership (November 1988)
- Parent Company (Basin Electric) provides power and water

PLANT PERFORMANCE

- Technical success
  - Reliable production
  - Production rates exceed design
  - Process refinements continue to:
    * Increase production
    * Lower operation and maintenance costs
- Plant failed to meet environmental objectives
- Plant failed financially
  - Low energy prices

CLEAN COAL ROUND III

$525 million available

- Up to 50% matching
  - Capital investment
  - Demonstration expenses

FUTURE

- Gas revenues have matched or exceeded plant operating cost
- Decline in synthetic natural gas revenue anticipated
- Byproduct development emphasized as source of additional revenue
- Methanol is a potential byproduct

METHANOL PROJECT

- Partners
  - Air Products & Chemicals Inc. (50%)
  - Dakota Gasification Company (50%)
- Project Scope
  - 500 tons/day (approx. 10% of SNG production)
  - $213.7 million project
    * Includes four years of production cost
  - $92.7 million DOE share
- Demonstration (Alternate Fuels)
  - Transportation fuel
  - Power generation fuel

DEMONSTRATION PROJECTS

Demonstration Partners	State
Kanawha Valley Regional Transportation Authority (KVRTA)	West Virginia
Southern California Rapid Transit District (SCRTD)	California
Miller Brewing Company	California
Hughes Aircraft Company	California

LIQUID PHASE METHANOL (LPMEOH)

History

1975	Concept potential
1975-1981	Bench scale testing
1983	Laboratory size testing
1984-1989	Demonstration plant (7 to 13 tons per day) - LaPorte, Texas

METHANOL (WOOD ALCOHOL)

Feed Stock

Natural gas (CH_4)

Coal gasification raw gas

Process

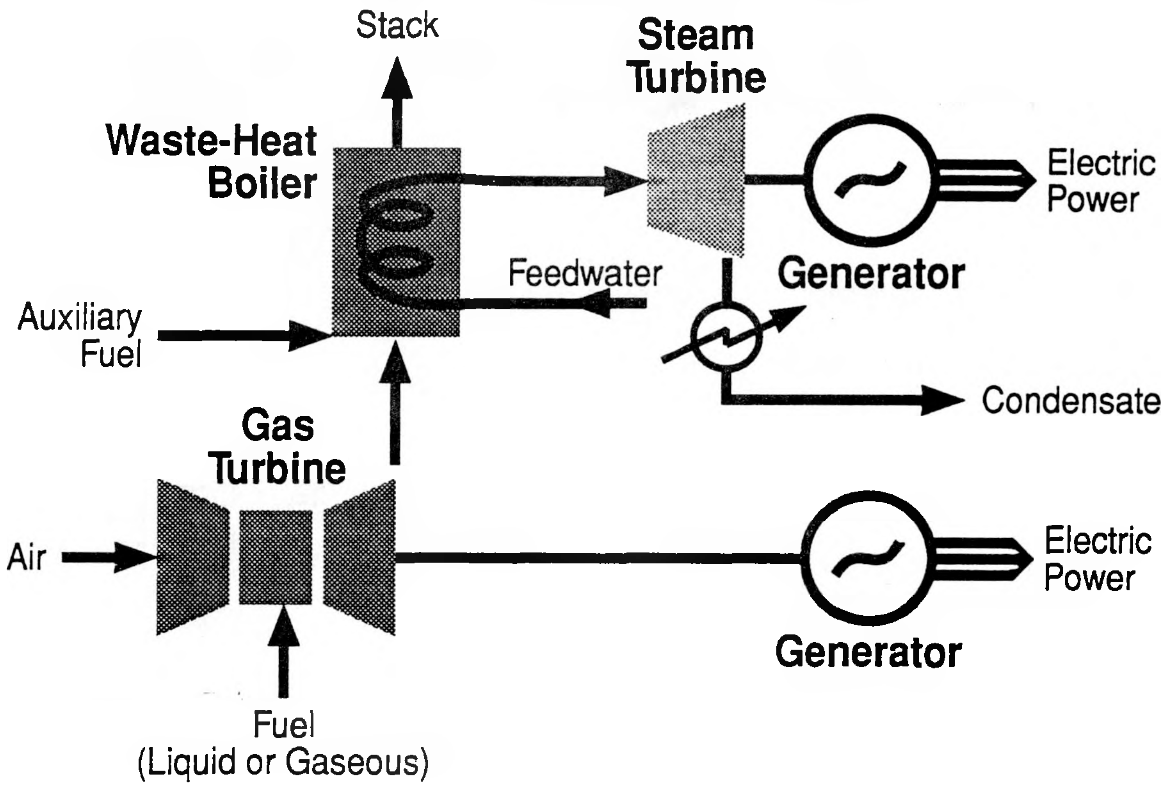
$$CO + 2H_2 \rightarrow CH_3OH \text{ (Methanol)} + \text{heat}$$

PROCESS ADVANTAGES

Liquid Phase vs. Gas Phase

- Higher throughput
- Better process control
- Rapid turn down
- Improved economics

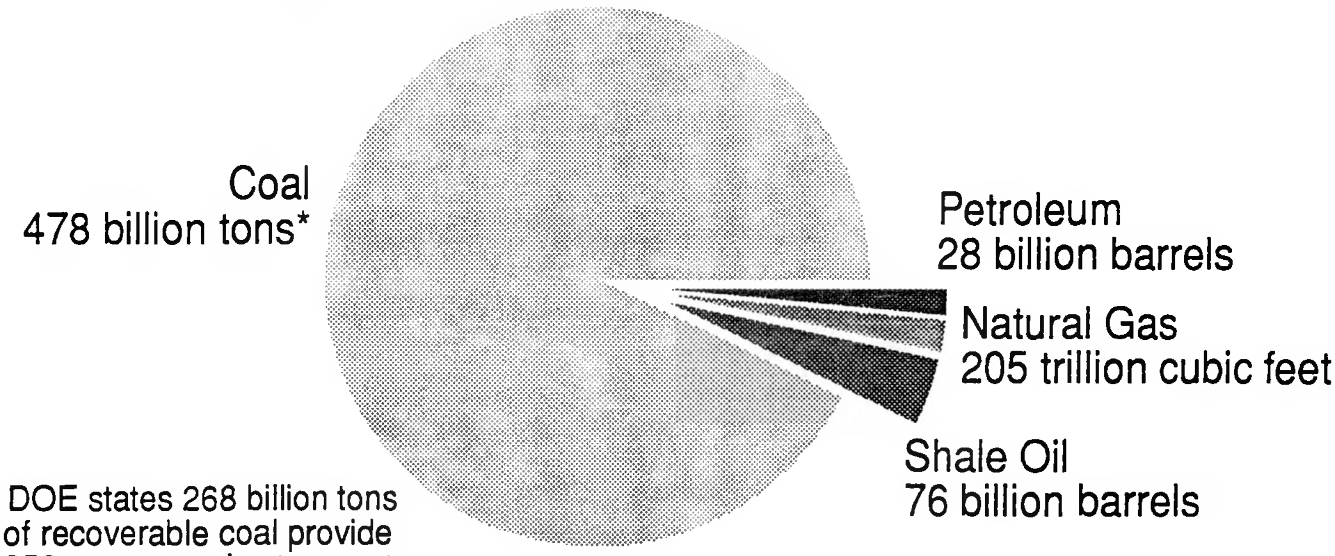
COMBINED CYCLE



COMBINED CYCLE POWER GENERATION

- Advantages
  - High efficiency (1/3 less fuel)
  - Low capital cost
  - Low environmental emissions
  - Short lead time (planning to commercialization)
- Disadvantage
  - Burns liquid or gaseous fuels

ESTIMATED U.S. ENERGY RESERVES

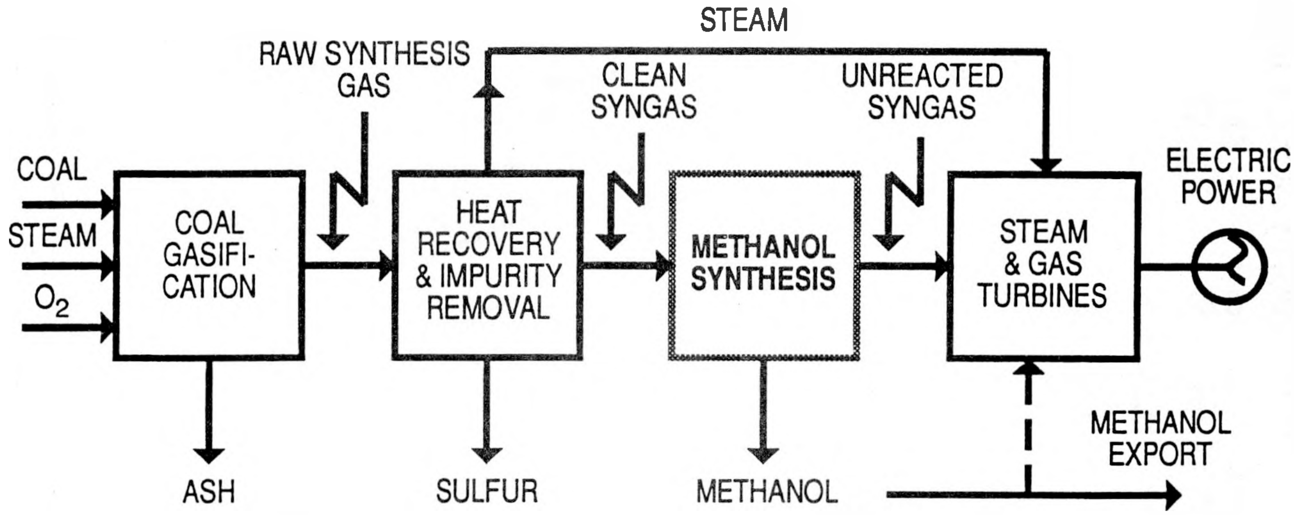


* DOE states 268 billion tons of recoverable coal provide 250 years supply at current usage.

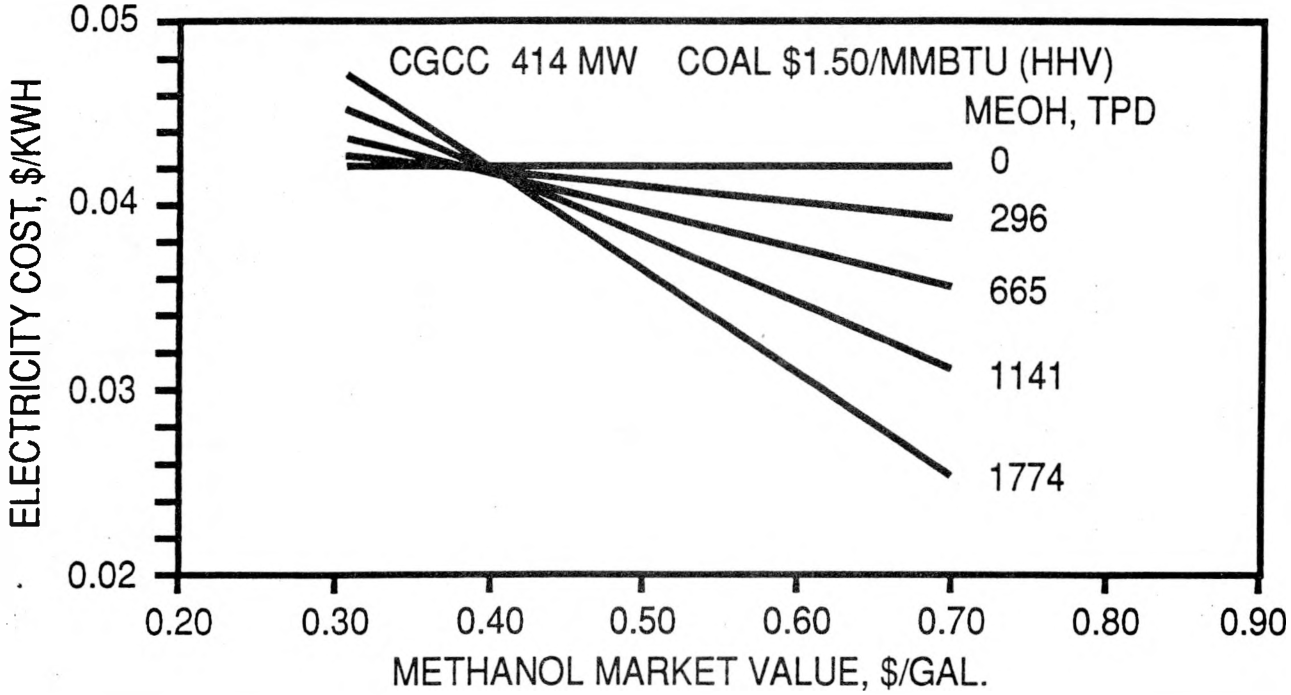
COAL GASIFICATION COMBINED CYCLE POWER GENERATION

- Advantage
  - Utilize coal which is plentiful and economical
- Disadvantages
  - Increased capital cost
  - Not proven commercially
  - Public perception that use of coal increases pollution

COPRODUCTION OF ELECTRIC POWER AND METHANOL VIA COAL GASIFICATION COMBINED-CYCLE (CGCC)



ELECTRICITY COST AS A FUNCTION OF METHANOL PRICE

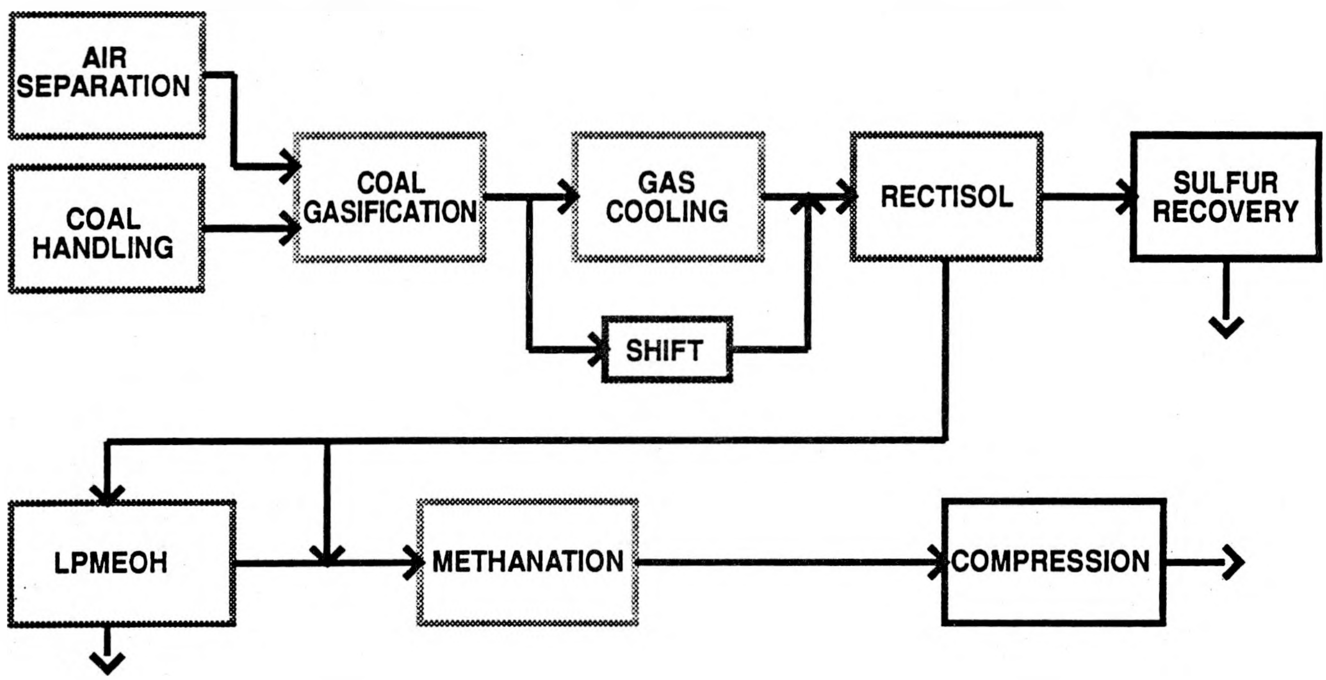


ENVIRONMENTAL CONSIDERATIONS

Plant Environmental Performance

Emissions, lb/MMBTU	Reference PC Plant	CGCC	CGCC/ LPMEOH
SO_2	3.8	0.12	0.01
NO_x as NO_2	1.2	0.12	0.12
Particulate Matter	0.10	0.008	0.001

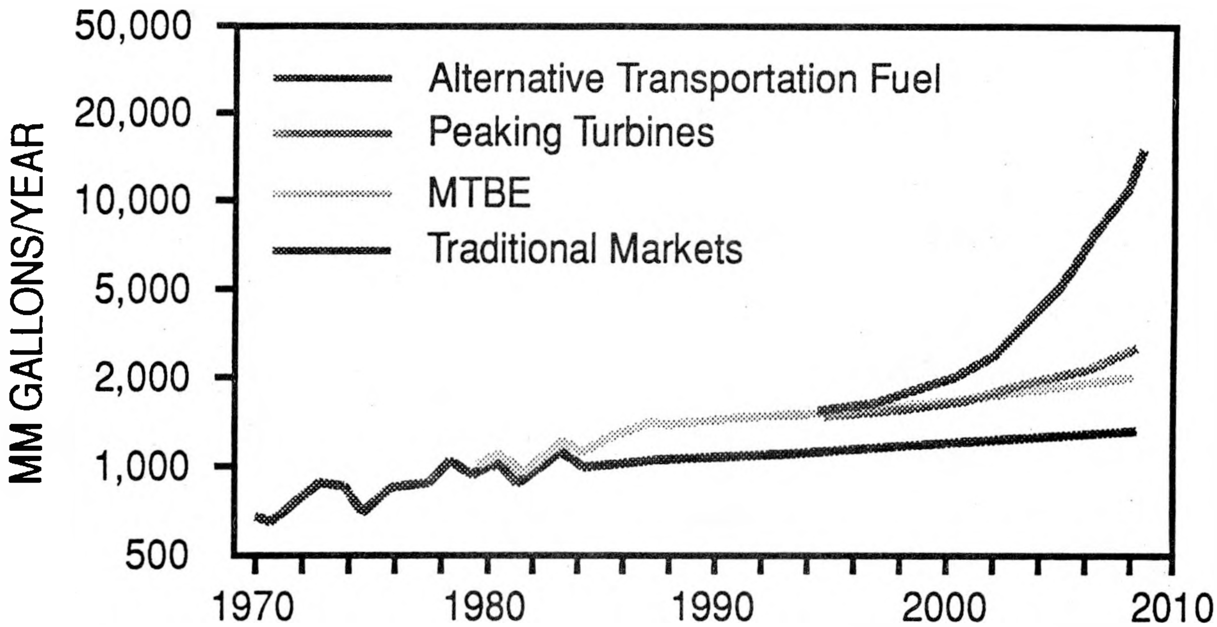
DAKOTA GASIFICATION WITH LPMEOH PROCESS INTEGRATION



DEMONSTRATION PROJECT FEASIBILITY

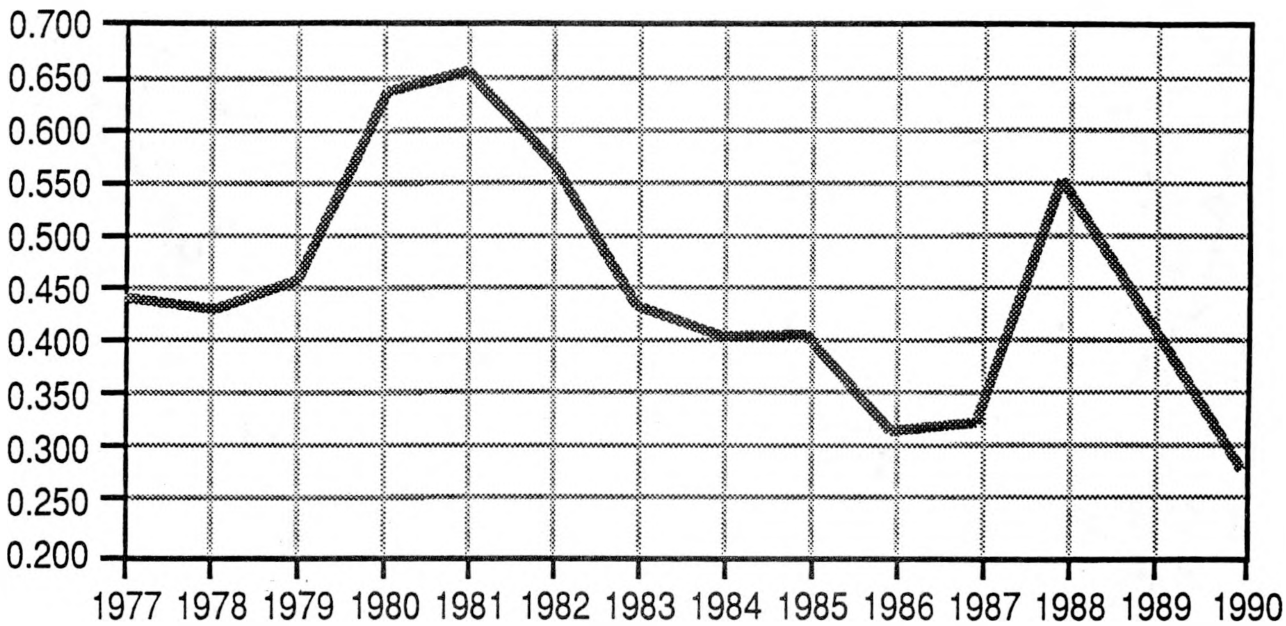
- Projected methanol consumption
- Methanol selling price
- Methanol markets
  - Transportation distance
  - Foreign competition

U.S. METHANOL CONSUMPTION



GULF COST MEOH PRICES

$/Gallon - 1977 to 1990



METHANOL MARKETS

PROJECT CONSIDERATIONS

- Clean coal funding vital to project feasibility
- DOE study finds methanol from U.S. natural gas will not be competitive with off-shore production
- Cost of feedstock from Synfuels plant even less competitive than natural gas
- Methanol U.S. spot prices currently at 27 to 28 cents/gallon
- Uncertainty of Federal legislation regarding energy taxes and environmental requirements
  - Will reformulated gasoline and/or alternate fuels be mandated?

AUTHORS' INDEX

AUTHORS' INDEX (Continued)