DOE/MC/30097 -- 5586
(DE97002233)

Task 3.14 - Demonstration of Technologies for Remote Power Generation in Alaska

Semi-Annual Report
July 1 - December 31, 1996

By
Michael L. Jones

Work Performed Under Contract No.: DE-FC21-93MC30097

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880

By
Energy and Environmental Research Center
University of North Dakota
P. O. Box 9018
Grand Forks, North Dakota 58202-9018

Disclaimer

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government, nor any agency thereof, nor any of their employees makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

EERC DISCLAIMER

LEGAL NOTICE This research report was prepared by the Energy & Environmental Research Center (EERC), an agency of the University of North Dakota, as an account of work sponsored by the U.S. Department of Energy. Because of the research nature of the work performed, neither the EERC nor any of its employees makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by the EERC.

ACKNOWLEDGMENT

This report was prepared with the support of the U.S. Department of Energy (DOE), Federal Energy Technology Center, Cooperative Agreement No. DE-FC21-93MC30097. However, any opinions, findings, conclusions, or recommendations expressed herein are those of the author(s) and do not necessarily reflect the views of the DOE.

TABLE OF CONTENTS

TASK 3.14 – DEMONSTRATION OF TECHNOLOGIES FOR REMOTE POWER GENERATION IN ALASKA

INTRODUCTION

In over 165 villages in Alaska, the use of local fossil fuel supplies or renewable energy resources could greatly reduce the cost of electricity and space heating. Currently, diesel generators are the most commonly used electrical generating systems; however, high fuel costs result in extremely high electrical power costs relative to the lower 48 states. The reduction of fuel costs associated with the use of indigenous, locally available fuels running modular, high-efficiency power-generating systems would be extremely beneficial.

OBJECTIVES

The overall goal of this project is a site-specific demonstration of a small, environmentally acceptable electric generating system fueled on indigenous fuels and waste materials to serve the microgrid or stand-alone power distribution systems typical of remote, isolated Alaska Native communities.

The objective of the project is to develop a commercialization plan that includes an analysis of the quantity, quality, and cost of the available fuels; a mapping of the electricity and district heating needs of a selected community, including electrical distribution layout and interconnecting steam piping; a step-by-step review of the environmental regulations and permit applications that need to be met; and a preliminary design and budget for the demonstration of a 0.5- to 6-MW_e power system to be completed by the Energy & Environmental Research Center (EERC) in a manner that provides technical and regulatory readiness to proceed with implementation of the demonstration.

The scope or work is divided into two phases. The first phase will involve a workshop to provide input for the final definition of the technology to be demonstrated and the selection of a study site, followed by process design verification studies as needed (e.g., combustion tests on candidate fuels). The second phase of the work will develop the preliminary engineering design and provide the engineering, economic, and regulatory information necessary to proceed with the full demonstration. Parallel work will be conducted as needed to support the demonstration of other power technologies for additional remote sites.

ACCOMPLISHMENTS

The EERC has been asked to coordinate a number of activities for the Federal Energy Technology Center (FETC) related to the use of fossil fuels to meet the energy needs of Alaska. A number of activities are under way under this project and are summarized as follows.

Atmospheric Fluidized-Bed Combustor for Remote Power

Results from two separate workshops on remote power technologies have identified atmospheric fluidized-bed combustion (AFBC) as having the potential to meet the needs for both electricity and district heating in rural villages. Two locations in Alaska, the villages of McGrath and Tok, were selected as possible sites for an AFBC demonstration. Parsons Power Group, Inc., has completed a study on the design for an AFBC system based on the Donlee combustor to meet the power requirement of McGrath. A position paper entitled "Status of the Conceptual Design Study for a 600-kWe Coal-Fired Cogeneration Plant in the Village of McGrath, Alaska," was completed by the participants in the program in July of 1996. Contributors to that paper included Parsons Power Group, Inc., Doyon Ltd., MTNT Limited, Donlee Technologies, McGrath Power and Light (MP&L), Alaska Department of Community and Regional Affairs (DCRA), J.S. Strandberg Consulting Engineers, and the EERC. A copy of the position paper is included as Appendix A. The position paper identified additional information necessary for MP&L to make the decision to proceed with a demonstration project. MTNT Limited, the village corporation representing McGrath, was given a contract to cover 50% of the cost of developing the additional information needed. MP&L retained J.S. Strandberg Consulting Engineers to complete the feasibility study. This report will be completed in March 1997.

The second site chosen as a potential site for an AFBC demonstration was Tok. Electricity is provided to this village by Alaska Power and Telephone (APT). APT has issued a request for proposals for a design and cost estimate for an AFBC system to meet the power needs of Tok. This competitive solicitation will allow vendors to offer design options to reduce the cost of power at Tok. Proposals are currently under review by APT, DCRA, and the EERC. APT will make a decision in February 1997, if it will proceed to a feasibility study based on these proposals.

Through a subcontract with Energy Resources International, Inc., an assessment of the market for similar systems in other parts of the world was completed. The report entitled "Global Market Assessment of Coalbed Methane, Fluidized-Bed Combustion, and Coal-Fired Diesel Technologies in Remote Applications" is included as Appendix B.

Coalbed Methane and Coal-Fired Diesel Technologies – Applications in Alaska

The EERC has been working with Arthur D. Little to move the clean coal technology demonstration project for a coal-fired diesel to a site at the University of Alaska in Fairbanks where plans were already under way for a coal–water fuel demonstration project. The transfer of this clean coal demonstration project from Maryland to the Fairbanks site was approved, and work was initiated to complete the environmental assessment to meet the National Environmental Policy Act (NEPA) requirement of this project. Jim Mangi and Associates were retained to complete the draft NEPA documents. This should be completed in February 1997.

Doyon, Ltd., has expressed interest in working with the state of Alaska to investigate and demonstrate coalbed methane as a viable energy source for remote areas of Alaska. Currently, the EERC is exploring the option for federal participation in this activity by providing support for a fuel cell to utilize the methane produced. The viability of a joint activity will be determined by March 1997.

FUTURE ACTIVITIES

- Complete feasibility study for an AFBC system at McGrath.
- Complete NEPA document for a coal-fired diesel demonstration project at University of Alaska-Fairbanks.
- Complete evaluation of proposals for the Tok demonstration project.

J:BAY3T3Q4

FORM EIA-459E
(10/88)

U.S. DEPARTMENT OF ENERGY
FEDERAL ASSISTANCE MANAGEMENT SUMMARY REPORT

FORM APPROVED
OMB NO. 1900 0127

1. Program/Project Identification No.	2. Program/Project Title	3. Reporting Period
DE-FC21-93MC30097	Task 3.0 Advanced Power Systems	10-1-96 through 12-31-96

4. Name and Address Energy & Environmental Research Center
University of North Dakota
PO Box 9018, Grand Forks, ND 58202-9018 (701) 777-5000

5. Program Start Date 01-12-93

6. Completion Date 12-31-97

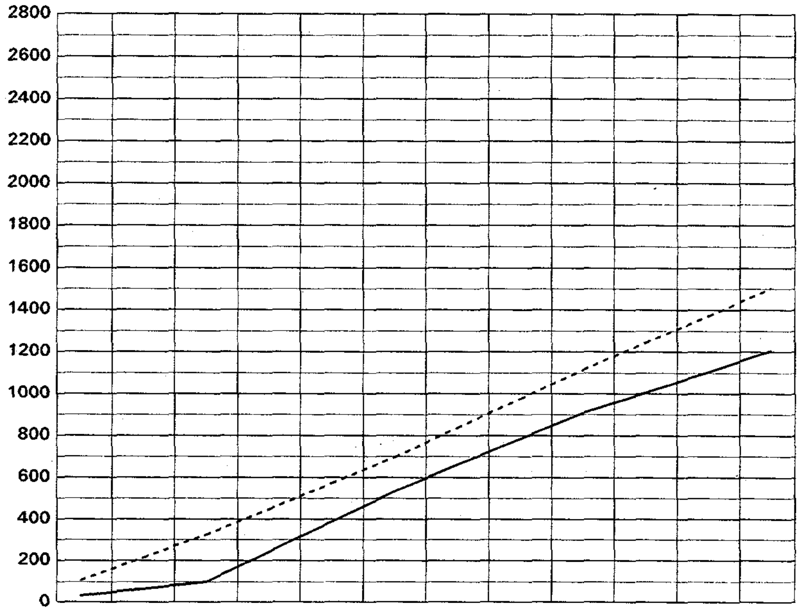
7. FY 95/96

8. Months or Quarters Quarters

b. Dollar Scale

1st			2nd			3rd			4th		
JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC

9. Cost Status a. Dollars Expressed In Thousands



10. Cost Chart

Fund Source		Quarter 1st	2nd	3rd	4th	Cum. to Date	Tot. Plan
DOE	P	324	374	417	387	1502	2657
	A	98	437	373	298	1206	
	P						
	A						
	P						
	A						
	P						
	A						
Total P		324	374	417	387	1502	2657
Total A		98	437	373	298	1206	
Variance		226	(63)	44	89	296	

P= Planned A = Actual

Total Planned Costs for Program/Project
$2657

c. Cumulative Accrued Costs

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Planned			324			698			1115			1502
Actual			98			535			908			1206
Variance			226			163			207			296

11. Major Milestone Status

	Units Planned / Units Complete
3.11 Fuel Quality Advisor	P
	C
3.12 Small Power Systems	P
	C
3.13 Hot-Gas Filter Testing	P
	C
3.14 Remote Power Gen. Alaska	P
	C
	P
	C
	P
	C
	P
	C
	P
	C
	P
	C

12. Remarks

13. Signature of Recipient and Date Michael D Mann 1/31/97

14. Signature of DOE Reviewing Representative and Date

J:BAY3T3Q4

FORM EIA-459E
(10/88)

U.S. DEPARTMENT OF ENERGY
FEDERAL ASSISTANCE MANAGEMENT SUMMARY REPORT

FORM APPROVED
OMB NO. 1900 0127

1. Program/Project Identification No.	2. Program/Project Title	3. Reporting Period
DE-FC21-93MC30097	Task 3.0 Advanced Power Systems	10-1-96 through 12-31-96

4. Name and Address Energy & Environmental Research Center
University of North Dakota
PO Box 9018, Grand Forks, ND 58202-9018 (701) 777-5000

5. Program Start Date 01-12-93

6. Completion Date 12-31-97

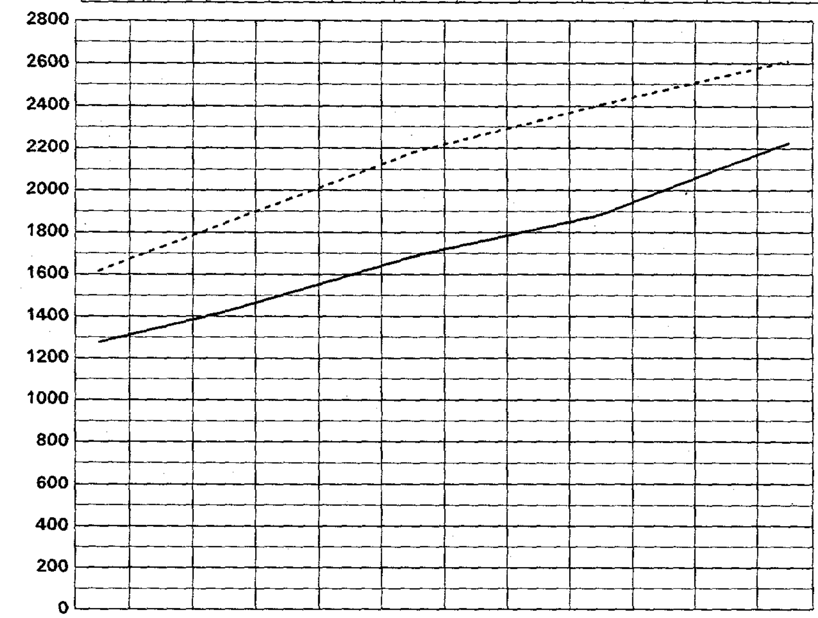
7. FY 96/97

8. Months or Quarters Quarters

9. Cost Status a. Dollars Expressed In Thousands

b. Dollar Scale

1st			2nd			3rd			4th		
JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC



10. Cost Chart

Fund Source		Quarter 1st	2nd	3rd	4th	Cum. to Date	Tot. Plan
DOE	P	341	334	229	206	2612	2657
	A	214	264	201	342	2227	
	P						
	A						
	P						
	A						
	P						
	A						
Total P		341	334	229	206	2612	2657
Total A		214	264	201	342	2227	
Variance		127	70	28	(136)	385	

P = Planned A = Actual

Total Planned Costs for Program/Project
$2657

c. Cumulative Accrued Costs

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Planned			1843			2177			2406			2612
Actual			1420			1684			1885			2227
Variance			423			493			521			385

11. Major Milestone Status	Units Planned / Units Complete
3.11 Fuel Quality Advisor	P
	C
3.12 Small Power Systems	P
	C
3.13 Hot-Gas Filter Testing	P
	C
3.14 Remote Power Gen. Alaska	P
	C
	P
	C
	P
	C
	P
	C
	P
	C
	P
	C

12. Remarks Please note the quarterly expenditures for the third quarter have been revised from $316 to $201(thousand). It appears the encumbrances were incorrectly included in quarter three.

13. Signature of Recipient and Date 1/31/97

14. Signature of DOE Reviewing Representative and Date

J:BAY3T3Q4

FORM EIA-459E
(10/88)

U.S. DEPARTMENT OF ENERGY
FEDERAL ASSISTANCE MANAGEMENT SUMMARY REPORT

FORM APPROVED
OMB NO. 1900 0127

1. Program/Project Identification No.	2. Program/Project Title	3. Reporting Period
DE-FC21-93MC30097	Task 3.0 Advanced Power Systems	10-1-96 through 12-31-96

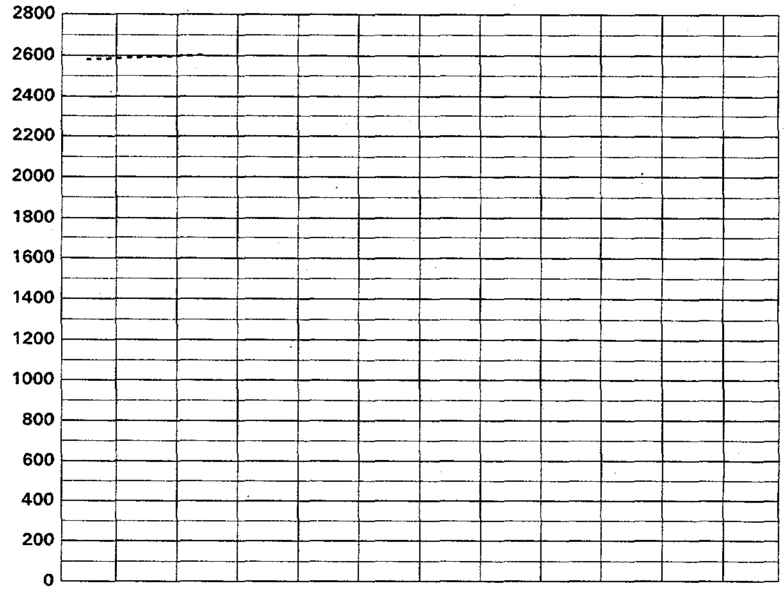
4. Name and Address Energy & Environmental Research Center
University of North Dakota
PO Box 9018, Grand Forks, ND 58202-9018 (701) 777-5000

5. Program Start Date 01-12-93

6. Completion Date 12-31-97

7. FY	8. Months or Quarters	b. Dollar Scale	1st			2nd			3rd			4th		
97/98	Quarters		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC

9. Cost Status a. Dollars Expressed In Thousands



10. Cost Chart

Fund Source		Quarter 1st	2nd	3rd	4th	Cum. to Date	Tot. Plan
DOE	P	45				2612	2657
	A					2227	
	P						
	A						
	P						
	A						
	P						
	A						
Total P		45	0	0	0	2612	2657
Total A		0	0	0	0	2227	
Variance		45	0	0	0	385	

P= Planned A = Actual

Total Planned Costs for Program/Project
$2657

c. Cumulative Accrued Costs

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Planned			2657			2657			2657			2657
Actual												
Variance												

11. Major Milestone Status	Units Planned / Units Complete	
3.11 Fuel Quality Advisor	P	
	C	
3.12 Small Power Systems	P	
	C	
3.13 Hot-Gas Filter Testing	P	
	C	
3.14 Remote Power Gen. Alaska	P	
	C	
	P	
	C	
	P	
	C	
	P	
	C	
	P	
	C	
	P	
	C	

12. Remarks

13. Signature of Recipient and Date	14. Signature of DOE Reviewing Representative and Date
Michael D. [illegible] 1/31/97	

FORM EIA-459E
(10/80)

U.S. DEPARTMENT OF ENERGY
FEDERAL ASSISTANCE MANAGEMENT SUMMARY REPORT

FORM APPROVED
OMB NO. 1900 0127

1. Program/Project Identification No.	2. Program/Project Title	3. Reporting Period
DE-FC21-93MC30097	Task 3.0 Advanced Power Systems	10-1-96 through 12-31-96

4. Name and Address
Energy & Environmental Research Center
University of North Dakota
PO Box 9018, Grand Forks, ND 58202-9018 (701) 777-5000

5. Program Start Date 01-12-93
6. Completion Date 12-31-97

Milestone ID. No.	Description	Planned Completion Date	Actual Completion Date	Comments
3.11	Fuel Quality Advisor	12-95		
a	Develop indices for ranking coal handleability	11-95	11-95	
b	Develop algorithms for incorporation into low-NOx ash formation model	9-95	7-96	
c	Develop algorithms for incorporation into the entrained flow gasification ash formation model	11-95	12-95	
d	Create a standardized and computerized shell and interface	7-95	7-96	
e	Incorporate ash formation, ash deposition, and coal handleability algorithms into Fuel Quality Advisor shell	12-95	7-96	
3.12	Small Power Systems	12-95		
1a	Identify best candidate sorbent for use in optimization studies	7-95	4-95	
1b	Determine optimal performance over operating range	12-95	--	Deleted
2a	Review the available data and select the best candidate cracking catalyst	4-95	9-95	Revised date 8-95
2b	Determine optimum operating conditions for the catalyst	12-95	--	Incorporate into 3c
3a	Select design(s) for further development	8-95	9-95	
3b	Identify barrier issues and develop demonstration and commercialization plan	12-95	9-95	
3c	Testing of barrier issues on pilot scale	12-95	12-95	Expanded scope
3.13	Hot-Gas Filter Testing			
a	TRDU upgrades	6-95	8-95	
b	Assembly and Installation of Filter Vessel	6-95	9-95	
c	200-HR FILTER TEST (shakedown)	9-95	12-95	Shorter test performed
d	Topical Report on First Filter Test	12-95	7-96	
e	Complete first 200-hr test	5-96	4-96	
f	Present Test Results to METC Representatives	7-96	7-96	
g	Complete Second 200-hr Test	11-96	11-96	
h	Present Test Results to METC Representatives	1-97		
3.14	Remote Power Gen. Alaska			
a1	Environmental Information Documentation	6-7-95	6-95	
a2	Regional Workshop	9-15-95	9-95	
a3	Site and Technology Selection	10-30-95	1-96	
a4	Status Report on McGrath AFBC Demonstration	6-96	6-96	
b1	Identify Environmental and Permitting Regulations	2-28-96		2-97
b2	Preliminary Engineering Design	5-31-96		3-97
	- Final Feasibility for McGrath Site	3-97		
	- Tok Site Preliminary Design	3-97		
c1	Evaluation of Technical Feasibility of Relocating Clean Coal Technologies to Alaska	12-31-95	9-96	*
c2	NEPA document preparation for CCT project in Alaska	2-97		

* Transfer of project approved

APPENDIX A

STATUS OF THE CONCEPTUAL DESIGN STUDY FOR A 600-kWe COAL-FIRED COGENERATION PLANT IN THE VILLAGE OF MCGRATH, ALASKA

TABLE OF CONTENTS

LIST OF TABLES

STATUS OF THE CONCEPTUAL DESIGN STUDY FOR A 600-kWe COAL-FIRED COGENERATION PLANT IN THE VILLAGE OF MCGRATH, ALASKA

1.0 INTRODUCTION

Alaska has over 160 isolated villages that depend on diesel fuel for space heating and electrical generation. There are no roads to these communities, nor are they connected to an electrical grid. Rural areas receive over 90% of their energy from oil products. Much of this oil is barged in during the summer months, risking possible environmental contamination to the waterways. However, the greater concern arises from the aging diesel oil storage facilities in the harsh, unforgiving environment of Alaska. Estimates indicate that between $200 and $400 million in repairs and new construction will be required to bring the bulk fuel tank farms into compliance with current federal and state regulations. Life-threatening fuel shortages still occur during winter months, because deliveries are made impossible by ice, snow, or cold weather. The average cost of electric power in rural Alaska is around 35 cents/kWh, while the cost of heating fuel in some communities can exceed $3.00 per gallon. Native families spend about one-third of their disposable income on household energy. Studies have indicated that rural residents allocate two to three times more of their household energy budgets to home heating than to electricity. Generally, rural Alaskans consume half as much energy as urban Alaskans at twice the cost.

Since the early 1980s, the state of Alaska has subsidized the cost of electricity to rural Alaska through the Power Cost Equalization (PCE) Program. In 1995, subsidies under the PCE Program were approximately $18 million. The revenue source for this subsidy (a tax on crude oil shipments through the Alaskan pipeline) is shrinking. If current trends continue, the PCE fund will be depleted by the year 2000. This fact has sparked speculation as to the future of the program. In any event, the Alaskan government is committed to finding lower-cost options for meeting the power needs of rural Alaska.

It is this combination of circumstances that led to the establishment of a joint project between Doyon Limited (Doyon), an Alaska native regional corporation, and the U.S. Department of Energy (DOE) Morgantown Energy Technology Center (METC) to explore options for small coal-based power systems to meet the power needs of rural Alaska. This joint activity has taken the form of a Cooperative Research and Development Agreement (CRADA), which has as its goals the following: 1) make affordable emerging energy systems available to remote villages in Alaska; 2) demonstrate low-emission systems that can contribute to integrated solutions of current environmental problems; 3) create local jobs in Alaskan villages; 4) demonstrate the capability and versatility of local fuel source emerging energy systems; and 5) provide a mechanism to help U.S. technology vendors market their technologies in developing countries throughout the world.

The CRADA between Doyon and METC has as its goal to develop a conceptual design of a coal-fired cogeneration power plant using a DOE-developed atmospheric fluidized-bed combustor (AFBC) clean coal technology, which could provide a cost-effective alternative to the subsidized electrical power generation presently being used in rural Alaska. Through the feasibility study for the village of McGrath developed under this CRADA, a major step has been taken forward in evaluating the viability of AFBC technology for rural Alaska. Participants in this CRADA include, in addition to METC (now represented by the Energy & Environmental Research Center [EERC]) and Doyon, McGrath Light & Power (ML&P), MTNT Limited, University of Alaska-Fairbanks, Mineral Industry Research Lab, and the state of Alaska Department of Community and Regional Affairs.

This paper has as its goal to 1) define where the feasibility study is today; 2) identify the opportunity represented by the proposed demonstration; 3) identify the outstanding issues that need to be addressed; and 4) provide clear guidelines to move the project forward.

Coal is the target fuel for this project to meet the energy needs of rural Alaska. The coal option is attractive for a number of reasons, including the following:

- Alaska has about half the estimated coal resources of the United States. In many cases deposits are located near rural communities in need of low-cost power-generating technologies.

- Diesel fuel must be imported. Coal is a local resource, the use of which increases local employment while decreasing the number of fuel dollars that leave the community, the region, and the state.

- Diesel fuel is increasingly expensive to purchase and presents handling problems, including the potential to contaminate water supplies through spills. Coal spills do not pose a danger to water supplies, nor is coal a significant fire hazard.

- Coal pricing is more predictable because it is cost-driven rather than market-driven, unlike diesel fuel. Utilities and individuals can expect to lock in long-term, stable pricing indexed to changes in production costs.

- Coal is a less expensive fuel than diesel on a $/million-Btu basis.

- Coal combustion technology has successfully burned multiple fuels such as tires, biomass, infectious hospital waste, and municipal waste, leading to solutions to current solid waste disposal problems.

- Coal offers an option for energy independence and self reliance.

Local support for the proposed project has been well documented. A resolution was passed by the City Council of McGrath on February 20, 1996, stating their support for the project. Additionally, ML&P, one of the most efficient rural electric utilities, and MTNT, the local native village corporation, are committed to the effort to site this demonstration project in McGrath.

The general approach for this effort was to design a highly reliable, modular, and transportable AFBC power plant for the cogeneration of electricity and process heat. The facility was designed to cofire coal, limestone, and solid waste and replace the present diesel oil-fired system. Existing diesel generation would remain for outage backup and peaking operation. This activity was based on the following assumptions:

- The project definition study has focused on an approximate 500-kWe to 1.2-MWe FBC power plant for electrical and district heat production in a remote Alaskan application.

- The plant will utilize advanced AFBC technology as the primary steam generator.

- The primary fuel is a Alaskan subbituminous coal with limestone local to the application area.

- Cofiring of nonhazardous municipal solid waste materials is a secondary fuel option.

- Conceptual costs were prepared to support a ±15% accuracy.

Details of this design activity are available in reports completed by Parsons Power Group Inc. and J.S. Strandberg Consulting Engineers (1–3).

2.0 TECHNOLOGY ISSUES

Based on the availability of local fuels (coal and municipal solid waste) and after examining other combustion technologies that would meet environmental criteria, the energy conversion technology selected for evaluation and demonstration is an AFBC, with design parameters as shown in Table 1. At this stage of the project, preliminary feasibility and conceptual designs have been completed; key performance parameters have been identified; the AFBC conceptual design has been pilot-tested to determine performance characteristics while firing Alaska coal and limestone; key equipment components have been identified and conceptualized; operational parameters and performance effects have been established; and project costs including capital, operating, and maintenance have been estimated. Cofiring of municipal solid waste was also evaluated as an enhancement to the overall project concept.

The technology assessment team consisting of Parsons Power Group Inc., J.S. Strandberg Consulting Engineering, and Donlee are in the final stages of defining and assessing the technologies related to remote-site power generation and district heating at McGrath. Their involvement in the project thus far has been to conceptualize and refine the design, construction, and operation of a highly reliable 750-kWe (gross), 595-kWe (net), power plant for cogeneration of electrical and district heat production (5 MMBtu/hr) at McGrath, Alaska. The facility in its current design consists of an AFBC that will cofire local coal and limestone, a conventional heat recovery steam generator, and steam turbine generator set. The facility also includes a diesel generator set rated at 125 kWe (gross) to supply peaking capacity and an auxiliary oil-fired boiler for district heating backup.

A technical assessment and review of the constructability and operability of a coal-fired power plant and the district heating system and a "truthing of the concept" were performed to establish the applicability and benefits of utilizing the AFBC technology. This technical review identified the following:

- An AFBC coal-fired power plant providing a nominal 600-kWe capacity will fully support ML&P's electrical demands and will provide 5 MBtu/hr for commercial heating, with a design that can easily expand to support 10 MBtu/hr.

- The design approach performed so far appears to be technically sound and is based on the application of proven equipment that has been tested at a scale directly applicable to the project. The project design has been studied thoroughly and is well documented in the Project Definition Study Final Report submitted to DOE.

- Construction of the project in McGrath, Alaska, can be accomplished utilizing local and in-state labor and within the required time constraints.

- A thorough study of alternative steam turbine configurations were evaluated for performance, reliability, operability, and cost using resources from Parsons Power, Bloomfield Associates, Thermal Systems, turbine manufacturers, and METC.

Table 1. FBC Power Plant Design

Assumptions	
Annual Demand, kWh/yr	3,071,250
Annual Production, net kWh/yr	2,940,000
Power Station Output, net kWe	595 (coal), 125 (diesel)
Thermal District Heating, MBtu/hr	5
Thermal District Heating, MBtu/yr	10,000–16,000
Thermal Supply Temperature, °F	245
Thermal Supply Pressure, psig	75
Design	
Coal Combustor System	Circulating AFBC
Diesel System	Caterpillar 3304
Steam Conditions	
Flow, lb/hr	17,876
Temperature, °F	500
Pressure, psig	200
Thermal Output, MBtu/hr	22.66
Primary Fuel	Little Tonzona Creek
Coal HHV, Btu/lb	6700–6800
Maximum Feed Rate, lb/hr	3455
Average Feed Rate, lb/hr	2004
Ignition/Diesel Fuel	
Oil HHV, Btu/lb	18,500–19,500
Max Feed Rate @125kWe, gpm	10.1
Ave Feed Rate @60kWe, gpm	4.6
Sorbent Type	McGrath limestone
Maximum Feed Rate, lb/hr	108
Average Feed Rate, lb/hr	63
Air Quality Control	
SO_2, average removal	70%, AFBC
Particulate	Baghouse

- Annual fuel and limestone consumption is estimated at 8200 tons of coal, 265 tons of limestone, and 9500 gallons of diesel fuel. On-site coal storage of 240 tons will provide a 6-day supply; a 36-ton limestone silo will provide a 45-day supply. Coal and limestone will be supplied from local sources near McGrath.

- District heating is a reliable, well-proven technology in Arctic applications. The district heating component of the project will provide a source of space heating for both residences and businesses that will alleviate many of the problems rural residents have with oil-fired heating. District heat will reduce fire danger and eliminate the maintenance problems that arise from operating and maintaining oil-fired space heaters.

- A thorough conceptual design of the district heating system was completed as part of the truthing report. The project team developed a preliminary layout for district heating piping, as well as an initial estimate for heating loads in the commercial district area of McGrath.

Demonstrated Technology

Many of the components that make up the system to be demonstrated have been used in commercial applications for many years, with the exception of the small fluidized-bed boiler.

The Donlee circulating fluidized-bed (CFB) boiler technology was developed under a DOE contract, starting in 1987. All the basic design philosophy was established and proven early on in a 10,000-lb/hr demonstration unit installed in Donlee's research facility.

Over the last 8 years, a number of different fuels have been tested in the demonstration unit, ranging from peat to anthracite, as well as various waste fuels. In addition, sorbents were also tested with many different fuels.

In 1994, Donlee was selected to test the Alaskan subbituminous coal, Little Tonzona, locally available to McGrath, Alaska. This testing was completed and indicated that the fuel was of excellent quality and could readily be utilized in the Donlee CFB for the purpose of producing steam for power generation in remote regions of Alaska. Specific test results pertinent to this demonstration are as follows:

- No problems with coal and limestone feed into the combustor.
- Greater than 99% carbon conversion.
- Excellent temperature and load control.
- State-of-the-art control of solid and gas emissions; SO_2, NO_x, CO, and total solid particulate (TSP) emissions were all low, and SO_2 emissions met New Source Performance Standards (NSPS) requirements.

Based on extensive testing of the Donlee CFB technology with the project-specific coal, the Donlee CFB is an excellent candidate for utilization at remote-site power generation units in Alaska. Furthermore, the testing done at Donlee demonstrates that the CFB technology can be operated with Little Tonzona coal with minimal difficulty and with minimal personnel and maintenance. A few outstanding issues such as load-following capability and additional automation controls will be demonstrated at the McGrath site.

3.0 ENVIRONMENTAL ISSUES

Based on the data obtained so far, the coal-fired AFBC power plant provides an environmentally sound approach to meeting the village of McGrath's electrical and district heat needs well into the future. The proposed technology results in low emissions (see Table 2), which will maintain the air quality of rural Alaska. A reduction in environmental concerns can be realized through the displacement of imported diesel fuel. Problems associated with transporting and storing (leaky tanks) can be minimized by firing coal as the primary fuel source. In addition, excellent control of gas and solid emissions can be achieved by using the FBC technology, all below allowable state and federal regulatory limits.

Table 2. Emissions Summary

Primary Emissions	ppm	lb/MBtu	Emission Limit
CO	18.5	0.02	NA*
SO_2	350	0.82	1.2
NO_x	126	0.21	NA
Particulates	---	0.008	0.03

* Not applicable.

Residual solids exiting the AFBC can be collected in the baghouse for disposal or utilization in other applications. Solids handling can be accomplished with conventional conveyors and storage bins connected to an ash-conditioning system to produce a solid briquette for disposal or for transport for use in other applications. Briquetting provides longer-term (2-year) storage for disposal by haulage to the mine every other year. Leachate tests have confirmed that mine disposal of the ash should not cause groundwater problems and therefore should not result in permitting delays.

The preferred method of disposal, however, is utilization of the solid residuals in applications in or near the McGrath community. The use of the solid residues in applications near McGrath was evaluated under the DOE–Doyon CRADA by Wormser Systems, Inc (1). Based on preliminary data, it was concluded that the material would not be suitable for aggregate or filler applications.

4.0 ECONOMIC ISSUES

Preliminary capital, operating, and maintenance cost estimates for servicing the village of McGrath's electrical and district heating needs were developed based on the electrical demand profiles for the previous 4 years, with a projected connected district heating peak load of 5 MBtu/hr. The facility proposed will service greater than 98% of the community's energy needs, including residential, government, and commercial businesses. The design process for which the costs were derived was conducted at a level of detail that allowed the size and capacity of all major equipment and components, process flow rates, and operating parameters to be specified for the purpose of manufacturers' review and budgetary estimate. The cost estimates shown in Table 3 are accurate within $\pm 15\%$ and are based on constant 1994 dollars. Note that contingency and escalation factors are not included in the projected cost of electricity (COE). Also note that Table 3 shows both capital (investment) and operating costs, with operating unit costs calculated based on electric generation only.

Based on construction and production estimates, the project definition study concluded as follows:

- Efforts should be undertaken to fully verify the costs and community-wide benefits of this investment. While the projected COE (about 41.5 cents/kWh) does not reflect a savings over the current rates, many benefits cannot be directly accounted for by a cost–benefit analysis, but are valuable to the local and state communities. For example, job growth and security, increased tax revenues, building of resources and community infrastructure, independence from foreign-controlled sources of energy, self-sustaining community.

Table 3. Estimated Cost of Electricity

Capital Costs	**$**	
Direct Costs		
Civil/Structural	838,460	
Mechanical	1,966,720	
Piping	388,850	
Electrical	446,780	
District Heating	1,415,990	
Adjustments*	(232,600)	
Subtotal	4,824,200	
Indirect Costs		
Engineering	234,000	
Const. Mngmnt.	75,000	
Freight	315,575	
Facilities/Const.	40,000	
Start-up/Spares	74,030	
Subtotal	738,605	
Proj. Contingency	Not incl.	
Total Capital Cost	5,562,805	
Annual Operating Costs	**$/year**	**¢/kWh**
Fixed O&M	145,300	5.0
Variable O&M	114,200	3.9
Consumables	18,700	0.6
Fuel Cost (@$60/ton)	508,300	17.4
District Heat Credit	(147,200)	(5.0)
Levelized Capital Cost	571,800	19.6
Total Cost of Electricity	**$1,211,100**	**41.5**

* Consolidation of labor hours and equipment.
Note that costs are based on fourth-quarter 1994 dollars, 595 kWe (net), and a capacity factor of 56%.

- The capital cost for the power block is estimated at $3,408,210; the district heating system $1,415,990; engineering, freight, and construction support $738,600; for a total project capital cost of $5,562,800. Based on a coal price of $60 per ton of coal, this equates approximately to a COE of 41.5 cents/kWh. Sensitivity analysis indicates that this cost can be reduced by 13% to 33% by lowering the cost of the fuel (coal) and reducing operations support.

- With capital investment support from state and federal agencies, long-term stable energy production cost may be possible using the coal-fired plant design to cogenerate electricity and district heat.

- District heating may provide a more stable and predictable pricing structure for community heat energy that is not subject to fluctuating world oil prices.

- Cost of energy is expected to be reduced from the first-of-a-kind demonstration unit with development of a competitive manufacturing base, lower cost of coal, reduced operations support, reduced capital cost for a more highly integrated modular design, and improved thermal efficiency.

5.0 COST OF COAL DELIVERED TO MCGRATH

Fuel oil has remained the preferred fuel for home heating and diesel electric generation. MP&L's 1996–1997 estimated average cost is $1.55/gallon for diesel fuel, which corresponds to an energy cost of about $10.90/MMBtu. Individuals pay significantly more. On a per Btu basis, coal has the potential to be significantly less expensive. Based on the analysis performed in the design and cost study on the power block, a $45/ton delivered price was set as a desired goal for the McGrath project. At this price, the Little Tonzona subbituminous coal, with a heating value of 6800 Btu/lb, represents an energy cost of $3.30/MMBtu.

The most recent cost estimates provided in the Behre Dolbear & Co. study report completed for Doyon in March 1996 indicate a base-case price of $56.80 for coal from the proposed Little Tonzona mine (4). This price covered only operating and equipment replacement costs, with the initial investment provided by demonstration grants from the state of Alaska and DOE. When capital recovery on the initial investment was included, the coal selling price increased to $72.12/ton. Capital requirements over the life of the project included an initial investment of $3.4 million for equipment, $2.2 million in replacement capital in the 11th year of operation, and $720,000 in working capital, partially offset by recovery of the working capital and $300,000 in salvage at the end of the 22-year project life. Both the $56.80/ton and $72.12/ton price estimates were made for a nonprofit operation without return on investment. The breakdown of costs for mining, haulage and capital recovery is shown in Table 4. The costs are based on supplying 10,000 tons annually to the proposed 600-kW$_e$ AFBC plant projected to start up in 1998.

The McGrath project, if implemented, will provide the incentive to begin mining the Little Tonzona Creek coal deposit on the north side of the Alaska range. This coal deposit is owned by Doyon, which has a strong interest in developing the resource. With a long-term contract to supply coal to ML&P, Doyon's initial capital costs would be covered, and further opportunities would be opened for supplying Little Tonzona Creek coal to other potential users in the Kuskokwim River Basin.

Significant details of the mining, haulage, and storage operations represented by these costs are as follows:

- Twenty thousand tons of coal would be mined during 3 winter months every other year and hauled 76 miles via a snow road for stockpiling at the limestone quarry at Noir Hill, about 15 miles from McGrath. Coal reloaded from the stockpile would be hauled to the coal bunker at the plant 2 days per week throughout the year, except during the biennial mining and haulage period, when it would be hauled directly from the mine.

- Previous exploration of the Little Tonzona coal deposit by McIntyre Mines in 1980 and 1981 indicated a reserve of approximately 2 million tons to a mining depth of 50 feet and 5 million tons to 100 feet between four test holes in an area encompassing 7000 feet, where seams were indicated to be up to 60 feet thick. Reserves are more than adequate to supply the 220,000 tons of coal needed for the 22-year life of the project and to provide opportunity for additional sales within an economic radius. However, further exploration

Table 4. Breakdown of Cost for Little Tonzona Coal Delivered to McGrath	
Operating Costs	$ per ton
Mining	3.88
Road Construction	2.30
Truck Haulage	31.39
Coal Transfer from Noir Hill to McGrath	4.81
Overhead, Taxes, Support, Miscellaneous	5.85
Subtotal for Total Operating Cost	48.23
Capital Recovery for Replacement Equipment	8.57
Coal Selling Price with Replacement Capital Recovery	56.80
Capital Recovery for Initial Investment	15.35
Coal Selling Price with Total Capital Recovery	72.15

is recommended at a cost of $55,000 for the purpose of 1) confirming the location of the thick seams, 2) determining rock and coal strengths to select mining methods, and 3) defining coal quality and stripping ratios for initial mining.

- Overburden removal and mining will be accomplished with a 4-cubic-yard mass excavator and two articulated trucks. One five-person crew is required for about 1 month to mine the 20,000 tons of coal required for 2 years of plant operation. In the event that the rock or coal are too hard for direct loading, blasting would be required at an added capital cost of $160,000 for a drill and an added operating cost of $0.50 per ton.

- Haulage from the mine to the Noir Hill stockpile will involve a staff of 20 working on a three-shift per day schedule during the months of January, February, and March every other year using four articulated trucks with pup trailers averaging 37.5 tons per load. Construction of the snow road using a D6 bulldozer and a 14-G grader will take 1 month and cost about $46,000 biennially.

- Transfer from the Noir Hill stockpile to the plant will be accomplished at a cost of $4.80 per ton using a Caterpillar 950 front-end loader and one articulated coal hauler with a pup trailer operating over an existing gravel road. Three round trips will be required 2 days per week. The 950 loader will also be used for shaping the coal pile to prevent spontaneous combustion of the low-rank coal.

Alternatives recommended for study in the Behre Dolbear report to reduce fuel cost at the power plant are as follows:

- Locate coal storage next to the power plant to achieve a net saving of about $3 per ton.

- Reduce or defer the $2 per ton coal royalty.

- Shop for used mining and haulage equipment to reduce capital investment.

- Seek commitments from other villages or industries for additional coal sales to spread capital and operating cost over larger coal tonnages.

- Evaluate possible savings from burning municipal solid waste in conjunction with coal.

- Look for coal or other energy deposits closer to McGrath.

- Promote industrial development in the McGrath area to better utilize plant, equipment, and staff in mining, haulage, heat and power generation, and distribution.

6.0 OUTSTANDING ISSUES AFFECTING PROJECT VIABILITY

The technical, environmental, and economic issues that still need to addressed at this time are summarized as follows.

6.1 Outstanding Technical Issues

Technical areas requiring further definition to assure the long-term operability of the coal-fired plant at McGrath include the following:

- Site-specific geotechnical data needed to refine the civil and structural design. These data would also assist in determining the requirements for electrical and district heat transmission and distribution.

- Selection of coal and limestone handling and feed systems to ensure plant availability during normal and adverse weather conditions and reduce labor requirements for operation and maintenance.

- Development of the load-following capability of the combustion/boiler/steam turbine train as required by the anticipated electrical and district heating load profiles.

- Definition of the automated control system and operations and maintenance shift structure for the power block.

- Establishment of the design approach for ash collection and handling methods and logistics for removal from site.

- Availability of local technical personnel for the operation of the power plant and district heating system. Hours of maintenance and costs for replacement parts must be addressed.

- Further development of the district heating design through canvassing the proposed area of service. This field work will verify the proposed pipe routing; review and catalog building construction for potential customers; and develop a better understanding of the needs for individual-house district heat conversion costs.

- Assessment of the combination of expected electrical generation load and the expected heat load. A simulation of plant operation should be performed to confirm the operability of the system (to supply both electricity and heat under all load conditions), as well as predict total plant fuel consumption and the system's seasonal energy utilization factor.

- Review of the steam/heat cycle to determine whether there is a more optimal configuration or arrangement of steam-related components. In an attempt to improve overall system performance, additional turbine manufacturers should be contacted to assess performance and efficiency gains.

- A more modular prefabricated design should be considered to reduce capital costs.

6.2 Outstanding Environmental Issues

The following environmental issues still need to be resolved:

- Because of the proximity of the proposed facility, noise and visual (fog, plume, etc.) effects should be evaluated relative to the community and school.

- Airborne coal dust impacts and necessary containment should be evaluated.

- Permitting and licensing. There are no known barriers, technical or environmental, that would limit the ability to obtain the required state or federal approvals and permits for the project when it proceeds to the permitting stage.

6.3 Outstanding Economic Issues

Economic issues requiring further definition to assure the long-term viability of a coal-fired plant at McGrath include the following:

- Assessment and refinement of operations and maintenance costs. A projection of the operation costs of the district heating system should be performed consistent with ML&P's cost-estimating practice.

- Refinement of the district heating capital and operating cost for servicing the McGrath community.

- Definition of the long-term benefits to the economic welfare of the community.

- Development of an economic incentive to ML&P for cofiring municipal solid waste.

- Use of reconditioned equipment to reduce capital cost. This is specific to McGrath and not necessarily characteristic of overall remote-system project design.

- Competitive bidding on major equipment purchases to ensure lowest costs.

- A tariff schedule for the heating service should be established and annual revenues calculated to determine the feasibility of district heating. Tariff setting should be accomplished in conjunction with electrical rate tariff work to assure an adequate rate of return and an equitable split between income streams from electric power and district heating.

- Evaluate reduction of delivered coal cost by reducing or deferring the $2 per ton coal royalty; locating the coal storage next to the power plant to achieve a net saving of about $3 per ton; shopping for used mining and haulage equipment to reduce capital investment; and seeking commitments from other villages or industries for additional coal sales to spread capital and operating cost over larger coal tonnages.

- System performance and cost sensitivity analyses should be performed to gather data that are subject to change as a function of the site location. The overall system design should be reviewed with cost reduction in mind. Specific design changes should be identified and evaluated to determine their impact on the COE.

7.0 CONCLUSIONS AND RECOMMENDATIONS

7.1 Status and Future Direction

The primary criterion for financial viability is that the new power system provide an efficient and environmentally acceptable means of generating heat and power from indigenous fuels in rural Alaska more cheaply than the current diesel oil systems. Other socioeconomic factors enter into the final determination, but they should not be used to de-emphasize the primary requirement for reducing the cost of energy. For a technology to be truly viable at McGrath, it should also meet the test of replicability—that is, it should be a marketable modular package. The currently available design study, which is the most thorough to date for Alaska, provides the benchmark for future planning.

While the purpose of this status report is not to determine financial feasibility, it should be recognized for the sake of future planning that the economics presented in the design study appear to be marginal and that further improvements are needed to achieve a financially viable replicable and marketable system. The design at present does not fully meet economic objectives for delivered fuel cost, cost of electricity, or capital costs that would be competitive with current diesel electric generation and oil-fired heating furnaces. These financial parameters need to be reevaluated on the basis of life cycle cost and in the context of a first-of-a kind system providing both electricity and district heating in rural Alaska.

The direction of the project from this point is to proceed to final feasibility determination. This determination will be made by ML&P, the Alaska Division of Energy and DOE, represented by the EERC. Taking into account the potential socioeconomic advantages to be derived from developing local coal deposits in Alaska, motivation is strong to develop and demonstrate the viability of small coal-fired plants in remote rural settings such as McGrath. The strategy taken under this feasibility determination will be to revisit the current design to determine whether any further efficiencies can be realized that will lower the cost of the overall system.

7.2 Action Items and Schedule

The actions required to expedite this project toward implementation are as follows:

- Week of June 10, 1996: Hold a meeting in Alaska to finalize contract documents on the next phase of the design and feasibility study. This meeting should be for the purpose of finalizing the follow-on activity, which includes funding from the State of Alaska Division of Energy and DOE. The DOE activities are coordinated by the Energy & Environmental Research Center.

- Week of September 23, 1996: Complete an agency review draft of the design and feasibility study. Hold a meeting in McGrath to review this draft study.

- Week of October 28, 1996: Complete final written report of the design and feasibility study. Disseminate to all interested parties.

- November, 1996: Deliver one or more presentations on the results of the design and feasibility study to interested audiences. Begin to seek construction funding if the project is feasible, or make recommendations for future actions if the project is not feasible.

8.0 REFERENCES

1. Gilbert/Commonwealth, Inc. (now Parsons Power Group Inc.). "Project Definition Study of a 500 kW_e Fluidized-Bed Facility for Electrical Generation in McGrath, Alaska," Project Definition Study Final Report for U.S. Department of Energy Contract No. DE-AC21-89MC25177; Jan. 1995.

2. Parsons Power Group, Inc. "Project Definition Study of a 600 kW_e Fluidized-Bed Facility for Electrical and District Heat Generation in McGrath, Alaska," Project Definition Study Final Report for U.S. Department of Energy Contract No. DE-AC21-94MC31166; Jan. 1996.

3. J.S. Strandberg Consulting Engineers, Inc. "An Interim Evaluation of a Proposed Coal Fired Thermal Power Station at McGrath, Alaska," Report No. 95-26; Oct. 19, 1995.

4. Behre Dolbear & Company, Inc. "Economics of Mining Coal at the Little Tonzona Prospect for Use as Fuel for a Power Plant at McGrath, Alaska," report prepared for Doyon, Limited; March 1966.

APPENDIX B

GLOBAL MARKET ASSESSMENT OF COALBED METHANE, FLUIDIZED-BED COMBUSTION, AND COAL-FIRED DIESEL TECHNOLOGIES IN REMOTE APPLICATIONS

TABLE OF CONTENTS

FIGURES

TABLES

EXECUTIVE SUMMARY

Background

Over the past five years, the Morgantown Energy Technology Center (METC) of the Department of Energy has been working with U.S. industry, Native Alaskans and Alaska state and local officials to demonstrate the viability of a variety of technologies to meet the energy, economic and environmental needs of the remote villages of Alaska. In 1995, METC contracted with the Energy and Environmental Research Center (EERC) to manage the program. EERC retained Energy Resources International, Inc. (ERI) to support them in developing and implementing a strategy to carry out the program and to conduct a broad, first order assessment of the international market potential of the technologies proposed for demonstration in Alaska. This report presents the results of the global market assessment.

The technologies proposed for demonstration in Alaska and, therefore, the technologies which are the focus of this study include: small scale (less than 10 MW) coal or mixed fueled fluidized-bed combustors, coalbed methane recovery (from active mining operations) linked to a gas-based generator of electricity (e.g., fuel cells, gas combustor, gas turbine). and coal-fired diesel generators. The Alaskan Initiative, which includes a brief description of the subject technologies, is provided in Attachment 1.

To carry out this assessment, the following steps were undertaken:

- The subject technologies were characterized (Section 1);
- The most important features of each technology, which could influence their market potential, were identified (Section 2);
- An assessment was conducted to determine those countries with the greatest market potential for each technology. The assessment considered factors such as the overall energy market size, private power developments/privatization, rural energy needs and the proximity of fuel (coal or coalbed methane) to the rural communities. This assessment was conducted for coalbed methane recovery from active mines (Section 3), and coal-fired fluidized-bed combustors and coal-fired diesels (Section 4); and
- Estimates of the market potential of each technology (by country) were compiled when sufficient reliable information was available. The technology and market hurdles that will have to be removed before their potential is realized were also summarized. This information is presented in Section 3 for coalbed methane recovery, and Section 4 for fluidized-bed combustors and coal-fired diesels.

This assessment is intended to provide a ballpark estimate of the market potential of the technologies. Site specific, case-by-case analysis of the technologies in individual countries (and communities) is necessary to determine the true market size for the technologies.

Findings

Large market potential was identified for each of the technologies analyzed. Due to differences with in-country market conditions and the availability/quality of power market information, a composite (quantitative) picture of the market for these technologies could not be prepared for inclusion in this report. Instead, only a qualitative assessment is possible.

The developing countries with the greatest near-term market potential for coal-bed methane recovery from active mines are: Russia, Ukraine, South Africa, China, Poland, and India. Based on existing mining operations in these countries, and assuming that 25-35% of the coalbed methane released from these mines is recoverable, then 181 to 459 billion cubic feet (BCF) per year could be available (in the near-term) for consumption in the identified markets. Greater recovery rates at existing mines and the inclusion of recovery at new mines expands the potential market considerably. A more detailed assessment is required, however, to quantify this opportunity. To realize the near-term (and longer-term) market potential of coalbed methane requires the removal of particular market barriers: capital cost of projects; cost of installing coalbed methane systems; lack of clear legal authority (and precedent) regarding ownership of the resource; and lack of understanding of the resource and its value, in-country.

The countries with the greatest market potential for small-scale fluidized bed combustors (FBC) and coal-fired diesels (CFD) are identified below by region:

Africa: Zimbabwe, Morocco
Asia: India, China, Pakistan, Indonesia, Vietnam, Philippines, and Thailand
Central/East Europe: Poland, Bulgaria
Middle East/Near East: Turkey
Central/South America: Peru, Columbia, Chile

Each of these countries were rated with "high" market potential for FBC and CFD technologies. The rationale for this rating includes:

- they are currently using coal for power generation, and thereby have the coal infrastructure in-place;
- they are projected to realize high growth rates in demand (> 6% per annum) and/or require investment in replacement capacity;
- they have a high percentage of rural population (>50%) and/or have isolated load centers due to topographical conditions;
- a small percentage of the rural population has access to the electric grid;
- the countries have policies to increase rural electrification and diversify their fuel sources (including reduced oil consumption by diesel generators); and
- they have private power development incentives and/or privatization programs, either in-place or proposed.

While the amount of new/replacement generating capacity in these countries range from 400 MW (Zimbabwe) to 400 GW (China), there remains a viable market for FBC and CFD technologies in remote applications within each of the identified countries for the aforementioned reasons. A more detailed assessment of the current power system and load demand in these remote areas is required before a quantitative estimate of the market potential for these technologies can be derived.

The major barriers to deployment of these technologies are: 1) competition with hydroelectric and natural gas technologies, which is prevalent in these countries due to resource availability; 2) capital availability, which is limited and generally requires external private power investors; and 3) lack of local information about (and benefits of) these technologies and their use in a micro-grid.

Recommendations

Significant market opportunities exist for each of the technologies being considered for demonstration in Alaska. To take advantage of these opportunities, the following are recommended:

(1) Proceed with the Alaskan Initiative as quickly as possible. Demonstration of the small scale fluidized-bed combustor and the coal-fired diesel are key to the utilization of these technologies in other parts of the World. This is less true for coalbed methane recovery which is already being carried out in most of the priority markets identified.

(2) Share the results of the Alaskan demonstrations with the appropriate representatives in the high potential market countries. Information on the technologies, their attributes and their costs should be shared to confirm their potential markets and to identify the most effective course of action to take to introduce the technologies into each country. As the demonstrations progress, information updates should be provided. The information dissemination should be undertaken with the involvement of the technology vendors and project developers and can take the form of seminars, workshops or one-on-one meetings with country representatives.

(3) The findings of this study should be shared with the Agency for International Development, the U.S./Asia Environmental Partnership, the Department of Energy, the Small Business Administration, the Trade Development Agency and other U.S. federal agencies that may have an interest and resources to help to introduce the technologies into the foreign markets. These agencies have the mandate to undertake programs and projects to eliminate poverty and pollution in the developing countries and/or to assist U.S. companies in the export of their goods and services. Use of the subject technologies could help to achieve those objectives. As a result, follow-on programs could be developed with them.

(4) The findings should also be shared with the United Nations Development Program, the World Bank and other multilateral organizations charged with economic development in the developing World. The objective of working with them is to identify funding sources for follow-on studies, conferences, workshops and seminars, training and education programs and pilot projects to introduce the technologies to the target countries.

1.0 TECHNOLOGY CHARACTERIZATION

1.1 Coalbed Methane

The recovery of methane from operating and undeveloped coal mines has been practiced for many years in many places throughout the World. Coalbed methane recovery is similar in nature to the recovery of natural gas and uses similar exploration, drilling and recovery technologies. However, in most cases, the quantity of coalbed methane resource at a given site is considerably smaller than typically required for an economic natural gas field development.

There are many attributes that coalbed methane recovery offers. These include:

- **Similarity to Natural Gas**. The methane that is produced is clean (or can be cleaned). Once removed from the ground, it can be handled, transported and used like natural gas (although its transport and use will depend upon its quality).

- **Multiple Uses**. Methane can be used to produce a wide variety of products including electricity, heat and chemicals.

- **Easy to Transport and Use**. Methane can be transported by pipeline and used in boilers, furnaces and other end-use devices without the need for highly trained personnel, and with very few operations and maintenance (O&M) staff.

- **Environmental**. Methane released to the atmosphere is a highly reactive greenhouse gas. However, if it is captured and utilized, its environmental effects are similar to those of natural gas – no sulfur dioxide, very low nitrogen oxides, non-detectable particulate matter emissions and less carbon dioxide than other fossil fuels.

- **Mine safety**. Coalbed methane poses a safety hazard (i.e., potential for explosions) for coal mining operations. Recovery of coalbed methane significantly reduces this hazard.

However, there are several hurdles to coalbed methane recovery and use. These include:

- **Cost competitiveness**. Significant costs are associated with exploration, production, gathering, upgrading, transporting and using coalbed methane. Unless significant quantities of methane are expected, and markets are willing and able to pay for the methane (or electricity or heat from the methane), the economics may not justify recovery.

- **Ownership**. Determining the rightful owner of the methane gas can be complicated. Surface land owners, coal mine owners, gas producers, mineral rights owners, governments and others may claim rights to the gas. In most countries, ownership issues have not been resolved.

- **Changing mind-sets**. The coal industry is not in the gas business. Effort must be made to show the coal industry the safety, economic and environmental advantages that could result from methane recovery and utilization.

1.2 Small-Scale Fluidized-Bed Combustion

Fluidized-bed combustion (FBC) is a well-proven technology for industrial and electric utility applications. Hundreds of FBCs, supplied by many equipment vendors, are in operation in the U.S. and other parts of the World. However, in Alaska, and potentially in many other remote locations in the World, very small – less than 10 MW (down to below 1 MW) – units are needed to meet local energy needs. Very little operational experience is available for FBC units of this size.

FBCs have many attributes that may make them very suitable for remote locations. These include:

- **Fuel flexibility**. FBCs have been successfully operated on a wide range of fuels and fuel combinations including all grades and ranks of coal, anthracite culm, wood, municipal solid waste, heavy oil and tires, among others. The technology is quite tolerant to variations in fuel quality, an important feature in remote locations where quality controls on fuel are likely to be lacking.

- **Configuration flexibility**. FBCs can be configured to cogenerate electricity and heat, significantly improving its thermal efficiency and in many cases reducing the cost of supplied energy.

- **Ease of operation and maintenance**. FBCs are relatively easy to operate and maintain. There are no special fuel handling requirements for FBCs. Because of its low combustion temperatures, solids deposition and boiler tube erosion/corrosion are minimized. The waste produced in an FBC boiler is dry, inert and relatively easy to handle.

- **Environmental**. FBCs can produce energy efficiently and with minimal environmental emissions. Because of their low operating temperatures, FBCs produce low levels of nitrogen oxides (NO_x). If lime or limestone is added to the combustor, sulfur dioxide (SO_2) emissions can be reduced by 90% or more. The dry wastes from the system are inert and can be used for road and building materials, or possibly as fertilizer.

However, there are several concerns associated with the use of small FBCs for use in remote applications. These include:

- **High capital cost**. FBCs can carry higher capital costs than diesel generators or current natural gas based systems (gas turbines or combined cycle). In many cases, even with higher capital costs, FBCs can produce electricity at competitive rates, because of low fuel costs.

- **Operation and maintenance**. Although FBCs can operate fairly "hands free", they requires trained operators to assure that 1) the fuel is properly fed, 2) the unit is operated and maintained appropriately, and 3) the waste is properly handled. FBCs may require operators with greater training than natural gas or diesel-fueled systems.

- **Waste production**. A considerable quantity of solid waste is produced in FBCs, especially if lime or limestone are added for SO_2 control. Although the waste is benign and possibly of commercial value, periodically it must be removed from the boiler site and transported to a disposal or end-use site.

1.3 Coal-fired Diesels

Coal-fired diesel engines have been under development for approximately 15 years. Several technology configurations have been explored to displace petroleum with coal for transportation applications (e.g., coal-fired locomotives), cogeneration systems and electric power systems. None of these systems are currently offered commercially, although one has been selected under the Department of Energy's Clean Coal Technology Program to demonstrate the engine for cogeneration applications.

Coal-fired diesels (CFD) have several attributes that may make them attractive for remote power applications. These include:

- **Fuel Cost**. CFDs use low cost coal rather than high-cost diesel fuel.

- **Environmental**. CFDs have the potential to reduce emissions of particulate matter and other harmful air pollutants associated with the combustion of diesel fuel.

- **Fuel Availability**. CFDs have the ability to use abundant coal resources in lieu of more scarce diesel fuel.

- **Operation and Maintenance**. As currently conceived, coal-fired diesels will be as easy to operate and maintain as diesel oil generators.

However, several barriers may impede the ability of coal-fired diesels to meet its market potential. These include:

- **Current stage of development**. Before coal-fired diesels will be considered in the commercial market, adequate demonstration of their reliability and performance is necessary.

- **Fuel Preparation**. The ability to produce ultra-clean coal water slurries at reasonable prices to use as a fuel for the system is uncertain, particularly in remote areas.

- **Fuel Cost**. The cost-competitiveness of coal-fired diesels compared with natural gas and diesel fuel depends on relative economics in the area of use.

2.0 FACTORS INFLUENCING THE MARKET POTENTIAL OF REMOTE POWER TECHNOLOGIES

Summarized below are some factors that are likely to influence the market potential for the three technologies being examined for remote applications in developing countries.

2.1 Coalbed Methane

The primary factors that will influence the market potential for coalbed methane are:

- The number of small remote communities that are isolated from central station electric supplies, natural gas or other potentially lower cost energy options.
- The size of end-use markets located close to the coalbed methane or the proximity of natural gas pipelines.
- Resolution of gas ownership issues.
- The economic viability of exploring, drilling, recovering, gathering, cleaning, transporting and utilizing the coalbed methane.

2.2 Small Scale Fluidized Bed Combustors

Several factors will influence the market potential for small FBCs. These include:

- The number of small remote communities that are isolated from central station electric supplies, natural gas or other potentially lower cost energy options.
- The proximity of low-cost coal to the FBC site. The further the FBC site is from the coal, the higher the costs. Low fuel cost is the principle economic advantage of FBCs.
- The willingness of technology suppliers to offer commercial guarantees for the FBCs.

2.3 Coal-fired Diesels

The primary factors that will influence the market potential for coal-fired diesels are:

- The number of small, remote communities that are isolated from central station electric supplies, natural gas or other potentially lower-cost energy options.
- The extent to which diesel-fueled generators are currently used to meet electricity and heat needs.
- The proximity to coals that can be economically cleaned to very low ash levels (i.e., 1% or less).
- The availability of water for producing coal/water mixtures as the feedstock to the coal-fired diesel generators.

- The willingness of technology suppliers to offer commercial guarantees for the coal-fired diesel systems.

In Sections 3 and 4, these factors are examined to the extent that data are readily available and project resources permit.

3.0 COALBED METHANE RECOVERY AND USE

3.1 Global Prospects

It is estimated that between 4,000 and 9,000 trillion cubic feet (TCF) of coalbed methane (CBM) resources exist throughout the World (USEPA, 1993). These resources consist of methane found in both unmined coal and coal that has been or is being mined. To put this figure in perspective, the U.S. – one of the major consumers of natural gas – consumes approximately 18 TCF of natural gas annually. If the full potential of worldwide coalbed methane is recognized, it could supply current U.S. natural gas demand for over 300 years.

The countries with the largest coalbed methane reserves include:

Country	Estimated Reserves (TCF)
Russia	600 - 4,000
China	1,000 - 1,200
United States	400
Ukraine	60
Poland	20-45
Kazakhstan	40
India	30
South Africa	30

During mining, considerable quantities of coalbed methane are released to the atmosphere. It is estimated that 1-2 TCF of coalbed methane is released to the atmosphere worldwide. This has become a major environmental issue since methane is a very reactive greenhouse gas, 21 times more effective at trapping heat in the atmosphere as carbon dioxide (CO_2). As a result, attention has been placed on minimizing these releases through capture and utilization.

The potential exists to recover some of the coalbed methane released to the atmosphere. However, it is unlikely that, with current technology and at current energy prices, all of these emissions are recoverable (Coal Industry Advisory Board, 1993). In addition, it is possible to recover methane that is located in unmined coal seams. However, because of lack of data, the latter source of coalbed methane was not fully analyzed in this report.

It is estimated that 25 - 45% of these reserves are recoverable. In 1990, some of the World's leading coal producers recovered 20% , but only utilized 7%, of the coalbed methane released at that time. In many countries, even less recovery and utilization has taken place. Table 3-1 summarizes CBM emissions by major emitting country, the amount of coalbed methane that was recovered in those countries and the potential recovery possible in the near term (USEPA, 1993).

3.2 Potential in Remote Regions

The market potential for coalbed methane to meet the energy needs of remote regions throughout the World is dependent on 1) the proximity of the methane to the remote communities, 2) access of the remote communities to other, possibly lower cost energy options, and 3) the economic viability of exploring, drilling, recovering, cleaning, gathering, transporting and utilizing the fuel versus other options. Each of these factors is discussed in the following paragraphs.

TABLE 3-1

CBM RECOVERY POTENTIAL IN COUNTRIES WITH LARGEST COALBED METHANE RESOURCES

Country	1990 Underground[1] Mine Coal Prod (10^6 ton)	Mine depth[2] (Meters)			CBM Resources (TCF)	CBM Emissions (BCF)	CBM recovered[3] (BCF)	Utilized (BCF)	Additional Recovery Possible [4] (BCF/Year)
		Max.	Min.	Avg.					
China	967	1000	--	300	1,050-1,225	475-830	14.5	9.0	115-285
Former Soviet Union	361	654	135	402	1,488-2,765	240-300	41.5	9.5	40-90
Poland	148	--	--	627	14-46	30-75	9.5	2.0	5-23
India	64	400	50	212	49	20	0	--	7-9
S. Africa	124	160	69	85	137	40-115	0	--	14-52

[1]Coal Industry Advisory Board, 1994, *Global Methane and the Coal Industry,* International Energy Agency.

[2]Kuchgessner, D.G., S.D. Piccot, J.D. Winkler, 1994, *Estimate of Global Methane Emissions from Coal Mines,* U.S. Environmental Protection Agency.

[3] U.S. Environmental Protection Agency, 1993, *Options of Reducing Methane Emissions Internationally, Volume II: International Opportunities for Reducing Methane Emission,* Report to Congress, (October).

[4] Assumes 25-35% recovery in China/Poland; 20-25% in CIS; 35-45% in India/S. Africa.

Several of the countries with the largest coalbed methane reserves are also among the most populated in the World. China and India rank 1 and 2 in population, respectively. Russia has the 6th largest population in the World. Table 3-2 summarizes the populations of each of the countries studied and their World rank.

In most of these countries, a considerable percentage of the population reside in rural areas, isolated from electricity. Table 3-2 provides information on the percentage of the population for each country that is located in rural areas. As can be seen, China and India have rural populations approaching 80% of their total population. The countries of the Former Soviet Union average 36% rural. In South Africa and Poland 40% of the population is located in rural areas.

In addition, many of the residents of these countries currently do not use electricity, or do not have access to it. Table 3-2 provides information on the electrification ratio in those countries where data exists. The electrification ratio – the percentage of the population having no access to electricity – is another indicator of remoteness. Those without access to electricity are prime markets for on-site electricity produced from coalbed methane.

3.3 Country Assessments

3.3.1 Russia

3.3.1.1 *Population and Land Use*

Russia, with a population of 149 million, is the most populated of the Former Soviet Union (FSU) States, and the sixth most populated country in the World. Approximately 25% of its population is rural. Thirteen cities in Russia have a population in excess of one million.

Most of the population of Russia is concentrated in the so-called fertile triangle (European Russia), with its base along the western border between the Baltic and Black Seas and which tapers eastward across the southern Urals into southwestern Siberia (Figure 3-1). In this region, the population density averages 65 persons per square mile, although it is much higher in urbanized areas such as the Moscow Oblast. Figure 3-2 shows the population densities throughout the Former Soviet Union.

More than one-third of the country's territory has fewer than 2.6 inhabitants per square mile. This region comprises northern European Russia and huge areas of Siberia.

Russia has the largest land area of any country in the World. The country has six major land regions. These are briefly described below and are shown in Figure 3-1.

(1) The European Plain. This is home to approximately three quarters of Russia's inhabitants. Most of the Nation's industries and most of its richest soils are located in this region. The Ukraine is located in this region.

(2) The Ural Mountains form a boundary between the European Plain and Siberia. The middle section is the most heavily populated section of the region.

(3) The Aral-Caspian Lowland, has broad sandy deserts and low grassy plateaus and is sparsely populated; it includes most of Kazakhstan.

TABLE 3-2

POPULATION CHARACTERISTICS IN COUNTRIES WITH LARGEST COALBED METHANE RESOURCES

Country	1993 Population [1] (10^6)	Population Rank[1]	Population Density [2] (per square mile)	% of Population In Rural Areas [3]	Electricity Consumption per Capita (1992) (kWh) [4,5]	Electrification ratio (% with access to electricity)
China	1,205	1	319	79	630	66 [2]
India	897	2	275	77	340	55 [2]
Kazakhstan	17	Top 75	Unknown	40	4,739	80-95 [7]
Poland	39	Top 40	314	40	3,570	95 [7]
Russia	149	6	23	25	6,782	95 [7]
South Africa	41	Top 40	74	40	4,100	35 [6]
Ukraine	52	Top 25	Unknown	33	5,410	Unknown

[1] Energy Information Administration, 1995, *International Energy Annual 1993*, U.S. Department of Energy, DOE/EIA-0219 (93) (May).
[2] World Bank, 1994, *Power Sector Statistics for Developing Countries, 1987-1991.*
[3] World Bank, Inc., 1986, *The World Bank Atlas.*
[4] World Book, Inc., *The World Book Encyclopedia*, 1988 Edition.
[5] In contrast, US per capita electricity consumption is 12,690 kWh.
[6] Surridge & Grabbelaar, 1994, *Energy Republic of South Africa: The Gas Connection*, (September).
[7] Estimates

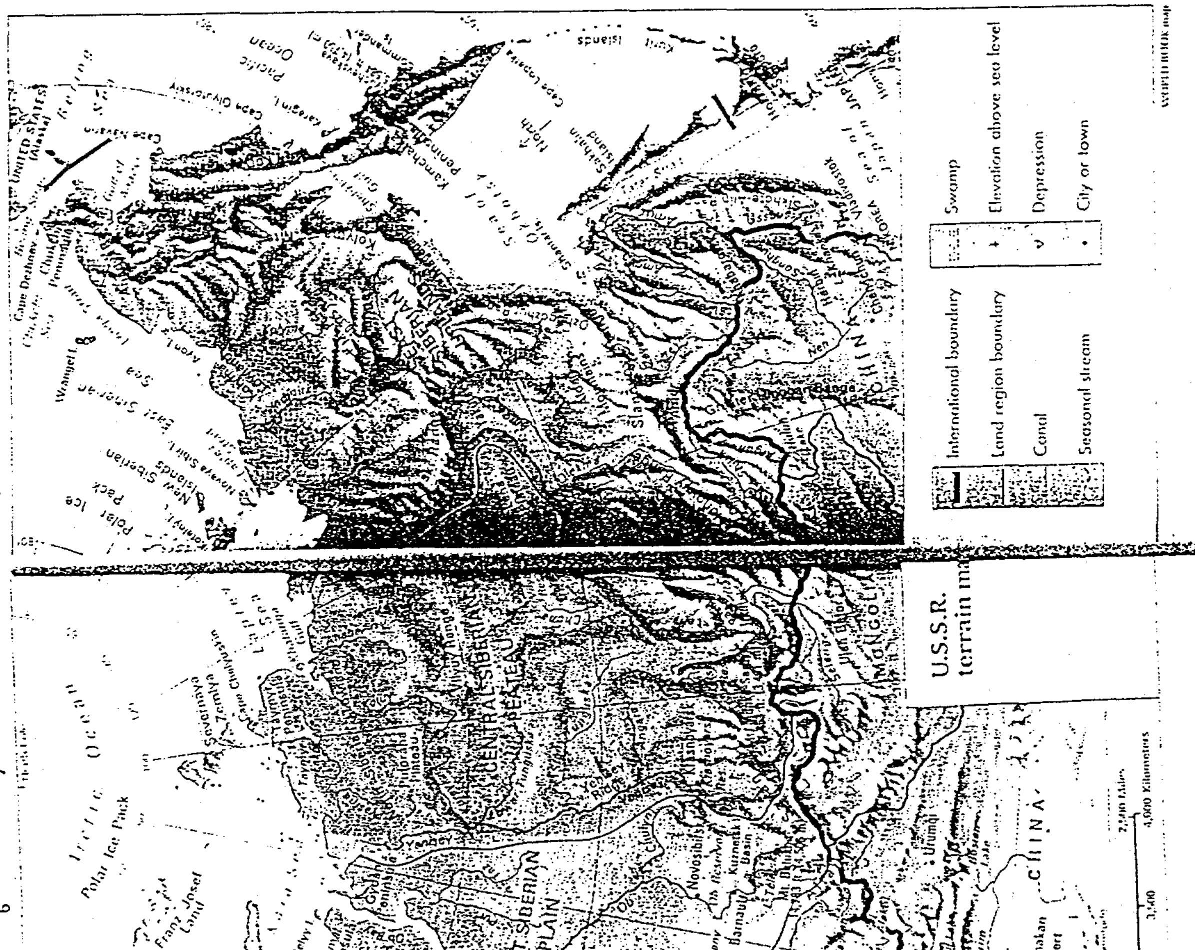
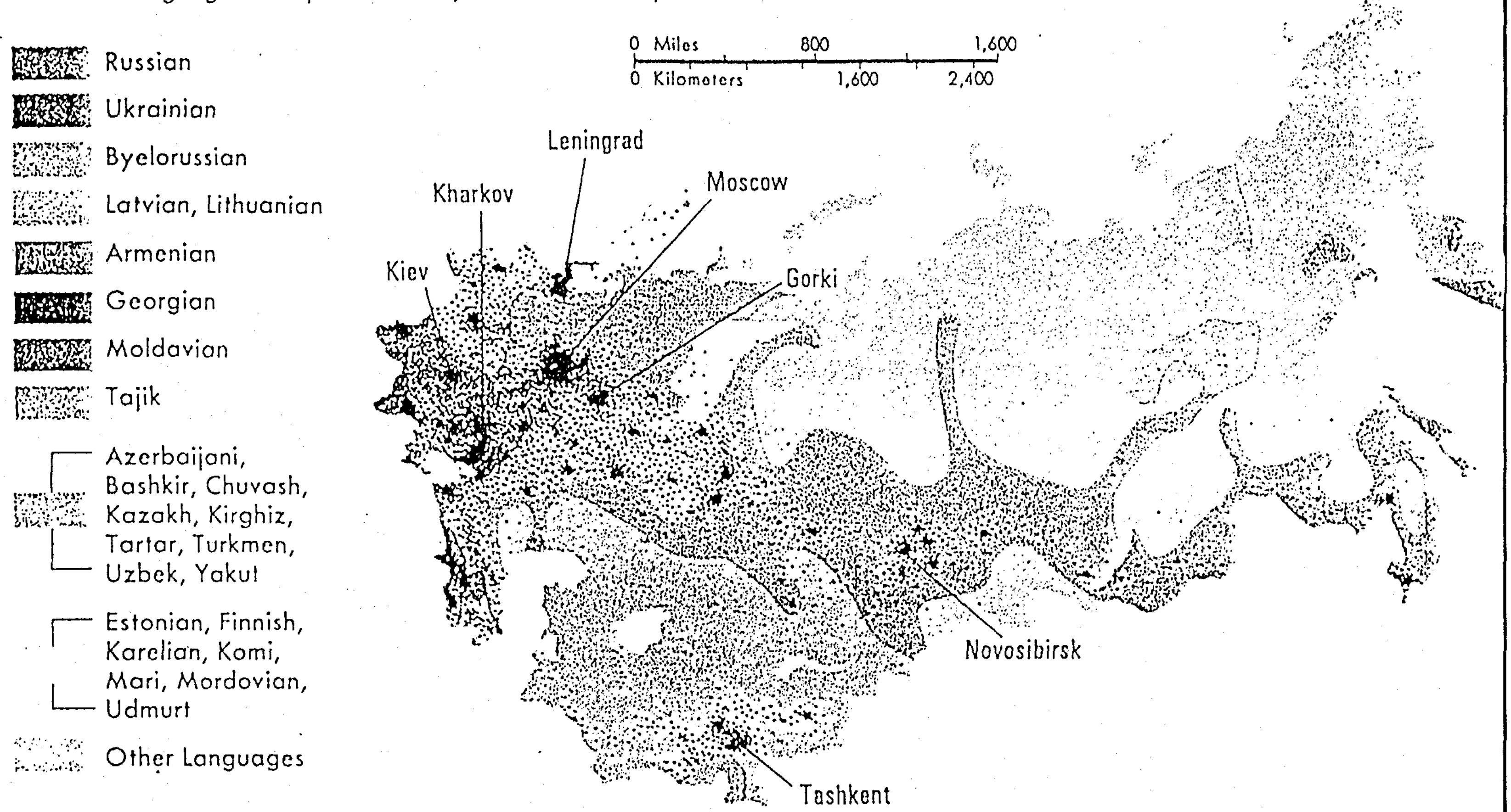


FIGURE 3-1. Map of Russia

FIGURE 3-2. Population Density of Russia

This map shows where the Soviet people live. Each dot represents about 65,000 people. The colors on the map show where the major languages are spoken. The regions in which these languages are spoken closely resemble the republics of the U.S.S.R.



(4) The Western Siberian Plain lies north of the Altai Mountains and is the largest level region of the World. This also is a sparsely populated region.

(5) The Central Siberian Plateau, a very sparsely populated region, where tremendous coal reserves lie.

(6) The Eastern Siberian Uplands are mainly a wilderness of mountains and plateaus. This region is rich in oil and gas resources.

3.3.1.2 Energy Resources

Russia is one of the richest countries in the World in terms of energy. Coal, natural gas and other energy resources are prevalent throughout Russia. In 1993, natural gas reserves in Russia were estimated to be 1,748 TCF.

In 1994, Russia produced 18.9 TCF of natural gas, 307 million tons of coal, and 6 million barrels of oil. It consumed (in 1992) 14.7 TCF of gas, 309 million tons of coal, and 3.2 million barrels of oil. Its electric generating capacity is estimated to be 213 GW.

Natural gas production and consumption in Russia are the largest in the World. Ninety percent of the natural gas production in Russia is currently taking place in Western Siberia (USDOE, 1994a). As production in existing fields declines, exploration and development is focusing in the Yamal Peninsula in the far northern part of the West Siberian Plain. Most of the future natural gas exploration and production is expected to take place in the far eastern reaches of Siberia.

Gazprom, the state-owned operator of Russia's 100 largest gas fields, administers 86,000 miles of gas pipelines, mainly located within Russia. Although initially intended for export to Europe, it is anticipated that much of the gas produced in Russia will be used domestically (because of difficulties in building pipelines).

Russia is also a major producer and consumer of coal. In 1993, it produced 307 million tons of coal and consumed approximately 309 million tons (USDOE, 1995). Approximately 220 million tons of hard coal were consumed in Russia in 1993. Figure 3-3 shows the locations of the major hard coal basins in Russia.

The largest coal basin in Russia is the Kuznetsk Basin in the Western Siberian Plain region. Approximately 53 million tons of coal were produced from this basin in 1994 (USEPA, 1995). It contains an estimated 637 billion tons of coal and produces high quality bituminous coal, mostly from underground mines. It has high potential for coalbed methane production. Other regions rich in hard coal include:

- the vast Tunguska Basin in the Central Siberian Plateau;
- the Taymyr Basin in the northern section of the Central Siberian Plateau
- the Pechora Basin in the far northeastern region of the European Plain, and
- potentially coal basins in Siberia.

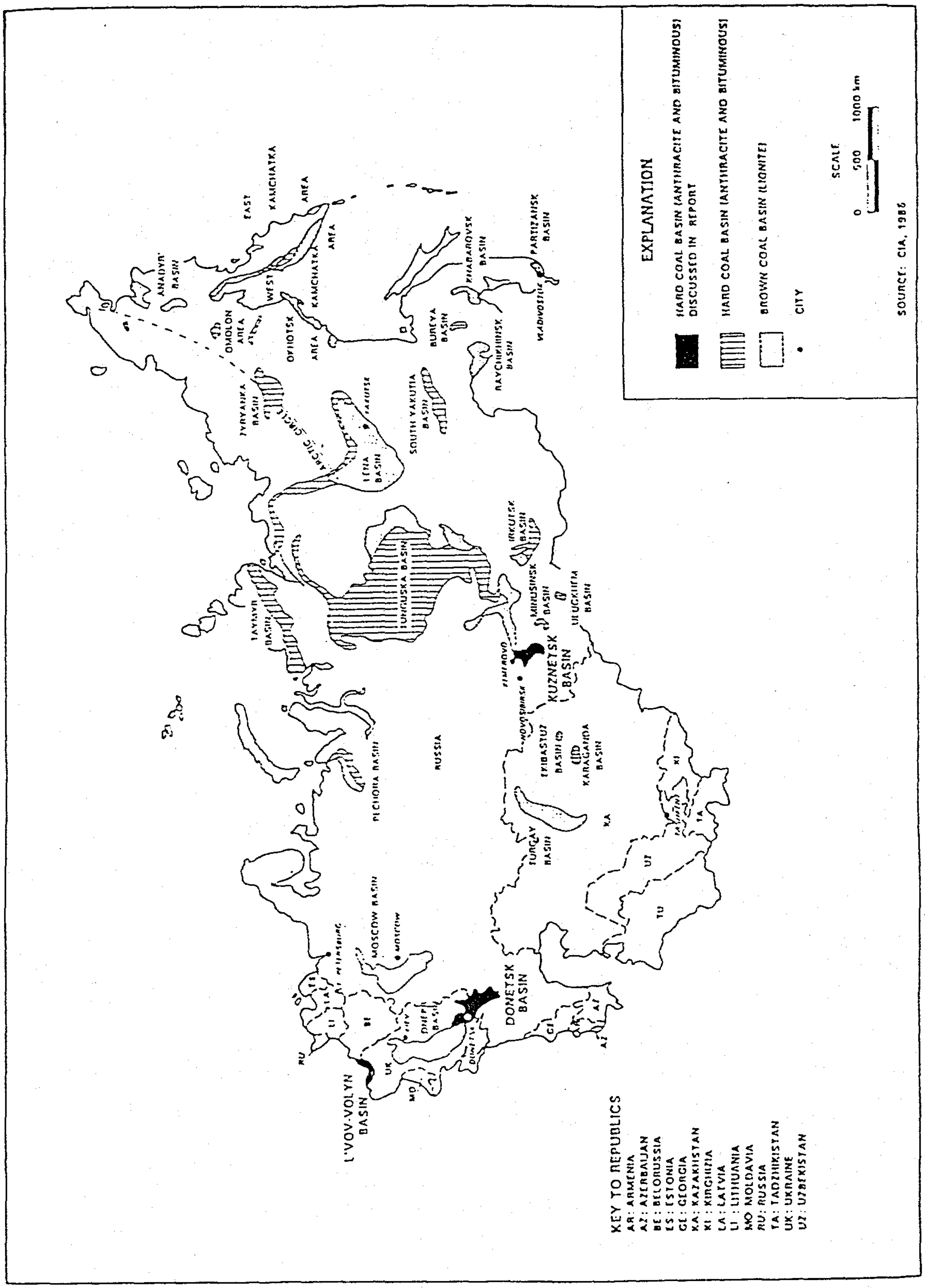


FIGURE 3-3. Major Coal Basins of the Former Soviet Union

3.3.1.3 Coalbed Methane Recovery Potential

The coalbed methane resources in Russia are estimated to be between 1,488 and 2,765 TCF, the largest in the World (USEPA, 1995). It is estimated that the coalbed methane potential of the Kuznetsk Basin alone is 7-12 TCF per year. Parts of the region are industrialized, creating opportunities for near-by markets to utilize captured coalbed methane. The region consumes large quantities of imported (to the region) natural gas (estimated to be 5 billion cubic feet per year), only one-third of its demand. Although precise gas pipeline maps were not available for this study, it appears as though gas pipelines run near the Kuznetsk Basin bringing gas from Western Siberia to Novosibirsk, to the northwest of the Basin.

The Pechora Basin, located in northern Russia, also has significant methane potential because large quantities of hard coal are mined there. However, since most of the Basin is above the Arctic Circle, the climate conditions may be so harsh that recovering the methane will not likely be cost-effective.

The vast Tunguska Basin also appears to have great potential for coalbed methane recovery, although no information could be found that characterizes the resource. However, since most of the coal produced in this region is from underground hard coal mines, large quantities of coalbed methane are likely. Since this Basin is also a major gas producing region, although it is isolated from significant population centers, limited pipeline capacity may be close enough to the coalbed methane to consider transporting it to markets outside of the region.

Other hard coal deposits are scattered throughout the Pechora and Taymyh Basins in north central Russia and several other Basins in eastern Russia. These too have the potential for coalbed methane.

3.3.1.4 Potential Applications for Coalbed Methane In Russia

Several market opportunities exist for coalbed methane in Russia. These include:

- Clean and efficient feedstock for boilers used to provide heat for the coal mines. Currently, large quantities of unwashed coal are being used in the Kuznetsk Coal Basin for such purposes in uncontrolled boilers (USEPA, 1995). A typical Kuzbass mine may consume 50,000 to 700,000 tons of coal per year in its boilers. More than 40% of the industrial coal consumed in this region is for this purpose. Diesel fuel is used to provide heat and electricity to those mines not using coal. Although no information is available for the other coal basins, it is expected that similar opportunities exist in other coal mines as well.

- Fuel for furnaces used in the metallurgical industry. Currently 69% of this need is being satisfied by natural gas and 25% by wood. Coalbed methane may offer a lower cost option to natural gas and a more environmentally acceptable option than wood. Kuzbass coal mines are located in close proximity to large iron and steel complexes in the region. Other regions of Russia may afford similar opportunities.

- Fuel for power generation at mine facilities. Currently, most mines in the Kuzbass purchase electricity from the power grid. Coalbed methane, used in simple or combined cycle mode, may offer a more economic and environmentally acceptable option to the use of electricity produced from coal in central power stations. Similar opportunities are likely in other regions of Russia as well.

3.3.2 Ukraine

3.3.2.1 Population and Land Use

The Ukraine, with a population of approximately 52 million, is among the 25 most populated countries in the World. Approximately one-third of its population is rural. The population density is moderate; on average, approximately 50 to 100 people inhabit each square mile (Nystrom Desk Atlas, 1994). Its most populated cities include:

- Kharkiv (1.6 million)
- Dnipropetrov'k (1.2 million)
- Donets'k (1.1 million)
- Odesa (1.1 million)
- L'viv (800,000)

Ukraine is a vast plain with very rich soil. Most of the country is used for agricultural purposes with the exception of the large cities and southern Ukraine which contain a variety of manufacturing facilities.

3.3.2.2 Energy Resources

Natural gas dominates the fuel mix in Ukraine. In 1992, gas represented 42% (4 TCF) of the energy consumed there. Coal (29%), nuclear (9%), and oil (19%) make up the rest of the energy consumed by the Ukraine in 1992.

Ukraine is also a major producer of natural gas, although it must import large quantities from Russia. In 1992, it produced 735 BCF of gas. Coal consumption in Ukraine in 1992 was 130 million tons; it produced 127 million tons.

Ukraine has an abundance of coal primarily found in two basins – the Donetsk and L'Lov-Volyn Basins (see Figure 3-3). It is estimated that the reserves in the Donetsk Basin are over 140 billion tons; those of the L'Lov-Volyn Basin are estimated to be just over 2 billion tons. Both Basins produce hard coal (anthracite and bituminous) from deep mines (USEPA, 1995).

Hard coal produced from the Ukraine portion of the Donetsk Basin (coal is also produced from this Basin by Russia) was nearly 130 million tons in 1991. This represents approximately 93% of the total hard coal production in Ukraine (USEPA, 1995).

3.3.2.3 Coalbed Methane Recovery Potential

The coalbed methane resources in the Ukraine are estimated to be 60 TCF. Almost 160 BCF of coalbed methane was released in 1991; most of this methane (nearly 120 BCF) was liberated from coal mining operations in the Donetsk Basin. Of the 160 BCF liberated, only 28 BCF (17%) was captured and 6 BCF (4%) was used (exclusively in boilers at the mines). The Donetsk Basin region is heavily industrialized. Therefore, many opportunities exist for the use of captured coalbed methane in nearby operations.

The L'Vov-Volyn Basin, located in western Ukraine, is the southeastern extension of the Lubin Coal Basin in Poland. The total coal reserves of the Basin are estimated to be 2.1 billion tons; in 1991, coal production was 9.5 million tons. It is estimated that 5.3 BCF of methane were released from mines in the L'Vov-Volyn Basin during 1991. Only 4% was captured, none of the methane was utilized.

It is estimated that if 35-45% of the coalbed methane released to the atmosphere in Ukraine is captured and utilized, an additional 14 to 52 BCF of methane could be recovered. Additional recovery from unmined reserves is also possible.

3.3.2.4 Potential Applications for Coalbed Methane in the Ukraine

As in Russia, market opportunities to use captured coalbed methane include the displacement of coal in industrial boilers and powerplants at coal mines, to produce heat and electricity needed at the mines. In addition, because Donetsk is located in a heavily industrialized region, methane from its mines can be used in machine factories, petrochemical plants, and metallurgical factories.

Because Donetsk is heavily industrialized, it has access to natural gas delivered by an extensive network of pipelines (Figure 3-4). As a result, it may be possible to use captured coalbed methane for many other applications by transporting it to end users by pipeline. However, as is discussed later in this report, doing so may be cost prohibitive.

Since the L'Vov-Volyn Basin is located within an agricultural region, methane captured from coal mining there will, most likely, be most cost-effectively utilized for meeting energy needs at the mines.

3.3.2.5 Barriers to the Recovery and Use of Coalbed Methane in Russia and Ukraine

Although coalbed methane is readily available in Russia and Ukraine – and has large market potential – its recovery faces several serious hurdles. These include:

- the unstable Russian legal and financial environment will make it difficult to finance such projects.

- high taxes and other costs of doing business in Russia may be prohibitively expensive.

In addition, piping coalbed methane through the extensive network of natural gas pipelines may be cost prohibitive. Pipeline quality gas must be more than 95% methane. However, coalbed methane recovered in Russia and the Ukraine typically has methane concentrations ranging from 30 to 50 percent (USEPA, 1995). Therefore, to transport the gas in pipelines, it must be enriched. In the U.S., enriching coalbed methane from 70 - 80% methane to pipeline quality is expensive, costing in the range of \$.01 - \$.09/cubic meter. Enriching the much lower concentrated Russian and Ukrainian gas is expected to be considerably more expensive.

3.3.3 South Africa

3.3.3.1 Population and Land Use

South Africa has a population of approximately 35 million. Approximately 60% of the people in South Africa live in urban areas, even though only three cities in the country have populations in excess of 500,000 (i.e., Cape Town, Johannesburg and Durban). Twenty-five percent of the population lives within a 43 mile radius of Johannesburg (World Book, 1988).

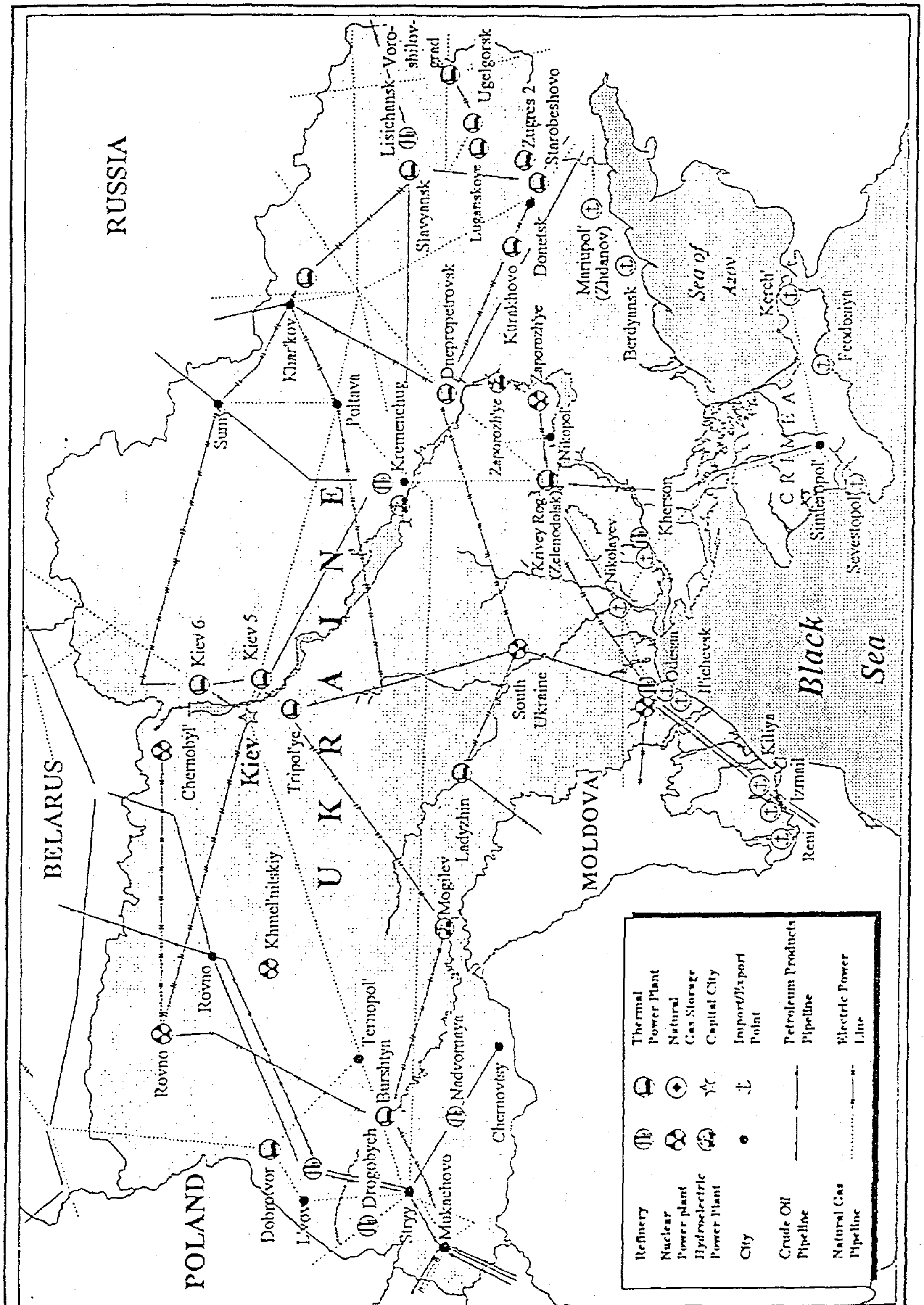


FIGURE 3-4. Transmission Network and Power Plants in the Ukraine

Although South Africa contains only 6% of the African continent's population and 4% of the continent's land area, it produces 40% of Africa's manufactured goods, half of its minerals, and half of the continent's electricity (World Book, 1988).

South Africa lands are used for a variety of applications (Figure 3-5). The Plateau, the largest land area, is the chief industrial and business area in South Africa. Middleveld in the Northwest, is sparsely populated ranch lands. The Coastal Strip is mainly agricultural with the exception of the land in the immediate proximity of Durban, which is an industrial center.

3.3.3.2 Energy Resources

South Africa is largely dependent upon coal as its primary energy source. In 1992, coal provided 82% of the primary energy in South Africa, followed by crude oil and biomass (e.g., wood) at 9% and 6%, respectively (Surridge &Grabbelaar, 1994). Biomass is mainly used in the rural sector for domestic heating and cooking.

In 1992, South African coal sales totalled 176 million tons. Twenty eight percent of the coal produced in South Africa was exported, 39% was used for electricity production, 16% for conversion to liquid fuels, 10% for commerce and industry and the remainder for metallurgy, and mining (Surridge & Grabbelaar, 1994).

The gas consumed in South Africa for commerce, industry and households is derived from coal. There are three main sources of natural gas available to South Africa:

- The Pande gas field, an offshore field with estimated recoverable reserves of 1.75 to 2.8 TCF. Use of this gas would require the construction of a 900 km pipeline.

- The Kudu gas field offshore Namibia, with estimated reserves of 3 to 8 TCF. Use of this gas would require development of the resource and construction of a 600 km pipeline.

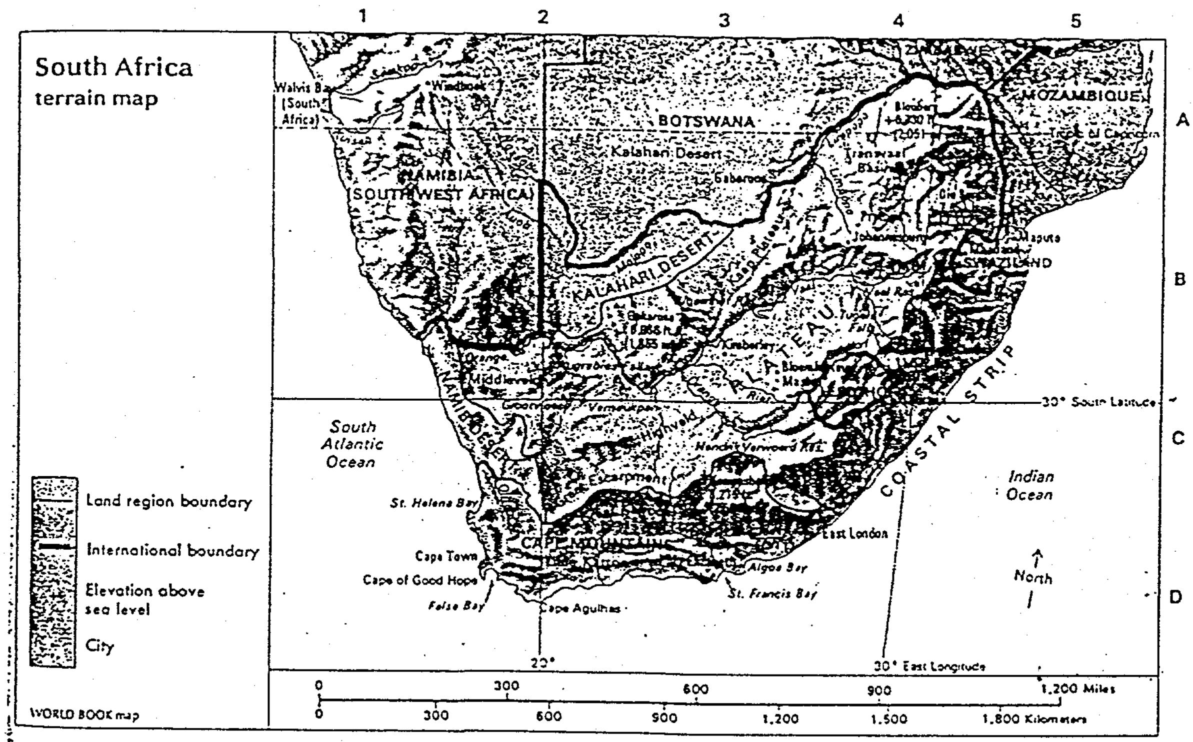
- Production from the natural gas field in South Africa, Mossgas. It is located 93 km from the mainland and has reserves estimated to be 700 BCF.

In 1989, South Africa produced over 160,000 GWh of electricity from its 37 GW of capacity. Approximately 92% of the generation was supplied by coal (Surridge & Grabbelaar, 1994). Among the 40 million inhabitants in South Africa, only 35% are electrified. The remainder of those without electricity and who do have access to electricity use wood and coal, primarily for cooking.

3.3.3.3 Coalbed Methane Recovery Opportunities

South Africa has demonstrated coal reserves of over 120 billion tons (Industrial & Petrochemical Consultants, 1991). Figure 3-6 shows the locations of the major coal fields in South Africa. The most important coal region is the Karoo Basin, which has demonstrated reserves of approximately 60 billion tons.

It is estimated that South Africa has up to 3 TCF of coalbed methane potential; based on current calculations 140 BCF/year of methane is emitted from coal mines, none of which is collected.



Physical features

Feature	Map key	
Algoa Bay	D	3
Augrabies Falls	B	2
Bloemhof Reservoir	B	3
Blouberg (mountain)	A	4
Caledon River	B	4
Cape Agulhas	D	2
Cape Mountains	D	2
Cape of Good Hope	D	2
Champagne Castle (mountain)	C	4
Coastal Strip	C	4
Die Berg (mountain)	B	4
Drakensberg (mountains)	C	4
False Bay	D	2
Gakarosa (mountain)	B	3
Great Escarpment	C	2
Great Karroo (plateau)	C	2
Great Fish River	D	3
Great Kei River	C	4
Groot River	D	3
Grootvloer (salt flat)	C	2
Hendrik Verwoerd Reservoir	C	3
Highveld (plateau)	C	3
Indian Ocean	C	5
Kaap Plateau	B	3
Kalahari Desert	B	2
Kompasberg (mountain)	C	3
Limpopo River	A	4
Little Karroo (plateau)	D	2
Middleveld (plateau)	C	2
Molopo River	B	3
Namib Desert	C	2
Olifants River	C	2
Orange River	C	3
Plateau	C	3
Pongola River	B	4
Rand, see Witwatersrand		
Riet River	C	3
St. Francis Bay	D	3
St. Helena Bay	C	3
South Atlantic Ocean	C	1
Transvaal Basin	A	4
Tugela Falls	B	4
Vaal River	B	3
Vaal Reservoir	B	4
Verneukpan (salt flat)	C	2
Witwatersrand (ridge)	B	4

FIGURE 3-5. South Africa: Geographic Regions

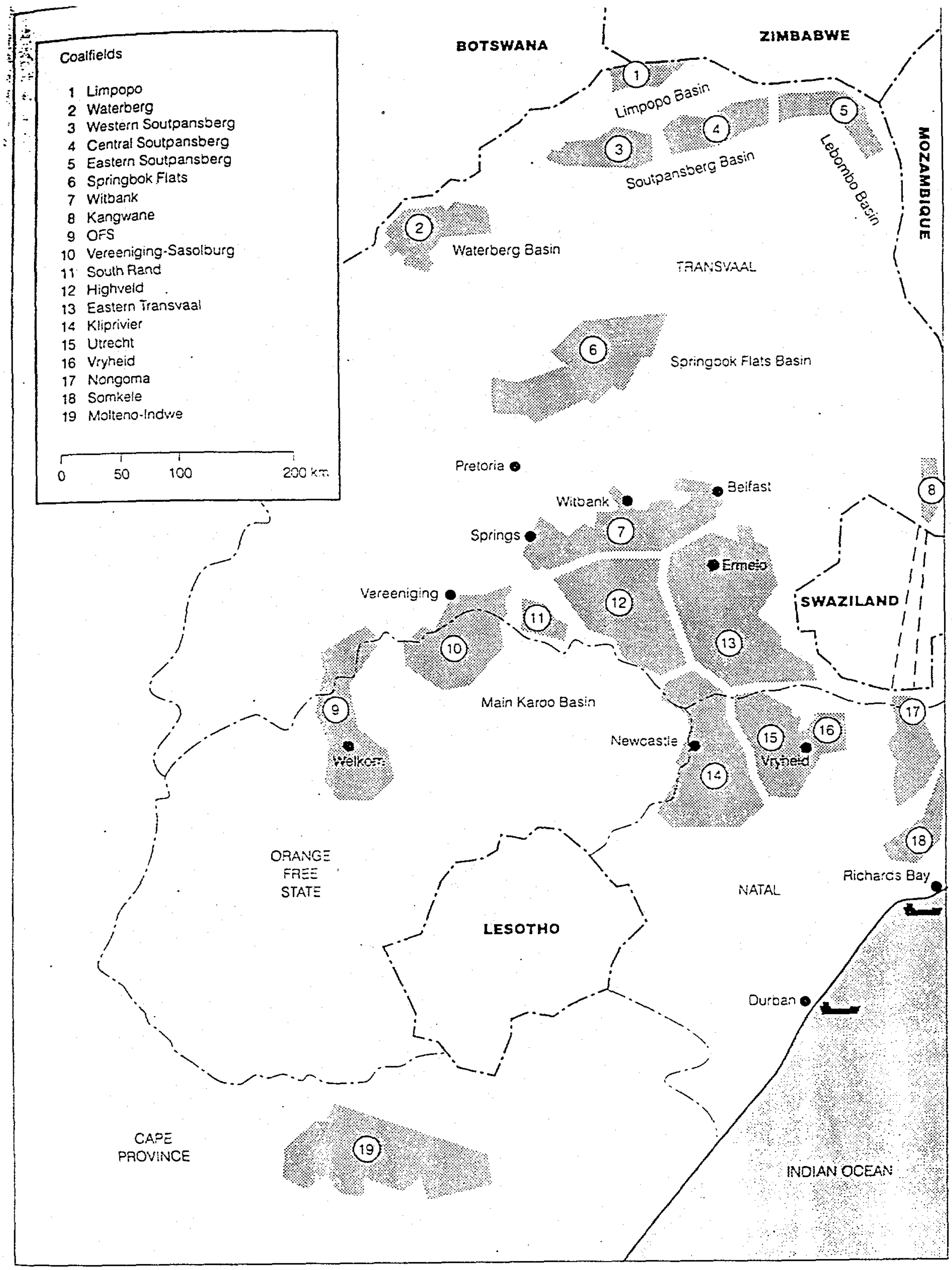


FIGURE 3-6. South Africa: Principal Coal Fields

Based upon the key factors for determining the coalbed methane potential from coal deposits – coal seam depth (deeper than 150 meters is desirable), high vitranite values, low volatile matter content, and high rank – the following can be concluded:

- Karoo Basin has high potential for coal fields found at depths below 150 meters;
- Orange Fee State Basin is low in potential because it is low in rank;
- Natal has high potential for those coal fields at depths greater than 150 meters;
- Molteno coal field is low in potential because it has high mineral matter content;
- Limpopo, Southpansberg and Sprigbrok Flats regions are low in potential because they are too isolated (and will not be cost-effective to produce and transport) and are faulting coal reserves.

As a result, the most promising areas for coalbed methane are: the Waterberg, Perdekop (Amersfoost) and Vhyheid coal fields.

3.3.3.4 Potential Uses for Coalbed Methane

Several markets are potentially viable for using coalbed methane, if recovered, in South Africa. These include:

- as a replacement fuel for wood and coal in residential stoves.
- as a fuel source for on-site power production from gas turbines, fuel cells, or combustors for villages without access to electricity.
- as a fuel source for meeting the energy needs at coal mines.
- piping the methane (once it is purified) to other markets (e.g., central electric power, industrial) throughout South Africa (although this option suffers from the lack of gas pipelines in the country).

3.3.3.5 Barriers to the Development of Coalbed Methane

Although significant potential exists for the recovery and use of coalbed methane in South Africa, several barriers exist. These include:

- the lack of information on the coalbed methane resource base;
- the lack of experience in recovering and using coalbed methane;
- the capital cost of coalbed methane projects. The cost of exploration, drilling, producing and transporting the methane, and converting end-use equipment to use coalbed methane may be prohibitively expensive.

3.3.4 China

3.3.4.1 Population and Land Use

China is the most populated country in the World. In 1993, its population was estimated to be 1.185 billion. Approximately 80% of China's population lives in rural regions although its population density – 319 people per square mile – is among the highest of the countries studied in this report. Figure 3-7 provides information on the distribution of China's population by Province (LBL, 1993).

China's population consumes only 630 kWh per capita, one of the lowest in per capita energy consumption in the World. In part, this is due to the fact that a significant percentage of China's population does not have access to electricity (estimated to be as much as one-third of the population).

China's vast land area varies greatly in composition, climate and use from mountainous to flat, mild to cool temperatures, sparsely populated to densely populated. Its large industrial complexes are centered in the north and northeast; although industrial centers are found in and around many of China's heavily populated cities as well (Figure 3-8).

3.3.4.2 Energy Resources

China produces and consumes more coal than any country in the World. In 1994, it produced approximately 1.2 billion tons and is expected to produce 1.4 billion tons by the year 2000. Almost all of the coal it produces it also consumes. China's coal reserves are estimated to be nearly one trillion tons.

The northern region of China accounts for 94% of its total coal resources. Approximately 75% of its total in-place coal reserves are located in three Provinces: Shanxi, Shaanxi and Inner Mongolia. Although a large portion of China's coal reserves are also located in the northwest portion of the country, the region suffers from unexplored reserves, the absence of infrastructure, and large distances from population centers. Figure 3-9 shows the locations of the coal-bearing sediments in China.

Coal satisfies approximately three-quarters of China's primary energy demand. On the other hand, natural gas supplies only 2% of the demand. In 1993, 595 BCF of natural gas was produced in China, one-half from Sichuan Province. Over 80% of the natural gas produced in China is consumed in the industrial sector for fertilizer manufacturing and in ammonia plants. Major impediments exist to expand production from the estimated natural gas reserves of 53 TCF. These include natural gas pricing (at below operations costs) and insufficient pipelines and gathering systems.

In 1991, China had 165 GW of electrical capacity; 115 GW was coal-fueled, 40 GW was hydroelectric and 9 GW was oil/gas-fueled. It is estimated that by 2010, China will have 428 GW of electrical capacity, 294 GW being thermal (almost all of it coal).

Sixty-seven percent of China's energy demand is in the industrial sector (i.e., manufacturing, mining and construction). Twenty-seven percent of the demand is in the domestic sector (i.e., residential, agricultural and commercial). Six percent of the demand is in the transport sector.

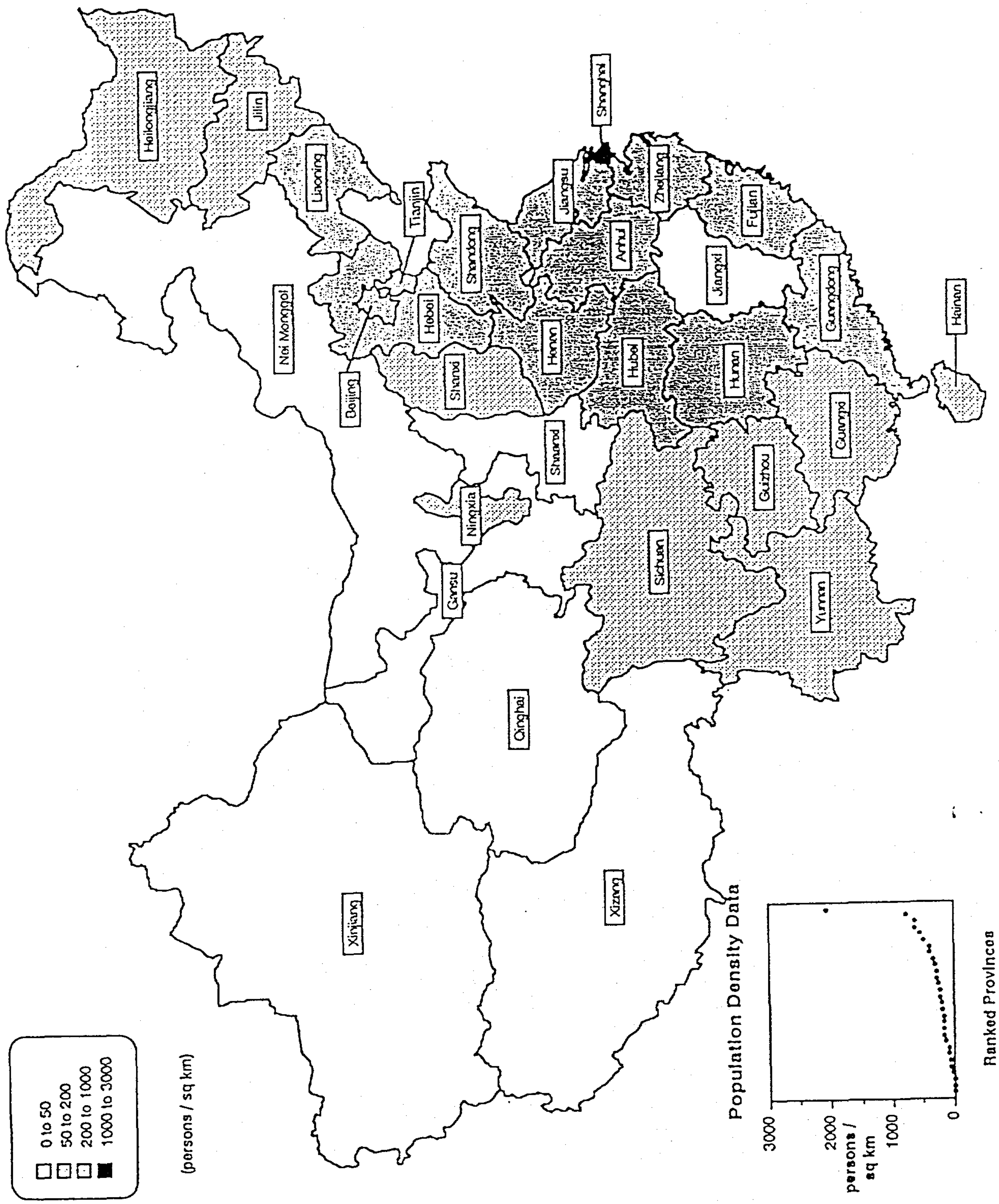
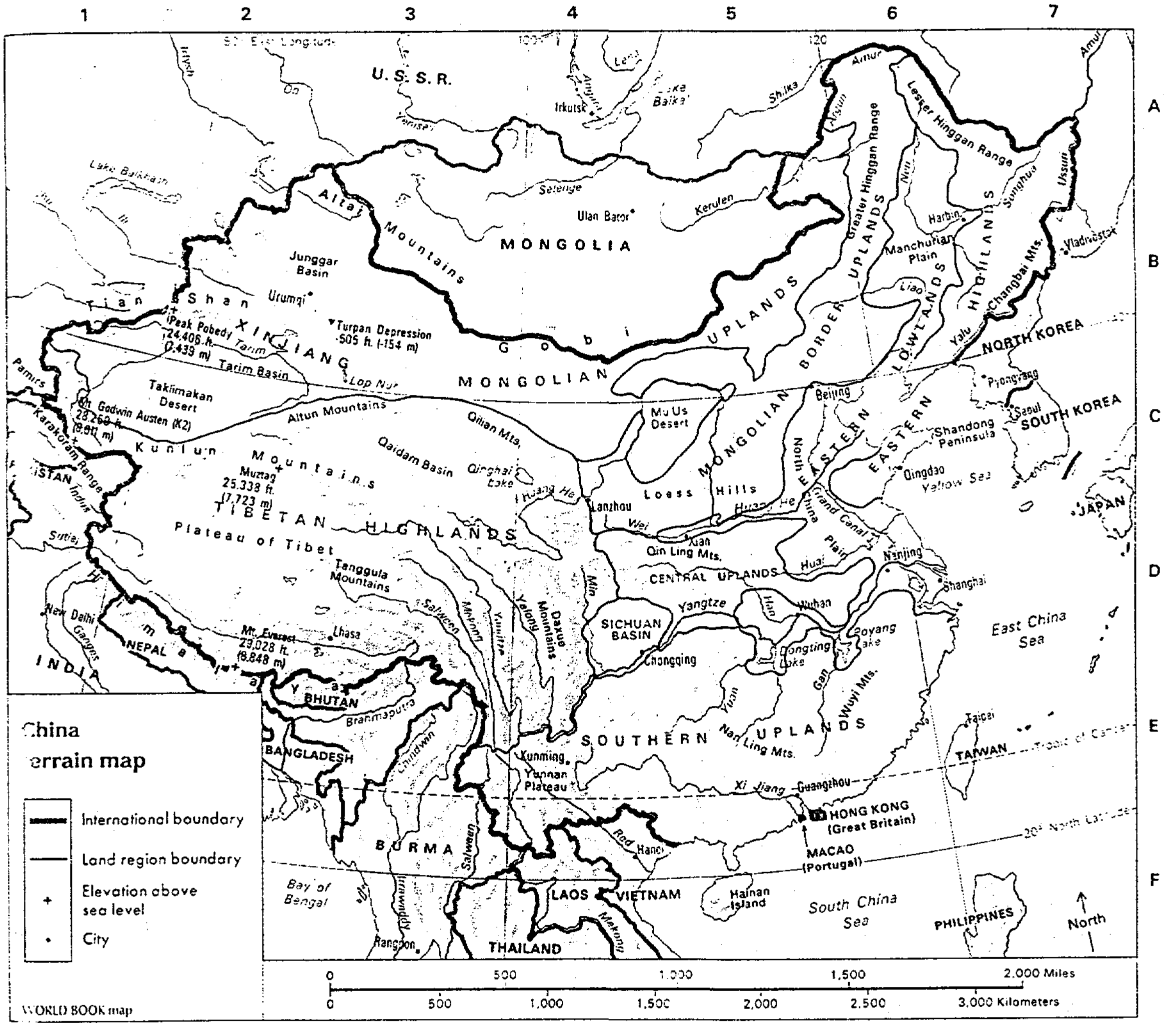


FIGURE 3-7. China: Population Density by Province (1989)



Physical features

Altai Mountains	B	3
Altun Mountains	C	3
Amur River	A	6
Changbai Mountains	B	7
Daxue Mountains	D	4
Dongting Lake	E	5
Gobi (desert)	C	4
Grand Canal	D	6
Greater Hinggan Range	A	6
Hainan Island	E	5
Himalaya (mountains)	E	2
Huang He (Yellow River)	D	5
Junggar Basin	B	2
Kunlun Mountains	C	2
Lesser Hinggan Range	A	6
Liao River	B	6
Loess Hills	C	5
Manchurian Plain	B	6
Mekong River	D	3
Mount Everest	E	2
Mount Godwin Austen (K2)	C	1
Mu Us Desert	C	5
Nan Ling Mountains	E	5
North China Plain	D	6
Pamirs (mountains)	C	1
Peak Pobedy	B	2
Poyang Lake	D	6
Qaidam Basin	C	3
Qilian Mountains	C	3
Qin Ling Mountains	D	5
Qinghai Lake	C	3
Shandong Peninsula	C	6
Sichuan Basin	D	4
Taklimakan Desert	C	2
Tarim Basin	C	2
Tibet, Plateau of	D	2
Tian Shan (mountains)	B	1
Turpan Depression	B	3
Wuyi Mountains	E	6
Xi Jiang (West River)	E	5
Yangtze River	D	6
Yellow Sea	C	6
Yunnan Plateau	E	4

FIGURE 3-8. China: Terrain Map

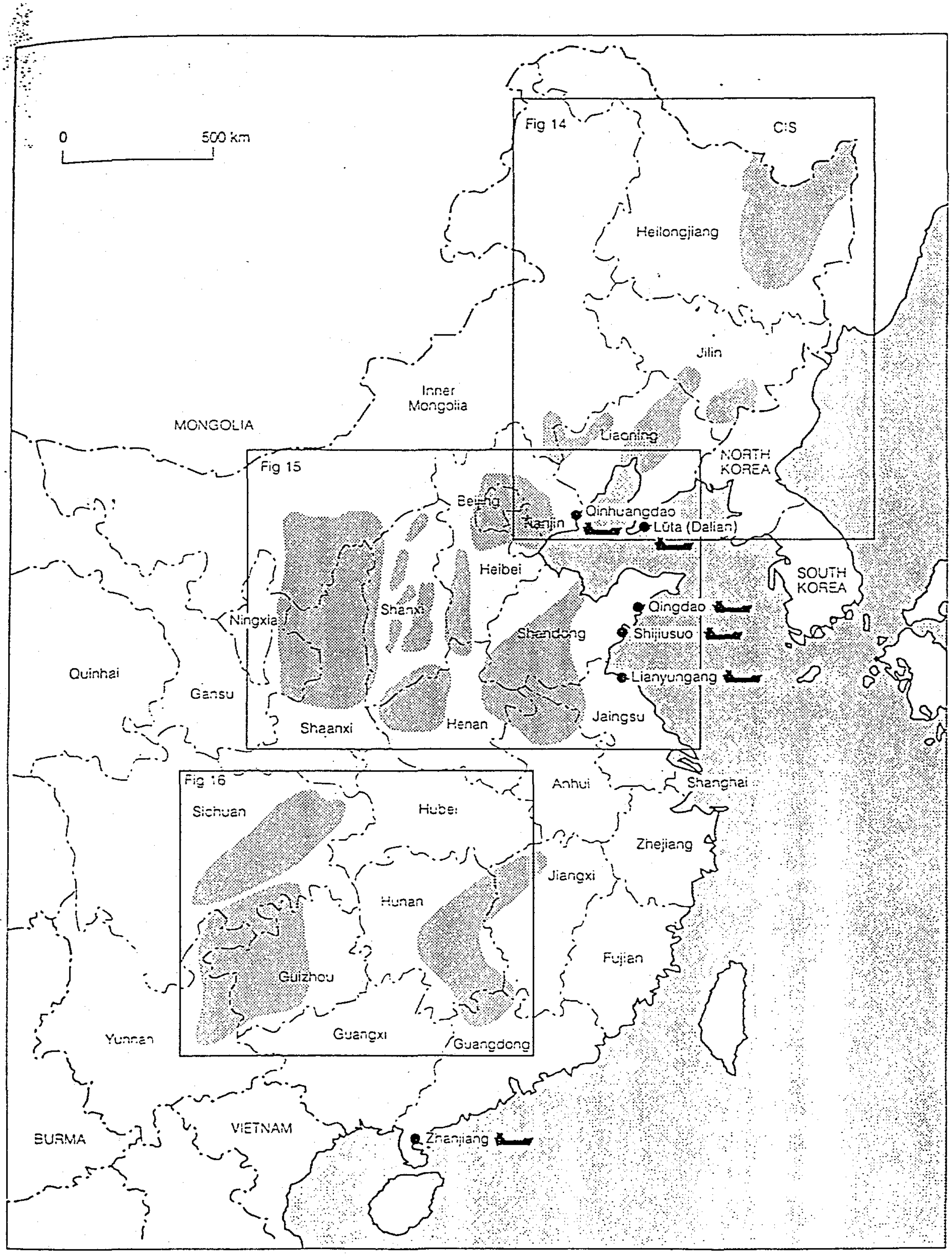


FIGURE 3-9. China: Principal Coal Basins

China's industrial sector has a fuel mix of 60% coal, 13% oil/gas, and 27% electricity. The largest energy consumers in this sector are the chemical, metallurgical, smelting and building materials industries. Many of China's industrial complexes are located in the northern and northeastern regions of the country, in proximity to the coal producing regions.

China's domestic sector has a fuel mix of 75% coal, 10% oil/gas, and 15% electricity. China's residential fuel consumption is twice that of the commercial and agricultural sectors combined. It is anticipated that there will be substantial growth in energy demand in the residential and commercial sectors, mainly fueled by electricity and possibly gas, if it becomes available at reasonable prices.

China's transportation sector has a fuel mix of 69% oil/gas, 6% electricity, and 25% coal. The rail system in China, consumes approximately one-half of the energy in this sector. This sector consumes most of the coal and electricity used for transportation in China. The International Energy Agency projects that oil demand in China's transportation sector will increase by 7% per annum, and that coal will be phased out by the year 2010.

3.3.4.3 Coalbed Methane Opportunities

China's coalbed methane resource is estimated to be between 1,050 and 1,225 TCF (USEPA, 1995b). Figure 3-10 shows the locations of China's coal basins and its estimated coalbed methane resources. As depicted, coalbed methane can be found throughout China with the majority found in its northern regions. Several basins have estimated coalbed methane resources in excess of 35 TCF. Several others have reserves estimated to be between 3.5 and 35 TCF. Many others have reserves of less than 3.5 TCF.

The primary factors influencing the size of the coalbed methane reserves in regions of China are (Coalbed Methane Clearinghouse, 1995):

- **Coal Seam Depth**. Coal seams between 300 and 1000 meters in depth are preferred to avoid weathered gas zones and to reduce the difficulty and cost of methane development. Ninety-five percent of Chinese coal mines are underground.

- **Coal Seam Thickness.** Coal seams greater than 2 meters in thickness are preferred to guarantee an adequate and stable quantity of methane.

- **Low to Medium Metamorphism and High Rank**. These characteristics of the coal ensure proper methane generation, adsorption and permeability.

- **High Coal Permeability.** This characteristic ensures good gas flow.

The coal in many of the regions identified in Figure 3-10 meet most of these criteria; as a result, China has significant coalbed methane reserves. To develop this resource requires a well developed regional industrial base and a large demand for coalbed methane in order to raise capital and create the necessary commercial impetus.

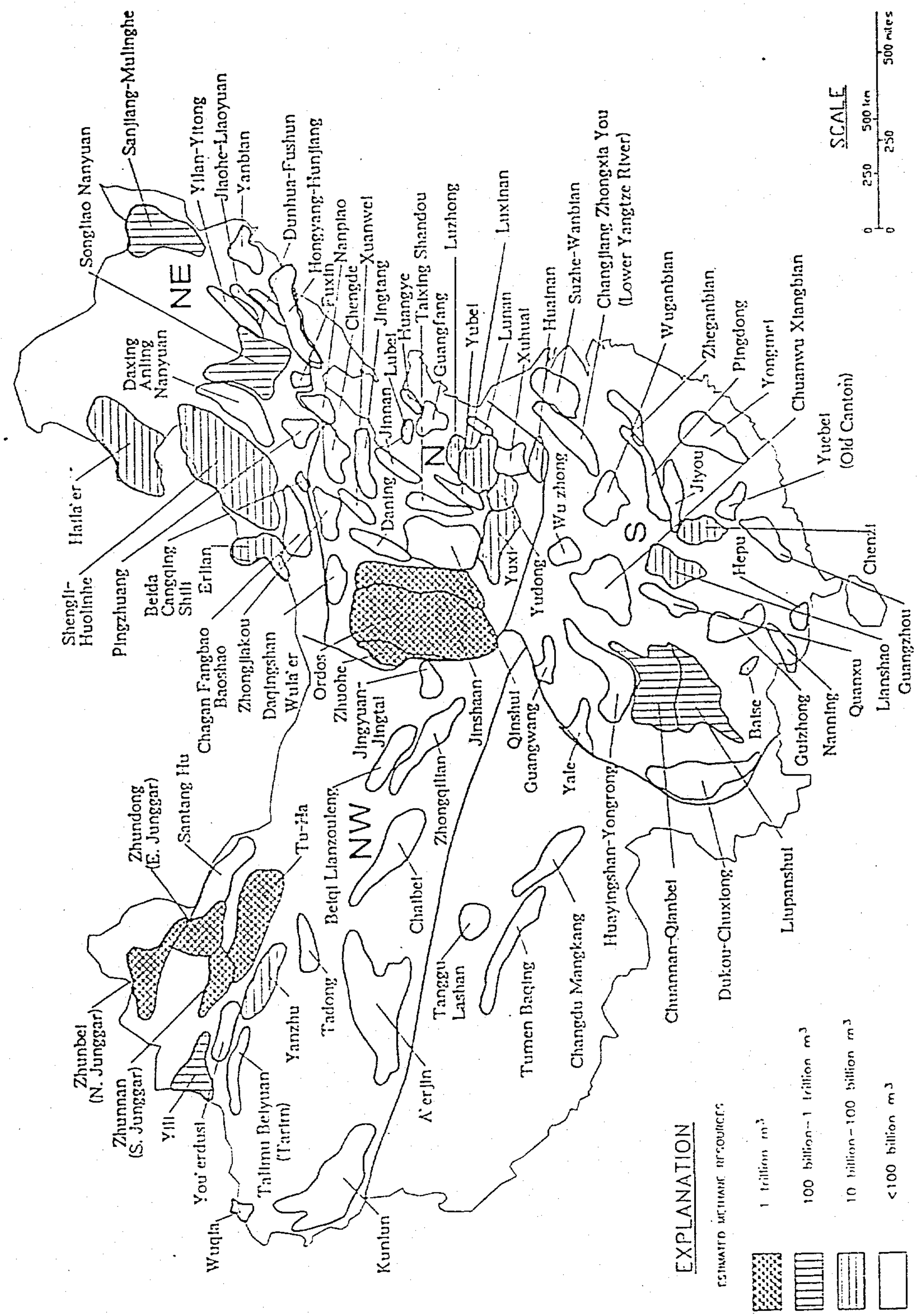


FIGURE 3-10. Location Map of China's Coal Basins and Estimated Methane Resources

China is the world's number one emitter of coalbed methane, releasing approximately one-third of the world's total. It is estimated that, in 1994, methane emissions from high gas coal mines were approximately 155 BCF (USEPA, 1995b); other sources indicate that total coalbed emissions in China in 1989 were 475-830 BCF (Kuchgessner et al, 1995). Over 60% of the methane emissions came from coal mines in 5 Chinese Provinces – (1) Heilongjiang, (2) Liaoning, (3) Shanxi, (4) Sichuan, and (5) Guizhou (USEPA, 1993). Of the amount of methane released, 13% (20 BCF) was recovered and 9% (14 BCF) was utilized. Almost 75% of the methane recovered, and 85% of that utilized, occurred in the three Provinces – Liaoning, Shanxi, and Sichuan.

Assuming that between 25% and 35% of the coalbed methane released from coal mining operations in China is recoverable, it is then possible to recover an additional 115-285 BCF of methane per year over what is recovered today (Coal Industry Advisory Board, 1993). Additional coalbed methane recovery from non-mined coal seams is also likely.

3.3.4.4 Potential Uses for Coalbed Methane in China

The best uses for the coalbed methane recovered from Chinese coal mines will vary depending upon the quality/quantity of the gas and local energy markets. However, general statements can be made about the potential uses for the gas.

One option is to use the methane to substitute for coal to meet the energy needs at the coal mines. Such needs include:

- on-site heating of water and air;
- thermal coal drying;
- heating of ventilation air; and
- production of electricity and heat in coal mine boilers.

Coalbed methane can be used as a substitute for coke gas, coal or natural gas in local residences and businesses. It also can be used with gas turbines or fuel cells to produce on-site electricity and heat. In addition, depending upon the quality of the gas and its proximity to gas pipelines, it could be transported to other regions of China and used for electric power, industrial, commercial or residential applications. However, since there are very few natural gas pipelines in existence in China today, this latter option may be cost prohibitive.

3.3.4.5 Barriers To the Recovery of Coalbed Methane in China

Despite the large coalbed methane resource that exists in China, there are several factors that will impede its recovery. These include:

- The capital cost of coalbed methane projects. The cost of exploration, drilling, producing, transporting, and converting end-use equipment to use coalbed methane may be prohibitively expensive.

- The cost of installing coalbed methane upgrading, transportation and utilization systems.

- Lack of clear legal authority (and precedent) regarding the ownership of the methane.

- Lack of understanding in many coal regions of China regarding the value of coalbed methane. As a result, many coal operations focus only upon coal recovery.

- Lack of sufficiently proven recovery technologies to meet the economic and technical conditions which exist in China.

3.3.5 Poland

3.3.5.1 Population and Land Use

Poland, with a population of approximately 39 million, is among the 40 most-populated countries in the world. Forty-one percent of the population lives in rural areas. It contains 5 cities with populations in excess of 500,000: Warsaw (1.7 million); Lodz (850,000); Krakow (740,000); Wroclaw (640,000); and Poznan (575,000). The population density of Poland is moderate (i.e., 100 to 250 people per square mile) except in its northern most areas where population density is 50-100 persons per square mile (World Book, 1988).

Figure 3-11 shows the main regions of Poland. The Coastal Lowlands of Poland, a narrow strip of land along the Baltic coast in the northwest contains three ports – Gdansk, Gdynia and Szczecin. No other major population centers exist in the region.

The Baltic Lakes Region covers most of northern Poland. The region contains thousands of small lakes and is very sparsely populated.

The Central Plains stretch across the entire width of Poland south of the Baltic Lakes Region. This region contains most of Poland's agricultural lands. In addition, it is the region in which three major cities are located: Poznan, Warsaw and Wroclaw.

The Polish Uplands consists of hills, low mountains and plains located south of the Central Plains Region; it is rich in mineral resources. The Katowice area is the most highly industrialized region in Poland. It is here that the coal fields, as well as copper, lead and zinc, are found.

The Carpathian Forelands lie within the branches of the Vistula and San Rivers in southeastern Poland. Much of this region is densely populated. Krakow is the region's most important manufacturing center.

The Western Carpathian Mountains form the southernmost region of Poland. This is a mountainous region which contains rural towns and villages scattered throughout.

The Sudetes Mountains border southwestern Poland. The region is scattered with farms and small cities and towns and is the textile center of Poland.

3.3.5.2 Energy Resources

Coal dominates Poland's fuel mix, comprising 76% of the energy consumed in 1992. Poland's energy demand in 1991 was approximately 2.5 quadrillion (10^{15}) Btu. Approximately 45% of the energy used in Poland is consumed in the household and commercial sectors; 40% was consumed in the industrial sector. The remaining 15% was consumed in the transportation sector. Approximately 96% of the electricity generated from all Polish sources (PSE and all hard coal generating and CHP companies under the Ministry of Industry and Trade, and the Ministry of Privatization) in 1991 was derived from coal.

FIGURE 3-11. Regions of Poland

In 1991, approximately 44% of the energy consumed in the household and commercial sectors was derived directly from coal or coke. Indirect use of coal via electricity and steam accounted for 39% of this sector's energy demand. Natural gas (12%) and oil (5%) made up the rest of the energy demand in this sector. It is expected that the current trend toward more use of natural gas and electricity in this sector is expected to continue.

Direct use of coal and coke accounted for 36% of the energy demand in Poland's industrial sector in 1991. In addition, coal-based electric power provided 50% of the energy consumed in this sector. Natural gas (10%) and oil (4%) made up the remainder of the industrial energy demand in 1991. A program was initiated to switch industrial consumers of coke oven gas to natural gas.

Eight-six percent of the transportation sector used oil in 1991 to meet its energy demand. The remaining demand in this sector was met by coal and coke in the form of electricity and steam (9%) and direct use of coal and coke (5%).

Polish hard coal production in 1993 was approximately 130 million tons. Hard coal is produced from three Basins in Poland – the Upper Silesian Coal Basin (USCB), the Lower Silesian Coal Basin, and the Lublin Coal Basin. The locations of these and other energy producing regions in Poland are shown in Figure 3-12 (USEPA, 1995c). The USCB produced 127 million tons or 98% of Poland's coal in 1993. Polish coal consumption in 1993 was approximately 105 million tons. The remainder of the hard coal produced (25 million tons) was exported. Lignite (brown coal) production in Poland in 1993 totalled 68 million tons; all of it was consumed domestically.

Natural gas production in Poland in 1993 was approximately 5 billion cubic meters while its consumption was almost 11 billion cubic meters. Russia supplies most of the imported natural gas. While natural gas consumption is projected to increase dramatically by the year 2010 – to as much as 43 billion cubic meters (by World Bank estimates) – the decline in domestic production and coupled with uncertainties in expanded supply from Russia, have introduced considerable uncertainty regarding the ability of Poland to meet this projection.

3.3.5.3 Coalbed Methane Recovery Potential

It is estimated that Poland's coalbed methane resources range from 14-46 TCF. In 1993, coalbed methane emissions in Poland were estimated to be 30 to 75 BCF. Of that amount, 9.5 BCF were recovered and 2 BCF were utilized. Table 3-3 provides information on coal production, and coalbed methane resources in the three principal polish coal basins.

FIGURE 3-12. Location of Coal Basins, Oil Fields, and Gas Fields, Poland

Table 3-3
Coal and Coalbed Methane in 3 Polish Basins

Basin	Upper Silesian	Lower Silesian	Lublin
Coal Resources (billion tons)	56.9	0.2	7.6
Hard Coal Production (billion tons)	127.2	1.2	2.2
Methane Potential (TCF)	14	Unknown	Unknown
Methane Liberated (BCF)	26	1	0
Methane Utilized (BCF)	6	0	0

Assuming 25%-35% recovery of coalbed methane emissions, 5 to 23 BCF per year of additional recovery is possible (Coal Industry Advisory Board, 1993). Considerable recovery from unmined coal seams is also possible.

3.3.5.4 Potential Markets for Coalbed Methane in Poland

Many markets exist for coalbed methane in Poland. This is brought about by Poland's increasing demand for, and declining production of, natural gas.

In the Upper Silesian region, coalbed methane has a large potential market for direct industrial use. This region is the most heavily industrialized in Poland and the largest energy consuming region as well. As a result, coalbed methane has potential to be used in the machinery, iron and steel, food, chemicals, and coal industries displacing coal and coke oven gas. The potential also exists for the methane to be used by industries who self-generate their electricity, displacing coal currently used for this application.

Currently 280,000 domestic consumers utilize coke oven gas for heating and cooking. As the coking operations in Poland are shut down, residences are being converted to natural gas. Since most of the gassy mines in Poland are in towns that currently use coke oven gas and that possess a gas network, this is a ready-made market for coalbed methane.

Piping coalbed methane in Poland does not appear to be a viable option today. This is so because: (1) natural gas pipelines are operating at full capacity; and (2) the quality of the methane in Poland (30 to 50% methane concentration) is not suitable for pipelines.

3.3.5.5 Barriers to the Recovery of Coalbed Methane in Poland

Despite the large coalbed methane resource that exists in Poland, there are several factors that will impede its recovery. These include:

- The capital cost of coalbed methane projects. The cost of exploration, drilling, producing, transporting, and converting end-use equipment to use coalbed methane may be prohibitively expensive.

- Lack of clear legal authority (and precedent) regarding ownership of the methane.

3.3.6 India

3.3.6.1 Population and Land Use

The population of India in 1993 was 891 million, making it the second most populated country in the world behind China. Although India is a very large country, it has a fairly high population density estimated to be 275 people per square mile. Approximately 27% of the population lives in urban areas.

There are several very large population centers in India. These include:

City	Population (millions)
Bombay	12.6
Calcutta	11.7
New Delhi	8.5
Madras	5.7
Bangalore	4.6
Hyderabad	3.5
Ahmedabad	3.6

India also has many small farm villages. It is estimated that there are 557,000 such villages with populations less than 1,000.

There are three major topographical areas of India (Figure 3-13).

- The Himalaya Mountains extend along much of the north border of India. This region is sparsely populated.

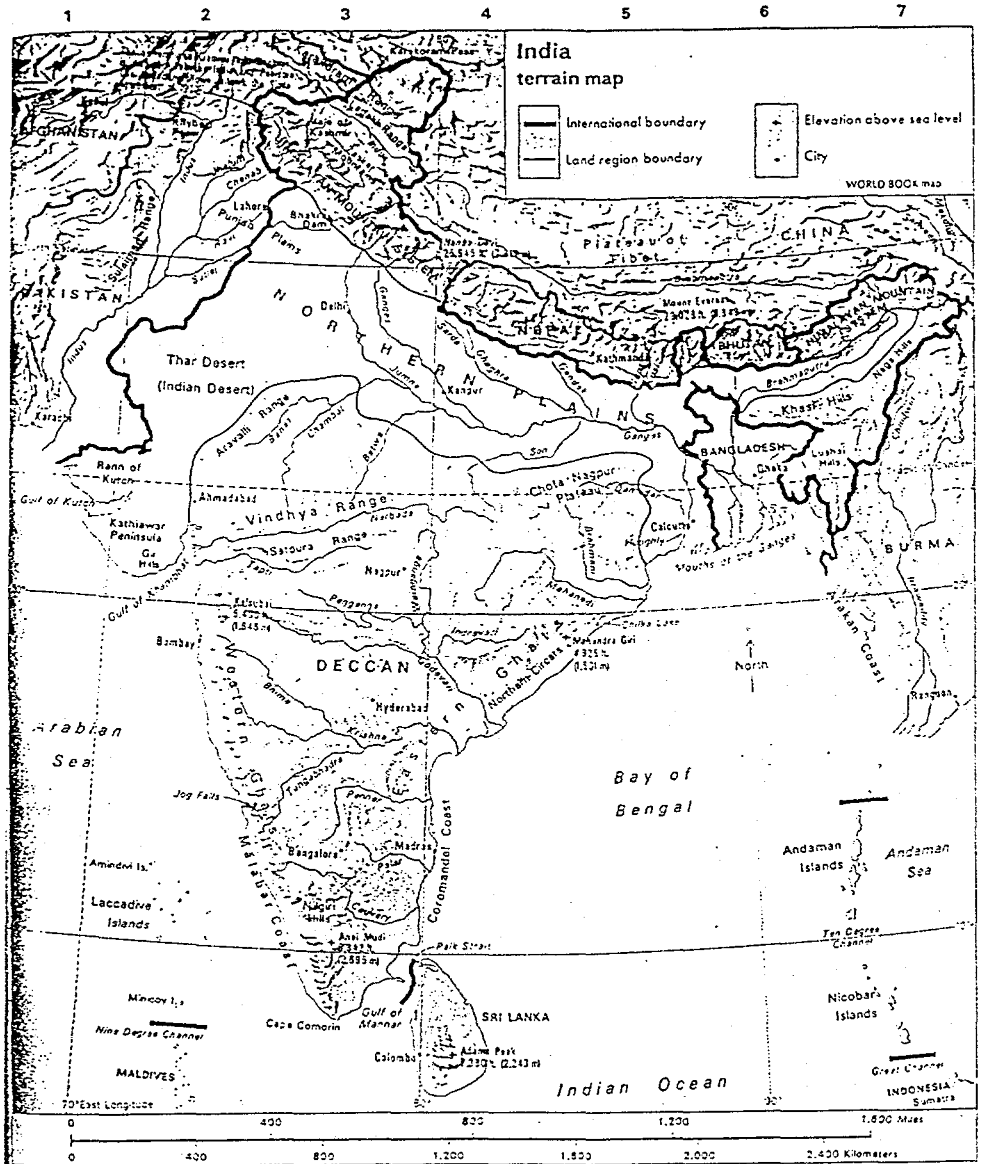
- The Gangetic Plain consists of the entire northern part of India, less the Himalaya Mountains. This is a well watered and very fertile region that is densely populated.

- The Deccan Plateau consists of the peninsula of India. It too is densely populated.

3.3.6.2 Energy Resources

India's total energy production in 1992 was estimated to be 170 million tons of oil equivalent (mtoe) (US DOE, 1994b). Its 1992 consumption was estimated to be 210 mtoe. In 1987, India's energy was consumed in the following proportions:

Sector	Share (%)
Industrial	51.4
Transportation	23.0
Residential	11.2
Agricultural	3.5
Other	10.9



Physical features

- Amindivi Islands ....F 2
- Anai Mudi (mountain) ....F 3
- Andaman Islands ....F 7
- Andaman Sea ....F 7
- Aravalli Range ....C 2
- Banas River ....C 3
- Bay of Bengal ....E 5
- Betwa River ....C 3
- Bhakra Dam ....B 3
- Bhima River ....E 2
- Brahmani River ....D 5
- Brahmaputra River ....C 6
- Cape Comorin ....G 3
- Cauvery River ....F 3
- Chambal River ....C 3
- Chenab River ....A 2
- Chilka Lake ....D 5
- Chindwin River ....C 7
- Chota Nagpur Plateau ....C 5
- Coromandel Coast ....F 4
- Damodar River ....C 5
- Deccan Plateau ....C 3
- Eastern Ghats (mountains) ....E 4
- Gandak River ....C 5
- Ganges River ....B 3
- Ghaghra River ....C 4
- Gir Hills ....D 1
- Godavari River ....E 4
- Great Channel ....G 7
- Gulf of Khambhat ....D 2
- Gulf of Kutch ....D 1
- Gulf of Mannar ....G 3
- Himalaya Mountains ....A 3
- Hooghly River ....D 5
- Indravati River ....D 4
- Indus River ....A 3
- Jhelum River ....A 2
- Jog Falls ....F 2
- Jumna River ....C 3
- Kalsubai (mountain) ....D 2
- Karakoram Pass ....A 3
- Karakoram Range ....A 3
- Kathiawar Peninsula ....D 1
- Khasi Hills ....C 6
- Krishna River ....C 3
- Laccadive Islands ....F 2
- Ladakh Range ....A 3
- Lushai Hills ....C 6
- Mahanadi River ....D 5
- Mahendra Giri (mountain) ....D 5
- Malabar Coast ....F 2
- Minicoy Island ....G 2
- Mouths of the Ganges ....D 6
- Naga Hills ....C 7
- Nanda Devi (mountain) ....B 4
- Narbada River ....D 3
- Nicobar Islands ....G 7
- Nilgiri Hills ....F 3
- Nine Degree Channel ....G 1
- Northern Circars (mountains) ....E 4
- Northern Plains ....B 3
- Palar River ....F 3
- Palk Strait ....G 3
- Penganga River ....D 3
- Penner River ....F 3
- Punjab Plains ....B 2
- Rann of Kutch (salt flat) ....C 1
- Ravi River ....B 2
- Sapt Kosi River ....C 5
- Sarda River ....B 4
- Satpura Range ....D 3
- Son River ....C 4
- Sutlej River ....B 2
- Tapti River ....D 2
- Ten Degree Channel ....F 7
- Thar Desert (Indian Desert) ....C 2
- Tungabhadra River ....E 3
- Vale of Kashmir ....A 3
- Vindhya Range ....D 3
- Wainganga River ....D 4
- Western Ghats (mountains) ....E 2
- Zaskar Mountains ....A 3

FIGURE 3-13. Topography of India

India uses the complete range of energy options. In 1992:

- 62.1% of the energy consumed was coal-based, of which 57% was used for electric power production;
- 27.2% was based on oil;
- 7.6% was based on natural gas;
- 2.8% was based on hydroelectricity; and
- 0.3% was based on nuclear power.

Coal is the dominant fuel used in India; it is the world's third largest producer of hard coal. In 1994, Indian coal reserves were estimated to be between 69 and 194 billion tons (USDOE, 1994). India's coal production in 1994 was approximately 303 million tons; its consumption was 310 million tons. Although in 1991, approximately 60% of the coal produced in India was surface mined, two-thirds of the 530 operating coal mines were underground. Coal is generally located in the poorer regions of India (i.e., Bihar, Uttar Pradesh, Madhya Pradesh, Orisa, and West Bengal, although some is located in wealthy regions like Maharashtra). Figure 3-14 shows the locations of the major coal fields in India.

In 1992/93, India produced approximately 19.6 billion cubic meters of natural gas (American Embassy, 1993). Seventy-five percent of the gas produced in India was consumed for the production of fertilizer and electric power. Because of infrastructure delays in building gas-fired powerplants, fertilizer and petrochemical plants, gas demand has not risen as rapidly as projected.

Significant quantities of natural gas are flared, again because of delays in building the infrastructure needed to capture and transport the gas. In addition, LPG imports increased 77% from 1991/92 to 1992/93 to 380,000 metric tons. LPG has become very popular for residential heating and cooking. A backlog of 7 million residences are awaiting LPG hook-ups.

In 1994, electrical generating capacity in India was approximately 82 GW (including autoproducers and private power). Sixty-nine percent of the electricity was produced by coal. India has electrified 80% of the country. However, only 55% of the population currently has access to electricity.

3.3.6.3 Coalbed Methane Recovery Potential

India's coalbed methane resources are estimated to be nearly 50 TCF. Although India has considerable coal resources, its coal is less gassy than other coal producing countries (India University of Environment and Forests, 1992). In part this is because much of the coal is shallow and surface mined. Coal seams in Orissa, Uttar Pradesh, Madhya Pradesh, Andhra Pradesh and Maharashtra are especially of low gas value.

Approximately 20 BCF of coalbed methane is emitted from coal mines each year in India. Although surface mines produce nearly twice as much coal as underground mines in India, underground mines produced four times the amount of coalbed methane in 1991. No coalbed methane is currently recovered in India.

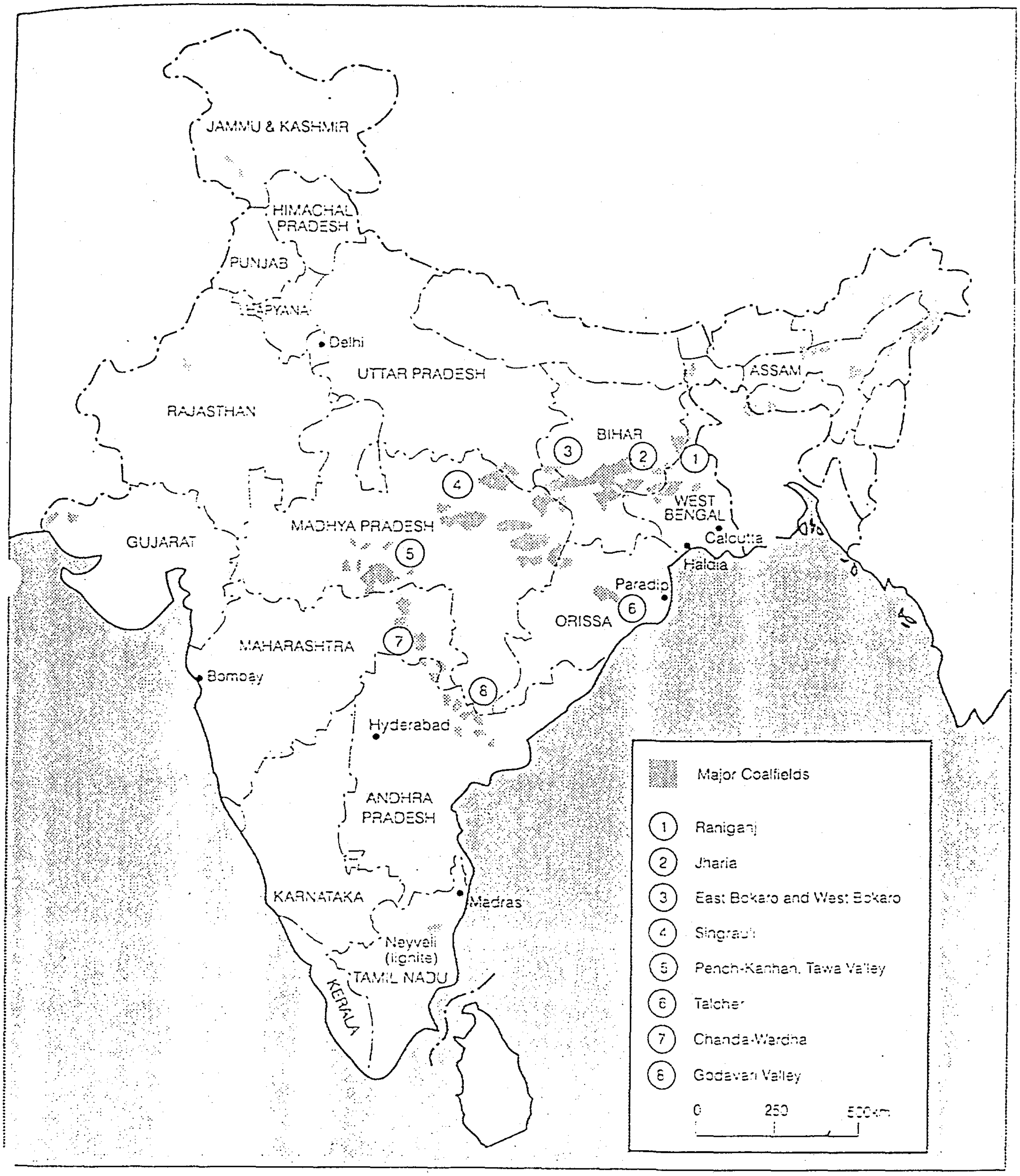


FIGURE 3-14. India: Principal Coal Fields

3.3.6.4 Potential Markets for Coalbed Methane in India

As a result of its growing appetite for natural gas and LPG, coalbed methane markets in India are potentially large. Some of the market applications include:

- as a source of heat and electricity at the coal mines.
- as a substitute for naphtha in the fertilizer and petrochemical industries. (The Indian government is currently encouraging the use of alternative fuels to displace petroleum-derived fuels).
- as a substitute for furnace oil in powerplants.
- as a substitute for kerosene in the residential market.
- as a substitute for LPG for home heating and cooking.

Several of these market applications could enable coalbed methane to meet the energy needs of remote communities and villages in India. If only 35 to 45% of the methane currently liberated from coal mines were recovered and used, 7 to 9 BCF of gas would be available for the marketplace.

3.3.6.5 Barriers To the Recovery of Coalbed Methane in India

Despite the large coalbed methane resource that exists in India, there are several factors that will impede its recovery. These include:

- the capital cost of coalbed methane projects. The cost of exploration, drilling, producing, transporting, and converting end-use equipment to use coalbed methane may be prohibitively expensive.
- lack of clear legal authority (and precedent) regarding ownership of the methane.
- high tariffs for imported goods and materials.
- an excessive bureaucracy in India that delays new concepts, like the recovery of coalbed methane.
- concerns over loss of intellectual property rights.

4.0 GLOBAL PROSPECTS FOR SMALL-SCALE, FLUIDIZED-BED AND COAL-FIRED DIESEL POWER SYSTEMS IN DEVELOPING COUNTRIES

As indicated in Section 2, the market indicators for fluidized-bed and coal-fired diesel power systems in remote applications worldwide include: low population density, low electricity use per capita, proximity to coal (and coal infrastructure), percent diesel generators, and access to water. This section identifies and discusses these indicators (except for access to water) for 42 developing countries.

The World Bank classifies 110 countries as "developing" with respect to their power sector.[1] Only a subset of these countries – those who currently produce/consume coal – are potential markets for small-scale, fluidized bed and coal-fired diesel units. Table 4-1 indicates data on the key market indicators for those countries that produced/consumed coal in 1990 (and thereby are presumed to have coal infrastructure):

- rural population (percent of total 1990 population)
- electricity/capita (kWh per person)
- electricification ratio (percent)

Data for 1990 was used since it was readily available for all the indicators of interest; the electrification ratio was not available for many countries. As evident from reviewing Table 4-1, no correlation exists between the percent rural population, electricity/capita and the electrification ratio.

The following sections (4.1-4.5) organized by region, discuss the electricity supply/demand situation in each of the countries identified in Table 4-1.[2] Within each region the countries are organized by their state of development (GNP/capita rank, lowest to highest). A *market assessment* discussion is included with each country profile; it provides an indication of the planned (or prospective) electric power developments and resource preferences of the country. Based on this information, an assessment of the market potential for small-scale FBC and coal-fired diesels is examined in Section 4.6.

4.1 Market Assessment: Africa

4.1.1 Mozambique

Mozambique generates up to 2 TWh per year of electricity, but most of it originates from Hidroelectrica de Cahora Bassa's 2,075 MW hydraulic plant located at Cahora Bassa Dam along the upper reaches of the Zambezi River. In the past, most of this power was exported to South Africa. The other Mozambique utility, Electricidad de Mozambique (EDM) has an interconnected system with three hydro plants, a steam-electric plant in the capital (Maputo), two gas turbine plants, and seven diesel plants. There are also four additional remote (non-interconnected) diesel sites.

[1] Developing countries were defined as either *low income economies* or *lower middle income/middle income economies* (less than $2,500 per capita in 1990).

[2] The discussion of the supply/demand situation draws extensively on Utility Data Institute, 1996, *International Directory of Electric Utilities*, Eighth Edition (January).

TABLE 4-1						
Indicators of Electricity Access and Remoteness for Selected Developing Countries						
Rank[a]	**Country**	**GNP/Capita (1990 US$)**	**Rural Pop (% 1990 TOTAL)**	**Electricity/Capita (kWh)**	**E-Ratio (%)**	**Electricity Imports, 1990 (%)[b]**
1	Mozambique	80	63	52	—[d]	40.1
2	Tanzania	110	67	36	2	—
5	Nepal	180	90	41	9	4.2
8	Laos	200	81	88	12	[139.7]
9	Malawi	200	88	69	—[d]	—
10	Bangladesh	210	84	74	14	—
11	Burundi	210	96	22	<5	10.9
12	Zaire	220	60	162	—[d]	[1.8]
14	Madagascar	230	75	48	—[d]	—
17	Nigeria	340	65	102	—[d]	[1.0]
18	Niger	310	80	46	—[d]	53.4
21	India	360	73	338	55	0.3
23	China	370	44	550	66	0.3
25	Kenya	370	64	133	—[d]	5.3
26	Pakistan	390	68	391	37	—
27	Ghana	390	67	336	20	[5.7]
30	Zambia	460	50	781	—[d]	[23.5]
32	Sri Lanka	470	79	185	29	—
33	Mauritania	500	53	71	—[d]	—
35	Indonesia	560	69	248	32	—
37	Egypt	610	53	754	—[d]	—
41	Myanmar	434	75	62	6	—
43	Vietnam	n/a	78	118	—[d]	—
45	Zimbabwe	680	72	1,064	<20	8.4
47	Philippines	730	57	428	61	34.6
50	Papua New Guinea	860	84	462	21	—
52	Morocco	970	52	388	25	1.1
53	Cameroon	950	59	235	—[d]	—
59	Peru	1,100	30	642	—[d]	—
61	Columbia	1,260	30	1,122	—[d]	0.6
62	Thailand	1,410	67	831	70	1.3
63	Tunisia	1,440	46	682	60	[0.5]
65	Turkey	1,640	39	1,013	—[d]	[1.3]
66	Romania	1,670	47	3,180	—[d]	12.8
67	Poland	1,680	38	3,549	—[d]	[0.8]
68	Panama	1,900	47	1,193	58	4.0
70	Chile	1,940	14	1,395	—[d]	—
72	Algeria	2,350	48	637	—[d]	[0.4]
73	Bulgaria	2,320	32	5,083	—[d]	9.6
74	Mauritius	2,310	59	716	—[d]	—
75	Malaysia	2,340	57	1,389	—[d]	[0.2]
76	Argentina	2,370	14	1,602	—[d]	1.6
77	Iran	2,500	43	1,004	—[d]	—

[a] Ranked in ascending order of GNP per capita.

[b] Net imports (GWh) divided by Gross Consumption (GWh); [ ] represents net exports as a percent of gross consumption.

[c] Not assessed due to current U.S. Government restriction on investment in Iran.

[d] Not computed in or computable from referenced sources.

Sources: World Bank, 1992, *World Development Report 1992, Development and the Environment*; and Heidarian, J. and G.Wu, 1994, *Power Sector Statistics for Developing Countries, 1987-1991*, The World Bank, (December).

Market Assessment: While Mozambique has one steam-electric plant, it relies extensively on hydroelectricity for baseload power generation. Repairs to the Cahora Bassa facility, resulting from disrepair during their long-running civil war, are underway. Construction of a new 60 MW power plant at the existing Massingir Dam, and several other hydro projects are envisioned. Information on the seven interconnected and four remote diesel plants is not available to assess their conversion to coal-fired systems.

4.1.2 Tanzania

Like many other African nations, Tanzania relies largely on hydroelectric power for its electricity. The Tanzania Electric Supply Co. (Tanesco) on the mainland, and the Zanzibar State Fuel & Power Corp. (ZSFP) on the island of Zanzibar are responsible for all public power generation and delivery. The system now has an installed capacity of 410 MW. Wood and biomass fuels provide 91% of the energy consumed in Tanzania, while imported oil accounts for 7%, with coal and electricity each accounting for only 1% of primary energy. Since 40% of the Tanzania's foreign exchange expenditures are for oil, the government is interested in increasing electricity supplies in the near-term. To meet this goal, and the 13% per annum growth in demand, Tanzania hopes to utilize its largely untapped 6,000 MW of hydro potential. Current expansion plans call for four new hydro plants totalling 632 MW. A 6-MW coal-fired power plant is now in operation.

Market Assessment: Recently, Tanzania has been saddled with a scarcity of hard currency for fuel purchases, which has impacted the operation of its diesel power plants. The result has been electricity rationing and interruptions in Dar es Salaam, the most important export port in East Africa. While Tanzania is exploring increased interconnections with its neighboring countries (Uranda, Kenya, Malawi, Burundi, and Zambia), it is also investigating the development of – and increased reliance on – other indigenous energy-producing resources including: bagasse (already used as fuel for steam plants), biogas feedstock from animal ruminants, photovoltaics, wind and geothermal. Natural gas is also likely to be a major power generation fuel, with the discovery of 1.1 TCF on Songo Songo Island. A 60- to 100-MW gas turbine or combined cycle power plant on the outskirts of Dar Es Salaam has been proposed to the World Bank.

4.1.3 Malawi

Malawi is a republic in southeastern Africa, which is nearly one-quarter covered by water (Lake Malawi and three other lakes). All baseload electricity comes from four hydroelectric plants (190 MW) operated by the Electricity Supply Commission of Malawi (Escom). Its single gas turbine and six diesel units are used for standby service only. Self-generators are estimated to have 24 MW of capacity from bagasse-fired steam units, diesels, and two small hydro stations.

Market Assessment. It is expected that Malawi will take advantage of its 400 MW of untapped hydroelectric potential, before it relies on its undeveloped bituminous coal reserves.

4.1.4 Burundi

Burundi is one of the most densely populated countries in Africa. However, less than 5% of its population has access to electricity. The state-owned utility Regie de Production et de Distribution d'Eau et d'Electricite (Regideso) has a capacity of 55 MW and produced 105 GWh in 1991. Regideso purchases the bulk of its electricity from Zaire. Burundi, along with neighboring Zaire and Rwanda, has formed an organization -- Communaute Economique des Pays des Grands Lacs (CEPGL) -- to consolidate power development projects.

Market Assessment. Burandi is likely to rely on the joint power production of CEPGL, and therefore be largely hydro-power based for the foreseeable future.

4.1.5 Zaire

Zaire has a considerable abundance of natural resources, including the Congo River, which provides a vast network of navigable waterways and a huge hydroelectric potential. It has been estimated that Zaire has about one-eighth of the world's total hydroelectric potential (120,000 MW). Societe Nationale d'Electricite (SNEL) is the national utility in Zaire; it had a total capacity of 2,504 MW in 1992, most of which was from hydro plants (98%). In addition to this public capacity, there are also 12 privately-owned hydro plants with a total capacity of 80 MW. The largest SNEL stations are INGA I and II, on the Zaire River. INGA II, completed in 1982, has eight 178 MW turbine/generator sets capable of producing more power than needed by Zaire. SNEL has the capability of producing about 11 TWh from its facilities, but usually generates only about one-half this total (5.5 TWh). Internally Zaire is interconnected via four subsystems, but with the exception of the Western and Southern systems are not connected to each other. Most of the distribution system (62%) is in the lower Zaire and Kinshasa area.

Market Assessment. While Zaire has 600-million tons of proven bituminous-coal reserves, along with vast quantities of recoverable oil, natural bitumen and natural gas, its hydroelectric resource base is extensive and continues to be the near-exclusive source of electrical supply. Fiscal restraints have limited SNEL's expansion plans, so most investment projects are devoted to rehabilitation of the existing system, including the effects of accelerated turbine deterioration due to underutilization. Complicating investment in generating capital stock is the unstable political situation which has caused the economy to grow by only 1% per year since 1960 (independence from Belgium).

4.1.6 Madagascar

The island of Madagascar is located off the East Coast of Africa. Electricity service is provided by Jir sy Rano Malagasy (Jirama), the Madagascar Electricity & Water Corporation. Jirama has a total capacity of 208 MW from 10 hydroelectric plants (108 MW) and 56 diesel plants; with this capacity Jirama generated 450 GWh in 1991. To decrease dependence on oil, Jirama is expanding its hydroelectric capacity: capacity at Andekaleka, which currently supplies one-half of the hydro capacity, is scheduled to double to 116 MW, and a feasibility study for a 300 MW plant on the Onive River has been completed. In addition, five new hydro facilities totaling 375 MW are under consideration.

Market Assessment. Other than the planned hydroelectric expansions, most future power investment in Madagascar is scheduled to be devoted to strengthening the T&D interconnections between the hydroelectric plants and the coastal demand centers in order to replace current diesel power.

4.1.7 Nigeria

Nigeria is the most populous country in Africa, and at one time possessed one of the most advanced power systems among the developing nations of Africa. At present, the system is plagued by power failures. The Nigeria Electric Power Authority (NEPA) operates 6,611 MW of capacity; it produced 11.3 TWh in 1991, of which 35% was hydroelectric. The following table delineates the plants operated by NEPA:

Plant Name	Size (MW)	Type	Fuel
AFAM	623	GT	gas/oil
EGBIN	972	GT	gas
JEBBA	642	hydro	
KAINJII	1056	hydro	
LAGOS	1350	F/GT[a]	oil/gas
SAPELE	720	F[b]	oil
SAPELE	285	GT	oil
SHIRORO	600	hydro	
UGHELLI	354	GT	oil/gas

[a] F/GT= fossil steam and gas turbine
[b] F = fossil steam electric

Besides the power generated by NEPA, independent power generators (i.e., state-owned oil company and other self-generators) produced another 50 GWh.

Market Assessment. A 330-kv transmission line was recently completed linking Nigeria's major urban centers. If and when Nigeria needs more electricity, it can (will) simply stop flaring 70% of its gas production, and begin burning it in gas engines or gas turbines. Natural gas use is also being advocated by the government in industrial and household applications. With natural gas reserves in excess of 2.8 tcm, Nigeria also signed a joint-venture agreement to liquify and export LNG. To counter a potential shortfall in future natural gas availability for electricity production, Nigeria is rehabilitating its coal mines to resume production that peaked in 1959 and is nonexistent at present.

4.1.8 Niger

Most of the land area in Niger is uninhabitable. Over 50% of the area lies within the Sahara. The central portion of the country is the Sahel, a semiarid and lightly wooded region. The southern and southwestern regions are fertile and forested areas where most of the 8.4 million people reside. Electricity in Niger is produced and supplied by the Societe Nigerienee d'Electricite (Nigelec), which purchases the bulk of its power from Nigeria. In 1991, Nigelec's capacity was 105 MW; 36 MW of it is from the Niamey II diesel- and gas-fired station. Niamey II supplied cities in the Niger Valley; 54 diesel units supply the isolated areas. Nigelec produced 230 GWh in 1991, while it imported 200 GWh from Nigeria.

Market Assessment. Niger is without indigenous energy resources, more than one-half of its electricity is imported and most of the power generated internally is diesel-fired. Replacement of the diesel units and imported power is possible, but not without importation of fossil fuels from Nigeria.

4.1.9 Kenya

The government-owned Kenya Power & Lighting Co. Ltd. (KPLC) and its two associated companies, Kenya Power Co. Ltd. (KPC) and Tana River Development Co. Ltd. (TRDC), supply almost all of Kenya's electricity. KPLC owns all the thermal plants and a few hydroelectric stations; TRDC owns hydroelectric plants; and KPC owns some small hydro plants and the geothermal power station. KPC is also importing power from the Urganda Electricity Board (UEB) and is developing future geothermal and hydro resources. Self-generators produce approximately 5% of Kenya's electricity.

Approximately 70% of Kenya's electricity is hydroelectric. In 1993, the Kenya power system's interconnected network had an installed capacity of roughly 800 MW, with 75% (600 MW) consisting of hydro. An additional 136 MW were fossil-fired units, and 45 MW were geothermal. Isolated diesel plants accounted for 4 MW, with another 30 MW available for import from UEB.

Market Assessment. Over the last five years, electricity demand has grown by 4.8% per year. However, if the proposed infrastructure investments are made, this level of growth could be met. The planned capacity additions include: diesel units at Kipeva near Mombasa (75 MW), the Olkaria Northeast geothermal plant (64 MW), and the Sondu/Miriu hydro project (60 MW). All three projects are awaiting further funding – the diesel and hydro plants from Japan. Funding will be difficult unless the electricity tariff structure is altered. Kenya, with World Bank funding, is making a determined effort in this regard; at present, electricity tariffs represent only 30% of the replacement cost of electricity supply.

4.1.10 Ghana

Hydroelectricity provides 98% of all power generated in Ghana. Between 1986 and 1992, domestic electricity demand in Ghana grew at an average annual rate of 9.7% per year, with total load growing at 7.4% per year, reflecting a steady expansion of electrification and generating capacity. Total load growth through 2000 is expected to be 2.2.% per year.

The Volta River Authority (VRA) was formed in 1961 to supervise the construction and operation of the 912 MW plant at Akosombo dam where four 147 MW units were commissioned in 1965, with two 162 MW units added in 1972. In 1981, the 160 MW Kpong plant was finished; in 1992, a 30 MW diesel plant at Tema was added. Both hydro plants are located in the southern portion of the Volta River basin.

VRA distributes power to mining companies, including the Volta Aluminum Co. (Valco) – its largest customer – and to the Electricity Corporation of Ghana (ECG). Through 1987, ECG was fully responsible for power distribution to all domestic customers, except the mines, several townships and a textile plant. Since 1987, ECG distribution is restricted to the developed southern half of the nation, for which it purchases power from VRA and operates its own 100 MW diesel plant. VRA now distributes power to the northern half of the country through its Northern Electricity Department (NED).

Market Assessment. Following several years of drought resulting in load reductions and legal disputes, VRA has instituted plans to construct a 300 MW combined-cycle power plant at Aboadze near Takoradi. The first 200 MW block of the $427 million plant is expected to be in service in 1997. Beyond Aboadze, VRA is exploring construction of a 400 MW hydro plant at BUI, a 93 MW plant at Hemang on the Pra River, a 50 MW plant at AWISAM also on the Pra, and a 130 MW gas turbine plant, which might be built jointly with the Ghana National Petroleum Corp to use gas reserves at the offshore Tano oil fields. To consume this power, VRA and ECG are cooperating on the National Electrification Project which, by 2020, intends to extend electicity to all towns and villages.

4.1.11 Zambia

Wood fuels contribute approximately 75% of Zambia's primary energy requirements with hydroelectricity the most important source at 15%. Seven hydro facilities – totaling 2,254 MW – have made the Zambia Electricity Supply Corporation (Zesco) a net exporter of power. Zambia's mining company also operates two hydro plants, totaling 48 MW, as well as some gas turbine and thermal capacity. In 1992, electricity production in Zambia was 7,780 GWh.

Zesco's three hydroelectric plants – Kafue Gorge (900 MW), Kariba North Bank (600 MW), and Victoria Falls (108 MW) – form an interconnected grid along the southern edge of the country, bordering Zimbabwe. Zesco's smaller plants – Lusiwasi (12 MW), Chishimba (6 MW), Musonda (5 MW), and Lunzua (750 MW) – are not linked to the main grid. Neither are its diesels, which have a capacity of 13 MW, operating in Kabompo, Kaoma, Kasempa, Luangwa, Lukulu, Mwinilunga, and Zambezi.

Transmission and distribution facilities, while well-established in Zambia, are in debilitated condition (largely attributed to a lack of maintenance and skilled labor) and require policy reform and institutional redevelopment. Currently, the northern and eastern regions of Zambia are linked to the national grid; several ongoing and proposed projects will reinforce reliability and permit export to Malawi. Export to Botswana will be possible when a new 66-kV line is completed. With its newly awarded independence, Zesco is also exploring the possibility of exporting power to Namibia.

Market Assessment. Hydroelectric will likely continue to be the primary source of electricity generation in Zambia for the foreseeable future. In addition to current capacity (identified above), Zesco is considering seven other hydro schemes. The site being most actively considered is at Botoka Gorge on the Zambezi, which could serve both Zambia and Zimbabwe. The current scheme, to be operated in conjunction with Kariba Dam, is designed to provide annual generation of 6.1 GWh from a capacity of 1,600 MW. Consideration of other fuels for electricity generation is unknown; however, Zambia's only coal mine -- Maamba Collieries – was recently saved from foreclosure by a South African bank.

4.1.12 Mauritania

Mauritania is an Islamic Republic in northwestern Africa situated almost entirely within the Sahara Desert. Societe Nationale d'Eau et d'Electricite (Sonelec) supplies electric power to the urban centers of Nouakchott and Nouadhibou as well as some isolated areas in Mauritania. In 1991, Sonelec had an installed capacity of 105 MW – 61 MW hydro and 44 MW diesel – and produced 135 GWh. Interconnection with Mauritania autoproducers (i.e., industrial self-generators), who have 70 MW of installed capacity, may increase reliability.

Market Assessment. Besides interconnection with Mauritania autoproducers, Sonelec also plans to import power, to meet future electricity needs, from the Manatali hydro plant expected to be constructed in Mali.

4.1.13 Egypt

In Egypt, electrical supply and central electrical planning and dispatching are the responsibility of the Egyptian Electricity Authority (EEA). The EEA owns all the major generating facilities and provides bulk power to municipal and regional distribution authorities and agencies. The Country Electricity Authority is responsible for subtransmission operations and the development of a national rural-electrification network. Electricity sales have grown rapidly over the last 10 years – up 70% from 1984 to 1993. But this growth is expected to slow by the end of the 1990s. During this same period, EEAs installed capacity expanded from 6,123 MW to 11,911 MW (95% increase), while peak load increased by 61%, from 4,672 MW to 7,503 MW.

Approximately 9,196 MW (77%) of the installed capacity is in thermal plants, which also contribute about 75% of Egypt's electrical output – 47 TWh in 1992/1993. The remainder is from the large hydroelectric plants at Aswan: the High Dam (2,100 MW), Aswan 1 (345 MW), and Aswan 2 (270MW). The large steam-electric plants operated by EEA are at Abu Qir (900 MW), Abu Sultan (600 MW), Ataka (900 MW), and Shoubrah (1,260 MW). Large gas-turbine plants are at Damietta (750 MW simple-cycle GT and 375 MW combined cycle). Cairo South has 440 MW of gas turbine capacity and 255 MW of steam-electric capacity.

Market Assessment. The three Aswan power plants have virtually exhausted the hydroelectric capabilities of the section of the Nile under Egyptian control, leaving thermal plants the primary near-term option for system expansion. In 1994, Egypt relied on combustion of natural gas (73%) and heavy fuel oil (27%) to fuel its thermal power plants. However, the Ministry of Electricity and Energy reports that by the year 2000, natural gas will be used in all generating units and oil will be saved for export. By 2010, Egypt hopes to have a fuel mix of 9.5% coal, 8.9% hydro, 75% natural gas, and 6.6% nuclear (although long-discussed nuclear projects show little signs of progress). These goals are reflected in EEA's current power plant construction program: development of a $1 billion gas-fired power plant at El-Kureimat (2 x 600 MW), with duel-fuel capability; 630 MW extension (2 x 315 MW) at the 350 MW Cairo West plant; efficiency improvements at the oil/gas Shoubrah plant (4 x 315 MW); and combined-cycle conversion of the 150 MW Cairo South plant. A 90 MW hydroelectric plant is also under construction at ESNA. Increased foreign participation in private power plants and power plant privatization are expected if Egypt eliminates the 6% subsidy on electric rates.

4.1.14 Zimbabwe

The Zimbabwe Electricity Supply Authority (ZESA) was formed from the Central African Power Corp., the Electricity Supply Commission, and municipal electricity departments in Baluwayo, Gweru, Harare, and Mutare. ZESA is the sole authority for the generation, transmission and distribution of electricity in the country.

ZESA's installed capacity is 1,930 MW, consisting of 663 MW at Kariba South and the remainder at coal-fired plants comprised of Hwange (920 MW), Harare (135 MW), Munyati (120 MW), and Bulawayo (120 MW). Most of the privately-owned generation has been dismantled. The tranmission system interconnecting these plants to the population centers runs north to south. Major transmission lines also connnect Zimbabwe with Zambia; Zimbabwe typically imports 10% of its power from Zambia. Interconnections are in progress (or planned) to import electricity from Botswana, South Africa and Mozamique. A 5% Development Levy on all electricity charges has been recommended to defray the cost of these transmission projects, along with needed power plant modernization and refurbishment.

Market Assessment. The severe drought in the early-1990s has changed some of the critical assumptions regarding the desirability of additional hydroelectric expansion. As of 1993, ZESA's expansion plan was geared to reaching 2,000 MW of installed capacity (from 1,930 MW), with sales of 13 TWh per year, by 2000 (an annual growth rate of 3.6%). New capacity would come from two 220 MW units at Hwange by the end of the century, although Kariba South may be expanded to 750 MW. While the desirability of hydro expansion is being questioned, several sites on the Zambesi River are being jointly explored by Zimbabwe and Zambia: Batoka Gorge, Devil Gorge, Mpata Gorge, and Victoria Falls. Plans are furthest advanced for a 800 MW plant at Batoka.

Rural electrification is underway in Zimbabwe, although less than 20% of all households in the country are connected. The government is particularly eager to connect poor urban sections to the grid, to reduce the strain on wood an other biomass fuel resources.

4.1.15 Morocco

The Office National de l'Electricite (ONE) supplies 90% of the electricity in Morocco; Regies Autonomes de Distribution distributes electricity to 10 of Morocco's largest towns. In 1993, ONE's installed capacity was 2,360 MW, consisting of 1,733 MW of steam and gas turbines (73.4%) and diesel units, and 687 MW of hydro power (29.1%). In addition to this domestic capacity, 1,027 GWh was imported from Algeria, and 135 GWh supplied by other generators; greater levels were imported during the two-year drought that ended in mid-1993, when a peak power shortfall of 250 MW existed.

The electrification ratio in Morocco is still relatively low at approximately 25%. A recent program conducted by ONE extended service to 2000 additional rural villages, yet much of Morocco's countryside remains without electricity. The European Investment Bank is currently funding a $73 million power distribution expansion project, which is expected to dramatically affect power availability through much of rual Morocco in the near future.

Market Assessment. To meet the estimated 7% growth in demand, ONE is exploring many options. On the supply-side, ONE currently plans to have 2,940 MW of additional fossil-fuel generated capacity available by 2000. The first two units at Jorf Lasfar (4 x 300 MW) are now in service; the second two units are to be completed by 1999. A consortium, including CMS Generation, has been selected to purchase and operate the plant. Revenues from privatization of Jorf Lasfar are intended to be used to complete other power facilities. In addition to Jorf Lasfar, three sets of 3 x 34 MW gas turbines have been recently completed, and two hydro plants are under construction at Al-Wahda (3 X 80 MW) and Allal El Fassi (3 x 83 MW). A pair of combined-cycle plants are under development at Mohammedia and Kenitra, but it is not yet clear who will build them. ONE has also made an agreement to build a large wind-energy plant at Dakhla.

The Moroccan government plans to spend $1 billion in the near-term on the power sector. At the same time, the private sector was invited to become equity partners in the aforementioned projects. Despite these steps, the basic problem with Morocco's energy sector is the necessity for additional import to compensate for the lack of significant domestic fossil fuel reserves; imported oil currently accounts for 80-90% of the country's commercial energy requirements. One option being explored by Morocco is to obtain royalty gas by providing transit rights for Algerian natural gas shipments to Spain via the Maghreb-Europe pipeline. However, before the Moroccan government can use this gas, a complete gas-distribution infrastructure will have to be constructed.

4.1.16 Cameroon

Societe Nationale d'Elecricite du Cameroon (Sonel) is responsible for the generation, transmission, and distribution of electricity throughout the national territory. It had 755 MW of installed capacity in 1991, most of it being hydroelectric, with diesel providing the remainder. Sonel is 93% owned by the Republic of Cameroo; the remaining shares are held by the French Central Fund for Economic Cooperation.

In 1991, Sonel generated 2,940 GWh; all but 41 GWh (1.4%) came from hydro. The transmission system is divided into four zones: North, an interconnected network supplied by Lagdo hydro station and small diesel plants; Littoral; West, Central, and South, an interconnected network supplied by the Edea and Song-Loulon (388 MW) hydro stations; and the isolated areas. A newly created East zone is supplied at the moment by thermal plants.

Market Assessment. Cameroon has 404-million barrels of proven oil reserves, 113 bcm of natural gas, and considerable untapped hydro potential. At present, almost all generation is hydro-based, with diesel for backup and distributed generation.

4.1.17 Tunisia

Tunisia is a relatively small country of 8.6 million inhabitants situated between Algeria and Libya in North Africa. Approximately 40% of the land area in Tunisia is in the Sahara; some of the land area in south-central Tunisia consists of low-lying salt lakes known as shatts.

Societe Tunisienne de l'Electricite et du Gaz (STEG) was formed in 1962, when Tunisia nationalized its power industry. In 1992, STEG had a total installed capacity of 1,329 MW. Steam and gas-turbine plants dominate the system, with some hydro and isolated diesel. STEG produced 5,479 GWh in 1992; autoproducers generated an additional 702 GWh.

Market Assessment. Over the next several years, STEG plans to boost its capacity to 1,500 MW; one element is a 357 MW combined-cycle plant at Sousse that recently came into service. Except for some isolated diesel units, STEG operates an interconnected system. Rural electrification is underway; to date it supplies nearly 60% of Tunisia.

4.1.18 Algeria

Algeria is a large republic at the western end of North Africa, between Morocco and Libya. More than 90% of the land area consists of gravel-covered deserts, leaving only about 3% of Algeria arable. The country has large reserves of oil and natural gas, and is a major exporter of LNG.

Societe Nationale d'Elecricite et du Gaz (Sonelgaz) is responsible for all public power supply. In 1991, Sonelgaz had a total capacity of 4,877 MW, with 400 MW of captive generating capacity. In addition to providing electricity internally, Sonelgaz also exports power to the neighboring countries of Tunisia and Morocco.

Market Assessment. Since its coal reserves and hydro potential are limited, Algeria plans to take advantage of its proven oil and gas reserves – 9.2 billion barrels and 3.25 tcm, respectively. Sonelgaz hopes to increase its capacity to 9,000 MW by 1999, primarily through the addition of 4,000 MW of new gas-fired steam plants on the coast, 200 MW of gas turbines, and 100 MW of diesels. To meet this goal, Sonelgaz will need to build an average of 600 MW of generating capacity each year along with additional high voltage transmission lines.

4.1.19 Mauritius

This republic in the western Indian Ocean consists of the islands of Mauritius, Rodrigues, and Agalega, and the Saint Brandon Group. The country has a single utility – Central Generating Board (CEB) – which generates and distributes electric power. In 1991, it had a total capacity of 235 MW, producing 425 GWh. Diesels supply power at the Fort Victoria and St Louis plants. The remaining capacity comes from six hydroelectric stations; the newest, Champagne, at 30 MW is the largest. Self-producing sugar estates own another 15 MW; CEB annually purchases about 40 GWh from these facilities.

Market Assessment. To meet future demand, CEB is investigating the construction of a bagasse-fired power plant. It has also scheduled rehabilitation of its small hydro plants.

4.2 Market Assessment: Asia

4.2.1 Nepal

The Nepal Electricity Authority (NEA) – comprised of what was the Nepal Electricity Corporation and the Electricity Department of Ministry of Water Resources – handles all aspects of planning, construction and operation of power plants in Nepal. In 1993, NEA had installed capacity of 277 MW. The largest plants in Nepal are the 69 MW Marsyangdi and the 60 MW Kalekhani I hydro stations. Other major hydro plants include Trisuli (21 MW), Gaudah (15 MW), Devighat (14 MW), and Sunk-Osihi (10 MW). Two hydro stations near completion are the Kulekhani II plant (32 MW) and the Andikerala plant (5 MW).

Utility production in 1993 was 936 GWh, with all but 61 GWh (6.5%) generated by hydro. The Central region accounts for 72% of the nation's consumption, but has only 33% of the population. The Eastern region consumes 14% of Nepal's electricity and over 95% of this energy is imported from India. The Western, Midwestern, and Far Western regions consume Nepal's remaining 9%, 3% and 2% of electricity, respectively.

The electrical systems in the Central and Western regions are interconnected. NEA is linking its six small hydro stations, as well as interconnecting the Eastern region to the Central and Midwestern regions.

Market Assessment. A current challenge for Nepal is the cost-effective, environmentally-acceptable utilization of its tremendous hydropower resources estimated to be in excess of 42 GW. With the cancellation of Arun 3 by the World Bank, when it determined that several smaller projects could produce the electricity more cheaply (than $3800/kW), the Nepalese government turned to the private sector to build its new power plants. In 1993, the government approved a new legislative and legal framework to faciliatate private power development and established an Electric Development Center to serve as a "one stop shop". In early 1995, the government of Nepal announced that it had 1,720 MW of hydroelectric projects available for private sector investment, in addition to several hundred "mini" projects of 100 kW to 1 MW.

4.2.2 Laos

Laos is Southeast Asia's only landlocked country. Mountains cover about 90% of the country. Laos exports over 80% of its electricity to Thailand, and these sales provide about one-half of the country's foreign exchange earnings. The state-owned utility, Electricite du Laos (EDL), has a 261 MW capacity – 190 MW of which is at Nam Ngum hydro plant in Vientiane province; 45 MW comes from a new hydro station near Saravane on the Xeset River; small hydro plants account for another 3 MW; and diesel units make up the remainder. These small stations are scattered throughout five city systems: Luang Prabang, Pakse, Thakhet, Savannakhet, and Vientiane. Both Thakhet and Savannakhet import supplies from Thailand. Country-wide electricity production totaled 900 GWh in 1993, but consumption was only 293 GWh.

Market Assessment. The main populations centers in Laos have access to electric transmission lines; in the near future, EDL plans to extend its transmission and distribution system to reach the country's southern and central provinces. Due to its central position – vis-a-vis the rapidly-growing Thailand and potential improvements in Vietnam – the Lao government is receptive to private development of its considerable hydro potential, estimated to be 20,000 MW. Two projects on the Nam Theun River are planned: Nam Theun 2 is a 600 MW plant under development with two Australian concerns; Nam Theun 1, a 210 MW plant designed for export to Thailand, is under discussion with a Scandinavian-Thai consortium. A third project is the 150 MW Hauay Ho plant, under construction on the Ho River in Champassak Province. While resettlement is not an issue with any of these hydro projects, due to the small Laos population, the major opposition to these schemes is from environmentalists concerned about the affect on fish brood stocks.

4.2.3 Bangladesh

Consumers in this densely populated country have limited access to electricity as supplies from the state-owned utility, Bangladesh Power Development Board (BPDB), reaches only 14% of the population. Electric power outages are frequent in Bangladesh due to aging power plants and distribution facilities; periodic floods and cyclones compound these supply problems.

The majority of the energy resources used for power generation – hydroelectric and natural gas – are located in the East. BPDB's capacity is 2,560 MW; it produces approximately 5.7 TWh per year, with over 50% from natural gas-fired facilities. Electricity sales are predominantly in four major metropolitan areas: Dhaka, Chittagong, Khulna, and Rajshahi. Transmission and distribution losses are estimated to be as high as 35%. The major transmission line – the East/West Interconnector – is energized at only 50% because other necessary facilities are unavailable. When fully energized this 500-MW transfer capacity will enable BPDB to reduce generation in the West, although some of the oil-fired generators will continue to operate in case of single-circuit tripping of the Interconnector.

Market Assessment. To meet the increasing demand for electricity, growing at up to 12% per year, BPDB has estimated that 2,500 MW of new capacity must be added by the year 2000, with another 6,000 MW between 2000 and 2010. Given the government's lack of funds and the generally slow pace of private power development in South Asia, the addition of 10,000 MW of new power plants in the next 15 years seems unlikely.

Nonetheless, the government has defined a two-part strategy to develop new power projects. With the help of the Asian Development Bank (ADB), a provisional power sector reform plan was developed at the end of 1994 with the immediate goal of building a 300 MW gas-fired combined cycle plant in Meghnaghat. The country's Ministry of Energy & Mineral Resources (MEMR) has also suggested several other sites and fuel schemes that it deems appropriate for private power projects and the government hopes that 2,300 MW of private power projects will be developed on a build-operate-transfer (BOT) basis. These developments will not happen without tariff reform, since the lowest tariff charge is lower than the least-cost generating facility.

Beyond Meghnaghat, a second proposed plant would fire coal-bed methane from fields near Jamalganj, while a third plant would burn petroleum products from the natural gas fields of Bakhrabad. A fourth facility is a 300 MW power plant that would use coal from the Barapukuria-Peerganj region in the Western zone. International financing is being pursued by Bangladesh for these and other proposed power plants. The key element in the overall Bangladesh strategy is to have developers ease the burden on the public supply by siting large plants at the nation's refineries, where they could burn surplus production of oil and naphtha. Other parts of the strategy include the establishment of free-trade zones to be served by smaller plants, and the leasing of captive capacity to BPDB.

Finally, a rural electrification program initiated in 1994 is scheduled to link 2000 villages with the national power grid. Thirty-five percent of the project cost is being paid by the Bangladesh government, with the remainder from donor agencies. Related to this electrification program is the formation of the Rural Power Company (RPC); RPC was formed from existing electric power cooperatives to accelerate rural development. Partial ownership of RPC resides with the government's Rural Electrification Board, which has promised to sell some its holdings on the stock exchange after 1997. Currently, the RPC has plans for a 60 MW gas-fired power plant at Mymensingh.

4.2.4 India

India is the second most populous nation in the world with a large but struggling electric power sector. Growth in the period 1990-1995 was 9.4%, with an average growth rate of 7.5% projected for the period 1995-2000. Installed "All India" capacity (in March 1993) was estimated to be 72,320 MW[3], but only approximately 65% is typically available on-peak. "All India" thermal generation in 1992/93 was about 225 TWh.

Three types of utilities operate in India: the State Electricity Board (SEB); Licensees; and government-owned generating companies. The SEBs – of which there are about 12 – control 65% of the country's installed generating capacity. For those projects too large or complex for individual SEBs to develop, the government formed several "Central Sector Power Corporations", including: National Thermal Power Corporation (NTPC) -- India's largest single plant operator; the National Hydroelectric Power Corporation (NHPC); the North Eastern Electric Power Corp (NEEPCO); the National Power Transmission Corp (NPTC); and the Nuclear Power Corp. Since India intends to form a national grid the government decided to transfer all transmission assets of the central sector power utilities to the newly formed NPTC and renamed it the Power Grid Corporation (PGC).

Deliverability of adequate supplies of electricity in India is hampered by equipment availability and T&D losses. The NTPC, India's largest utility with 13,054 MW of installed capacity, reported a 1992/93 load factor of 70%, compared to the "All India" thermal plant load factor of 57%. Increasing the load factor of SEB baseload units is a major planning objective.

NTPC has ambitous plans to increase capacity and improve supply. It is building four super thermal plants at Singrauli (2,000 MW), Korba (2,100 MW), Ramagundam (2,100 MW), and Farakka (2,100

[3] Excludes 6,250 MW of autoproducer capacity and 2,900 MW of capacity operated by five private utilities.

MW). Altogether, NTPC has 10 coal-based projects and five gas-based combined cycle power projects on-line or in development with a total approved capacity of 16,835 MW. Since 1980, NTPC has commissioned 13,054 MW.

Development of new hydroelectric plants is planned by the NHPC and the SEBs. NHPC is presently building new hydro units and has plans for six more (totaling 3,730 MW). The SEBs are also seeking 19 new hydro stations (2,073 MW). The Nuclear Power Corporation, confronted with budget reductions and success with indigenous plant designs and manufacturing, has scaled-back its ambitous plans for 10,000 MW of nuclear capacity by the year 2000, and will instead concentrate on completing six 220 MW pressurized heavy water reactors (PHWRs) and starting construction on its 500 MW design.

Faced with continuing power shortages, many Indian utilities have been exploring private power development in their service territories. The Indian Ministry of Power solicited third-party ownership of new capacity by proposing amendments to its electricity legislation in January 1991. This legislation allows private companies to install their own capacity and/or distribute electricity as a licensee of the SEBs; sale of surplus power from industrial plants is also permitted. Since privatization of the SEBs is unlikely in the near-term, international private power companies will likely invest in power plants rather than utilities.

There are currently five private power utilities in India with installed capacity of approximately 2,900 MW; an additional 6,250 MW is available from autoproducers (9% of "All India" capacity). Estimates of the private power in India range up to 21,000 MW by the turn of the century, but at this point, only private utilities have built "private" plants. The largest "pure" private power projct in India was/is the Dhabol combined-cycle plant (3 x 660 MW) under construction by Bechtel, Enron, and General Electric.

Market Assessment. India is a very large power market. Due to its high growth in electricity demand – past, present and future – large power projects have been proposed to meet this demand. While the NTPC and the NHPC have many large projects under development, private power projects for the SEBs is likely to be the source of most new capacity additions, once the Dhabol situation is resolved. Besides traditional fuels for large power plants (coal, oil/gas, nuclear), India – like China and other Asian countries – is trying to develop small amounts of "alternate fuel" generating capacity. While many comparisons between the Indian and Chinese electric power markets are made, there are significant and inexplicable differences between the power sectors of the two countries. One notable difference is that the Chinese have added new generating capacity at a more rapid pace: installed capacity in India today is only about half that in China and the gap is widening. This has left per capita electricity consumption in India at about 65% of that in China. Compounding the large power needs is the absence of a fully-integrated network, large variations in transmission line voltage and substantial T&D losses, which impact deliverability, reliability and rural electrification.

4.2.5 China

China is currently the third largest producer and consumer of energy in the world. Within China, the Ministry of Electric Power (MOE) is responsible for policy direction, technical guidance and oversight of the power sector. The MOE estimates demand growth of 7-8% per year for the next 10 years (or more), after double-digit growth during the past five years. Heavy industry continues to be the biggest consumer of electricity in China at 61% (1993), with "light" industry the next largest sector at 16%. In 1993, electric power accounted for 32% of total primary energy consumption, almost double its share in 1980. As a reflection, new capacity additions have been averaging 15-20 GW a year; this rate of capacity expansion is expected to continue through 2005. In its ninth five-year plan China outlines a plan to increase installed electric generating capacity from 199 GW in 1994 to 300 GW by 2000, 400 GW by 2010, and 800 GW by 2020.

Under the direction of the MOE are the following electric power systems: national corporations for coal, oil and nuclear operations; five regional electric power corporations; and approximately 12 supra-regional utility organizations, with 18 provincial power grids reporting to them. Four of the regional power grids have capacities exceeding 25 GW; three of the other grids are over 10 GW. In addition, many cities and provinces have their own power companies and there are several other state-owned entities set up to finance and/or construct power plants. However, the relationship between the city suppliers and regional utilities is often obscure.

Regional power networks – covering several provinces – are Central China, East China, Northeast, North China, and Northwest. Provincial grids are in Fujian, Guangdong, Guangxi, Guizhou, Hainan, Shandong, Sichuan, and Yunnan. The remaining two systems – Xinjiang and Xizang – are in so-called autonomous regions. The regional networks and provincial grids are designed, constructed, and operated by the regional electrical enterprises.

Market Assessment. At present, 75% of Chinese generating capacity is thermal (predominantly coal), with the remaining share hydroelectric. This fuel-source distribution is projected to remain constant for the foreseeable future. China is currently developing a mega-hydroelectric plant, the 17,600 MW Three Gorges project. In addition, other giant hydro plants recently completed or planned include: Xiaowan (4,200 MW), Longtan (4,000 MW), Tianshengqiao I & II (2,520 MW), Lijiaxia (2,000 MW), Manwan (1,500 MW), Suikou (1,400 MW), Wuquiangxi (1,240 MW), and Dachaoshan (1,260 MW). Ertan (3,300 MW) is being built with substantial Western equipment and engineering services as was the Guangzhou pumped-storage plant (4 x 306 MW) completed in 1994. A second 1,200 MW plant is planned for service in 1999. Several other pumped-storage plants are under development with Western technology: Shisanling (4 x 204 MW), Tianhuangping (6 x 300 MW).

There are also many large thermal plants planned or recently completed. Many of these plants are located in Shanxi Province, including the Yangcheng (8 x 660 MW) minemouth plant. In addition, 4,000 MW plants are under construction at Taishan and another plant at Ymin in Tibet. In all, China has 40 plant sites at which more than 1,000 MW of capacity is planned or installed; some of these sites are considering installation of clean coal technologies.

There are several reasons for the Chinese emphasis on central station developments. First, there is a large base of domestically constructed units standardized at 50, 100, 200 and 300 MW; and Chinese fabrication and manufacturing facilities are designed for these sizes. Second, coal and nuclear – the technologies of choice in China – are most cost-effective in large units. Third, the Chinese believe that centralized facilities allow the most efficient use of economies of scale for labor and other resources. Fourth, large amounts of power are needed quickly. While most of the emphasis is on large plants, the small-plant business is extremely active; one equipment supplier estimates that 10% of the installed capacity in China are diesel engines.

While the power sector opportunities in China are immense, the obstacles can be formidable. Some of the obstacles that relate directly to small-power production include: First, there is often insufficient revenue from electricity sales to support power plant investment; recent tariff increases are still below the actual cost of production and transmission, this is particularly true in remote areas. Second, China is a large country – almost 10 million km^2; 1.2 billion people live in urban areas along the coast and major rivers, and several hundred million people live in remote rural locations. Third, per capita electricity consumption is approximately 650 kWh/yr (compared to worldwide average of 2,300 kWh/yr), and many rural residents have no access to electricity. It is difficult (to impossible) to accurately predict future electricity growth and capacity needs to serve households with these characteristics.

4.2.6 Pakistan

Pakistan had a total generating capacity of about 11,581 MW in 1994, but shortages at peak periods reached 2,000 MW. Approximately 1,750 MW (15%) is from autoproducers, with the remainder owned by Pakistan's two big utilities: Water and Power Development Authority (WAPDA) and Karachin Electricity Supply Corp (KESC). Of the total, 70% is thermal, 29% hydro, with a single nuclear plant that provides 1%. Oil and gas are the dominant fuels representing 55% and 42% of thermal capacity, respectively. Coal is only marginally used, although there are substantial reserves. At present, electricity is currently available to about 40% of the population.

As of 1991, WAPDA had an installed capacity of 7,039 MW (59% thermal, 41% hydro); KESC had 1,540 of installed capacity (1993). The big hydro plants at Tarbela (3,478 MW), Mangla (720 MW) and Warsak (240 MW) in northern Pakistan are connected to load centers and to the large thermal plants at Guddu (1,154 MW), Kot Addu (440 MW), and Jamshoro (880 MW).

Severe power shortages have existed in Pakistan for decades, which is the result of power plant and transmission inefficiencies and a double-digit growth rate for power. A drought in 1993/94 reduced output from the county's two largest hydro plants by 30%, and even with newly commissioned capacity, load shedding for up to seven hours per day was reported in 1995. Pakistan has proposed that 13,000 MW of new capacity be added, with one-third coming from private power.

Pakistan became the first developing country to provide for private power development, when it promulgated a new policy permitting private power participation in plant construction and operation in 1985. The 1,300 MW Hub River project (4 x 325 MW) now under construction by a private consortium was originally scheduled for startup in 1994; Hub River is now scheduled to be commissioned in 1997.

Market Assessment. Pakistan is blessed with fairly large reserves of natural gas (estimated to be approximately 21,000 bcm), together with 288 million tons of coal and lignite reserves (although much of it is classified as poor quality), and 30,000 MW of hydroelectric potential (10 times the installed base). Therefore, the quantity and diversity of fuel for power production is not an issue.

Major utility power projects in Pakistan include completion of Tarbela (two of four new 432 MW units began operation in 1993), two 100 MW units at Mangla, and eight 22 MW low-head hydro units at Chasma. At Kot Addu, a 450 MW combined cycle block is coming on-line, while KESC plans to build a 210 MW addition at Bin Qasim (Unit 6) by 1196 and a 300 MW addition is under study at Korangi (Unit 5). Other new steam capacity is planned or under construction at Jamshoro and Muzza-Fargah (2 x 210 MW by Chinese suppliers).

China National Nuclear Corp broke ground in 1992 for a 300 MW nuclear unit at Chasma; startup is scheduled for 1998. The World Bank is examining the possibility to provide financial assistance in the recently initiated 1,450 MW Ghazi Barodaa on the Indus River; plans exist for two additional hydro plants, including Basha (3,360 MW) and Kalabagh (2,400 MW).

The government of Pakistan believes that 14,500 MW of new capacity must be added by 2000 to fill the current supply gap and meet future electricity demand, forecast to continue growing at 10% per year. Pakistan would prefer that the private sector development most of this capacity, by constructing 2,000 MW per year, equally divided between coal, hydro and oil-fired capacity. Judging by the Hub River experience, it is difficult to predict whether utilities or private power will be the dominant force in meeting this demand.

As in most other developing countries, plant utilization is an issue for utility management. Pakistan recognizes that increased utilization factors (which are related to increased reliability of the T&D system), expansion of cogeneration, and expanded market services, would all increase available capacity. To this end, Pakistan has announced restructuring plans for the utility sector. The strategy is to 1) urge existing industrial plants to install their own generating plants; 2) facilitate foreign investment in industrial parks where captive generators can sell surplus power to the national grid; and 3) privatize all or parts of WAPDA and the government's stake in KESC. None of this, however, will occur without effective tariff reform.[4]

4.2.7 Sri Lanka

Sri Lanka is an island republic in the Indian Ocean off the southeastern coast of India. The Ceylon Electricity Board (CEB) is the sole state authority responsible for generation and transmission, and a large share of the distribution of electricity on the island. The Lanka Electricity Company (LECO) is responsible for distribution on the southern and western coastal areas. At the end of 1993, CEB had a generating capacity of 1,409 MW, of which 80% was hydro with the remainder a mix of oil-fired steam turbines, gas turbines, and diesels.

Market Assessment: The island grid is interconnected and with the addition of a large hydroelectric plant on the Mahaweli River, the CEB has an adequate reserve margin. About one-half of the hydro potenial on Sri Lanka is being utilized; however, in order to diversify its fuel mix the government is shifting toward the construction of thermal plants.

Sri Lanka is hoping for private sector investment, because the World Bank and Asian Development Bank are reluctant to make further loans to the CEB for conventional power generation. Loans for DSM and power delivery projects are still being considered since 70% of the island households (300,000) still have no access to grid electricity. One private power project, being constructed on a BOT basis is the 300-MW facility at Trincomalee. Other private projects planned by the CEB include 44- and 204-MW powerplants at Kotmale Oya.

4.2.8 Indonesia

Indonesia, the fifth most populous country in the world, is rich in many natural resources, including coal, oil, gas and timber. Less than one-half of the country's 13,000 islands are inhabited. Sixty percent of the population (187 million) reside on the main island of Java; 8.8 million in Jakarta.

[4] Since almost all generation and transmission equipment is imported devaluation is important; the rupee has declined in value (relative to the U.S. dollar) from 10:1 in 1980 to 31:1 in 1995. In addition, cross-subsidization is an issue, whre commerical/industrial customers are being charged electricity rates that approximate marginal delivered costs, while residential customers are paying one-half the recovery rate,with many paying nothing at all. Lastly, WAPDA and KESC have attempted to equalize tariffs, eventhough WAPDA is hydro-dominated and KESC serves mostly an urban environment with thermal plants.

The national electric utility is PT PLN Persero – formerly known as Perusahaan Umum Listrik Negara (PLN). PLN has engineered a five-fold increase in generating capacity since 1970; in addition, electricity sales have increased by 32% per year since 1980 (6.5 TWh in 1980 vs. 27.7 TWh in 1990). Total PLN electricity production in 1991 was approximately 30.3 TWh (68% of total generation); this was supplemented by autoproducers who provided an additional 14.4 TWh. Even with all of this capacity and sales growth, less than 10% of the Indonesian population – scattered among seven island groups – has access to power supply.

Indonesian power demand is projected to increase by about 15% per year. At present PLN is meeting demand with 9,100 MW of installed capacity, consisting of steam-electric (43%) and hydroelectric (23%) plants. Due to the fragmented nature of its service territory, diesel power plants are numerous and comprise approximately 20% of capacity. In addition, PLN has about 140 MW of installed geothermal capacity that supplies 3.2% of the country's output. The remaining 13% of capacity is in gas turbines, but this is the fastest growing segment of PLN capacity.

Indonesia is one of the world's major oil exporters and the largest exporter of LNG. Together these fuels provide some 40% of total export revenue, and the government is intent on maintaining high levels of export for as long as possible. With domestic oil consumption increasing at about 5% per year, and little prospect of major new discoveries, Indonesia may cease being a major oil exporter early next century. This leaves coal and gas as the fuels of choice for power generation; and gas exports – via LNG – may replace oil as the means for government revenue generation in the future.

Indonesia coal reserves are estimated at 32 billion tons, much of it high quality. Coal production in 1993 was 28 million tons/year; with exports accounting for 19 million tons. Several large coal-fired power stations have recently been completed or are under construction on East Java; most notably Paiton, where the first project financed 2 x 600 MW units were constructed and another 2 x 600 set is under construction. Besides coal, natural gas is the next most desirable fuel for power generation. Indonesia has proven reserves of 74 tcf and gas production of 2 tcf/year, half of which is currently exported to Japan as LNG; LNG exports to Korea and Taiwan are also under development. The remaining gas is burned in large gas turbine and combined cycle power plants such as Gresik (1,500 MW), Tanjung Priok (1,200 MW), and Tambok Lorok (500 MW). These, and other smaller gas plants, have developed since they could be constructed faster and at a lower capital cost than coal-fired power stations to meet the rapid growth in electricity demand.

Indonesia also has substantial hydroelectric resources – perhaps as much as 35,000 MW – but it is mostly located in Irian Jaya and Kalimantran, far from load centers. Another renewable resource, geothermal, could have up to 10,000 MW of viable capacity. Several hundred megawatts of geothermal power is under development by PLN, with approximately 500 MW available for private power.

Market Assessment: With Paiton as the flagship project, the Government of Indonesia (GOI) hopes to add 10,000 MW of new capacity from 1995-1999, largely from private power entities. The second phase of Paiton (2 x 610 MW) is currently under development by Mission Energy, with a second pair of 600-MW units to be built by a team led by Siemens. Electricity costs for the Mission Energy plant are front-end loaded starting at 8.56 cents for the first six years, dropping to 5.54 cents in the final 18 years. PLN's average tariff is about 6.6 cents at present.

Indonesia needs new capacity very badly, but the government and PLN are financially strapped, and privatization of PLN appears unlikely. So, private power holds considerable promise if bidding and financial arrangements can be more transparent and open. In addition, PLN cash flow would be greatly improved if tariffs could be raised. Compounding these matters, PLN hopes to install thousands of new low- and medium voltage transmission lines to rural areas, with the goal of electrifying 2,500 Indonesian villages.

4.2.9 Myanmar

The state-owned utility Myanma Electric Power Enterprise (Mepeum) holds an effective monopoly on electricity supply in Myanmar (Burma). Generating capacity in 1993 was 1,151 MW consisting of hydroelectric plants, oil-fired steam turbines, gas turbines, and isolated diesel units. The 196 MW Lawpita hydroelectric plant on the Irrawaddy River provides the bulk of Mepeum's supply, which totals 980 MW (85% of country-wide generating capacity). Total generation in 1993 was 3.2 TWh, roughly one-third from Lawpita. Mepeum operates three grids interconnected by 230-kV line, which enables the transfer of excess capacity from one system to another.

Market Assessment: Hydroelectric resources in Myanmar are immense, estimated at 108,000 MW. To meet long-term energy demands -- and possibly serve an export market -- Mepeum has several hydroelectric stations under consideration, either for its own development or for construction by private power developers. These include Paunglaung (280 MW), Bilin (240 MW), Kunchaung (84 MW), Baluchaung (28 MW), Zaungtu (18 MW), and Yenwe (16 MW). The country's other energy-producing resources include 145-billion barrels of oil, 289 bcm of natural gas, and 119-million tons of subbituminous coal.

Reportedly, Chinese and Thai developers are actively involved in developing several of the hydroelectric sites for power export. China has agreed to construct the Paunglaung plant (280 MW); a 6,000 MW hydro plant on the Salween River has been discussed, with 80% of the electricity exported to Thailand. Finally, a Thai logging company has signed a MOU to build two hydro plants in Shan State with a total capacity of 125 MW; 90% of this power would be exported to Thailand.

4.2.10 Vietnam

Since 1992, the Vietnamese economy has been growing at about 8% per year. This is largely attributed to a gradual transition from a centrally-planned to a market economy. Over the next five years, electricity demand is expected to grow at a faster pace than the economy, 12-14% per year. Long-range forecasts published by the Ministry of Energy estimate domestic power demand of 110 TWh by 2015, a ten-fold increase from 1994 levels of 12.7 TWh. To generate this electricity, investment of $7.5 billion is needed: $6 billion for generating facilities and $1.5 billion for T&D projects.

Currently, 75% of Vietnam's electricity is from hydro plants, the largest of which at Hoa Binh (1,930 MW) was completed at the end of 1994, with thermal plants accounting for 17% of output and gas turbines the remainder. In 1994, Vietnam had total installed capacity of 4,100 MW. Completion of the Russian-supplied Hoa Binh hydroelectric plant increased electricity output by 15% from 1993 to 1994. Vietnam hopes to export surplus power to Laos and perhaps China (southern provinces) to help defray the cost of its power system expansion.

Until recently, Vietnam had three government-owned power companies operating under the auspices of the Ministry of Energy: Power Company No. 1 served the northern region, Power Company No. 2 served the southern region, and Power Company No. 3 served the central region. In 1995, these three power companies were consolidated into a new entity called Electricity of Vietnam. The generating capacity that comprises Electricity of Vietnam is a mixture of vintages and manufacturers: Russian and

Eastern European manufacturers in the north, and American and Japanese in the central and southern regions.

Although as yet largely undeveloped, Vietnamese energy resources are substantial and currently account for approximately one-third of the country's export earnings. Estimates of hydroelectric potential are as high as 15,000 MW, with 2 billion tons of coal, 170 million tons of oil and 106 bcm of natural gas.

Market Assessment: Due to its large hydroelectric resource, Vietnam expects much of its future electricity capacity to be hydraulic. Several sites are already under development along the Dong Nai River: Bonron (320 MW), Can Don (60 MW), Da Mi (172 MW), Dong Nai 4 (250 MW), Dong Nai 8 (120 MW), and Nam Thuan (300 MW). A number of thermal plants are also under construction: Phu My 2 Phase 1 (200-300 MW gas turbine); conversion of three 37.5 MW gas turbines to combined cycle plants at Ba Ria (170 MW); and rehabilitation and conversion of the Thu Duc plant to gas.

Since Vietnam cannot afford to make all the necessary investments itself, foreign companies are expected to construct some of the new generating capacity; one captive power project is being jointly developed by BHP (Australia) and General Electric (U.S.) at a new fertilizer complex near Ho Chi Minh City. Vietnam also hopes to interconnect the country through the formation of a master plan for rural electrification.

4.2.11 Philippines

The Philippines has a population of 65 million spread over 7,100 islands; it therefore resembles Indonesia insofar as infrastructure requirements, but lacks the large oil and gas reserves. Philippines is also unique in Asia (with the exception of Japan) as having the most diverse and advanced electric utility system.

National Power Corporation (NAPOCOR) is a large Phillipine utility that provides almost all of the utility-owned generation to the three principal islands: Luzon, Visayas, and Mindanao. However, NAPOCOR is more of a power wholesaler than a retail utility. The Philippines is divided into six separate grids corresponding to the main island or island groupings of Luzon, Mindanao, Cebu, Negros-Panay, Leyte-Samar, and Bohol. The single largest electricity distributor is Meralco, the privately-owned distributor for four cities – Manila, Quezon City, Coloocan, and Pasay – and adjoining municipalities commonly referred to as Metro Manila, which sells approximately 75% of NAPOCOR's generation. There are about 15 other private or municipal utilities in the country. In addition, there are 120 rural electric cooperatives, whose operation is overseen by a separate government agency, the National Electrification Administration (NEA).

Rural electrification programs are vital to stem the urbanization tide that threatens to overwhelm many rapidly-growing Asian cities. The Philippine program is very aggressive: by 1992 (after 23 years), cooperatives were serving 3.2 million consumers with electrification levels of 60%. The goal is for 77% electrification by 2000. This is viewed as an ambitious target, and given recent financial and operating problems, will only be achievable with attention to fundamentals and the availability of sufficient electricity.

Market Assessment: While there are sufficient coal reserves to support some expansion of coal-fired generating capacity, they are not located near current load centers. With limited oil/gas reserves, the Philippines will probably expand its already significant geothermal power plant capacity (presently 22% of NAPOCOR output). There is an active auto producer (i.e., captive power) segment, and there is considerable potential for alternative fuel development. One possibility is bagasse (sugar cane waste) combustion at sugar mills; solar power may also assist in the electrification of remote areas. Still over 50% of utility generation is oil-fired, further exacerbating balance-of-payment problems.

In the near-term, NAPACOR is hoping that private power developers will construct most new projects. Since 1987, when the government invited private sector investment in power generation there has been a positive response; in 1994 alone, 1,600 MW of private power was built together with 150 MW of utility capacity.[5] To respond to peak power demand, NAPOCOR has also built a number of power barges with big diesel engines and simple-cycle turbines.

The government estimates that 20,698 MW of capacity additions are needed to meet demand in the 1993-2005 period. The new capacity will likely consist of: hydro 1,872 MW; geothermal 1,673 MW; coal 12,400 MW; and oil/gas 4,753 MW.

4.2.12 Papua New Guinea

The Electricity Commission (Elcom) is the principal electric utility in Papua New Guinea. It owns and operates 19 discrete power systems; the two largest are in Port Moresby and Ramu. In 1992, Elcom had total capacity of 252 MW and generation of 624 GWh. On Ramu, capacity is 111 MW – 87 MW are hydro and 24 MW are in the form of diesel and gas turbines. The Port Moresby system has an installed capacity of 105 MW, of which 62 MW are hydro and 43 MW are diesel and gas turbines.

Market Assessment: Baseload capacity is served by hydroelectric capacity; there is an estimated 15,000 MW of future potential. Grid connection in both Port Moresby and Ramu is extremely difficult due to the topography.

4.2.13 Thailand

The Electric Generating Authority of Thailand (EGAT), the major power generator in Thailand, had 12,900 MW of capacity in 1994; 47% thermal, 32% combined cycle, 20% hydoelectric and 2% simple-cycle turbine. During 1994, peak demand was 10.7 GW, a 10% increase over 1993, but considerably lower than the 14% rate experienced between 1987-1991.

EGAT has over 3,100 MW of new capacity under construction or committed; by the year 2011, EGAT hopes to have 44,000 MW available to the grid. This represents the addition of 1,000-1,500 MW per year. Of this 75% is expected to be thermal plants, 15% combined cycle, with the balance hydro and simple-cycle turbine plants. In 1992, EGAT had the following fuel distribution for power generation: natural gas (44%); lignite (20%); heavy fuel oil (28%); and hydro (5%).

Lignite consumption is expected to increase when EGAT completes the two additional 300 MW units

[5] One of the first private power plants in Asia was built at Navotas near Manila (3 x 70 MW) by Hopewell Holding Company in 1991; a fourth unit was added in 1993, and Hopewell is now building a 700 MW coal plant (2 x 350 MW) at Pagbilao, and a larger, 1,320 MW coal-fired plant at Sual in Pangasinan Province (2 x 660 MW). Other completed private projects include: hydro plants in Banguet Province (22 MW); three diesel plants developed by Enron (241 MW); two combined cycle blocks at Limay Bataan (2 x 300 MW); a refurbished hydro plant at Binga (100 MW); and a variety of other diesel power plants. Private power developers are also active in the development of geothermal power; one prominent participant is the Philippine National Oil Co. (PNOC) which is working on a 120 MW plant at Mount Apo and 660 MW in two blocks at Tongonan, Leyte.

at Mae Moh (2,600 MW). A severe air pollution episode at the plant induced EGAT to install FGD scrubbers on the newest units; it was also forced – by public pressure – to cancel the proposed Ao Phai plant (4 x 700 MW). Severe air pollution in the capital also caused EGAT to switch to low-sulfur fuel oil in its urban plants and to natural gas combined cycle at its newer plants, such as the 1,200 MW Wang Noi. There is also environmental concern over the construction of new hydroelectric facilities; EGAT was forced to redesign the dam a Pak Mun to minimize displacement of local residents.

The Metropolitan Electric Authority (MEA) distributes the power produced by EGAT througout Bangkok, and the provinces of Samutprakarn and Nonthaburi. The Provincial Electric Authority (PEA), aided by a small number of diesel engines, supplies rural areas and other cities with power.

Market Assessment: Thailand's National Energy Policy Committee announced in early 1995 that Thailand will no longer build dams for power production. Rather, it will encourage importing electricity and promote private investment in other forms of electricity generation. EGAT was ordered by the Committee to cancel its plans to build two hydroelectric power projects (Kaeng Krung Dam in Surat Thani, and Mae Lamat Luang Dam in Tak) on the grounds that they would severly damage the surrounding environment and ecological systems. Such concerns will hamper any large-scale exploitation of the country's remaining 6,000 MW of hydroelectric potential. As a result, natural gas is likely to be the fuel of choice for power generation.

Thailand has proven reserves of 6.4 TCF, and in 1994 the Petroleum Authority of Thailand (PTT) concluded an agreement to import gas from Myanmar's Yadana gas field, which has recoverable reserves estimated at 5.8 TCF. PTT is also looking to increase domestic production from the Gulf of Thailand and hopes to import up to 10 million tpy of LNG. This gas will be needed to offset the use of coal in power generation that may be stymied by environmental activism. In March 1995, EGAT cancelled Ao Phai and two lignite-fired plants at Mae Kham and Lampang.

To meet future power needs, private power options are emerging in Thailand. As an interim measure to full privatization, EGAT created a subsidiary called the Electricity Generating Company (EGC) and then in October 1994 sold it the Rayong combined cycle plant (1,200 MW). In addition, EGAT hopes to encourage additional production from autoproducers, who currently have 10% of the installed capacity, and private power developers, who were offered 3.8 GW of projects for completion by 2002.

4.2.14 Malaysia

Malaysia's relatively low population density, wealth of natural resources, and central location in the ASEAN have resulted in an expanding economy and large growth in electricity demand. The country's largest utility, Tenaga Nasional Berhad (TNB) which serves West Malaysia, expects power sales to increase by 10% per annum through 2000. Estimates for peak demand of 9,500 MW by 2000 correspond with capacity additions of 650 MW/yr. By 1997, TNB is planning to have 9,500 MW of installed capacity, together with an additional 4,500 MW from private power developers. Two other utilities serve the remainder of Malaysia: Sarawak Electricity Supply Corp (SESCO) and Sabah Electricity Board (SEB) provide electricity to the states of Sarawak and Sabah on the large island of Borneo (East Malaysia) that they share with Brunei and Indonesia. Overall, TNB produces about 90% of the electricity in Malaysia with installed capacity of 5,909 MW (1993).

Market Assessment: TNB has adopted a four-fuel strategy and is busy diversifying its fuel base. Coal-fired capacity was introduced at two 300 MW triple-fuel units constructed at Sultan Aziz. Currently, TNB has two large construction projects: a 600 MW hydroelectric plant at Pergau for service in 1996, and two 500-MW triple-fuel units at Sultan Aziz. TRB continues to order and build gas-turbine and combined-cycle power plants to avoid power shortages, as occurred in 1992. Recent projects include: conversion of GTs at Pasir Gudang and Paka to combined-cycle operation; a 220 MW GT plant at Malacca; a 330 MW extension at Pasir Gudang; and six gas turbines at Kajang. In addition, there are six private power projects totaling 4,000 MW slated for operation in 1996: a 720 MW gas-fired combined cycle plant at Kuala Langat; two 405 MW combined-cycle blocks at Paka and one 405 MW block at Pasir Gudang; a 1,300 MW (2 x650 MW) combined-cycle plant at Lumut; a 440 MW (4 x 110MW) GT facility at Port Dickson; and four 123 MW gas turbines at Teluk Gong. With all this new capacity the government of Malaysia has put a halt on new development while it reassess private power developments and the price offered – TNB reported signed contracts paying $0.06/kWH, insuffucient to earn a profit on its own power investments.

Power plant construction is also underway in both Sabah and Sarawak. In Sabah, a refurbished 14 MW gas turbine was installed in 1993, while Sesco installed new turbine equipment at Kuching and Bintulu. In addition, on Sarawak with 20,000 MW of untapped hydro potential, a phased development of 16,000 MW of hydroelectric capacity is planned at Bakun.

To interconnect the land areas, there are many transmission projects, including several submarine cable interconnections.

4.3 Market Assessment: Central/Eastern Europe

4.3.1 Romania

The Romanian Electricity Authority (RENEL), formed in 1990, has responsibility for most of the generation, transmission, and distribution of electricity in the country. RENEL has installed capacity of 20,632 MW: 5,783 MW of hydro; 8,614 MW of lignite-fired; and 6,235 MW is oil- or gas-fired. Romanian autoproducers and other generators have an additional 1,400 MW. RENEL generated 53.8 TWh in 1994, with sales of 44.3 TWh. RENEL owns 96 % of the installed generating capacity in Romania and provides 97% of its electric power.

Market Assessment: As with most Eastern European and FSU countries, the electric power industry in Romania has shrunk substantially as state-owned industries closed or were reorganized. Today, Romania has excess generating capacity and a poorly-developed subtransmission and distribution system. One notable sign is that while gross consumption declined to 2,453 kWh/capita (from 3,614 kwh/capita in 1989), household consumption increased from 189 kWh to 290 kWh during that same period.

To meet future demand, Romania is attempting to complete its first (of five) 700 MW nuclear plant at Cernavoda. RENEL also has 1,200 MW of hydroelectric capacity under development, and 1,020 MW of thermal capacity. RENEL also hopes to modernize 5,800 MW of existing capacity; 42% of the country's generating stock is over 20 years old and requires upgrading. RENEL is also trying to reduce its dependence on indigenous lignite; it hopes to use more natural gas and imported hard coal.

4.3.2 Poland

A state-owned holding company, Polske Sieci Elektroenergetyczne (PSE), was established in 1990 to handle dispatch, maintenance and development of the transmission system, electricity import/export, and coordination of power system development. The electricity dispatched by PSE is sold by 33 state-owned enterprises, while 37 generating companies operate most of the 33,171 MW of installed capacity (1994). Of this, 57% is in hard- coal fired plants, 27% in brown-coal plants and 3% in hydro stations. In addition to PSE, the Ministry of Industry and Trade, and Ministry of Privatization, also operate 13 hard coal generating companies and 21 hard coal CHP companies combined. Autoproducers have 6% of the country's generating capacity.

Market Assessment: PSE estimates that Poland will need 5,100 MW of new capacity by the year 2000 and an additional 8-12,000 MW by 2010. Some of this capacity might be recaptured through efficiency upgrades. The government's long-term strategy includes the replacement of 3,000 MW of pulverized coal capacity by fluidized-bed boilers, gas-fired powerplants and the retrofitting of low-NOx burners on existing plants. This strategy also reflects a law passed several years ago requiring a 70% reduction in powerplant SO2 emissions by 1997. Four of the twelve brown-coal fired plants at Belchatow are being equipped with FGD units; a magnesium FGD units is being installed on a 100 MW boiler at the 550 MW Skawina station.

4.3.3 Bulgaria

In 1993, Bulgaria had installed capacity of 12,000 MW (50% thermal, 35% nuclear, and 15% hydro). Production was approximately 45 TWh, of which nuclear supplied 12 TWh (27%). The state-owned electricity company is Natsionalna Elektricheska Kompania (NEK). The overriding issue in the Bulgarian electricity sector is the country's nuclear power program: two of the four nuclear units at Kozloduy were built in 1974/75, are among the oldest of the Russian V-230 reactor design, and are in poor condition. Various financing and management arrangements have been proposed to resolve the issue, but replacing the nuclear capacity means increasing the utilization of the country's large lignite-fired plants and their associated air pollution.

Market Assessment: Bulgaria hopes to build six new coal- and lignite-fired plants totaling 1,500 MW to replace obsolete equipment. The country also plans to install FGD units on two existing and all future coal/lignite-fired plants; it also hopes to convert several 50 MW coal-fired boilers to fluidized bed combustion.

4.4 Market Assessment: Middle East/Near East

4.4.1 Turkey

At year-end 1992, Turkey had installed capacity of 18,714 MW, with 67.3 TWh in generation. Electricity sales were about 55 TWh with industry consuming 58%. In 1993, the Turkish government issued a decree that split the Turkiye Elektrik Kurumu (TEK) – the state-owned enterprise (SEE) that had produced and distributed power throughout Turkey – into two separate public companies: Turkiye Elektrik Uretim-Iletim A.S. (TEAS) for generation and transmission, and TEDAS for distribution. TEAS has about 18,500 MW of installed capacity: 40% hydraulic and 60% fossil fueled (lignite 35%; natural gas 16%; fuel oil 8%; and hard coal 2%). TEAS also maintains high-voltage transmission links with Bulgaria, Georgia, Romania, and Russia. Although hydro plants represent 37% of installed capacity, they account for up to 50% of generation in peak flow situations.

Turkey's largest powerplants include: 1,376 MW coal-fired Afsin-Elbistan; 1,340 MW hydroelectric Keban; 2,400 MW hydroelectric Ataturk; and two gas-fired combined-cycle plants at Ambarli near Istanbul (1,350 MW) and Hamitabat (1,200 MW).

While TEAS dominates the Turkish electric power supply industry, private entities are growing in importance. The major private power suppliers are Cukurova Electric in Adana and Kepez Electric in

Antalya; between them they have 600 MW of hydroelectric capacity. Cukurova has six hydro plants (480 MW) and a combustion turbine plant at Mersin (4 x 27 MW); Cukurova is considering converting Mersin to a combined-cycle plant and has obtained World Bank credit for a new 510 MW hydroelectric plant on the Ceyhan River. Kepez Electric has three hydroelectric plants totaling 130 MW and is developing four additional hydroelectric projects (Beskonak, Alarahan, Esen and Sinanhoca).

Market Assessment: Electricity demand in Turkey is expected to increase to over 300 TWh in 2010, growth of about 8% per year. This would require generating capacities to expand to 33,400 MW by 2000 (178% from 1992 levels) and 58,000 by 2010 (310%). In the near-term, Turkey plans to increase its production of fossil fuels (coal, oil, gas); double or triple its coal imports; and build additional gas transmission capacity from Russia. However, by 2010, some forecasts indicate that indigenous oil/gas supplies will be depleted, forcing Turkey to rely increasingly on its lignite and hydroelectric resources.

Turkey is encouraging private power development, but so far progress has been slow; only the Izmir coal-fired power plant and a 227 MW lignite-fired BOT project near Orta are proceeding. In its latest plan, Turkey envisions that 32,435 MW of its planned 48,000 MW expansion by 2010 will be constructed by private power developers.

4.5 Market Assessment: Central/South America

4.5.1 Peru

Peru is the third largest country in South America in land area, and fourth largest in terms of population. Peru's electric-supply system is run by the state-owned Empresa Publica de Electricidad del Peru (ElectroPeru) and its ten regional subsidiaries. ElectroPeru has a total installed capacity of 2,700 MW, with hydroelectric stations (2,000 MW) accounting for 75% and thermal plants for the remainder. In 1993, about 80% of ElectroPeru's output of 14.3 TWh was hydro-based. Auto producers in Peru – largely copper, zinc, silver and iron-ore mines and smelters – have total installed capacity of 1,400 MW (50% of ElectroPeru capacity), some of which is connected to the grid. Most of the autoproducer plants are oil-fired diesels and steam turbine generators. Neither ElectroPeru nor the autoproducers burn any coal or gas; Peru now imports most of its oil, even though it has some 350 million barrels of reserves.

ElectroLima's capacity only suffices to satisfy one-half of the normal demand by metropolitan Lima; the remainder is provided by ElectroPeru. ElectroPeru and ElectroLima, which provide electricity to only 35% of the population, have not added a new hydroelectric plant in almost 20 years, and almost 50% of its themal capacity (310 MW) is older diesel machines. Only a region called the North Central System is interconnected at the present time.

Market Assessment: Peru expects power demand growth to be 4% per annum. In response, ElectroPeru hopes to construct over 1,200 MW of new capacity over the next ten years, 40% in new hydro plants and the balance in gas- and oil-fired thermal plants. Peru has about 74,000 MW of untapped hydroelectric capacity, when its rivers are flowing at normal levels. An expanded role for natural gas is contingent on the construction of a 500-mile pipeline linking the coast to Camisea – a large gas field discovered in the mid-1980s. Peru has very small coal reserves.

The ability of ElectroPeru and ElectroLima to meet future generation needs is questionable due to lost revenue due to terrorist attacks (on transmission towers), low tariffs and high generating costs. In response, the stage has been set by the government for some of Peru's future capacity needs to be met by private power developers. Recent degrees (Supreme Degree 162-92-E and Degree Law 25844) repeal restrictions on foreign investment and permits the government to grant concessions to foreign corporations/individuals. Privatization of ElectroPeru and ElectroLima is proceeding, but the sale of assets have been deferred.

4.5.2 Columbia

Columbia has the third largest population in Latin America and is rich in energy resources. Initially all of Columbia's power plants were privately owned, largely by the mining industry. Today, Columbia has three state-owned utilities that generate power and perform other utility functions: Interconextion Electrica S.A. (ISA); Instituto Colombiano de Energia Electrica (ICEL); and Corporaction Electrica de la Costa Atlantica (Corelca). ICEL coodinates Columbia's national electrification plan and distributes power to rural areas through 13 electric companies it owns or controls. The two major municipal utilities are Empresa de Energia de Bogota (EEB) and Empresas Publicas de Medellin (EPM). EEB and EPM own approximately 15% of Columbia's generating capacity, respectively. Together they deliver power to 40% of the population.

Columbia has 9,400 MW of installed capacity; almost 80% is hydroelectric, with 16% fossil steam and the remainder gas turbines and diesel power plants. Load growth is expected to expand at a rate of 6% per annum. To meet this demand, domestic utilities will have to add between 2,000-3,000 MW of capacity before 2000, 60% of which is currently expected to be hydroelectric. In addition to its 93,000 MW of hydroelectric potential, Columbia has estimated coal reserves of 16.5 billion metric tons and 120 bcm of natural gas reserves.

Market Assessment: By most accounts, the electric power sector in Columbia is in critical need of private-sector involvement. Investments in new generation capacity have dropped steadily during the past ten years, creating a near-term capacity shortfall of up to 1000 MW. As a result, the government issued an emergency decree removing all restrictions on ownership of private power plants, once a project is approved by the Ministry of Mines and Energy. Several large utility power projects are already underway, including the 340 MW Urra hydroelectric plant in Cordova province. To coordinate financing of electric sector investment, Columbia created Financiera Electrica Nacional (FEN) to mobilize domestic savings and conduct foreign credit operations.

4.5.3 Panama

A 1992 government committee recommended that several state-run enterprises, including the Instituto de Recursos Hidraulicos y Electrificacion (IRHE) – the state-owned electric utility – to be privatized and that all new generating plants in Panama be constructed by the private sector. Except for serving the Canal Zone, IRHE is the sole power supplier with installed capacity of 887 MW. IRHE is two thirds hydro – dominated by the 300 MW Edwin Fabrega station on the Chiriqui River (3 x 100 MW) – and one-third from older oil-fired steam, gas turbine and diesel plants. The Panama Canal Commission, a U.S. government agency, owns and operate 151 MW of capacity; two hydroelectric plants with a combined rating of 60 MW, and the Miraflores station consisting of 55 MW and 36 MW of steam and gas turbines, respectively. Panamanian autoproducers have a total installed capacity estimated at 57 MW.

Market Assessment: Before the Privatization Framework Law, IRHE expected to add another 205 MW of capacity by 1999; most of which would be at the Bahia Las Minas station where IRHE planned to add an 80 MW diesel-fueled combined cycle plant, convert two simple cycle gas turbines to combined-cycle units, and rehabilitate 80 MW of steam-turbine capacity. IRHE had also been examining a 150 MW coal-fired station (2 x 75 MW), and several other hydroelectric plants. Since Panama has no significant fossil fuel reserves it would require them to be imported; hydroelectric potential is estimated at 6,600 MW. To date, private sector investors have not had much interest in Panama, despite its tax exemptions, no restrictions on repatriation of profits and use of the U.S. dollar as currency.

4.5.4 Chile

The topography of Chile makes provision of electric power difficult: it is 4,345 km long and 170 km wide; the bulk of the population, industry and arable land are in the central valley between the Andes Mountains in the east and the Pacific coastal mountains to the west. Today, Chileans get 90% of their electricity from three large utilities: the investor-owned Empresa nactinal de Electricidad S.A. (Endesa) and Compania Chilena de Generacion Electrica S.A. (Chilgener), and the state-owned Empressa Electric Colbun-Machicura (Colbun). The state also owns Empresa Electrica del Norte Grande (Edelnor), the power generator and distributor in the fast-growing nothern mining region. Together, Endesa, Chilgener and Colbun have a total installed capacity of 3,200 MW; autoproducers and regional utilities have another 1,200 MW. Nationwide, hydroelectric plants (mostly owned by Endesa) account for 2,800 MW (64%), steam-electric 1,000 MW, oil-fired gas turbines 425 MW, with diesels generators the remainder.

Virtually all of the utility capacity feeds the Central Interconnected Systesm (SIC), which comprises more than 7,500 km of transmission lines. Edelnor has another grid serving the autoproducers in the northern region. In the far north – Norte Grande – a separate grid known as the Sistema Interconectade del Northe Grande (SING) is dominated by independent producers. The southern zone comprises several isolated systems with an installed capacity of 46 MW.

The larger Chilean generators belong to Centro de Despacho Economico de Carda (CDEC), which is responsible for determining the sale prices of electrical energy among the generating companies. Sale prices are regulated by a marginal tariff system established in 1982; sale prices charged to distributors correspond to so-called "node prices" determined by another government authority, Comision Nacional de Energia (CNE).

Market Assessment: To meet an expected 5% annual growth in electrical demand, Chile plans to add approximately 1,500 MW – 55% thermal and 45% hydraulic. Chile currently imports low sulfur coal, to supply its thermal plants, which are typically sited along the coast. It also imports oil and natural gas from Argentina, since most of its own natural-gas reserves (119 bcm) are located in the far south. New pipelines to transport gas are under development to fuel a series of gas-fired combined cycle power plants.

CNE is also interested in acquiring clean coal technologies to intensify development of its 4,600 million metric tons of coal reserves. However, higher-than-expected recovery coal costs and high sulfur content in the Coronel-Lota-Concepcion region caused new mining operations to be closed. At the same time, new deposits of subbituminous coal have been discovered along the Straits of Magellan.

Although all fossil fuels will be used in the future, Chile is very interested in exploiting its 26,000 MW of hydroelectric potential. Recently completed projects include: 144 MW Canutillar station (Endesa), 160 MW Alfalfal station (Chilgener) and the 500 MW Pehuenche station (Perhuenche). The biggest ongoing hydroelectric project is a 500 MW station on the Bio-Bio River at Pangue.

Private power is also expanding in Chile: Chilgener awarded a turn-key contract to build a 130 MW coal-fired unit at Tocopila. The unit, owned by Corporacion Nacional de Cobre de Chile (CODELCO), will provide power to several mines in the vicinity. Also under construction is a 125 MW coal-fired unit in Mejillones near Antofagasta and another 125 MW coal-fired unit at the port of Huasco south of Antofagasta.

4.5.5 Argentina

The power sector in Argentina is rapidly becoming privatized; the government is unbundling utility-owned power plants from the associated transmission and distribution facilities. Today, much of the responsibility for operation of larger plants and T&D operations is in the private sector. However, the federal government still retains substantial equity in the privatized companies and plants.

Over the past five years, electricity consumption in Argentina increased at 6.8% per year, reaching 57 TWh in 1994. Of this, industrial users accounted for 50%. Installed capacity at year-end 1994 was 15,740 MW: 7,300 MW thermal, 7,435 MW hydroelectric, and 1,005 MW nuclear. Another 1,195 was expected on-line last year.

Before privatization began, four public utilities, one binational agency, 19 provincial utilities and several electric cooperatives supplied Argentineans with power. The major entities are (were):

- Agua y energia Electrica (AYEE) was responsible for generation and transmission nationwide and distribution in four provinces. AYEE aslo coordinated the national power pool.
- Servicios Electricos del Gran Buenos Aires (SEGBA) supplied electricity to the capital and surrounding cities.
- Hidroelectrica Norpatagonia (Hidronor) coordinated development of the hydroelectric resources in North Patagonia, as well as owning power plants and transmission lines.
- Comision Nacional de Energia Atomica (CONEA) operates Argentina's two nuclear plants and ancillary nuclear services.
- Comision Technica Mixta del Salto Grande (CTMSG) runs the 1,900 MW Salto Grande hydroelectric project on the border with Uruguay.
- Provincial utilities – which serve all but four provinces – and the cooperatives in 16 mostly-rural provinces also remain publicly held.

Cia Administradora del Mercado Mayorista Electrico SA (Cammesa), the government agency that coordinates operations of the Argentine electric power sector, estimates that electrical demand growth will be about 4.5% per year for the next several years. In addition, Ente Nacional Regulador de la Electricidad (ENRE) was formed to regulate the country's power privatization process. The Argentine interconnected system, known as Sistema Argention de Interconexion (SADI), covers 90% of the country; it also interconnects Argentina with Uruguay, Paraguay, Bolivia and Chile.

Market Assessment: Before privatization was initiated, government utilities planned to invest $10 billion in 7,215 MW of new power plants. These plants will probably be completed under their current ownership schemes, but will be confronted with a competitive market for the sale of the electricity generated (3.75-4.4 cents/kWh, as established by ENRE). The mega-projects under development include: 2,700 MW Yacyreta plant being built with Paraugay (20 x 155 MW); 1,400 MW Piedra del Aguila (4 x 350 MW); and a second unit at Atucha nuclear station (745 MW). Another mega-project is the 4,500 Corpus Christi, being developed by Comision Mixta Argentino-Paraguay de Rio Parana, on the Alto Uruguay and Parana Rivers, will produce 20 TWh/year for sale to Argentina, Brazil and

Paraguay. Beyond these hydro projects, development of Argentina's reserves of natural gas, estimated at 560 bcm, is expected to promote the development of gas turbines and combined cycle plants.

4.6 ASSESSMENT OF TECHNOLOGY MARKET POTENTIAL AND BARRIERS

Based on the power market assessment by country in the preceding sections, the following summarizes the market potential for small-scale fluidized bed combustors and coal-fired diesel generators in the identified developing countries. In general, data on fuels other than coal were not readily available. In addition, proximity of the local load to coal fields/transport systems and identification of communities without grid access and needing power requires a site-specific analysis not included in this screening analysis. Additional market details are provided for those countries rated with "high" potential.

4.6.1 Africa

Table 4.6.1 summarizes the power market indicators by country in Africa. It indicates that only a few countries have coal reserves and currently use coal for power generation. Alternatively, 10 countries have large hydroelectric potential, with many countries relying on hydro power for over 90% of their generation. While an interconnected grid exists in all countries, the extensiveness of the grid and degree of electrification is low in most African countries. Finally, several countries have explicit programs to increase rural electrification (see Section 4.1 for details).

Table 4.6.2 relates the market potential for FBCs and CFDs in Africa by country, together with the major market barriers. While market potential exists for these technologies, in most countries the potential for FBCs is low, since hydroelectric generation is the primary source of current and future baseload power. Alternatively, CFDs could exploit a niche by displacing oil-fired diesels in both urban and remote areas, particularly where a country has experienced difficulty financing oil purchases (e.g., Tanzania, Zaire) and has instituted a program to explore alternatives. While both Madagascar and Niger have a large number of diesel units, they are rated as "moderate" since they are without indigenous coal resources, and any increased coal consumption would necessitate development of potentially costly coal infrastructure.

Most of the developing countries in Africa have instituted some type/level of private power and/or privatization program, which introduces opportunities for advanced power technologies, if they can be price-competitive. Until electric tariffs are revised and rate subsidies removed this the market is likely to be distorted against coal-based power systems. Further examination of these markets is necessary before a more precise indication of the market potential for FBCs and CFDs can be provided.

Two countries are rated with "high" market potential: Zimbabwe and Morocco.

Zimbabwe. Through its rural electrification program Zimbabwe hopes to expand grid connection beyond the 20% level that currently exists. In addition, Zimbabwe is eager to electrify rural households to reduce their use of wood and other biomass fuels. Installation of coal-fired (and/or multi-fuel) fluidized bed boilers and coal-fired diesels on micro-grids would achieve this goal and reduce the need to string costly transmission lines to remote villages.

Table 4.6.1
Market Indicators Summary: Africa

Country	Coal Reserves	Power Gen: Coal	Hydro Resources	Power Gen: Hydro	Power Gen: Diesel	NG Reserves	Power Gen: NG	Interconnected Grid	Demand Growth	Electricity Transfer
Mozambique	✓	✓	large	✓	✓	--	--	partial	moderate	export
Tanzania	✓	✓	large	✓	✓	large	--[a]	partial	high	import
Malawi	--	--	small	✓	✓	--	--	partial	moderate	--
Burundi	✓	--	large	✓	--	--	--	partial	low	import
Zaire	large	--	large	✓	✓	large	--	partial	low	export
Madagascar	--	--	large	✓	✓	--	--	partial	low	--
Nigeria	✓	--	moderate	✓	✓	large	--[a]	partial	low	export
Niger	✓	--	--	--	✓	--	--	partial	low	import
Kenya	--	--	large	✓	✓	--	--	partial	moderate	import
Ghana	--	--	large	✓	✓	--	--	partial	high	export
Zambia	✓	--	large	✓	✓	--	--	partial	low	export
Mauritania	--	--	small	✓	✓	--	--	partial	low	import
Egypt	--	✓	low	✓	✓	✓	✓	moderate	moderate	--
Zimbabwe	✓	✓	moderate	✓	✓	--	--	moderate	moderate	import
Morocco	✓	✓	low	✓	✓	--	✓	partial	high	import
Cameroon	--	--	large	✓	✓	✓	--	moderate	moderate	--
Tunisia	--	✓	low	✓	✓	--	✓	moderate	low	--
Algeria	--	--	low	✓	✓	large	✓	moderate	moderate	export
Mauritius	--	--	low	✓	✓	--	--	partial	low	--

[a] under development

TABLE 4.6.2
Market Potential Rating: Africa

Country	FBC Market Potential	Coal-Fired Diesel Market Potential [a]	Major Barriers
Mozambique	low	moderate (11)	hydroelectric
Tanzania	low	moderate	hydroelectric, natural gas
Malawi	low	low (6)	hydroelectric
Burundi	low	low	hydroelectric
Zaire	low	low	hydroelectric, cash flow, low growth
Madagascar	low	moderate (56)	hydroelectric, no indigenous coal, underutilized capacity
Nigeria	low	low	hydroelectric, natural gas
Niger	low	moderate (54)	imported-power, no indigenous coal
Kenya	low	low	hydroelectric, investment, electricity tariffs
Ghana	low	low	hydroelectric, natural gas
Zambia	low	low (16)	hydroelectric
Mauritania	low	low	hydroelectric, imported power
Egypt	moderate	moderate	mechanisms for private powers, elimination of 6% subsidy on electric rates
Zimbabwe	high	high	hydroelectric
Morocco	high	high	natural gas from Algeria
Cameroon	low	low	natural gas, hydroelectric
Tunisia	low	moderate	
Algeria	low	low	natural gas, no indigenous coal
Mauritius	low	low	no indigenous coal; bagasse and hydroelectric

[a] numbers in parentheses ( ) indicate number of known diesel units.

Morocco. While Morocco does not have significant coal reserves, it currently produces and consumes coal for power generation. With a projected growth in demand of 7%, a program to increase rural electrification beyond the current 25% level, and U.S. private power developers already active in Morocco, the opportunity exists for U.S. distributed coal-fired power systems to serve the Moroccan power market. In addition, Morocco hopes to reduce its reliance on imported oil, which currently accounts for 80-90% of its commercial energy requirements, by obtaining royalty gas for transit rights associated with Algerian natural gas shipments to Spain via the Maghreb-Europe pipeline; but this requires a construction of a complete gas infrastructure.

4.6.2 Asia

Table 4.6.3 presents the markets indicators for Asia. Most of the developing countries in Asia rely extensively on hydroelectricity for baseload power: Indonesia, India and China have equal and growing shares of coal-based power to serve baseload demand. Since many of these countries are projected to have large growth rates in demand for the foreseeable future – even with there extensive hydroelectric capacity and resource potential – there remains many opportunities for small, coal-based technologies. These technologies would complement the rural electricification programs underway in many of these countries (see Section 4.2).

A summary of the market potential for these small, coal-fired power technologies is contained in Table 4.6.4. Six countries (India, China, Pakistan, Indonesia, Vietnam, Philippines and Thailand) have high potential for FBC adoption; the same countries are categorized as having a high potential for coal-fired diesels. The major barrier, when not hydroelectric potential, is project financing. Many (most) of these developing countries do not have an internal means to generate capital (i.e., savings or pension funds), so they must rely on outside investors for equity and debt capital. This impacts all power projects; however, it may have a lesser impact on small-scale projects since they demand less capital and often have less commercial/technological/political risk than larger projects. Another development that might facilitate investment is private power laws and privatization. Many of these Asian countries have created (or are in the process of creating) an environment to entice private power developers to construct the required generating capacity.

Six countries are rated with a "high" market potential: India, China, Pakistan, Indonesia, Vietnam, Philippines and Thailand.

India. While India has many large-scale coal and natural gas power projects under development, the T&D system still does not serve many remote villages and experiences large variations in line voltage and substantial losses thus impacting deliverability, reliability and rural electrification. To satisfy the rapidly expanding power needs of the Indian states, micro-grids supplied by coal-fired FBCs and coal-fired diesels would achieve the electrification goals and reduce demands on the overburdened national grid.

China. China is projected to need 400 GW of new generating capacity by 2020. Moreover, China has hundreds of remote villages that – like the explosion of cellular telephones usage – are probably best served by advanced concepts such as micro-grids powered with small, coal-fired generators (FBCs and CFDs) rather than stringing new transmission lines. Since many of these villages are co-located in those areas with coal reserves, minimal coal transportation is likely to be required. A geographic mapping of the coal reserves, remote population load

TABLE 4.6.3
Market Indicators Summary: Asia

Country	Coal Resources	Power Gen: Coal	Hydro Resources	Power Gen: Hydro	Power Gen: Diesel	NG Reserves	Power Gen: NG	Interconnected Grid	Demand Growth	Electricity Transfer
Nepal	--	--	large	✓	✓	--	--	partial	low	import
Laos	--	--	large	✓	✓	--	--	partial	low	export
Bangladesh	--	--	moderate	✓	✓	✓	✓	partial	high	--
India	large	✓	moderate	✓	✓	✓	✓	moderate	high	--
China	large	✓	large	✓	✓	large	✓	partial	high	--
Pakistan	✓	✓	large	✓	✓	large	✓	partial	high	--
Sri Lanka	--	--	large	✓	✓	--	--	partial	low	--
Indonesia	large	✓	large	✓	✓	✓	✓	partial	high	--
Myanmar	✓	✓	large	✓	✓	✓	--	partial	moderate	export
Vietnam	large	✓	large	✓	✓	large	✓	partial	high	export
Philippines	✓	✓	✓	✓	✓	small	✓	partial	moderate	--
New Guinea	--	--	✓	✓	✓	--	--	partial	low	--
Thailand	✓	✓	moderate	✓	✓	large	✓	partial	high	import
Malaysia	✓	✓	large	✓	✓	large	✓	partial	high	export

TABLE 4.6.4
Market Potential: Asia

Country	FBC Market Potential	Coal-Fired Diesel Market Potential	Major Barriers
Nepal	low	moderate	hydroelectric
Laos	low	low	hydroelectric
Bangladesh	moderate	moderate	natural gas; cash flow; refinery by products
India	high	high	continuity of project support; LNG/NG combined cycle
China	high	high	project funding
Pakistan	high	high	project funding; tariff structure
Sri Lanka	moderate	moderate	hydroelectric
Indonesia	high	high	project funding; tariff structure
Myanmar	moderate	moderate	hydroelectric
Vietnam	high	high	hydroelectric; project funding
Philippines	high	high	coal not located near load centers; project funding; alternative fuels
New Guinea	low	low	hydroelectric; small resource base
Thailand	high	high	natural gas
Malaysia	moderate	moderate	natural gas

centers, and current power generation sources is needed to assess the viability of micro-grids, from which an economic assessment of the technology options could be then conducted.

Pakistan. Pakistan estimates that it needs 14,500 MW of new capacity by 2000 and would prefer to have private power developers construct most of these plants. In addition, 288 million tons of coal and lignite reserves exist. Electricity is available to 40% of the population; most rural areas are not electrified. Since Pakistan is experienced with private power, micro-grid opportunities by U.S. vendors of FBC and CFD technologies could be more readily developed.

Indonesia. Due to the large demand for power on Java, most recently completed and planned projects have been large in scale (greater than 1000 MW). However, there are approximately 2,500 remote villages not yet connected to the grid; moreover, many villages are on outlying islands currently served by diesel generators (20% of capacity). Indonesia is exploring options to reduce domestic consumption of oil and natural gas in order for these fuels to be used to generate governmental revenue as export commodities. Thus, with its extensive coal resource base (32 billion tons) there are likely to be opportunities for small, coal-fired systems to serve as power sources for micro-grids within some of these remote villages currently served by diesel generators or not yet electrified.

Vietnam. Electricity demand in Vietnam is expected to outpace the economy, with growth of 12-14% per year. While it has substantial hydroelectric capacity (75% of current generation), with potential for 15,000 MW of additional capability, Vietnam also has 2 billion tons of coal. Since Vietnam cannot make all of the necessary power sector investments, private power project opportunities exist to serve both the urban and rural areas with whatever generating technology is most appropriate and cost-effective. One option is for small-scale FBCs and CFDs to serve the domestic market, while hydroelectric capacity is used to generate export revenues through sales to Laos and China (southern provinces).

Philippines. The Philippines has 65 million people spread over 7,100 islands, with 120 rural electric cooperatives. Like many other Asian countries, rural electrification is a means to stem the urbanization tide. In the Philippines, rural cooperatives have achieved an electrification level of 60%, with a goal of 77% by 2000. This goal, coupled with the goal to reduce the share of oil-fired generation (currently 50%) to improve balance-of-payments, presents market opportunities for small-scale, remotely sited coal-fired power systems. A more in-depth analysis of the market is needed, however, before an estimate of the potential market can be determined.

Thailand. Thailand is projected to add more than 25 GW by 2011; it announced in early 1995 that no further hydroelectric capacity will be permitted due to potential damage to surrounding environmental and ecological systems. As a result, at present, natural gas is the fuel of choice; however, Thailand has considerable coal reserves and with advanced power systems these reserves could be used to produce electricity with negligible environmental impact. This is particularly true if small-scale FBC and CFD systems are used as power sources for micro-grids in remote villages.

4.6.3 Central/Eastern Europe

Table 4.6.5 relates that the three developing countries considered in this study (Romania, Poland and Bulgaria) rely on all fuel sources for power generation. While all three countries have a "moderate' interconnected grid, there remains opportunities for small-scale power systems due to inefficiencies in the current grid and isolated pockets of demand growth. As a result there is a "moderate" to "high" market potential for FBC and CFD applications in these markets (Table 4.6.6). The primary competition for deployment of these technologies is with the excess (although inefficient) capacity that currently exists in each country. The available capital for power sector investments will be competed between refurbishment and new plant. In Romania and Bulgaria the other competing issue is whether to continue operation of their nuclear plants. Additional investigation of these competing demands is necessary in order to better define (and quantify) the market potential for FBC and CFD in remote applications.

Two countries are rated with a "high" market potential: Poland and Bulgaria.

> **Poland.** More than 95% of the electricity generated in Poland is coal-based. An additional 5,100 MW of new capacity is projected by 2000. Due to the need for new capacity, coupled with the replacement/refurbishment and environmental retrofit (achieving 70% SO2 control) of 3,000 MW of existing capacity, there exists an opportunity for small-scale, advanced coal-fired power systems to serve the incremental demand growth cost-effectively and in-excess of current environmental requirements. With emissions trading being considered, there would be economic value to this over-control, which could – if necessary – compensate for any higher technology capital cost of the advanced systems.

> **Bulgaria.** Bulgaria hopes to build six new coal- and lignite-fired power plants totaling 1,500 MW to replace obsolete equipment. In addition, Bulgaria plans to install FGD units on all future coal/lignite plants and convert several 50 MW coal-fired boilers to FBCs. These plans, coupled with the possible need to replace the two V-230 nuclear reactors, create an opportunity for small-scale FBCs and CFDs to serve current/future load requirements.

4.6.4 Middle East/Near East

Turkey is the only developed country in this region considered, and it was rated with a "high" market potential. While Turkey has a large hydro resource base and a moderate interconnected grid, it is projected to experience a high rate of growth (8%/annum) in demand (Table 4.6.7); this would require installed capacity to expand from 18,714 in 1992 to 33,400 MW by 2000 and 58,400 by 2010. By 2010, some sources project that indigenous oil/gas supplies in Turkey will be depleted, forcing Turkey to rely increasingly on its lignite (and hydroelectric) resources. These facts, coupled with the topography and distributed nature of the population and coal resource base, presents numerous opportunities for small-scale FBC and CFD units (Table 4.6.8).

Table 4.6.5
Market Indicators Summary: Central/Eastern Europe

Country	Coal Reserves	Power Gen: Coal	Hydro Resources	Power Gen: Hydro	Power Gen: Diesel	NG Reserves	Power Gen: NG	Interconnected Grid	Demand Growth	Electricity Transfer
Romania	✓	✓	✓	✓	✓	--	✓	moderate	low	--
Poland	large	✓	✓	✓	✓	--	✓	moderate	low	export
Bulgaria	✓	✓	✓	✓	✓	--	✓	moderate	low	import

TABLE 4.6.6
Market Potential Rating: Central/Eastern Europe

Country	FBC Market Potential	Coal-Fired Diesel Market Potential	Major Barriers
Romania	moderate	low	nuclear power; excess capacity; need to refurbish existing capacity
Poland	high	moderate	competition for funds required to refurbish existing capacity and install environmental controls
Bulgaria	high	moderate	uncertainty in operation/investment requirements of nuclear power plants; project funding

Table 4.6.7
Market Indicators Summary: Middle East/Near East

Country	Coal Reserves	Power Gen: Coal	Hydro Resources	Power Gen: Hydro	Power Gen: Diesel	NG Reserves	Power Gen: NG	Interconnected Grid	Demand Growth	Electricity Transfer
Turkey	✓	✓	large	✓	✓	✓	✓	moderate	high	export

TABLE 4.6.8
Market Potential Rating: Middle East/Near East

Country	FBC Market Potential	Coal-Fired Diesel Market Potential	Major Barriers
Turkey	high	high	project funding

4.6.5 Central/South America

Table 4.6.9 summarizes the market indicators for Central/South America. Those countries classified as "developing" in Central/South America have either a moderate or large hydroelectric resource base. They also have only a partial interconnected grid; this is attributable to their topography and current population load center distribution. In most cases, these countries are projected to experience moderate growth in electricity demand.

Since these countries have a need for small power systems to meet current and future power needs, they have either a moderate/high potential for both FBC and CFD systems (Table 4.6.10). The major barrier to their adoption appears to be competition with hydroelectric or natural gas capacity; however, many of these countries wish to diversify their fuel base in order to increase reliability and avoid the power shortages experienced during the past several years. This policy, coupled with the privatization and private power initiatives in many (most) of these countries, permits the introduction of advanced small-scale FBC and CFD technologies.

Three countries were rated with a "high" market potential: Peru, Columbia and Chile.

> **Peru.** Almost 50% of Peru's thermal capacity (310 MW) is older diesel machines. In addition, ElectroPeru and ElectroLima have not added a new hydroelectric plant (2,000 MW) in 20 years. If coal can be imported, then coal-fired diesels have an opportunity to replace some of this older thermal capacity, and potentially serve the projected 1,200 MW of new load over the next 10 years. The major competitor for coal is natural gas; but it requires the construction of a 500-mile gas pipeline to link the new gas field at Camisea with the coastal load centers.
>
> **Columbia.** There is a 1000 MW capacity shortfall at present, with a projected need for 2,000-3,000 MW of additional capacity before the year 2000. While 60% of this capacity is expected to be hydroelectric, construction of these facilities may not be in-time to serve the projected load growth, thereby creating a protracted capacity shortfall. Small-scale FBCs and CFDs could be constructed rapidly by U.S. vendors, draw on Columbia's extensive coal reserves (16.5 billion metric tons), and be responsive to the emergency degree issued by the Ministry of Mines and Energy removing all restrictions on ownership of private power plants, once approved by the Ministry.
>
> **Chile.** Annual load growth is expected to be 5%, corresponding to the addition of approximately 1,500 MW of new capacity (55% thermal, 45% hydraulic). Given the topography of Chile (4,345 km long, 170 km wide), small-scale, coal-fired power systems would best serve local load centers and maintain overall system reliability; these technologies could also readily provide the generation for micro-grids in remotely-sited villages in the mountainous areas of Chile. These market characteristics coupled with the promotion of private power development and Chile's interest in clean coal technologies, enhances the market potential for FBCs and CFDs.

TABLE 4.6.9

Market Indicators Summary: Central/South America

Country	Coal Resources	Power Gen: Coal	Hydro Resources	Power Gen: Hydro	Power Gen: Diesel	NG Reserves	Power Gen: NG	Interconnected Grid	Demand Growth	Electricity Transfer
Peru	✓	✓	large	✓	✓	✓	✓	partial	moderate	--
Columbia	✓	✓	large	✓	✓	✓	✓	partial	moderate	--
Panama	--	--	moderate	✓	✓	--	--	partial	low	--
Chile	✓	✓	large	✓	✓	--	✓	moderate	moderate	--
Argentina	--	✓	moderate	✓	✓	large	✓	high	moderate	export

TABLE 4.6.10
Market Potential Rating: Central/South America

Country	FBC Market Potential	Coal-Fired Diesel Market Potential	Major Barriers
Peru	moderate	high	hydroelectric, natural gas; low tariffs
Columbia	high	high	project financing
Panama	moderate	moderate	no indigenous fossil fuels; lack of interest by private power developers
Chile	high	high	hydroelectric, natural gas
Argentina	moderate	moderate	hydroelectric, natural gas

References

American Embassy- New Delhi, 1993, *Petroleum and Natural Gas in India.*

Coal Industry Advisory Board, 1993, *Global Coalbed Methane Recovery and Use: Current Practices and Prospects for Expansion* (September).

Coalbed Methane Clearinghouse, 1995, *China Coalbed Methane* (May).

India Ministry of Environment and Forests, 1992, *Scientific Report Number 4, Global Change – Greenhouse Gas Emission In India.*

Industrial & Petrochemical Consultants (Pty) Ltd., 1991, *Coal-Bed Methane Resource Development* (May).

Kuchgessner, et al, 1995, *Estimate of Global Methane Emissions From Coal Mines*, U.S. Environmental Protection Agency.

Lawrence Berkeley National Laboratory, 1993, *China Energy Databook*, LBL-32822.Rev.3.UC-350.

Microsoft, *Encarta '95*, 1995.

Surridge & Grobbelaar, 1994, *Energy In South Africa: The Gas Connection*, (September 22).

The Nystrom Desk Atlas, 1994.

U.S. Department of Energy, 1994a, *Country Factbook*, Energy Information Administration Report (December).

U.S. Department of Energy, 1994b, *Presidential Mission on Energy and Trade to India* (July).

U.S. Department of Energy, 1995, *International Energy Annual 1993*, Energy Information Administration Report DOE/EIA-0219(93) (May).

U.S. Environmental Protection Agency, 1991, *Assessment of the Potential for Economic Development and Utilization of Coalbed Methane in Poland* (August).

U.S. Environmental Protection Agency, 1993, Report to Congress, *Options for Reducing Methane Emissions Internationally; Volume II: International Opportunities for Reducing Methane Emissions* (October).

U.S. Environmental Protection Agency, 1995a, *Reducing Methane Emissions from Coal Mines in Russia: A Handbook for Expanding Coalbed Methane Recovery and Use in the Kuznetsk Coal Basin* (September).

References (continued)

U.S. Environmental Protection Agency, 1995b, *Reducing Methane Emissions from Coal Mines in China: The Potential for Coalbed Methane Development* (October).

U.S. Environmental Protection Agency, 1995c, *Reducing Methane Emissions from Coal Mines in Poland: A Handbook for Expanding Coalbed Methane Recovery and Utilization in the Upper Silesian Coal Basin* (April).

World Book, 1988, *The World Book Encyclopedia*, 1988 Edition.

ATTACHMENT 1

THE ALASKAN INITIATIVE

GOAL OF THE ALASKAN INITIATIVE

The goal of the Alaskan Initiative is to demonstrate emerging energy systems to displace imported diesel fuel in rural villages in Alaska. The energy systems would provide electricity and, in some cases, heat or steam for heating buildings. In addition, they may co-fire municipal waste. The fuel would be locally produced coal or natural gas including coal-bed methane. The U.S. Department of Energy (DOE), Morgantown Energy Technology Center (METC), and the Energy & Environmental Research Center (EERC) have been working closely with several Alaskan native corporations, Alaska government officials, and U.S. vendors of small power generation equipment to initiate this activity.

BENEFITS OF THE ALASKAN INITIATIVE

1. Make *Affordable* Emerging Energy Systems Available to the Over 120 Remote Villages in Alaska

   Energy costs in remote villages are currently very high. Most villages have stand-alone systems to produce electricity using oil-fired diesel generators. Residents in the village also use oil for heating their homes and for cooling. The severe climate makes it necessary to barge or fly an entire year's supply of oil into each village during the summer season. Because of high transportation costs, electricity and fuel costs are 4 to 12 times higher than in the lower 48 states. The state of Alaska subsidizes this high cost of electricity in rural villages. However, the revenue source for this subsidy (a tax on crude oil shipments through the Alaskan pipeline) is shrinking, which may lead to the elimination of the subsidy. Thus both the native corporations and the state government want to identify lower-cost energy systems for both electricity and heat production.

2. Demonstrate *Low-Emission* Systems that Can Contribute Toward Integrated Solutions of Current Environmental Problems

   Many want the Alaskan environment to remain pristine and, therefore, want energy systems with very low emissions. Systems with lower emissions than those of uncontrolled diesel generators are desired.

   Alaskans also want energy systems that can help alleviate current environmental problems with leaking oil tanks and with municipal solid waste. Villages store a 1-to 1.5-year supply of oil in above-ground, bulk storage facilities that were installed by the Bureau of Indian Affairs in the 1940s and 1950s. Leaking tanks in these facilities are creating major environmental and safety problems. Replacing the tanks will cost $200 to $400 million, exclusive of the cost to remediate the current ground and water contamination. Fewer tanks will need to be replaced if emerging power systems fueled by natural gas or coal were to be installed under the Alaskan Initiative. The risk of future ground or surface water contamination would also be reduced.

   Disposal of municipal solid waste is an ongoing problem in Alaska. Harsh weather conditions and permafrost preclude the use of many of the disposal options common to the lower 48 states. Thus energy technologies that have the flexibility to codispose municipal waste are desirable.

3. Create *Local Jobs* in Alaskan Villages

Undeveloped coal and natural gas resources underlay much of Alaska. Although Alaska has only one operating coal mine (the Usibelli mine in central Alaska), it has vast untapped resources of very low-sulfur coal throughout the state. Many rural villages are close to known, shallow coal deposits. Most of Alaska's known natural gas resources are located on the North Slope. In the interior region, the geology indicates there is a good potential for natural gas, although this has not been confirmed by exploratory drilling. Because of the vast amount of coal throughout the state, the potential for coal-bed methane is also good. Thus many Alaskan villages have coal or gas resources located nearby. Many of these resources are near the surface and, therefore, have the potential to cost-effectively supply the relatively small amounts of fuel needed for a rural village power generation project.

Using coal or natural gas that is locally produced creates local jobs. The funds to buy fuel stay in the region instead of being siphoned off to out-of-state suppliers of diesel fuel.

Transportation cost is the major contributor to the high cost of diesel oil. Because of lower transportation costs, locally produced fuels should be lower in cost, which, in turn, would reduce the cost of electricity and heat for local residents. In Alaska, the legal issues surrounding energy resource development are relatively simple since the native corporations typically own the energy resources on their land. (This is unique to Alaska; in the lower 48, Native Americans typically do not have rights to the energy resources on their land.)

4. Demonstrate the *Capability and Versatility* of Coal-Fired or Natural Gas-Fired Emerging Energy Systems

Over the past several years, DOE METC has supported Research & Development (R&D) on small-scale power generation technologies. Several of these technologies are in the early commercialization stage and have the characteristics desired by remote villages in Alaska, i.e.,-cost-effectiveness, low emissions, reliability, standardized design, and the ability to be factory fabricated. Technology options include:

- Phosphoric acid fuel cells (PAFCs). PAFCs in the 200-kW size are ready for commercial deployment. They can operate on pipeline or lower-quality natural gas and are sold as prepackaged units. In addition to electricity, PAFCs provide hot water for heating and other uses. They are among the cleanest and most efficient energy technologies.

- Atmospheric fluid-bed combustors (AFBCs). AFBCs can use virtually any quality coal to produce electricity and process steam cleanly and efficiently. The coal can be fed with minimal preparation. The coal feed can be supplemented with waste materials. AFBCs are currently commercial in larger sizes. Small-size AFBCs are in the demonstration stage to prove their cost-effectiveness in these applications.

- Diesel engines fueled by coal–water fuel (CWF). Diesel engines fueled with CWF are entering the demonstration stage. A hot-water-drying process to produce CWF is being explored. Diesel engines with back- end emission control have less than 1/10 of the NO_x emissions of uncontrolled engines operating on diesel oil. Diesels can provide hot water or steam for heating or other uses. The sponsors of a DOE clean coal technology project funded to demonstrate a CWF diesel are reviewing the opportunity to transfer the project to Alaska.

These fossil-based systems could be used in hybrid systems that also incorporate renewable energy technologies, such as wind turbines, photovoltaic cells, or storage batteries. These renewable systems are being developed by DOE's Office of Energy Efficiency and Renewable Energy (EERE). Hybrid systems would provide reliable operation independent of wind or sunlight conditions.

5. Provide a *Mechanism to Help U.S. Technology Vendors Market* Their Technologies in Developing Countries Throughout the World

   Alaska is representative of many developing countries in that it has a large number of remote communities that do not have developed transportation systems (other than air) or electrical transmission systems connecting communities. The lack of roads or rail, and seasonally limited water transport, makes it expensive to transport bulk commodities such as fuel. The remoteness also makes field fabrication of power systems very expensive. Without a transmission system in place, small, dispersed power generation systems capable of operating on local fuels are frequently the most economic option.

   The knowledge base that U.S. equipment vendors develop by supplying small systems to Alaska is applicable to many developing countries. Thus business information being developed as part of projects implemented in Alaska will create business opportunities for U.S. equipment and technology in the international market.

WHAT HAS METC–EERC DONE SO FAR?

METC/EERC has been serving as a catalyst for this Initiative by providing information on small power systems to Alaskan native corporations and by networking U.S. vendors of small power generation technologies with these potential users in Alaska. Specific activities include the following:

1. Alaskan Driver

   Over the past 4 years, METC has been conducting both joint and individual in-depth discussions with representatives from the Alaskan native corporations and from the Alaskan state government. METC continues to provide both groups with information they require to make decisions on what technological solutions best meet the needs of Alaskan residents.

2. Workshop

   METC cohosted a workshop sponsored by the State of Alaska Department of

Community and Regional Affairs (DCRA) in Anchorage on May 17-18, 1994. The purpose of the workshop was to introduce alternative power systems to Alaska and to educate vendors of power systems about Alaskan issues. Over 130 people attended the workshop, including representatives from 20 different U.S. technology vendors and 53 representatives from Alaskan native corporations, village utilities, or Alaskan governmental agencies. The proceedings from the workshop are available.

A second workshop sponsored by the EERC, is planned for September 25-26, 1995. This workshop will showcase the Alaskan Initiative to transfer the technologies to other Native American groups.

3. Cooperative Research and Development Agreements (CRADAs)

   METC has signed CRADAs with the Alaskan Department of Community and Regional Affairs (DCRA) and with the Doyon Native Corporation. The primary purpose of these CRADAs is to conduct screening studies and more detailed feasibility studies of specific small power systems in Alaskan villages.

4. Assessments

   As part of the Alaskan CRADAs, METC-EERC and their CRADA partners are conducting (or will conduct) assessments for the installation of emerging power systems at several Alaskan locations, including Tok and McGrath.

5. Team Building

   METC-EERC have been actively developing teaming arrangements for possible demonstration projects in Alaska. Discussions have included all members of a vertical integration energy supply team including native corporations, state and federal agencies, well drillers, coal mine owners, utility operators, and equipment vendors.

6. Coal Testing

   In support of the CRADA-associated systems studies discussed above, the University of Alaska has conducted lab-scale testing of a potential coal feedstock for a proposed atmospheric fluidized-bed combustion (AFBC) system for the village of McGrath. The University is testing Little Tonzona coal. Donlee Technologies is testing 30,000 lb of this coal in its AFBC pilot plant in Pennsylvania.

7. Cooperation with EERE

   METC is closely cooperating with EERE on this Initiative. In FY94, METC assisted EERE in reviewing the proposals it received in response to a request for proposals to develop integrated energy systems on Native American lands under Article XXVI of the 1992 Energy Policy Act. At METC's invitation, DOE EERE participated in the Alaskan workshop.

8. Support Tasks with the EERC

   The FY95 Interior Appropriation provided $600K for EERC to support METC Alaskan activities. As part of this activity, the EERC:

- Provided support for the May 1994 workshop held in Anchorage.

- Obtained cost-share funding from an Alaskan Consortium to study the feasibility of building a plant to produce a low-rank coal-water fuel (LRCWF) in Alaska. Usibelli coal will likely be used for the project. The Consortium has identified a site at the University of Alaska-Fairbanks, as the likely location for the project.

- Is conducting studies to determine the market potential for CWF both in Alaska and in the export market.

- Is working with METC to finalize in-depth assessments of villages considering advanced power systems.

9. College of West Virginia

Under its multistrata completion contract with METC, the College of West Virginia has reviewed existing coalfield data and plans to drill one or two wells at Chignik Lagoon to produce coal-bed methane which will be fed to a fuel cell to produce electricity and heat for local use.

WHAT'S NEXT?

METC proposes to support several near-term demonstrations to introduce emerging power generation technologies to rural Alaskan villages. Under the leadership of the EERC, METC will work with entities in Alaska and elsewhere to support the demonstration of the following technologies:

- A 200-kW phosphoric acid fuel cell (PAFC) operating on coal-bed methane in the Chignik region. Natural gas-based fuel cell projects are also being explored.

An atmospheric fluid-bed combustion (AFBC) system fueled by coal at McGrath and/or Tok based on guidance from Doyon, Ltd., and the state of Alaska.

A diesel engine fueled by coal-water fuel (CWF) funded under the Clean Coal Technology Demonstration Program.

PAFC DEMONSTRATION

A demonstration of a 200-kW PAFC operating on coal-bed methane is being planned by the College of West Virginia at the village of Chignik Lagoon. The project will involve an Alaskan drilling firm and will be conducted in cooperation with the Chignik Lagoon Regional Corporation, the Bristol Bay Native Corporation, the Chignik Lagoon Tribal Council, International Fuel Cells Corporation and the Department of Energy.

In 1994 and 1995, METC provided funds to the College of West Virginia to conduct studies at five Alaskan remote Native American (including Native Alaskan and Eskimo) sites to determine the feasibility of producing enough methane from coal seams to feed a 200-kW fuel cell. Based upon the information derived, the College of West Virginia, in cooperation with Native American and Alaskan authorities, was requested to select one of the five sites for the conduct of a demonstration. As a result of this effort, Chignik Lagoon was selected as the most promising site.

Plans call for the College of West Virginia to lead the effort to drill two production wells at Chignik Lagoon and couple the methane produced to a fuel cell to produce clean, efficient, and competitively priced electricity to the village. The project will also create jobs for local

Native Americans in the village. If successful, the technology could be deployed throughout other remote regions in Alaska, other parts of the United States, and in foreign countries.

The estimated cost for the project is $2.05 Million. This estimate includes drilling and completing the wells and putting them into production, purchasing and installing the fuel cells and integrating the unit operations into the local transmission and distribution system. Funds for the integrated project will come from funds already appropriated to the College of West Virginia by METC, additional funds expected from Alaskan sources, financing of some elements of the project, and the FY95 fuel cell "buy-down" program directed by METC.

Electricity could be produced from the project as early as late 1995.

Other related programs in Alaska are aimed at assessing the opportunities to demonstrate PAFCs in locations where natural gas is available or can be cost-effectively obtained. One such project is being pursued at the National Guard Armory at Fort Richardson in Anchorage. Here, the fuel cell "buy-down" program being administered by METC is being discussed as the mechanism to purchase one of two PAFCs using natural gas already supplied to the site.

AFBC SYSTEM DEMONSTRATION

The economic feasibility of demonstrating AFBC at specific village sites is currently being examined by METC-EERC for its their CRADA partners. Under the CRADA with the Doyon Corporation, a feasibility study of an AFBC at the village of McGrath will be completed in August 95. The AFBC would cofire Little Tonzona coal and possibly village wastes. Plans call for McGrath Power & Light to build a 1-MWe AFBC plant to produce electricity to displace much of its current high-cost diesel fuel-based capacity.

The utilization of waste heat from the plant is also being studied. The plant and coal facilities will use local labor.

A conceptual design of the AFBC plant is currently being developed to a sufficient level of accuracy to allow bank financing of the project. To support the design activities, 30,000 pounds of Little Tonzona coal and limestone was mined by Doyon and shipped to Donlee Technology, a Pennsylvania boiler manufacturer, where it was test-burned in a pilot AFBC. A decision by Doyon on whether to proceed with the project is expected by the fall of 1995.

Under the DCRA CRADA, DCRA and METC selected the villages of Tok and Tanana as two probable locations for an AFBC demonstration. This selection was based on input from the Anchorage workshop. A 2.5-MWe project at Tok has higher priority because of the active interest being shown by the local utility Alaska Power & Telephone (AP&T) and because of the announced closing of the local landfill. The project would use Jarvis Creek coal which has been leased by AD&TR from the Alaska Department of Natural Resources. In addition, locally produced municipal solid waste would be cofired in the combustor. The new plant would be used to meet increasing electricity demand, replace some of the existing and high diesel fuel-fired capacity, and produce heat which would be used in several commercial buildings now dependent upon diesel fuel. A feasibility study for the project is expected to be completed in December of 1995.

Both projects could be used as stepping stones to the utilization of this clean, efficient and economically competitive technology in other remote locations throughout Alaska and the rest of the world.

DEMONSTRATION OF DIESEL ENGINES FUELED BY COAL–WATER FUEL

METC-EERC, with their CRADA partners, are investigating the feasibility of a project to demonstrate the operation of a coal-fueled 5-MW diesel. Cooper-Bessemer has developed this technology for small power plants (1–50 MW) and it appears ideal for Alaskan communities with high delivered-oil prices and access to a coal–water fuel (CWF) production facility.

A clean coal demonstration project has already been funded to demonstrate this technology. This project could be located at the University of Alaska-Fairbanks with the planned Alaskan Consortium project to build a low-rank coal–water fuel (LRCWF) production plant. Some of the fuel produced at the LRCWF facility would be fed to the coal-fired diesel to produce heat and electricity to meet energy growth in the region and to reduce dependence upon diesel fuel. Cooper-Bessemer's standard CWF supplier (Coal Quality, Inc.) would work with the Consortium to optimize the approach for producing engine-grade CWF in Alaska. The estimated cost of a 5-MW, 3-year demonstration project integrated with the LRCWF demonstration is approximately $40 million, half of which will be provided by METC.

AUTHORIZATION FOR THE ALASKAN INITIATIVE

METC's Alaskan Initiative is being conducted under the broad auspices of Title XXVI, Indian Energy Resources, of the Energy Policy Act of 1992. Section 2603 of this Title provides that "the Secretary of Energy in consultation with the Secretary of the Interior shall establish and implement a demonstration program to assist Indian tribes in pursuing energy self-sufficiency and to promote the development of a vertically integrated energy industry or Indian tribe, . . . including any Alaska native American village or regional or village corporation as defined in or established pursuant to the Alaska Native Claims Settlement Act."

CONCLUSION

METC and EERC are in the early stages of implementing an Initiative in cooperation with Alaskan interests to demonstrate emerging energy systems in rural villages in Alaska. The benefits of this Initiative are as follows:

- Affordable emerging energy systems being made available to the over 120 remote villages in Alaska.
- Low-emission systems that can contribute toward integrated solutions to current environmental problems.
- Local job creation in Alaskan villages.
- Demonstration of capability and versatility of coal-fired or natural gas-fired emerging energy systems.
- Provision of a mechanism to help U.S. technology vendors market their technologies in developing countries throughout the world.

It is envisioned that several demonstration projects of emerging technologies driven by Alaskan interests will be conducted under this initiative. Title XXVI, Indian Energy Resources, of the Energy Policy Act of 1992, authorizes these types of projects. METC and the EERC are establishing teaming arrangements with groups that are in a position to help implement such demonstrations. Those groups include Doyon, Ltd., and other native corporations, local Native American communities, the Alaskan Department of Community and Regional Affairs, the College of West Virginia, the University of Alaska, other state and federal agencies, well drillers, coal mine owners, utility operators, and equipment vendors. These organizations have the capability to establish "virtual corporations" to conduct demonstration projects in Alaska and to provide most of the required funding. Because of its intimate knowledge of small power generation technologies, the METC-EERC team are in the ideal position to catalyze this activity.