# COGENERATION/IPP DEVELOPMENT IN THE VIRGINIA COALFIELDS: COAL AND NATURAL GAS AVAILABILITY

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**May 1990**

# ACKNOWLEDGEMENTS

This study was conducted under a grant provided by the Virginia Coalfield Economic Development Authority. The primary source of data was interviews with executives of major coal and natural gas companies operating in Virginia. The study could not have been accomplished without the extreme cooperation of these individuals. For this we are most grateful.

A draft report was completed in March 1990 and circulated for review. We would also like to acknowledge several individuals for their comments on that draft: Gene Dishner, Virginia Department of Mines, Minerals and Energy; Clem Conner, Virginia Division of Legislative Services; Bob Carney, Bob Combs, and Jeff Jones from Virginia Power; and representatives of surveyed fuel producers.

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## EXECUTIVE SUMMARY

This study attempts to quantify the potential for cogeneration and independent power production (IPP) development based on local fuel availability in the Virginia coalfields. An estimate of available fuel is determined from interviews with a sample of the region's largest coal and natural gas producers. They were asked specifically what quantity of coal or gas they would be willing to provide under long-term contract to such local facilities. Certain assumptions on price and fuel quality were provided.

The study demonstrates that, given the right price conditions, substantial coal supplies could be available to such a local cogeneration/IPP market. Surveyed producers indicated about 4.5 million tons per year might be available. These producers represent 82 percent of Virginia's coal production. The major factors affecting their willingness to provide this coal include: (1) the desirability of long-term contracts; (2) the flexible coal quality specifications such plants would accept; and (3) the dedicated, local market that would help secure them from the uncertainty of distant markets and rail transport costs.

On the other hand, natural gas availability is not demonstrated. Representing 90 percent of Virginia's gas production, the producers interviewed indicated some aversion to long-term contracts because of the need for marketing flexibility. Those feeding an interstate pipeline to the south expect there is capacity and markets for their incremental production. Pipelines to the north may have more limited capacity, but producers feeding them do not think they would have substantial gas available for long-term contracts to local generating facilities. However, gas producing areas not served by interstate pipelines may offer fuel potential for local markets.

There is also a possibility that coalbed methane, produced from wells expected to be drilled this year in Buchanan County, might be available in the future for local power generation. More information is needed to quantify this potential, and this may have to await progress in developing these wells and in developing the cogeneration/IPP market.

Although some gas and coalbed methane may ultimately be available for cogeneration/IPP facilities, the study conservatively bases the development potential on coal supplies. The available coal (4.5 million tons annually) could fuel 1,575 MW of generating capacity.

Economic benefits that could accrue to the coalfields from cogeneration/IPP development include: (1) short-term (4 years) employment and wages in plant construction; (2) indirect jobs and wages during construction; (3) long-term (20 years) employment and wages in plant operation; (4) employment and wages from incremental coal production; (5) indirect jobs and wages accruing from plant operation and coal production; (6) incremental local property and severance tax revenues; and (7) incremental state income and sales tax revenues.

Using conservative multipliers for indirect benefits, this study estimates that cogeneration/IPP development of 1,575 MW, requiring a capital investment of $2 billion, would result in more than 2,500 direct and indirect jobs, and annual benefits of $75 million in wages, $12 million in local property tax revenues, $1.3 million in severance tax receipts, and $4 million in state tax revenues.

This study has demonstrated that coal supplies are available to support the development of a large scale cogeneration/IPP industry in the Virginia coalfields and that development would provide considerable economic benefits for the region. To develop this potential, however, requires sufficient electrical transmission capacity and satisfactory wheeling agreements; cooling water and water use permits; building sites, air quality permits; and possibly permits for waste disposal. To fulfill these requirements, cogeneration/IPP developers may have to provide additional investments.

## INTRODUCTION

Virginia Power Co. and other utilities are looking to non-utility, independent power producers (IPPs) and cogenerators[1] to supply significant amounts of new electrical generation capacity. Locating these non-utility generating facilities in the Virginia coalfields could provide economic benefits to the region from plant construction and operation; additional coal and gas production; and new industry attracted by low-cost electrical and thermal energy.

Although prospective coalfield cogeneration/IPP developers have previously submitted competitive bids to Virginia Power under its solicitations for new capacity, they have not been successful in obtaining contracts because of their inability to obtain power "wheeling" agreements from Appalachian Power Co. (APCo). Wheeling is simply transmission service; in this context, prospective generators in Southwest Virginia require APCo to provide wheeling services to transmit their power to Virginia Power's transmission grid. APCo has asserted that transmission capacity limitations inhibit its ability to provide such services. APCo and Virginia Power are currently conducting a joint study into the needs for transmission between the two utilities.

The transmission issue has also prompted a wheeling study by a Joint Subcommittee of the Virginia General Assembly. While the committee's deliberations have focused on the transmission bottleneck, another unanswered question arises: How much incremental capacity of coal and natural gas exists in the coalfields that could support cogeneration/IPP development in Southwest Virginia? The answer could help establish the upper limit of electric transmission capacity necessary to transmit power from the coalfields to purchasers. It could also help quantify economic benefits that could be realized from developing this capacity.

This report provides the results of a study commissioned by the Virginia Coalfield Economic Development Authority (CEDA) to address the fuel availability question. It quantifies the coal and natural gas that major coalfield producers could provide through long-term contract to locally sited electrical generation facilities. It translates this estimate of available fuel into both potential generation capacity and benefits to the local economy.

Following a description of the context for coalfield cogeneration/IPP development, the report details study objectives and methods; presents results on fuel availability, potential generating capacity, and economic effects; and discusses related issues of transmission capacity and cooling water availability.

## BACKGROUND: A VISION

### Virginia Coalfield Energy to Serve Eastern Virginia Electrical Demand Growth

Economic growth in eastern and northern Virginia has created new electricity demand and an attendant need for additional generating capacity. Virginia Power, the utility serving this

[1] Under the Public Utility Regulatory Policies Act (PURPA) of 1978, cogeneration plants are defined as non-utility facilities that produce both electricity and useful heat (this thermal portion must equal at least 5 percent of input energy). PURPA also defines small power producers (SPPs) as non-utility electricity generating facilities less than 80 megawatts (MW) that use renewable energy or wastes for at least 75 percent of their energy input. Under PURPA, cogenerators and SPPs are "qualifying facilities" (QFs) and are provided certain benefits: they are exempt from public utility regulation and utilities must purchase the electrical power they produce. Independent power producers (IPPs) are non-utility electricity generating facilities that do not qualify as cogenerators or SPPs. However, in the all-source bidding process conducted by Virginia Power, they can compete with QFs for available capacity.

region, is providing a substantial portion of this new capacity by purchasing power from non-utility generating facilities contracted through a competitive bidding process.

In contrast to eastern and northern Virginia, the far southwestern region of the state suffers under a relatively depressed economy (Kraybill, et al., 1987; Knapp 1987; Seltzer 1987). However, the region possesses substantial resources of coal, natural gas, and other energy sources. The region's coal has historically fueled Virginia Power's in-state power plants, but rail transport and production costs have limited Virginia-mined coal's share to less than 25 percent of utility needs.

Yet the opportunity exists to meet Virginia Power's electrical capacity while bolstering the state's coalfield economy. It rests on developing non-utility generating facilities in Southwest Virginia, fueled by local energy resources, to meet eastern Virginia's growing power demand. The state's needs would be met by the state's resources. Instead of energy being transported to eastern Virginia by rail, it would be delivered by transmission line. Coal transport savings could offset transmission costs and losses and translate into lower power costs. Local power plants would provide dedicated, long-term markets for the region's coal. The coalfields would share in the economic growth enjoyed by the rest of the state. Coalfield economic benefits would include additional employment and income from constructing and operating generating plants, and from the incremental production of coal and natural gas to fuel these plants. In addition, local generation of low-cost electricity and steam would attract energy-intensive industry to the region.

**Opportunities and Constraints**

The prospects for this vision have been bolstered by growing interest to develop generating facilities in the Virginia coalfields. For example, in response to Virginia Power's 1988 solicitation for new capacity, eight parties prepared bids for coalfield projects totaling more than 750 megawatts (MW) (Table 1).

**Table 1: Proposals for Cogeneration/IPP Projects in APCo's Service Area under Virginia Power's 1988 Solicitation**

| Virginia Coalfields Developer | County | Capacity |
|---|---|---|
| Applied Energy Systems | Dickenson | 180 MW |
| Ultrasystems/United Coal | Buchanan | 50 MW |
| Ultrasystems/United Coal | Buchanan | 50 MW |
| Ocean Transport Systems, Ltd | Wise | 100 MW |
| Island Creek Coal | Buchanan | 72 MW |
| Bechtel/Pittston Coal | Russell | 100 MW |
| Energy America/Island Creek Coal | Buchanan | 200 MW |
| Resource Enterprises | Buchanan | 5 MW |
| TOTAL | | 757 MW |
| **Ten other proposals in western Virginia** | | 589 MW |
| **Twelve other proposals in West Virginia** | | 1,757 MW |
| **Total in APCo's Service Area** | | **3,103 MW** |

Source: Maliszewski, 1989

In addition, Coastal Coal Corp., in partnership with other investors, has planned development of 400 MW of capacity in the coalfields. The co-fired plant would use a mixture of 75 percent coal and 25 percent natural gas (Simpson, 1989).

However, for these firms to successfully compete for Virginia Power capacity, they must demonstrate means of transmitting power to the utility's grid. Most of western Virginia is served by APCo. Any non-utility power originating in the coalfields must be wheeled via APCo transmission lines to Virginia Power.

APCo has been unable to enter into wheeling agreements with prospective generators because of limited transmission capacity and the magnitude of requests. With regard to the latter issue, the utility indicates that in addition to the coalfield proposals of 750 MW outlined above, the Virginia Power 1988 solicitation yielded other proposals in its service area totaling another 2,350 MW (Table 1). Since this solicitation, APCo has received additional requests for wheeling services (Maliszewski 1989). The company's policy is to evaluate each request on a case-by-case basis. However, APCo has denied all requests for west-to-east wheeling, because of its capacity constraints.

While transmission capacity is the principal constraint to realization of electrical generation capacity in the Southwest Virginia coalfield, other questions have been raised: Is there a long-term, readily available supply of coal, natural gas, and/or other energy resources to fuel cogeneration/IPP facilities? Are there sufficient land sites and cooling water available?

## OBJECTIVES AND STUDY METHODS

This study focuses on the fuel availability question, with transmission and water constraints reviewed at the end of the report. The principal objectives of the study are to:

1. Determine the quantities of coal and natural gas that would be available under long-term contracts (15-25 years) for cogeneration/IPP facilities located in the Virginia coalfields.
2. Calculate the generating capacity that could be supported by these fuel increments.
3. Estimate the economic effects to the coalfields that would result from the development and operation of such capacity and from incremental coal and natural gas production.

To achieve these objectives the following methods were applied:

1. Review of relevant literature and information sources. This information includes testimony before the Joint Subcommittee (VDLS, 1989); data on coal and natural gas reserves from the Virginia Division of Mineral Resources (DMR); and other sources.
2. Survey of a sample of the largest coal and natural gas producers in Virginia to determine the quantity of coal and gas they would be willing to provide to local cogeneration/IPP facilities in long-term (15-25 years) contracts.
   a. Largest producers/mineral owners were identified from the *Virginia Coal Directory* (VCCER 1989) and from information provided by the Virginia Division of Gas and Oil. The survey was limited to the largest coal and gas producers because: (1) it is assumed that they would be more apt to enter into long-term contracts; and (2) these companies represent the vast majority of coal and gas production and reserves in the coalfields.
   b. Different survey questionnaires were produced for coal and gas producers following review of drafts by project sponsor.
   c. The appropriate questionnaire, project summary, and cover letter on CEDA letterhead (signed by Charles Yates) were sent to each survey participant (provided in Appendix A). After receipt of the packet, participants were contacted by telephone. Project team members visited participants and conducted 1 to 2 hour interviews.
   d. Information from individual respondents was aggregated for this report. No attempt was made to extrapolate results to the universe of producers.

3. Information analysis involved three components:
   a. Analysis of coalfield fuel availability for cogeneration/IPP facilities. Based on survey results and reserves information from DMR, estimates were made of future fuel availability.
   b. Assessment of cogeneration/IPP capacity that available fuel supplies can support.
   c. Estimate of economic effects of coalfield cogeneration/IPP development. Economic benefits were estimated with multipliers for probable employment/income accrued from coal production, gas production, plant construction/operation, and support services.
4. Review of other issues: transmission capacity, cooling water availability, air pollution permitting, solid waste management.
5. Preparation of draft report.
6. Circulation of draft for review and incorporation of comments into final report.

# AVAILABLE FUEL RESOURCES

## Coal and Related Resources

Study results indicate adequate coal resources available to fuel substantial cogeneration/IPP capacity in Virginia's coalfields. Through personal interviews with a sample of the region's major coal-producing firms, information was obtained on coal reserves and on producer willingness to enter long-term coal supply contracts (see questionnaires, Appendix A). Participating firms represent approximately 82 percent of Virginia coal production. To gain additional perspectives on the question of long-term production potential and total reserves, information was also obtained from representatives of the Virginia Division of Mineral Resources (Charlottesville).

### *Coal Producers Willingness to Supply Cogeneration/IPP Facilities*

At current prices, surveyed producers would be willing and able to provide between 4,150,000 and 4,900,000 tons annually to cogeneration/IPP facilities on a long-term contract basis (Table 2). This tonnage assumes mine-mouth market prices (indexed to Virginia Power's delivered coal price) and flexible specifications (less than 3% sulfur, less than 15% ash, and more than 10,000 Btu/lb). An additional 450,000 to 550,000 tons would be available if 5 to 10 percent price premiums were available. These numbers include the totals of figures supplied by participating firms only, and thus represent a low estimate; no attempt was made to extrapolate results to non-participating firms.

Producers recognize a number of potentially significant advantages of competing in a local cogeneration/IPP market:

1. **Long-term contracts** are preferred to the uncertain spot market. Coal production requires major capital investments, and compared to spot market sales, long-term commitments minimize financial risks.

2. **Flexible quality specifications** of coal for such plants would create a market for lower quality Virginia coals. While higher quality compliance-grade and metallurgical coals will continue to compete well in the broader marketplace (even with high transportation costs), prospects for lower quality coals are less certain. Some companies indicate they may be able to meet the less demanding coal quality specifications proffered by this market with little or no cleaning, thereby reducing production costs.

3. **The dedicated, local market** provided by these plants would offer some security to producers facing market uncertainty, made even more uncertain by prospects for acid rain controls, greenhouse gas controls, and a fickle international market.

**Table 2: Estimated Coal Tonnage Potentially Available to SW Virginia Cogeneration/IPP Market from Surveyed Producers[1]**
(Annual - Thousand Short Tons)

| Source | Market Prices[2] | Additional: Price Prem.[3] |
|---|---|---|
| Increased production: | | |
| Active facilities (no expansion) | | 150 - 250 |
| Active facilities (expansion) | 515 - 615 | 300 |
| Idle facilities | 1,200 - 1,700 | |
| Diversion from current markets | 2,085 - 2,235 | |
| Purchases from subcontractors | 350 | |
| **Total** | **4,150 - 4,900** | **450 - 550** |

[1] Tonnages which producers are willing and able to commit to long-term contracts. Coal meeting the following quality specifications: less than 3% sulfur, less than 10% ash, at least 12,500 Btu/lb. Surveyed producers account for approximately 75 percent of Virginia's annual coal production.
[2] Quantities available at market prices, indexed to Virginia Power's delivered price of coal. Some producers indicated that prices based on Virginia Power contracts may not be satisfactory.
[3] Additional quantities available if 5 to 10% price premium paid by cogeneration/IPP market.

As Table 2 indicates, producers expect estimated available tonnage to come from increased production (45%), diversion from current sales (48%), and additional purchases from subcontractors (7%). Increased production would come primarily from idle facilities, but also from increased output at currently operating mines. Facility expansions include increased preparation plant capacities to handle increased mine output.

A large portion of the idle capacity cited by producers has resulted from recent expansions intended to serve the anticipated strong demand for Virginia's low sulfur coals. These expansion activities are now reaching completion, and producers are actively seeking sales contracts. Because of the anticipated effects of pending clean Air Act amendments, they anticipate no problems in finding additional markets. Given the right price and contract conditions, this production could also be available to a local cogeneration/IPP market.

Producers indicated that only a relatively small production increment (approximately 500,000 tons annually) would result from a five to ten-percent price premium in a cogeneration/IPP market. This does not mean that price is unimportant. Virtually all producers insisted that acceptable price indexing and escalation factors are essential if they are to commit coal to this new market. According to these producers, Virginia Power's current method of indexing does not provide an acceptable benchmark. In fact, several producers stated the utility has gained a reputation for driving one of the hardest bargains in the coal marketplace.

No producers indicated that the more stringent quality specifications of survey question 7 (less than 1.5% sulfur, less than 10% ash, more than 12,500 Btu) would hinder their ability to provide coal to the cogeneration/IPP market. Though they were not specifically asked about their willingness to supply compliance-grade coal to this new market, their comments indicated that current markets for this coal are strong. Presently, compliance coal emits less than 1.2 lbs. $SO_2$ per million Btu; that is, at 12,500 Btu/lb, it contains a maximum 0.75% sulfur.

Assuming the amended Clean Air Act continues to provide incentives to burn compliance-grade coal producers would be most willing to supply non-compliance coal (such as that defined by quality specifications in survey questions 5 and 7).

In addition to the idle capacity shown in Table 1, surveyed producers indicated there is considerable idle capacity for high-grade coals production (minimum of 2.8 million tons per year). However, they would be unwilling to devote these reserves to a cogeneration/IPP market unless an unspecified "substantial" price premium were available (well above 10 percent). It is uncertain what portion, if any, of this idle, high-grade coal capacity could become available to the cogeneration/IPP market regardless of price, since these producers perceive that it is in their interest to preserve existing markets for high-grade coal.

### *Other Coal-Related Resources*

Two producers indicated that substantial quantities of high-Btu coal refuse (5,000 to 8,000 Btu/lb) are available as a component of a coal-refuse mix to fuel power production facilities. One producer has already conducted an in-depth study of the economic feasibility of constructing such facilities. These results indicated that if reasonably-priced power wheeling arrangements were available, it would be economically feasible to construct at least two 80 MW power plants to burn refuse/coal mixtures. The quantity of high-Btu refuse available to this producer exceeds one million tons. If such plants were to be built, each would require approximately 50,000 tons of newly mined coal annually from additional production at existing facilities.

One producer cited waste heat from a currently operating facility as an energy source that could be utilized to generate electricity. A completed feasibility study indicates that the available waste heat could support an 80 MW power plant if favorable power wheeling arrangements were available.

These potential coal refuse and waste heat resources are not included in the figures presented in Table 2.

### *Total Coal Reserves*

Surveyed producers, representing 82 percent of Virginia's annual production, reported 1,770 million tons of clean, recoverable coal reserves. Extrapolating this figure to cover reserves owned by other producers based on annual production, clean, recoverable coal reserves in Virginia total approximately 2,160 million tons.

This estimate of clean, recoverable reserves compares reasonable well to publicly available data and information on Virginia's coal reserves from the Virginia Division of Mineral Resources and from the U.S. Department of Energy. This information is described in Appendix B.

These reserves amount to less than the commonly held perception of "100 years of coal in Virginia." They would last 44 years at the current production rate of 49 million tons per year. However, these reserves are substantial relative to the requirements of a regional cogeneration/IPP industry, and attests to the ability of the Virginia coalfield to provide sustained supplies to such an industry well into the future.

## Natural Gas and Related Resources

Study results indicate that natural gas is not likely to be as available as coal to fuel local cogeneration/IPP facilities. Interviews with a sample of gas producers provided information on their willingness to enter into long-term contracts with this market (see questionnaire,

Appendix A). Participating firms represent more than 90 percent of Virginia's natural gas production. Interview results, as well as prospects for coalbed methane as a fuel source for these facilities, are discussed below.

#### *Gas Producers' Willingness to Supply Cogeneration/IPP Facilities*

Natural gas producers were far less interested than coal producers in entering into long-term contracts with local cogeneration/IPP facilities. In general, the gas industry prefers short-term contracts because of uncertain future prices and desired flexibility to move into new markets. In fact, one producer indicated that if a contract to the cogeneration/IPP market were based on Appalachian Producers' Index (McGraw-Hill, 1989), he would require a 5 to 6 percent price premium, or a fixed annual escalator of perhaps 6 percent, ***and*** a 3-year re-opener clause calling for contract renegotiation.

For the majority of gas producers that participated with this study, current access to major transmission pipelines offers satisfactory markets and the capability to accept new production increments. The most favorable market conditions are offered by the East Tennessee Natural Gas (ETNG) pipeline spur that runs south from Dickenson County. The Consolidated Natural Gas (CNG) spur into Buchanan also offers an opportunity for incremental production. Pipeline spurs to the north from Wise, Dickenson and Buchanan counties tie into a Columbia Transmission Gas (CTG) pipeline that has less capacity for new gas.

Gas industry officials indicate that while large producers favor pipeline markets, there are gas deposits in the region that are not served by interstate pipelines that could be produced for local markets.

#### *Prospects for Coalbed Methane*

Prospects for coalbed methane production have been spurred by 1990 General Assembly emergency legislation. Developers intend to drill hundreds of wells in Dickenson and Buchanan counties this year to take advantage of a federal tax credit for unconventional energy sources that terminates at year's end. In Dickenson County, where the only existing commercial methane wells are located, incremental production will likely feed the ETNG pipeline (Randolph and Balasubrahmanyam, 1990).

However, in Buchanan County, where the greatest coalbed methane resources are located, plans for substantial production may be constrained by limited markets. Prospective developers are looking to the CNG line to market initial production. Although additional pipeline spurs to the ETNG or CGT pipelines are possible, they would be difficult and costly to build considering the terrain and problems in obtaining the necessary right-of-ways in a county known for complex property deeds. One prospective coalbed methane developer indicated that interstate pipelines will provide the initial market for produced gas. He envisions local, cogeneration/IPP facilities possibly providing a market for future production, perhaps in the second or third phase of development, but this potential is unquantified and uncertain.

One coal producer in Buchanan County has experimented with on-site cogeneration using mine-vented methane, but that system is no longer operating. The company did look into wheeling excess power, but quickly recognized that APCo's transmission constraints and reluctance to wheel power precluded this option. Water availability in the area was also considered a substantial constraint.

## Summary of Fuel Resource Availability

While there may be natural gas available for the cogeneration/IPP market, especially from smaller producers without access to major pipelines, interviews with large producers indicated that current pipeline markets and contracting strategies inhibit their participation. Coalbed methane may offer some fuel potential in Buchanan County, but estimates of availability await progress in well development and gas marketing. It is prudent to conservatively assume at this time that little or no natural gas is available for the cogeneration/IPP market.

That leaves coal as the principal energy source for cogeneration/IPP facilities. Approximately 4.5 million tons may be available from Virginia mines, of which about 2.4 million tons would come from incremental production by interviewed producers or subcontractors (Table 2). The remaining 2.1 million tons would be diverted from existing markets. It should be reiterated that this figure is based on the specific responses from participating coal firms, indicating availability <u>today</u> from these companies <u>only</u> This can be viewed as a conservative estimate.[2]

## COGENERATION/IPP POTENTIAL AND ECONOMIC EFFECTS

### Potential for Cogeneration Capacity Based on Fuel Availability

Table 3 summarizes available fuel and computes resulting potential cogeneration/IPP capacity. This 1,575 MW figure should be viewed as a conservative estimate based on the fuel available from a <u>sample</u> of producers indicated <u>at this time</u> (no effort was made to extrapolate to all producers). Actual proposals for facilities might generate greater interest among suppliers including natural gas producers. In addition, the 1,575 MW is dispatchable capacity, i.e. fuel is available to actually produce this amount of power. Since actual plants would operate at less than 100 percent capacity factor (baseload plants operate at 60 percent and above), the name-plate capacity of plants to use this fuel would likely be well above 1,575 MW and would expand some of the economic effects. To be conservative, however, the following analysis assumes an installed capacity of 1,575 MW.

**Table 3: Available Fuel and Potential Cogeneration/IPP Capacity**

| | |
|---|---|
| **Fuel Available:** | |
| Coal | 4.5 million tons/year[1] |
| Natural Gas | 0 |
| Coalbed Methane | 0[2] |
| **Cogeneration/IPP Fuel Requirements:** | |
| Coal | 350,000 tons/year per 100 MW[3] |
| Natural Gas/CBM | 7 billion cubic feet (bcf)/year per 100 MW[4] |
| **Potential Cogen/IPP Capacity:** | |
| Coal | 1,575 MW[5] |
| Natural Gas | 0 |
| Coalbed Methane | 0[2] |

[1]Available from producers participating in this study, who represent 75 percent of current Virginia production. 2.4 million tons from incremental production, 2.1 million tons diverted from existing markets.
[2]None available from existing development in Dickenson County; potential from Buchanan County unknown at this time.
[3]Assumes 12,500 BTU/lb coal, 35% generating efficiency, and dispatchable capacity (i.e., 100% capacity factor).
[4]Assumes 1,030 BTU/cf gas, 41% generating efficiency, and dispatchable capacity (i.e., 100% capacity factor).
[5]Dispatchable capacity (i.e., 100% capacity factor).

[2] Indeed, in response to the draft of this report, one firm which had initially responded that it had no fuel available for this market, stated: "There is little doubt that many times the 4.5 million tons per year of coal would be available if sufficient demand existed. Some of this production might come from new capacity, which the report doesn't appear to adequately consider, but it would likely be forthcoming at prices that would still make IPPs economically competitive with other potential sources of electricity to Virginia Power."

## Economic Effects:
### Cogeneration/IPP Development and Incremental Fuel Production

Estimating the local economic effects of potential coalfield cogeneration/IPP capacity is a difficult and imprecise task. The first step requires identifying a number of multipliers associated with three economic activities associated with the potential development: (a) construction of the cogeneration/IPP plants, (b) operation of the plants, and (c) production of local fuel to feed the plants. The second step is application of these multipliers to potential capacity and coal production determined in the previous sections of this report.

Table 4 lists the multipliers used in this analysis. They are based on a number of economic estimates for cogeneration/IPP plants planned in Virginia (Virginia Power, 1989; Randolph, 1989b); testimony at hearings of the "wheeling" subcommittee (Simpson, 1989; Yates, 1989); and a previous study of the economic impacts of coal production in Virginia (Randolph, 1989a), updated using more recent data (VCCER 1989). The multiplier for local property

**Table 4: Economic Effect Multipliers Coalfield Cogeneration/IPP**

| | |
|---|---|
| **Plant Construction.** 4 years | |
| • Capital investment | $137 million per 100 MW |
| • Construction employment | 125 per 100 MW |
| • Construction wages | $16.5 million per 100 MW |
| • Local indirect effects of investment, wages | Unquantified |
| • State income and sales taxes investment on wages | Unquantified |
| **Plant Operation:** 20 years | |
| • Plant employment | 44 per 100 MW |
| • Annual wages | $1.32 million per 100 MW |
| • Support employment (1 for 1) | 44 per 100 MW |
| • Annual support wages ($1 for $1) | $1.32 million per 100 MW |
| • Annual local property taxes (0.55% of value) | $754,000 per 100 MW |
| • Annual state income taxes (4% on 3/4 of wages) | $ 79,200 per 100 MW |
| • Annual state sales taxes (4.5% on 1/2 of wages) | $ 59,400 per 100 MW |
| • State corporate and/or utility taxes | Unquantified |
| **Coal Production:** 20 years | |
| • Mine employment | 250 per mill. tons |
| • Annual mine wages | $6.96 million per mill. tons |
| • Support employment (1 for 1) | 250 per million tons |
| • Annual support wages ($1 for $1) | $6.96 million per mill. tons |
| • Coal revenue | $28 per ton |
| • Annual local severance taxes (2% of coal revenue) | $560,000 per mill. tons |
| • Annual contribution to CEDA (12.5% of sever. taxes) | $ 70,000 per mill. tons |
| • Economic benefits of CEDA (3x contribution) | $210,000 per mill. tons |
| • Annual state income taxes (4% on 3/4 of wages) | $417,600 per mill. tons |
| • Annual state sales taxes (4.5% on 1/2 of wages) | $313,200 per mill. tons |
| • State corporate and/or utility taxes | Unquantified |

Sources: Randolph, 1986b, Virginia Power, 1989; Simpson, 1989; Yates, 1989; Randolph, 1989a; Brown, 1989.

taxes (0.55% of value) conservatively assumes that the real estate tax rather than the machinery and tools tax would apply to these investments.[3] Some potential effects, such as state corporate taxes, are not quantified.

Table 5 gives the results of applying these multipliers to available fuel estimates and potential cogeneration/IPP capacity. The potential capacity would require an investment of more than $2 billion, and during construction would employ nearly 2,000 workers and provide $260 million in wages.

Long-term benefits would accrue from plant operation and incremental coal production, itemized in Table 5 and summarized in Table 6. Total employment (plants, mines, and support) is estimated at more that 2,500; this amounts to 5 percent of the total 1987 employment in the seven coal counties. Total annual wages are estimated at $75 million. Local annual

**Table 5: Potential Economic Effects of Coalfield Cogeneration/IPP Based on Fuel Availability**

| | |
|---|---|
| **Capacity of Plants:** | 1,575 MW |
| **Coal Production:** | 4.5 million tons |
| **Incremental Coal Production:** | 2.4 million tons |
| **Construction of Plants:** 4 years | |
| • Capital investment | $2.16 billion |
| • Construction employment | 1,969 |
| • Construction wages | $260 million |
| **Operation of Plants:** 20 years | |
| • Plant employment | 693 |
| • Annual wages | $20.8 million |
| • Support employment | 693 |
| • Annual support wages | $20.8 million |
| • Annual local property taxes | $11.9 million |
| • Annual state income taxes | $1.25 million |
| • Annual state sales taxes | $940,000 |
| **Coal Production:** 20 years | |
| • Mine employment | 600 |
| • Annual mine wages | $16.7 million |
| • Support employment | 600 |
| • Annual support wages | $16.7 million |
| • Annual local severance taxes | $1.34 million |
| • Annual contribution to CEDA | $168,000 |
| • Annual benefit to CEDA | $504,000 |
| • Annual state income taxes | $1.00 million |
| • Annual state sales taxes | $752,000 |

[3] 0.55% is the average of "effective" real estate tax rates for the seven coalfield counties (Brown, 1989). The average machinery and tool tax is 1.22% of value. It is uncertain how these taxes would be applied to cogeneration/IPP facilities. They may be considered in the same category as coal preparation plants which pay the real estate tax.

| Table 6: Summary of Annual Economic Effects Accruing from Plant Operation (1,575 MW) and Incremental Coal Production (2.4 mill tons) | |
|---|---|
| Direct and indirect employment: | 2,586 |
| Wages: | $ 75 million |
| Local property tax revenue: | $ 11.8 million |
| Local severance tax revenue: | $ 1.34 million |
| Contribution to CEDA: | $ 168,000 |
| State non-corporate tax revenue: | $ 3.94 million |

property taxes (at 0.55% of investment) would be more than nearly $12 million; severance taxes more than $1.3 million; and state non-corporate taxes nearly $4 million. Contributions from severance taxes to the Coalfield Economic Development Authority ($168,000) would further enhance economic benefits.

## OTHER ISSUES AFFECTING COALFIELD COGENERATION/IPP DEVELOPMENT

The above discussion clarifies the potential benefits of coalfield cogeneration/IPP development based on fuel availability. However, other issues must be resolved before this potential can be realized. This section provides a brief overview of four issues: transmission capacity, cooling water availability, air emissions permitting, and waste disposal.

### Transmission Capacity

Before any coalfield cogeneration/IPP plants can be built to serve eastern Virginia, means must be provided to transmit the power produced. Prospective plant developers have unsuccessfully sought service agreements with APCo to wheel power across its transmission system to Virginia Power's service area. APCo and its corporate parent, American Electric Power Co. (AEP), have maintained that the utility does not have enough available transmission capacity to provide wheeling services.

Major lines for east-west power transmission are shown in Figure 1. The 345 kV Amos-Funk-Cloverdale line and the 765 kV Broadford-Jackson's Ferry-Cloverdale line are the principal means of moving power from APCo's service area to its interconnection with Virginia Power. In addition, Virginia Power's 500 kV Cloverdale-Lexington line is the principal means of bringing this power into the utility's system.

Operation of the transmission system and opportunities for transfers are complicated by several factors. First, APCo lines are part of the major interface between midwest and east coast power grids. As load fluctuations occur elsewhere in the interface, the capabilities of APCo lines are affected. Second, APCo and Virginia Power have a long-term power transfer agreement for 900 MW originating in Indiana. Unless it is extended by the utilities, this agreement expires on December 31, 1999. Movement of this power affects the marginal capabilities of the lines mentioned above as well as APCo's capacity along its north-south interface.

Table 7 gives a conceptual analysis of APCo transmission capability for power transfers to Virginia Power. These data were provided by AEP to the Virginia State Corporation Commission in July 1989 (AEPSC, 1989). The north-south interface situation affects APCo's ability

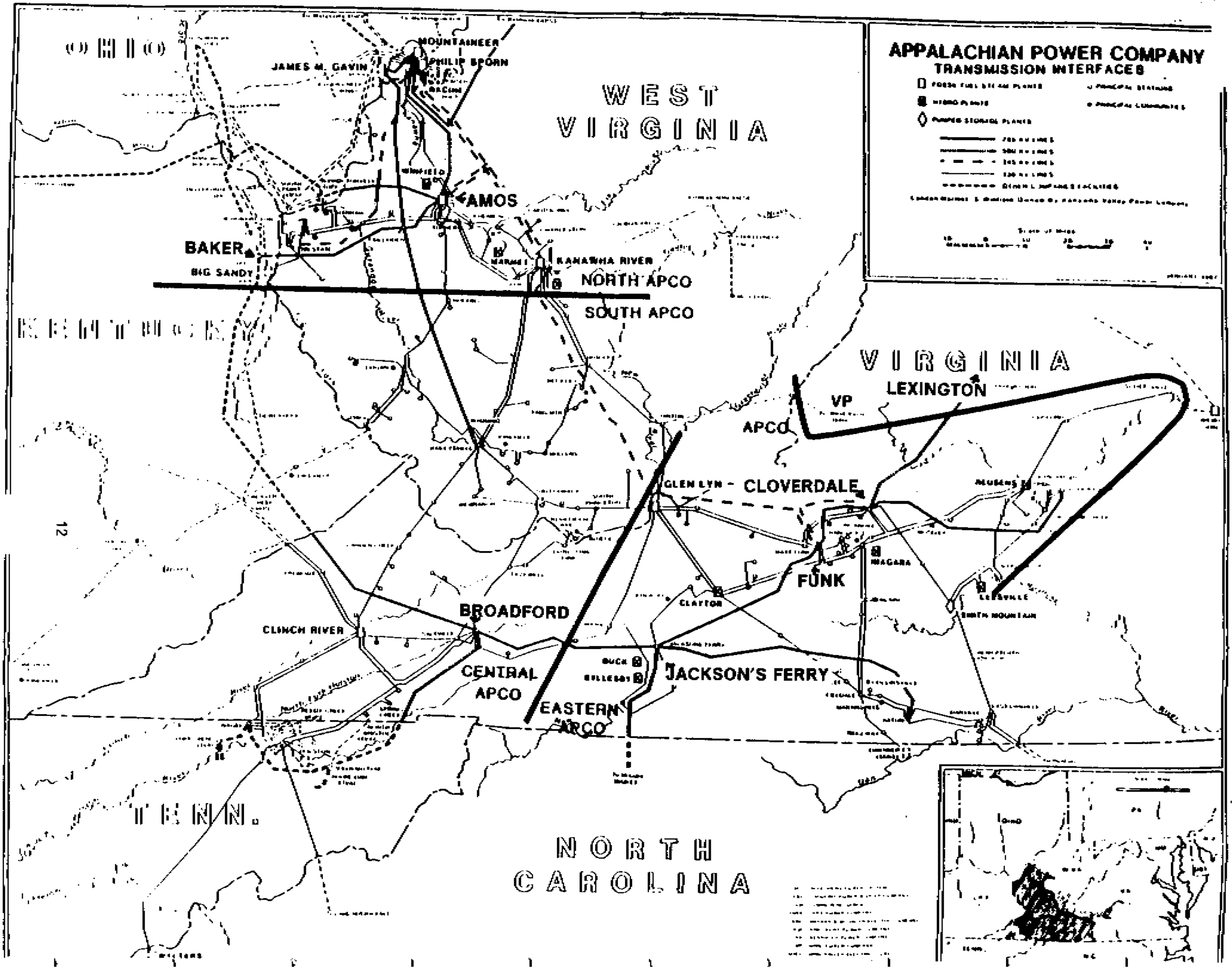


Figure 1 (AEPSC 1989)

to move power from northern power plants (such as those in Indiana and Ohio) to its own service area in West Virginia and Virginia as well as to Virginia Power. Increases in native load (i.e., APCo's local demand) are expected to shrink the transmission capacity margin from 555 MW to 240 MW by 1994-95. This interface capacity should not have a direct effect on transfers of power generated in Southwest Virginia.

The central-eastern interface is critical for transfers from Southwest Virginia, and it currently shows a margin of 355 MW. This margin is expected to more than double by 1994-95 due to current and planned transmission modifications.

Although this analysis shows excess transmission capacity, the margin dissolves when APCo's operating criteria are applied. APCo operates its system based on a "first contingency" basis. This means that the transmission system must operate within capabilities under forecasted load **and** the forced outage of a single major component. For example, with the outage of the 765 kV Baker-Broadford or Broadford-Jackson's Ferry lines, transmission

**Table 7: Conceptual Analysis of APCo Transmission Capability for Power Transfers to Virginia Power**

| | Time Period | |
|---|---|---|
| | **1988/89 W** | **1994/95 W** |
| **North/South Interface** | | |
| Transmission Capability | 5,175 MW | 5,485 MW |
| Local Generation | 1,150 MW | 1,150 MW |
| Total Supply | 6,325 MW | 6,635 MW |
| Native Load | 4,870 MW | 5,495 MW |
| Long Term Transfers | 900 MW | 900 MW |
| Short Term Transfers | - | - |
| Total Demand | 5,770 MW | 6,395 MW |
| Margin | 555 MW | 240 MW |
| Emergency Transfers | 0-800 MW | 0-800 MW |
| **Central/Eastern Interface** | | |
| Transmission Capability | 2,945 MW | 3,685 MW |
| Local Generation | 450 MW | 450 MW |
| Total Supply | 3,395 MW | 4,135 MW |
| Native Load | 2,140 MW | 2,390 MW |
| Long Term Transfers | 900 MW | 900 MW |
| Short Term Transfers | - | - |
| Total Demand | 3,040 MW | 3,290 MW |
| Margin | 355 MW | 845 MW |
| Emergency Transfers | 0-400 MW | 0-400 MW |

Source: AEPSC, 1989

demand would exceed the 880 MW loadability of the Amos-Funk line during summer and winter peaks. From this analysis, APCo concludes that its "transmission network is often operating at or near its maximum capability and capacity to handle additional requirements is severely constrained" (AEPSC 1989, p.14).

Though there are other smaller lines connecting APCo and eastern Virginia, the 500 kV Cloverdale-Lexington line is the principal interconnect with Virginia Power. A conceptual analysis of the interconnection capability between the two utilities it (Table 8) shows that while considerable capacity may be available under normal conditions, it would be insufficient if an outage were to occur on the Cloverdale-Lexington transmission line.

In March 1989, APCo and Virginia Power initiated a joint transmission capability study. The study aimed to evaluate transmission upgrades within and between the two utilities to meet internal load requirements and inter-utility transfer needs as well as capability to deliver non-utility generation located in APCo's service area to Virginia Power. To meet these objectives new EHV (extra high voltage) transmission capacity would be needed between APCo's system in West Virginia and Virginia. Also, new transmission would be needed from the APCo's eastern boundary to Virginia Power's major load complex (Maliszewski 1989).

**Table 8: Conceptual Analysis of APCo Transmission Capability for Power Transfers to Virginia Power[1] (Contract Path Capability)**

| APCo-Virginia Power Ties | Normal | One Cloverdale Transformer Out | Cloverdale-Lexington Out |
|---|---|---|---|
| Transmission Capability | 2,227 MW | 1,405 MW[2] | 583 MW[3] |
| Long Term Transfers | 900 MW | 900 MW | 900 MW |
| Short Term Transfers | - | - | - |
| Total Demand | 900 MW | 900 MW | 900 MW |
| Transmission Margin | 1,327 MW | 505 MW | <317 MW> |
| Emergency Sales | 0-100 MW | 0-100 MW | - |

[1]Analysis applies to both 1988/89 Winter and 1994/95 Winter.
[2]Based on normal loadabilities for remaining facilities.
[3]Based on emergency loadabilities for remaining ties.

Source: AEPSC 1989.

The joint study was completed in March 1990, and the utilities announced an agreement to construct new major transmission facilities to reinforce the ability to exchange power between the two utilities. As illustrated by Figure 2, the program involves 212 miles of new transmission lines in West Virginia and Virginia. APCo will build a 110-mile, 765 kV line from its Wyoming station to its Cloverdale station. Virginia Power will build an 88-mile, 500 kV line from APCo's Joshua Falls station to Virginia Power's North Anna station, and a 14-mile, 500 kV line from North Anna to its Ladysmith station. The announcement indicated the program could be completed in the late 1990s at a cost of $430-450 million. APCo would bear 58 percent of the cost, with the remainder borne by Virginia Power.

In announcing the program, Virginia Power President James T. Rhodes, APCo's President Joseph H. Vipperman, and Delegate Alson H. Smith, Jr., Chairman of the "Wheeling"

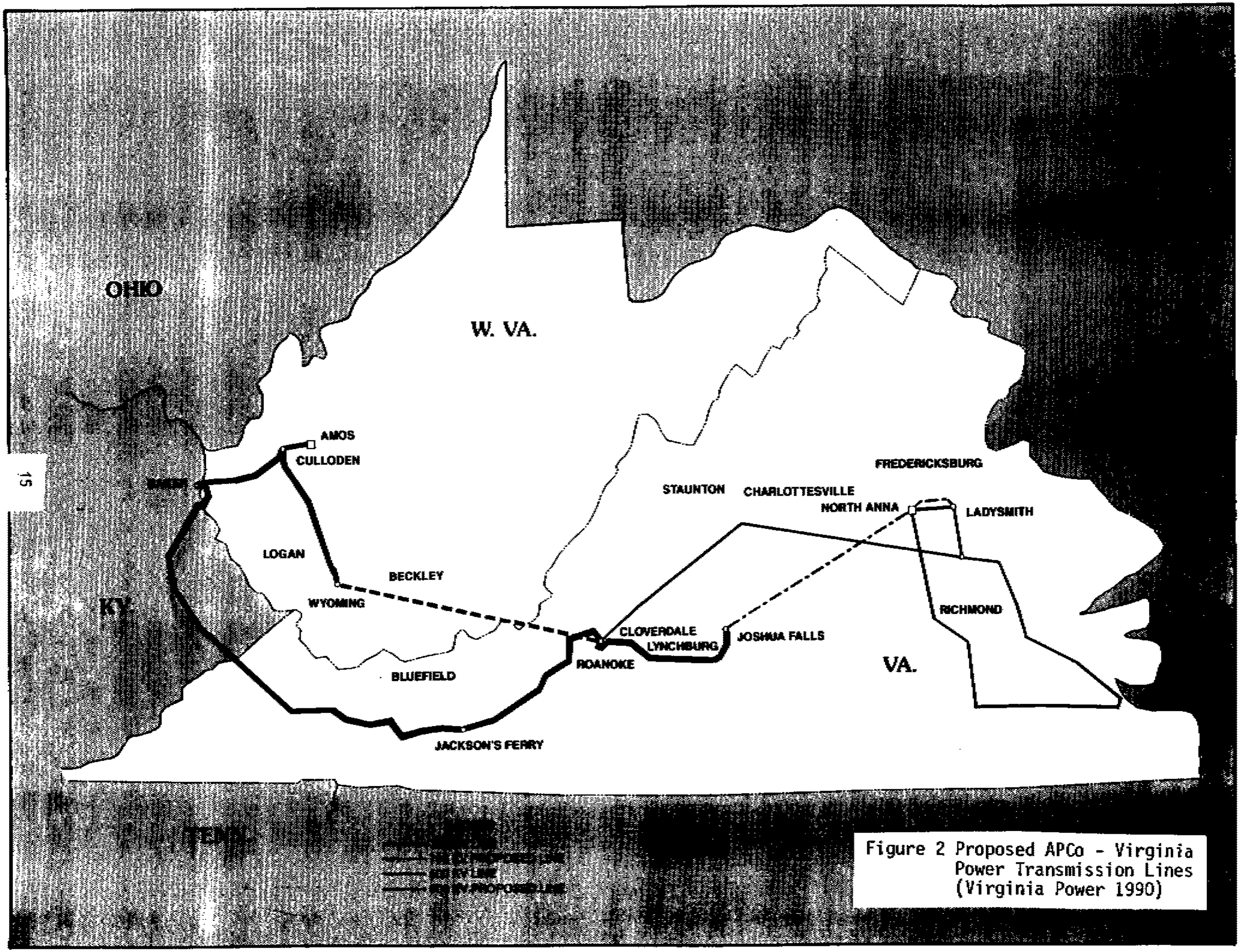


Figure 2 Proposed APCo - Virginia Power Transmission Lines (Virginia Power 1990)

Joint Subcommittee, all referred to the potential benefits this new transmission capacity could offer the Southwest Virginia coalfields (Virginia Power 1990).

While the new lines would not directly serve the coalfields, the Wyoming-Cloverdale line would free capacity on the 765 kV Broadford-Jacksons Ferry-Cloverdale line. This freed capacity could be used to wheel prospective coalfield cogeneration/IPP facilities' electricity in APCo's service area to Virginia Power.[4] There is a possibility that these facilities could acquire a guarantee of transmission service by purchasing some of the excess capacity or by assisting APCo in the construction of the new line.

However, the improved linkage between APCo and Virginia Power would also enhance the ability of APCo and other AEP utilities to enter the Virginia Power market. Even if transmission service to cogeneration/IPP facilities were guaranteed, these facilities would have to compete with APCo, AEP utilities, as well as prospective independent West Virginia generators in Virginia Power's competitive, all-source bidding process.

## Cooling Water Availability

Another possible constraint to cogeneration/IPP development in the Virginia coalfields is the availability of water resources for cooling. Power plant cooling options include once-through or recirculated water from surface sources; recirculated groundwater from deep aquifers or flooded abandoned mines; wet cooling towers; hybrid wet/dry cooling towers; and dry cooling towers.

If water is used as the primary cooling medium, consumptive use would be on the order of 1 to 3 cfs per 100 MW, depending on the type of system used. The lower consumption figure applies to systems that have a substantial heat sink available other than the atmosphere, such as a storage pond or a free-flowing river that can accept heated water discharge. The higher figure applies to systems using wet cooling towers.

Table 9 contains information on water flows in the region's major streams. Potential water resource impacts of withdrawals from any free-flowing stream would be based on an analysis of minimum-flow conditions.

The region's major water resource is the Clinch River, which is also habitat for more endangered fish and crustaceans than any other river in the state. Any effort to site a cogeneration/IPP plant on the Clinch River is likely to focus substantial public attention on potential water resource impacts. The Nature Conservancy is currently involved in endangered species protection efforts on the Clinch River. Cogeneration/IPP proposals have prompted public concern in southside Virginia over water impacts (Stallsmith 1990).

Other major water resources are the Levisa Fork below Grundy, the Russell Fork near the Kentucky state line, and the John W. Flanagan reservoir.

In order to site a plant with major water consumption on any of the region's minor streams, and to mitigate some of the environmental concerns, on-site reservoir storage would probably be required for the plants to operate during low-flow conditions. On-site water storage for cooling purposes would substantially increase the land requirements and the cost of such a plant.

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[4] It should be noted that a good portion of the coalfields is not within APCo area (see Figure 2). To transmit electricity to Virginia Power, prospective generators in this non-APCo area must also acquire means of wheeling power to APCo's system.

The Corps of Engineers is currently planning a federal multipurpose flood control-recreation reservoir on the Russell Fork near Haysi. If industrial water supply could be added as a project purpose, this project could potentially provide water for a cogeneration/IPP facility. This would require cost sharing as well as local public sponsorship.

Another possibility would be to use groundwater for cooling, either by withdrawal from a large reservoir (such as an abandoned deep mine) or circulating groundwater between cooling use and such an underground reservoir. We have no information on the amount of water

**Table 9: Water Flows in Selected SW Virginia Rivers**
(cubic feet per second)

| Monitoring Station | Max Daily Flow | Avg Daily Flow | Min Daily Flow | Min Monthly Flow | 7 day - 10 year Low Flow | Period of Record |
|---|---|---|---|---|---|---|
| Big Sandy Basin | | | | | | |
| Levisa Fork at Grundy | 13,600 | 290 | 0.3 | 0.9 | 1.1 | 1941-85 |
| Levisa Fork at Big Rock | 24,800 | 383 | 5.1 | 6.8 | 9.5 | 1968-87 |
| Russell Fork at Haysi | 30,600 | 331 | 0.2 | 2.1 | 1.3 | 1927-87 |
| N.Fork Pound River at Pound | 1,710 | 28 | 0.04 | 1.2 | 0.2 | 1962-87 |
| Pound River near George's Fork | 5,090 | 120 | 1.7 | 2.3 | 3.9 | 1964-87 |
| Crane's Nest River near Clintwood | 8,000 | 78 | 0.7 | 1.7 | 2.0 | 1964-87 |
| Pound River near Haysi | 16,100 | 273 | 0.1 | 0.5 | 0.8 | 1927-87 |
| Russell Fork at Bartlick | 29,800 | 668 | 5.5 | 11 | 18.5 | 1963-87 |
| Clinch and Tributaries | | | | | | |
| Clinch River at Richlands | 7,000 | 193 | 8.8 | 16 | 16 | 1946-87 |
| Clinch River at Cleveland | 27,800 | 708 | 37 | 54 | 53 | 1921-87 |
| Guest River at Coeburn | 4,000 | 141 | 1.6 | 1.8 | 2.0 | 1950-80 |
| Clinch River at Speer's Ferry | 42,500 | 1593 | 77 | 94 | 105 | 1921-81 |
| Clinch River above Tazewell, TN | 83,300 | 2072 | 108 | 136 | | 1919-87 |
| Powell River | | | | | | |
| Powell River at Big Stone Gap | 7,860 | 202 | 5.0 | 7.3 | 6.8 | 1945-81 |
| North Fork at Pennington Gap | 6,360 | 130 | 0 | 2.6 | 0.9 | 1945-81 |
| Powell River near Jonesville | 35,000 | 531 | 18 | 23 | | 1932-87 |
| Powell River near Arthur, TN | 50,300 | 1147 | 60 | 76 | | 1920-82 |

Source: Virginia Water Resources Research Center

potentially available from groundwater sources and are unable to comment on the feasibility of such a cooling process.

An alternative to consuming water for cooling purposes is the use of dry cooling towers. These systems function by circulating a coolant fluid through a closed loop heat exchanger, venting excess heat to the atmosphere without evaporative loss. However, this cooling strategy would be more costly, and in many cases less efficient than a strategy based upon water consumption.

Water is a critical ingredient for successful development of power capacity. In southside Virginia abundant water has attracted proposals for several cogeneration and utility power plants, but concerns over impacts on water resources have prompted citizen opposition to the plants. Although the State Water Control Board granted permits for three of the plants in December 1989, in response to appeals of land owners and the Environmental Defense Fund, the Board agreed to reconsider the permits (Stallsmith, 1990).

## Air Quality Permitting[5]

Another constraint facing successful development of cogeneration/IPP facilities, especially coal fired capacity, is meeting requirements for air pollution control.

At present, Virginia Department of Air Pollution Control has no specific, coal quality-related policy for permitting cogeneration/IPP facilities. Recent permit approvals reflect coal quality specifications on the order of 1.3 percent maximum sulfur content per shipment, with a 1 percent maximum annual average, and 92 percent sulfur removal from flue gases by scrubbing.

The Department of Air Pollution Control requires that each source be controlled by the Best Available Control Technology (BACT). This has a formal definition but, in summary, it is the best available control that can be achieved after energy, environmental, and economic factors are considered. BACT for cogeneration/IPP plants may include limitations of fuel sulfur content, ash content, and heat content as well as add-on controls and/or coal pretreatment. Application of BACT could cause the previously-cited limits to change. Clean air legislation currently under development at the federal level could also have an impact.

Clean air standards will affect the cost of cogeneration/IPP plant permitting, construction, and operation. They may also reduce the quantity of coal cited in this study as available for such plants, but this potential impact is unclear. It is also uncertain how co-firing the plants with natural gas might affect permit requirements.

## Solid Waste Management[6]

A final issue relevant to development of cogeneration/IPP facilities is disposal of solid wastes from coal fired capacity. These include fly ash, bottom ash, and air pollution control residues (primarily flue gas desulfurization sludge), collectively known as coal combustion by-products.

Currently, the Virginia Department of Waste Management (DWM) has no written regulations that require specific handling practices for these materials. By both federal and state regulations, these materials are defined as non-hazardous solid wastes. Thus, coal combustion by-products may be disposed of in sanitary or industrial landfills if acceptable to the operator.

DWM's current policy is to exclude these materials from regulation when used without treatment or modification for construction fill, highway road base fill, land leveling, and the like. However, a permit from the Virginia Water Control Board may be required for this type of use if there are potential adverse water resource impacts. At this time, work is underway to document uses, such as those described above, which have not resulted in adverse impacts and would not require permits.

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[5] Language in this section was developed with the assistance of Jack Schubert, Virginia Department of Air Pollution Control, Richmond, May 7, 1990.

[6] Language in this section was developed with the assistance of Bill Robinson, Virginia Department of Waste Management, Richmond, May 18, 1990.

## CONCLUSIONS

This study has attempted to quantify the potential for cogeneration/IPP development based on local fuel availability in the Virginia coalfields. The major conclusions of the study include the following:

1. Given the right price conditions, about 4.5 million tons per year of coal might be available for a local cogeneration/IPP market.
2. Although some natural gas and coalbed methane may become available for such facilities in the future, producers are currently reluctant to dedicate supplies to this prospective market.
3. The available 4.5 million tons per year of coal could fuel about 1,575 MW of generating capacity.
4. Development of this capacity, along with incremental coal production, could provide significant economic benefits to the region including more than 2,500 jobs, $75 million in annual wages, $12 million in local property taxes, $1.3 million in severance taxes, and $4 million in state tax revenues.
5. Development of this capacity requires sufficient transmission capacity and wheeling agreements; cooling water and water use permits; building sites; air quality permits; and permits for waste disposal. To fulfill these requirements, cogeneration/IPP developers may have to provide additional investments.

Further investigation of these investments and the constraints offered by these factors is necessary to provide a comprehensive estimate of cogeneration/IPP capacity potential in the Virginia coalfields.

## APPENDIX A: Cover Letter, Questionnaires

# VIRGINIA COALFIELD ECONOMIC DEVELOPMENT AUTHORITY

Dickenson County
Buchanan County
Russell County
Tazewell County

Wise County
Lee County
Scott County
City of Norton

Reply to:
P.O. Box 1060
Lebanon, VA 24266

Reply to:
Telephone: (703) 889-0381
Fax: (703) 889-1830

January 23, 1990

Dear

As you may know, the Coalfield Economic Development Authority has commissioned a study of the incremental coal and natural gas production capacity in southwest Virginia. The purpose of our study is to determine the region's potential to support independent power production (IPP) and cogeneration facilities. The Authority believes that such facilities offer considerable potential for economic development in the coalfields by providing (a) employment in the generating plants, (b) new markets for coal and gas, and (c) inexpensive thermal and electrical energy to attract new industry. Many proposed facilities have not been constructed due to limited transmission capacity.

Information generated by this study will be provided to the Joint Subcommittee of the General Assembly which is currently studying how transmission capacity to "wheel power" from southwest Virginia to markets in eastern Virginia has constrained this development. The Authority believes this study will help convey the IPP/cogeneration potential in our region, its economic benefits, and the upper limits on needed transmission capacity.

This study is being conducted by John Randolph and Carl Zipper at the Virginia Center for Coal and Energy Research and Michael Hensley at Virginia Tech's Economic Development Assistance Center. The study requires them to obtain information from major coal and gas producers concerning incremental production capacity that would be available for IPP/cogeneration facilities. This information will be aggregated to give total values. Individual company responses will be strictly confidential.

Your company has been selected to be part of this survey. You will be contacted by one of the above individuals who will schedule an appointment to visit you. During the visit, you will be asked to respond to the questions on the enclosed form. These are being provided in advance to clarify what information is requested and to give you an opportunity to think about your response.

We would like to make the findings of the study available for the Joint Subcommittee and the General Assembly. Therefore, the study team will need this information within the next two weeks. You will receive a call by the end of this week to set up an appointment.

Thank you for your assistance in this important study and for your continuing interest in the economic development of the Virginia coalfields.

Sincerely,

Charles S. Yates
Executive Director

Enclosures

cc: Mr. John Randolph
Mr. Gene Dishner

# STUDY OF INCREMENTAL VIRGINIA COAL AND NATURAL GAS PRODUCTION CAPACITY AVAILABLE FOR COALFIELD COGENERATION/IPP DEVELOPMENT

Virginia Power and other utilities are looking to independent power producers (IPPs) and cogeneration to supply significant amounts of needed electrical capacity. This may provide a market opportunity for coal and natural gas produced in the Virginia coalfields. If such facilties were developed in the coalfields, the region would benefit economically not only from plant construction and operation, but also from the additional coal and gas production.

Although prospective coalfield IPP/cogeneration developers have submitted competitive bids to Virginia Power under its solicitations for new capacity, they have not been successful in obtaining contracts because they have not been able to obtain power wheeling agreements from Appalachian Power. APCO has asserted that limitations in transmission capacity inhibit its ability to provide wheeling services to prospective generators in Southwest Virginia. APCO and Virginia Power are currently conducting a joint study about the needs for transmission between the two utilities.

This transmission issue has prompted a "wheeling study" by a Joint Subcommittee of the General Assembly. As that study has proceeded, one unanswered question is: What incremental capacity of coal and natural gas exists in the Virginia coalfields that could support IPP/cogeneration development in Southwest Virginia? The answer to this question could help establish the upper limits of electric transmission capacity needed to transmit power from the coalfields to purchasers. It could also be used to help quantify economic benefits that could be realized from development of this capacity.

The Coalfields Economic Development Authority has commissioned a study to investigate this question. It is being conducted by the Virginia Center for Coal and Energy Research and Virginia Tech's Economic Development Assistance Center. The study aims to quantify the incremental production capacity that major coal and natural gas producers in the Virginia coalfields would have available in long-term contracts (i.e., 15-25 years) for locally sited (e.g., mine-mouth) electrical generation facilities. The contracts would be based on market prices, i.e., prices indexed to market indicators such as Virginia Power's delivered coal price or the Natural Gas Producer Price Index.

The information needed from individual coal and natural gas companies is articulated in the attached questions. They address existing reserves and production, and inquire specifically about how much fuel individual producers would be interested and able to provide such facilities under long term contract. The responses of individual companies to these questions will be strictly confidential. Only aggregated information will be used in the study report.

## INTERVIEW QUESTIONS:
## VIRGINIA COAL PRODUCTION CAPACITY FOR IPP MARKET

1. What are your current recoverable coal reserves? __________ tons

   What portion of these reserves are less than 3% sulfur, less than 15% ash, greater than 10,000 btu/lb.? __________ tons

2. What is your current annual production? __________ tons/year

3. How much of your current annual production do you process? __________ tons/year

4. How much excess mine production capacity do you currently have? __________ tons/year

A 100 MW, coal-fired independent power producer (IPP)/cogeneration plant uses about 350,000 t/y. The following questions pertain to your interest and ability to <u>increase your production</u> to supply coal to such plants in Southwest Virginia.

5. At market prices (indexed to Virginia Power's delivered price of coal) and reasonable specifications (less than 3% sulfur, less than 15% ash, greater than 10,000 btu/lb.) would you enter into long term (15-25 year) supply contracts for the following quantities:

   _____ < 350,000 t/yr (specify amount: _________ t/yr)
   _____ 350,000 t/yr
   _____ 700,000 t/yr
   _____ 1,050,000 t/yr
   _____ Other (specify amount: __________ t/yr)
   _____ I would not enter into such contracts. Reason:
      _____ Insufficient reserves
      _____ Other:

6. Would you need to expand your production capacity to produce this additional tonnage?
   ______ yes ______ no

7. Would tightening the quality specifications for the IPP/cogeneration market (1.5% sulfur, 10% ash, 12,500 Btu/t) affect your response to Question 5?

   ______ yes ______ no If so, by how much? _______t/yr

8. Would a 5% premium in coal price for the IPP/cogeneration market affect your response to:

   Question 5? ______ yes ______ no If so, by how much? _______t/yr

   Question 7? ______ yes ______ no If so, by how much? _______t/yr

**NOTE: Individual responses to this survey will be confidential; only aggregated results will be used in the study report.**

## INTERVIEW QUESTIONS:
## VIRGINIA NATURAL GAS PRODUCTION CAPACITY FOR IPP MARKET

1. What are your current recoverable natural gas reserves? ________ mcf

2. What is your current annual production? ________ mcf/year

3. How much excess gas production capacity do you currently have? ________ mcf/year

A 100 MW, gas-fired independent power producer (IPP)/cogeneration plant uses about 7,000,000 mcf/yr. Co-fired gas/coal IPP/cogeneration plants could also be constructed to produce markets for lesser volumes. The following questions pertain to your interest and ability to increase your production to supply gas to such plants in Southwest Virginia.

4. At market prices (indexed to the Gas Producer Price Index), would you enter into long term (15-25 year) supply contracts for the following quantities:

   _____ < 1,000,000 mcf/yr (specify amount: ________ mcf/yr)
   _____ 1,000,000 mcf/yr
   _____ 2,000,000 mcf/yr
   _____ 3,000,000 mcf/yr
   _____ 4,000,000 mcf/yr
   _____ Other (specify amount: ________ mcf/yr)
   _____ I would not enter into such contracts. Reason:
      _____ Insufficient reserves
      _____ Other:

5. Would you need to expand your production capacity to produce this additional volume?

   _____ yes _____ no

6. Would a 5% premium in price for the IPP/cogeneration market affect your response to Question 5?

   _____ yes _____ no If so, by how much? ________

**NOTE: Individual responses to this survey will be confidential; only aggregated results will be used in the study report.**

## APPENDIX B: COAL RESERVE ESTIMATION

Three different sources of information were accessed to estimate total clean and recoverable coal reserves in Virginia:

1. The results of the producer survey conducted during this study.
2. Adjusted Demonstrated Reserve Base: an estimate based upon the U.S. DOE Demonstrated Reserve Base (DRB), adjusted using information provided by personnel at the Virginia Division of Mineral Resources.
3. The latest estimate provided by the U.S. Energy Information Administration.

### Producer Survey

Surveyed producers, representing 82 percent of Virginia's annual production, reported approximately 1770 million tons of clean, recoverable reserves. Using a linear extrapolation to extend this figure to cover reserves owned by other producers based on annual production leads to an estimated 2160 million tons of clean, recoverable reserves in Virginia.

However, a linear extrapolation may not be appropriate, because our survey did not cover a random sample of producers. Only the largest producers were surveyed. Some of the smaller, unsurveyed producers may be operating in holdings owned by larger producers, which would be included in the 1770 million ton survey total. If the reported reserves are accurate and these assumptions are true, total clean and recoverable reserves could be less than 2160 million tons.

### Adjusted Demonstrated Reserve Base

The U.S. Department of Energy (1988) estimates Virginia's coal resource Demonstrated Reserve Base (DRB) of 2752 million tons, as of January 1, 1988. The DRB figure is designed to quantify confirmed, mineable coal reserves. It includes all mineable bituminous reserves, (defined as greater than 28 inches thickness, less than 1000 feet of overburden). Only measured and indicated reserves (i.e. within 1/2 to 3/4 miles of a sampling point) are included within the DRB.

The current DRB estimates are based upon Andrew Brown's comprehensive compilation of Virginia coal resources, completed in 1952 (Brown et al., 1952). Brown's figures were adjusted to develop the 1989 DRB figure. The primary adjustment is to compensate for depletion. Deep mined tonnage is subtracted from the DRB as it is mined, using a depletion factor of 2.0 because traditional room-and-pillar mines remove only about 50 percent of the coal within a mined seam. A depletion factor of 1.25 is used for surface mined coal.

An additional, one-time adjustment to Virginia's DRB was made because Buchanan County's Pocahontas # 3 seam constitutes mineable coal, even though it's overburden is greater that 1000 feet in thickness. Virginia's DRB figures were increased by 600 million tons on January 1976 (U.S. DOE, 1981).

Table B.1 provides an estimate of Virginia's total mineable reserves. The first step in the calculation was to adjust the 1989 DRB for depletion by mining during 1989. There is evidence that the resulting DRB seriously underestimates mineable reserves in Virginia, however, since it is based primarily on Brown's 1952 work.

**Table B.1**
**Estimated Clean and Recoverable Reserves**
**Southwest Virginia Coal Region**
(Million Short Tons)

| | |
|---|---|
| 2752 | Demonstrated Reserve Base (DRB) - Jan. 1, 1988 |
| - 179 | Depletion adjustment - 1988 and 1989 mining |
| 2573 | Calculated DRB - Jan. 1, 1990 |
| - 600 | Pocahontas #3 coalbed |
| 1973 | |
| x 2.0 | Reserve adjustment - increase in measured and indicated reserves since 1952 |
| 3946 | |
| + 600 | Pocahontas # 3 |
| 4546 | Adjusted DRB - Jan. 1, 1990 |
| - 455 | Minus 10% mining restrictions factor |
| 4092 | Estimated mineable reserves - Jan. 1, 1990 |
| - 2046 | Minus 50% mineability factor |
| 2046 | Estimated clean and recoverable reserves, Jan. 1, 1990 |

Considerable information on Virginia's coal resource base has been accumulated since 1952, most notably during the Virginia Division of Mineral Resource's (VDMR) current effort to update its geologic maps of the southwestern coalfields. One result is increased measured and indicated reserves due to increased observations. This "new" (post-1952) information on Virginia's coalfields has been incorporated into the calculated reserve base for Lee County by VDMR staff (Campbell et al., 1990). This study indicates that actual reserves in Lee County are approximately double the DRB estimate calculated by adjusting Brown's data for depletion by mining.

Other evidence that reserve estimates based on Brown's figures substantially underestimate actual reserves are provided by coal availability studies conducted in Vansant and Wise quadrangles (Sites et al, 1990; Campbell and Sites, 1990). Personnel at VDMR believe that actual reserves are probably about double the reserve base calculated from Brown's numbers.[7] This reserve adjustment factor of 2.0 is a rough approximation based upon currently available information.

One purpose of the VDMR Coal Availability Study in Vansant and Wise quadrangles was to estimate the amount of coal rendered unmineable by factors such as proximity to oil and gas wells, cemeteries (surface mining only), major streams, towns, National Forests (surface mining), buffers around old mine workings, vertical proximity to other mined or mineable seams, and seam thickness. For this study, 40 inches was considered to be the minimum mineable thickness for subsurface coals, where mining requires vertical shafts. In these two quadrangles, approximately 10 percent of the total remaining reserves in excess of 28 inches in thickness was affected by one or more mining restrictions

[7] Personal communication, E. Campbell, 15 February 1990

Thus, mineable reserves are estimated at 4092 million tons, as of January 1, 1990. The vast majority of these reserves will only be mineable using deep mining methods. Assuming a 50 percent mineability factor, the result is a 2046 million ton estimate of "clean and recoverable" reserves in southwest Virginia's coalfields.

However, the following debatable assumptions associated with the analysis shown in Table B.1 should be noted:

1. Depletion adjustments: The depletion factors (2.0 for underground, 1.25 for surface) used to account for the fact coal production is never 100% efficient, are very approximate even for conventional room-and-pillar mining and conventional surface mining, much less longwall mining and auger mining (considered a subset of surface mining).

2. The 2.0 reserve adjustment to update measured and indicated reserves is very approximate, an extrapolation of a limited area study to the entire coalfields.

3. The 10 percent mining restrictions factor was extrapolated from 2 quadrangles to the entire coalfields area. Again, this is very approximate.

4. The 50 percent mineability factor is also a very imprecise estimator. Where longwall mining is utilized, coal removal efficiencies well in excess of 50% are generally obtained.

5. The Pocahontas # 3 adjustment could have been handled more precisely; i.e., the 600 million ton figure used in Table B.2 should be reduced by the cumulative production from the seam from 1976 through 1987.

The major source of imprecision is the 2.0 mineable reserve adjustment factor. However, this is also the factor for which the least information is available.

**U.S. Department of Energy Estimate of Recoverable Coal Reserves**

U.S. DOE (1989) estimates "recoverable" coal reserves to be 1609 million tons, as of 1987. This figure is also based on the Demonstrated Reserve Base estimates.

To arrive at this figure, the U.S. DOE adjusted the Demonstrated Reserve Base figures to compensate for the following factors which act to limit coal recovery.

1. Factors affecting coal accessibility, such as natural (geologic) and manmade obstructions, and environmental and other legal restrictions. Examples of factors affecting accessibility include proximity to archeological and historical sites, location under towns or properties where subsidence is a concern, and geologic features such as faults and other structural complications.

2. Other factors affecting recoverability, primarily including the inability of mining technologies to recover 100 percent of available coal. This study assumes that modern surface mining technologies are capable of recovering 80 percent of available coal, while typical underground mining methods are able to recover 60 percent.

This estimate is considerably below that produced by adjusting the Demonstrated Reserve Base figures using Virginia DMR data. Although it incorporates most of the same factors on accessibility and mineability, no assumption was made that future exploration would confirm the existence of additional mineable coals, thereby increasing the Demonstrated Reserve Base. In other words, this figure does not reflect any adjustment corresponding to the 2.0 "reserve adjustment" factor of Table B.1.

**Summary**

Virginia's total production during 1989 was approximately 49 million tons. Estimates of Virginia's "clean and recoverable" coal reserves range from 1609 to 2160 million tons (Table B.2). Using these results, Virginia's static reserve index (the number of years today's reserves would last at today's production rate) is calculated to range from 33 to 44 years. These results indicate that, if mining were to continue at present rates, total coal reserves constitute considerably less than the "100 years of coal" often discussed in popular circles.

**Table B.2**
**Three Estimates of Virginia's**
**Clean and Recoverable (C&R) Coal Reserves**

| Souce (effective date) | Estimated C&R Reserves | Static Reserve Index |
|---|---|---|
| Producer Survey (1990) | 2,160 mill. tons | 44 years |
| Adjusted DRB (1990) | 2,046 mill. tons | 42 years |
| U.S. DOE (1987) | 1,609 mill. tons | 33 years |

These results are based upon currently available information, the potential application of current technologies to known coal seams, and other assumptions given above. The development of new mining technologies could have the effect of increasing Virginia's total "mineable coal" reserves. Analysis of data collected by Virginia DMR's recent geologic mapping effort in the coalfields allow refinement of the assumptions. Results will include a considerable reduction in the uncertainty surrounding questions pertaining to Virginia's coal reserves and the projected lifetime of the Virginia coal industry as a major economic force.

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