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Publication of this paper sponsored by Committee on State Role in Waterborne Transportation.

Economic Feasibility of Transporting Western Coal on the New York State Barge Canal System

JAMES E. VITALE

The results of a comparative economic study of the feasibility of transporting western coal to New York State utilities via the barge canal system are presented. Three coal-supply regions are delineated: southwestern Pennsylvania and northern West Virginia, Wyoming, and Montana. Site-specific projections of potential coal consumption developed for coal from each region are presented. A costing framework that includes all unit operations in the mine-to-stack coal-use cycle is used in making economic comparisons of the use of the three coals at new generating stations. This framework is designed to account for major expenditures that vary as a function of the characteristics of coal quality, including (a) extraction costs, (b) distribution costs, (c) flue-gas-desulfurization system investment and operating costs, and (d) balance-of-plant investment expenditures. The methodology is applied to a comparison of the economics of using the three coals at a future mid-Mohawk River Valley generating facility.

In recent years, commercial traffic on the New York State barge canal system has steadily decreased. To ascertain the causes of this decline and estimate future traffic volumes, the New York State Department of Transportation engaged Roger Creighton Associates, Inc., to conduct a market study of the canal system. Cargo potentials and transportation cost savings resulting from the use of the canal were estimated for two situations: (a) continued operation of the existing facilities and (b) operation of an improved and modernized canal that could accommodate larger barges and tows.

A major component of the market study was an assessment of the economic feasibility of transporting western coal to New York State utilities via the canal system. It was felt that emerging federal policies on energy resources and environmental quality might create pressures for increased use of western coal in the state. This potential demand for western coal, coupled with the construction of a proposed transshipment facility at the Port of Buffalo, might in turn lead to significantly increased traffic on the canal system. Thus, western coal was considered to be the bulk commodity that had the greatest potential for large-volume, long-term shipment via the canal.

The primary purpose of this paper is to report and update the coal-related portion of the market study. It also serves to illustrate the importance of using a total systems approach in estimating future levels of coal traffic on waterways and rail lines and through ports.

GENERAL METHODOLOGY

A comparative economics approach was used in the study to assess the feasibility of transporting western coal to New York State utilities via the canal system. This methodology consisted of four major components, each of which is discussed in this paper:

1. Three coal-supply regions were delineated: southwestern Pennsylvania and northern West Virginia (coal A), northern Wyoming (coal B), and Montana (coal C). There are major differences in physical characteristics and free-on-board (FOB) mine prices for coals produced in these regions. Moreover, northeastern utilities either use or have considered using coal produced in these areas.
2. Site-specific projections of potential coal consumption (for coal from each region) were developed. These estimates were derived from the announced plans of New York State utilities (1) and interviews with personnel of the New York State Public Service Commission.
3. A costing framework that included all unit operations in the mine-to-stack coal-use cycle was developed and quantified. Since this analytic construct was to be used to compare the economics of using alternative coals at new generating stations, it was designed to account for all major expenditures that vary as a function of coal quality.
4. This framework was applied to all potential supply-demand pairs, and estimates of future western coal traffic on the canal system were made. Rational economic behavior on the part of potential coal consumers was assumed; that is, it was assumed that the source of coal supply and the transportation mode or route configuration for which total annual costs would be lowest would always be chosen.

COAL-SUPPLY REGIONS

For the purposes of this inquiry, one eastern and two western coal-supply regions were delineated. It was assumed that eastern coal would originate from mines located in southwestern Pennsylvania and northern West Virginia, a region that has large quantities of untapped reserves and excellent access to New York State markets via the existing rail system.

The boundary between the states of Wyoming and Montana was used to divide the Powder River Basin into two supply regions. This strategy was dictated by differences in quality characteristics and FOB mine prices of coals produced in these states as well as differences in the accessibility of these regions to eastern markets via major transportation corridors.

The physical characteristics of the coals used in this study are given in Table 1 (2). It should be noted that characteristics such as heat and sulfur content vary both within and between coal seams. Thus, the information given in Table 1 is considered to be "typical".

POTENTIAL DEMAND FOR WESTERN COAL

For the purposes of this study, I have focused exclusively on the use of western coal as a fuel to fire new steam electric generating stations. It has been assumed that all plants in the state that currently burn eastern coal will continue to do so. It has also been hypothesized that generating stations that might reconvert from oil to coal would fire eastern coal. Use of western coal at such facilities could require extensive expenditures for boiler modifications, rehabilitation or expansion of coal-handling equipment, and acquisition of new (or enlarged) storage areas. Moreover, use of western coal at stations originally designed to burn eastern coal would result in a substantial reduction in the generating capacities of the plants.

It has been assumed that five new coal-fired power plants with a combined capacity of 6650 MW will come on-line before the year 2000. The locations, gross generating capacities, and target service dates of these facilities are given in Table 2. All information given on the three known stations reflects the expansion plans of member utilities of the New York Power Pool for the next 15 years. Interviews with New York State Public Service Commission personnel revealed that two additional 1700-MW coal-fired stations--a Lake Ontario plant northeast of Oswego and a facility in the mid-Mohawk River Valley--might be constructed before the year 2000. It was optimistically assumed that this additional base-load capacity would come on-line in accordance with the schedule given in Table 2.

Table 1. Average characteristics of coals A, B, and C.

Source	Designation	Heat Content (Btu 000s) Per Pound	Per Ton	Sulfur Content Percentage by Weight	Pounds per Million Btu
Pennsylvania and West Virginia	A	12	24 000	2.3	3.83
Powder River Basin					
Wyoming	B	8.3	16 600	0.5	1.2
Montana	C	8.8	17 600	0.85	1.93

Site-specific and total estimates of potential coal demand are given in Table 3. Two points regarding these projections are worthy of note. The first is that the volume of coal required to generate 1 kW•h of electricity is a function of (among other factors) coal heat content. I have therefore reported three different estimates of potential coal demand by assuming the use of coal produced in the supply regions described above. The second point is that all site-specific coal requirements have been derived from the demand forecasts developed for the Niagara Mohawk Power Corporation's proposed Lake Erie Generating Station (2). Here it is assumed, in effect, that the heat rates (heat input required to generate 1 kW•h of electricity) and capacity factors (proportion of time that a unit is on-line) of all facilities given in Table 3 will be identical to those for the Lake Erie station. The impact of these assumed parameter values on potential annual demand for the three candidate coals studied is illustrated by the data given in Table 4.

ANALYTIC FRAMEWORK

A sequential, integrated construct was used to assess the feasibility of transporting western coal to New York State utilities by way of the canal system. Since this framework was developed for the purpose of comparing the total economics of using alternative coals at new generating stations, it was designed to account for major expenditures that vary as a function of the characteristics of coal quality, including (a) extraction costs, (b) distribution costs, (c) flue-gas-desulfurization (FGD) system investment and operating costs, and (d) balance-of-plant (BOP) investment expenditures (for equipment such as boilers and coal-handling and storage facilities).

It should be noted that, whenever possible, procedures and cost estimates developed by personnel of the Public Service Commission and utility industry consultants were used in an attempt to render the analyses as realistic and meaningful as possible.

Extraction Costs

The FOB mine prices used in the study are given in Table 5 (2). It was assumed that Appalachian coal would originate from large underground mines in which continuous mining equipment and the room-and-pillar mining plan are used. All Powder River Basin coal was assumed to originate at large surface mines.

As Table 5 indicates, two FOB mine prices for Appalachian coal were used in all analyses. This strategy was dictated by a lack of consensus among coal producers as to the most appropriate contract

Table 2. Projected additions to generating capacity.

Location	Facility	Operating Company	Capacity (MW)	Target Service Date
Pomfret	Lake Erie Generating Station (LEGS)	NMPC	1700 (two units at 850 MW each)	Unit 1, 1988; unit 2, mid-1989[a]
Niagara County	Somerset	NYSEG	850	November 1983[a]
Arthur Kill	700 Fossil	PASNY	700	November 1984[a]
Lake Ontario northeast of Oswego[b]	–	Unknown	1700 (two units at 850 MW each)[c]	Unit 1, 1993; unit 2, mid-1995
Canajoharie (mid-Mohawk River Valley)[d]	–	Unknown	1700 (two units at 850 MW each)[c]	Unit 1, 1996; unit 2, 1998

Note: NMPC = Niagara Mohawk Power Commission; NYSEG = New York State Electric and Gas; PASNY = Power Authority of New York State.

[a] New York Power Pool Planning Committee (1, p. 318).
[b] Use of this site suggested by Weber of the New York State Public Service Commission during an interview conducted on April 12, 1978.
[c] Declared the most probable configuration for new coal-fired plants by Swanson of the New York State Public Service Commission during a March 3, 1978, meeting.
[d] Use of this site suggested by Swanson, Hausgaard, and Cummings of the New York State Public Service Commission during a March 3, 1978, meeting.

Table 3. Potential annual coal demand.

Location	Facility	Unit No.	Potential Annual Demand (tons) Coal A	Coal B	Coal C
Niagara County	Somerset	1	1 861 083	2 834 518	2 637 784
Arthur Kill	700 Fossil	1	1 532 602	2 334 226	2 172 715
Pomfret	LEGS	1	1 861 083	2 834 518	2 637 784
		2	1 861 083	2 834 518	2 637 784
Sackets Harbor	–	1	1 861 083	2 834 518	2 637 784
		2	1 861 083	2 834 518	2 637 784
Canajoharie	–	1	1 861 083	2 834 518	2 637 784
		2	1 861 083	2 834 518	2 637 784
Total			14 560 183	22 175 852	20 636 703

Table 4. Operating parameters for one Lake Erie Generating Station 850-MW coal-fired unit.

Parameter	Coal A	B	C
Coal heat content (Btu/ton)	24 000 000	16 600 000	17 600 000
Net station heat rate (Btu/kW·h)	9410	9795	9770
Net unit capability (kW)	785 350	794 800	786 200
Differential capability (kW)	9450	Base	8600
Average annual capacity factor (%)	69	69	69
Time in operation (h/year)	6044	6044	6044
Annual burn[a] (Btu x 10^{12})	44.666	47.053	46.425
Annual coal consumption[b] (tons)	1 861 083	2 834 518	2 637 784

[a]Net station heat rate X net unit capability X time in operation.
[b]Annual burn ÷ coal heat content.

Table 5. Extraction costs for coals A, B, and C.

Coal	Type of Mine	Quotation	Production Costs ($/ton)
A	New underground shaft or slope	Avg from several producers or sales agents	24.76[a]
		Consolidation Coal Company	29.52[a]
B	Surface		7.50[b,c]
C	Surface		9.00[b,d]

Note: Costs are in 1977 dollars.
[a]Deescalated from 1978 FOB mine prices provided by the staff of Coal Week.
[b]Figures that have been used by the New York State Public Service Commission.
[c]Includes 17 percent Wyoming severance tax.
[d]Includes 30 percent Montana severance tax.

price for a 12 000-Btu/lb, 2.3 percent sulfur coal produced at a new underground mine in that region. An informal telephone survey of coal producers and sales agents was conducted by the staff of Coal Week. This survey revealed that Consolidation Coal Company would supply a coal that complies with the above specifications for $31/ton whereas the average FOB mine price quoted by all other parties interviewed was $26/ton. In the opinion of Coal Week staff, Consolidation Coal Company is able to obtain a higher price for the same product because the large sales volume of the company's operations in the region enables it to provide unusually reliable service to consumers.

Distribution Costs

It was assumed that western coal destined for New York State would be loaded into unit trains at the mines in Montana and Wyoming and transported (via the Burlington Northern) to the Midwest Energy Terminal at Superior, Wisconsin. At that point, the coal would be unloaded, stored, and loaded into specially constructed, self-unloading vessels (with capacities of 67 000 tons) for delivery to either a lake-site plant or a proposed bulk commodity terminal at the Port of Buffalo. (Use of the proposed transshipment facility for movements to lake-site plants has also been analyzed on a case-by-case basis. It has been assumed that consumers always opt for the least-cost mode or route configuration.) Coal destined for inland plants would then be loaded into hopper cars or barges for final delivery via rail or the canal system.

It has been assumed that all western coal destined for inland plants passes through the proposed Buffalo transshipment facility. Thus, all such consumers face identical FOB Buffalo prices for Montana and Wyoming coals. The unit costs included in these prices (2) are given below (the rail rate is for unit train shipments from mine to midwest energy terminal; rail car costs are amortized, assuming 10 000-ton unit trains and a five-day round-trip time):

Item	Coal B (Wyoming)	Coal C (Montana)
Cost per ton ($)		
FOB mine	7.50	9.00
Rail		
Rate	9.75	7.00
Car costs	1.50	1.50
Transshipment at midwest energy terminal	1.50	1.50
Great Lakes vessel to Buffalo	4.10	4.10
Transshipment at Buffalo	1.15	1.15
Total	25.50	24.25
Total cost per million Btu ($)	1.54	1.38

As noted above, it was assumed that western coal is transported from Buffalo to New York State utilities by either the rail mode or the canal system, depending on relative modal costs (shipments are always assigned to the least-cost mode or route configuration). It was further assumed that all eastern coal would originate at Pittsburgh and be transported directly to the consumption sites. Since rail rates for coal shipments between most of the origin-destination pairs analyzed do not exist, the following strategy was used.

Unless otherwise noted, all estimates of unit train rates were derived from a regression equation that expresses rates (in dollars per ton) as a function of length of haul. Data from the New York State Public Service Commission on existing rates for 13-unit train shipments from Pennsylvania and West Virginia mines to New York State generating stations were used to calibrate this equation (all rates were applicable to shipments of bituminous steam coal, effective as of November 30, 1977). Since short-line rail distances were not reported, they were estimated from 1976 state transportation maps of New York, Pennsylvania, and West Virginia, which were prepared by the U.S. Geological Survey.

The calibrated relationship is

$$U = 3.771 + 0.0122X \quad R^2 = 0.61 \tag{1}$$

where

U = unit train rate ($/ton),
X = length of haul (miles), and
R^2 = proportion of variation in rates accounted for by distance.

Table 6. FGD system efficiencies that comply with original and revised NSPS.

NSPS	Maximum Allowable SO_2 Emissions (lb/million Btu)	Coal A		Coal B		Coal C	
		Uncontrolled SO_2 Emissions (lb/million Btu)	Removal Required (%)	Uncontrolled SO_2 Emissions (lb/million Btu)	Removal Required (%)	Uncontrolled SO_2 Emissions (lb/million Btu)	Removal Required (%)
1971	1.2	3.83	69	1.2	0	1.932	38
1979	≤0.6	3.83	84	1.2	50	1.932	69

Note: All removal requirements are computed for a 30-day averaging period.

Table 7. Investment requirements for FGD systems for two 850-MW units.

Item	Coal A		Coal B		Coal C	
	Original NSPS	Revised NSPS	Original NSPS	Revised NSPS	Original NSPS	Revised NSPS
Total direct construction cost ($)	202 876	209 151	0	194 833	176 821	206 046
Indirect cost, contingencies, and fees ($)	52 233	53 849	0	50 167	45 524	52 954
Total construction cost ($)	255 109	263 000	0	245 000	222 345	259 000
Net generating capacity (kW)	1 570 700	1 570 700	1 589 600	1 589 600	1 572 400	1 572 400
Cost of net capacity ($/kW)	162	167	0	154	141	165

Note: Figures are in 1985 dollars.

Table 8. Annual FGD system operating costs for two 850-MW units.

Coal	NSPS	SO_2 Removal Requirement (%)	Annual FGD System Operating Costs[a] ($000s)
A	Original	69	20 542
	Revised	84	23 530
B	Original	0	0
	Revised	50	10 936
C	Original	38	13 806
	Revised	69	17 267

Note: Costs are in 1985 dollars.

[a]Includes annual costs for limestone, lime additive, waste disposal operating costs, and annual capability charge.

Transportation costs for shipment via the canal system were estimated for two scenarios: (a) continued operation of existing facilities and (b) operation of an improved and modernized canal. Currently, lock chambers on the canal constrain vessel and tow size to a maximum width of 43.5 ft and a maximum length of 300 ft. Effective drafts are 13 ft on the Oswego Canal and the Erie Canal west of Three Rivers, New York, and 11 ft on the remainder of the system. In the second scenario, which assumed a canal system expanded and modernized to handle specially constructed, self-unloading barges, lock chambers were assumed to be 1000 ft long and 110 ft wide and to have a depth over sill of 27 ft.

Distribution costs were estimated for each scenario. Individual components included in those cost estimates were variable and fixed operating costs, profits, transit times, locking and terminal times, and inventory costs.

An in-depth discussion of the method used to estimate costs for transportation via the canal system is given elsewhere (3).

Flue-Gas-Desulfurization Costs

It has been assumed that all generating stations included in this analysis will use limestone FGD systems. Capital and operating costs for such systems depend on several factors, including the maximum allowable rate of sulfur dioxide (SO_2) emissions, the sulfur content and heating value of the coal, boiler size and capacity, boiler status (new or retrofit), and replacement power requirements (4). The complex manner in which many of these factors interact, and thus affect costs, dictated the use of generic cost estimates. However, to assess the impacts of recently promulgated environmental standards on the costs resulting from the use of eastern and western coal, estimates were developed for two sets of SO_2 emission limitations.

The Clean Air Act Amendments of 1970 required the U.S. Environmental Protection Agency (EPA) to develop primary and secondary national ambient air quality standards for sulfur dioxide (although emission limitations for particulates and nitrogen oxide were also established, sulfur dioxide regulations have had the greatest impact on coal production and distribution patterns). In December 1971, EPA responded to that mandate by establishing New Source Performance Standards (NSPS), which limited emissions from new electric generating stations to 1.2 lb SO_2/million Btu of heat input.

It is important to note that utilities could comply with those regulations by either (a) direct combustion of low-sulfur (primarily western) coals or (b) use of high-sulfur coals in conjunction with FGD systems. The actions of many major utilities indicate that use of low-sulfur western coal was considered to be the most economical and technologically workable alternative. The attractiveness of this compliance strategy is demonstrated by the fact that in 1976 more than 11 million tons of western coal were consumed in Illinois, a state endowed with large quantities of high-sulfur coal reserves (5).

In accordance with the Clean Air Act Amendments of 1977, EPA issued modified NSPS in June 1979. These revised standards require all new coal-fired power plants to install and continuously operate FGD systems, regardless of coal sulfur content. Thus, as a direct result of these regulations, the cost associated with use of western coal will increase.

Statistics on requirements for the removal of sulfur dioxide for the coal-supply options considered in this analysis are given in Table 6 for the 1971 and 1979 NSPS. As the data given in that table indicate, direct combustion of the Wyoming coal would have been permissible under the provisions of the 1971 standards. The revised NSPS allow use of this coal only if scrubbers are installed and one-half of the uncontrolled SO_2 emissions are re-

Table 9. BOP order-of-magnitude investment costs.

Item	Cost ($000s) Coal A Unit 1	Coal A Unit 2	Coal A Total	Coal B Unit 1	Coal B Unit 2	Coal B Total	Coal C Unit 1	Coal C Unit 2	Coal C Total
Direct construction costs	188 077[a]	148 660	336 737	225 503[b]	171 784	397 287	225 503[b]	171 784	397 287
Indirect construction cost, contingencies, and fees (28 percent of direct)	52 662	41 625	94 287	63 142	48 100	111 242	63 141	48 100	111 242
Total	240 739	190 285	431 024	288 644	219 884	508 529	288 645	219 884	508 529

Note: Costs are in 1985 dollars.

[a]Does not include cooling-tower make-up (intake) and blow-down (discharge) lines or coal-receiving equipment.
[b]Does not include cooling-tower make-up and blow-down lines or coal-unloading facility and tunnel.

Table 10. Fuel-supply analysis for an inland facility.

Item	Coal A Min	Coal A Max	Coal B Canal 1[a]	Coal B Canal 2[b]	Coal B Rail	Coal C Canal 1[a]	Coal C Canal 2[b]	Coal C Rail
FOB mine ($/ton)	24.76	29.52	7.50	7.50	7.50	9.00	9.00	9.00
FOB terminating mode at Buffalo[c]($/ton)	NA	NA	25.50	25.50	25.50	24.25	24.25	24.25
Rail rate to destination ($/ton)	9.44	9.44	NA	NA	6.43	NA	NA	6.43
Canal charges from Buffalo to site[d] ($/ton)	NA	NA	8.46	1.67	NA	8.46	1.67	NA
Total ($/ton)	34.20	38.96	33.96	27.17	31.93	32.71	25.92	30.68
Total ($/million Btu)	1.43	1.62	2.05	1.64	1.92	1.86	1.47	1.74

Note: Analysis for Canajoharie location as described in Table 2.

[a]Existing canal dimensions (costs for unloading at plant are assumed to be $1.50/ton).
[b]Entire canal system reconstructed to accommodate self-unloading vessel 1000 ft long and 110 ft wide with 27-ft drafts.
[c]For coals B and C, includes FOB mine price.
[d]Includes unloading costs.

moved from all flue gases.

The generic capital cost estimates used in this study for installation of FGD waste stabilization and disposal systems, assuming use of coals A, B, and C at a 1700-MW generating station, are given in Table 7 (2) for the original and revised NSPS.

The study performed by Ebasco Services, Inc. (2), was also used as the basis for estimates of FGD system operating costs. Supplemental data on the impacts of alternative SO_2 removal requirements on annual operating costs were provided by Weber of the New York State Public Service Commission. Table 8 gives generic estimates of FGD system annual operating costs for two 850-MW units.

Balance-of-Plant Investment Costs

BOP comparative investment costs include expenditures for major items that are dependent on the quality characteristics of a particular coal. Such items include steam generators, electrostatic precipitators, and all requisite concrete, structural steel, and electrical equipment.

All BOP cost estimates used here are, again, derived from work performed by Ebasco Services, Inc. (2). Table 9 gives these comparative investment costs for two 850-MW units. Expenditures for items common to both units are assessed to unit 1.

Illustrative Application

To facilitate the reader's comprehension of the methodology used in this study, the procedures have been applied to assessing the comparative economics of coals A, B, and C at the proposed mid-Mohawk River Valley generating facility. Three points about this illustrative application are worthy of note:

1. FGD system investment and operating cost estimates have been computed for SO_2 removal efficiencies that would have been required to comply with the 1971 NSPS.
2. The following escalation and amortization parameters were used in all calculations:

Parameter	Amount
Annual fixed capital charge rate (%)	18
Discount rate (%)	11.5
Escalation rate (%)	
Fuel (per year)	5
Materials	6
Labor	8
Operations and Management	5
Plant life (years)	30

Escalation rates for materials, labor, and operations and management are from Ebasco Services, Inc. (2). The other parameters given above are recommended by the New York State Public Service Commission.

3. To provide insight on the impacts of eastern coal prices on overall comparative economics, the two FOB mine prices for this fuel given in Table 4 were included in the analyses.

Computations of total delivered prices for the three types of coal at the mid-Mohawk River Valley location are given in Table 10. It was assumed that western coal destined for this inland plant would pass through the proposed Buffalo transshipment facility. Transportation costs were estimated by assuming shipment from Buffalo to the plant via the existing canal, an expanded and modernized canal, and unit trains. Eastern coal was assumed to be shipped directly from mines to the consumption site in unit trains.

It is of interest to note the effects that coal heat contents have on total delivered prices (Table 10). Assuming massive reconstruction of the canal system, the delivered price of eastern coal (with an

Table 11. Fuel charges for unit 1, proposed Canajoharie facility.

No.	Item	Coal A Min	Coal A Max[a]	Coal B	Coal C
	Annual Fuel Charge				
1	Fuel escalation rate (%/year)	5	5	5	5
2	Fuel cost as of operation date ($/million Btu)	3.61	4.09	4.14	3.71
3	Levelized fuel cost ($/million Btu)	5.66	6.41	6.49	5.81
4	Net generating capacity (kW)	785 350	785 350	794 800	786 200
5	Net station heat rate (Btu/kW·h)	9410	9410	9795	9770
6	Average operating time (h/year)	6044	6044	6044	6044
7	Annual burn (Btu x 10^{12})	44.666	44.666	47.053	46.425
8	Levelized annual fuel charge (no. 3 x no. 7) ($000s)	252 810	286 309	305 374	269 729
	Energy Charge for Equivalent Generation				
9	Differential capability (kW)	9450	9450	Base	8600
10	Average charge (no. 3 x no. 5 x no. 6) ($/kW-year)	322	365	Base	343
11	Energy charge (no. 9 x no. 10) ($000s)	3043	3449	0	2950
12	Total annual fuel charge for this unit (no. 8 + no. 11) ($000s)	255 853	289 758	305 374	272 679

[a]Sensitivity alternatives.

Table 12. Fuel charges for unit 2, proposed Canajoharie facility.

No.	Item	Coal A Min	Coal A Max[a]	Coal B	Coal C
	Annual Fuel Charge				
1	Fuel escalation rate (%/year)	5	5	5	5
2	Fuel cost as of operation date ($/million Btu)	3.98	4.51	4.57	4.10
3	Levelized fuel cost ($/million Btu)	6.24	7.07	7.16	6.42
4	Net generating capacity (kW)	785 350	785 350	794 800	786 200
5	Net station heat rate (Btu/kW·h)	9410	9410	9795	9770
6	Average operating time (h/year)	6044	6044	6044	6044
7	Annual burn (Btu x 10^{12})	44.666	44.666	47.053	46.425
8	Levelized annual fuel charge (no. 3 x no. 7) ($000s)	278 716	315 789	336 899	298 049
	Energy Charge for Equivalent Generation				
9	Differential capability (kW)	9450	9450	Base	8600
10	Average charge (no. 3 x no. 5 x no. 6) ($/kW-year)	355	402	Base	379
11	Energy charge (no. 9 x no. 10) ($000s)	3355	3799	0	3259
12	Total annual fuel charge for this unit (no. 8 + no. 11) ($000s)	282 071	319 588	336 899	301 308
13	Total 1996 annual fuel charge for this unit ($000s)	255 847	289 876	305 577	273 295
14	Total annual fuel charge for all units ($000s)	511 700	579 634	610 951	545 974

[a]Sensitivity alternatives.

Table 13. Investment cost summary for Canajoharie facility under 1971 NSPS.

No.	Item	Cost ($000s) Coal A	Coal B	Coal C
1	BOP construction costs	818 219	965 341	965 341
2	Coal-receiving equipment and cooling-tower make-up and blow-down lines	17 085	7 593	7 593
3	Indirect costs, contingencies, and fees for no. 2	4 784	2 126	2 126
4	Total BOP comparative investment costs	840 088	975 060	975 060
5	FGD system	484 274	0	422 078
6	Total comparative investment costs (no. 4 + no. 5)	1 324 362	975 060	1 397 138
7	Annual capital charge (no. 6 x 0.181)	239 709	176 486	252 882

Note: Costs in 1996 dollars.

Table 14. Comparative economics for Canajoharie facility under 1971 NSPS.

Item	Amount ($000s) Coal A Min	Coal A Max	Coal B	Coal C
Annual capital charge	239 709	239 709	176 486	252 882
Annual fuel charges	511 700	579 634	610 951	545 974
Annual operating charges	35 134	35 134	0	23 613
Annual revenue requirements	786 543	854 477	787 437	822 469

Note: Figures are in 1996 dollars.

FOB mine price of $24.76/ton) is approximately $8/ton higher than that of Montana coal. However, when the heating values of the coals are used to convert these delivered prices to equivalent prices per million Btu, eastern coal enjoys a slight cost advantage. Thus, dollar-per-ton cost comparisons of

Table 15. Summary of site-specific annual revenue requirements.

Plant and Location	Operating Company	Status	Target Service Date	NSPS	Revenue Requirements ($000s) Coal A Min	Coal A Max	Coal B	Coal C
Somerset	NYSEG	Proposed	11/83	Old	203 320	223 219	214 693	221 183
				Revised	204 109	224 008	238 203	225 121
700 Fossil, Arthur Kill	PASNY	Proposed	11/84	Old	183 714	200 135	196 478	203 496
				Revised	185 859	202 280	217 753	207 581
LEGS, Pomfret	NMPC	Proposed	1/88	Old	505 155	552 271	503 542	528 073
				Revised	508 882	555 957	564 263	538 418
Sackets Harbor, Lake Ontario		Potential	1/93	Old	679 434	742 242	697 904	730 899
				Revised	684 283	747 091	778 378	749 018
Canajoharie		Potential	1/96	Old	786 543	854 477	787 437	822 469
				Revised	794 365	860 166	882 743	838 489

coals with different heat contents can be quite misleading.

Tables 11 and 12 give the annual fuel-charge computations for units 1 and 2 of the proposed generating station. Only the delivered prices of western coals that assume shipment via the minimum-cost mode and route configurations are subjected to further analysis.

As data given in Table 11 show, 1977 delivered prices (in dollars per million Btu) are converted to corresponding 1996 prices (the target service date for unit 1) by assuming an escalation rate of 5 percent/year. The resultant figures are then levelized to account for the present worth of price increases (at a rate of 5 percent/year) over the 30-year plant life (all fuel supply analyses conducted by New York State utilities use levelized fuel cost estimates). The levelization factor (LF) was calculated from the following formula:

$$LF = \{[1/(i - r)] \exp[(i - r)n] - 1\}/[-(i/r)\exp(-rn) - 1] \quad (2)$$

where

i = escalation rate (5 percent),
r = discount rate (11.5 percent), and
n = plant life (30 years).

Levelized fuel costs are determined by multiplying fuel costs (in dollars per million Btu) by the levelization factor. These costs are then multiplied by the projected annual burn (the product of net generating capacity, net station heat rate, and operating time) to obtain estimates of levelized annual fuel charges. Total annual fuel costs are equal to levelized annual fuel costs plus energy charges for differences in net generating capacities. The method used to compute energy penalties is presented in Table 11.

Total annual fuel charges for unit 2 are calculated in an analogous manner. Those costs are then converted to equivalent 1996 dollars and added to unit 1 charges to obtain total annual fuel charges for the plant (Table 12).

A summary of required investment expenditures for the proposed generating station is given in Table 13. These investment costs are amortized and added to annual fuel charges to determine the estimated revenue requirements given in Table 14.

Examination of that table reveals that the comparative economics of eastern and western coal at this hypothetical generating station are extremely sensitive to assumptions regarding the FOB mine prices of eastern coal. Use of the lower price ($24.76/ton in 1977 dollars) yields results that suggest that eastern coal would be the preferred fuel-supply option. If, however, comparisons are based on the higher price ($29.52/ton), the eastern coal alternative would be the most costly.

RESULTS AND CONCLUSIONS

Table 15 summarizes the comparative economics of eastern, Wyoming, and Montana coals at the five proposed New York State generating stations. Several points regarding the information displayed in Table 15 warrant discussion.

It should be noted that annual revenue requirements for the Montana and Wyoming (B and C) coal options were estimated by assuming the existence of a transshipment facility at the Port of Buffalo and an expanded and modernized canal system. (The locations of the Lake Erie Generating Station and the Somerset facility rendered shipment via the canal infeasible. In addition, direct delivery of western coal to the Lake Erie Generating Station was less costly than shipment through the Port of Buffalo.) In the absence of such facilities, delivered prices (and consequently annual revenue requirements) would be significantly higher.

Table 15 provides insight into the effects of the 1979 NSPS on the competitive position of western coals in New York State. As the table shows, the increases in total annual costs attributable to those standards are substantial, particularly for the Wyoming coal option.

The impacts of the assumed FOB mine prices for eastern coal on the costs related to its use at new coal-fired plants are significant. I am of the opinion that the annual revenue requirements based on the lower estimate ($24.76/ton in 1977 dollars) most accurately reflect prevailing coal market conditions. According to Coal Week, as recently as October 1979, 12 800-Btu/lb, 2.5 percent sulfur coal produced in southwestern Pennsylvania could be purchased under long-term contract for $27.00/ton FOB mine. When escalated (at 5 percent/year) to 1979, the minimum FOB mine price is $27.30/ton.

A comparison of the revenue requirements for coals A (minimum), B, and C in Table 15 for the revised NSPS scenario reveals that eastern coal is the preferred fuel supply option for all of the proposed generating stations. Thus, no large-volume shipments of western coal can be expected to traverse the canal system, even if it is modernized to deep-draft standards.

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Publication of this paper sponsored by Committee on State Role in Waterborne Transportation.

Foreign Trade Zones and Inland Ports: A Question of Size

JOHN J. DA PONTE, JR.

Although all domestic ports of entry are "entitled" to establish foreign trade zones under federal law upon meeting certain technical and economic requirements, the volume of international trade at inland ports is often marginal in terms of the need for zone services. Since many of these communities wish to use zones as a means of helping to attract new international-trade-related operations, their zone projects are often conceived for a small amount of activity at the outset and with an uncertain medium- and long-term outlook. The requirements of federal law and how they have been interpreted with regard to smaller zone projects are discussed. Recent interpretations and practices of the Foreign-Trade Zones Board and the U.S. Customs Service are discussed in terms of how they affect the feasibility of zones in inland areas that have an inherently smaller "zone-use base". A general analysis is presented of the first few inland zones. Some methods of structuring smaller zones to reduce and spread capital and operating costs are suggested. It is concluded that, whereas current federal procedures and practices make it possible even for smaller inland ports of entry to use zones in their economic development efforts, such communities should be mindful of the financial risks involved.

Although foreign trade zones have constituted a chapter in U.S. customs laws for some 45 years, it has not been until the past decade that they have become widely available in the United States. Congress coined the term "foreign trade zone" when the law that authorized these facilities--the Foreign Trade Zones Act--was enacted in 1934. In this paper, the term is used interchangeably with the general terms "free trade zone" and "customs-free zone". All are limited versions of the historic "free port".

Before 1970, fewer than 10 U.S. cities had foreign trade zones, all of them ocean or Great Lakes ports. By the end of the decade the number had increased to 50, and several of the new projects were bringing this international trade service to U.S. inland ports of entry for the first time.

Although the inland ports have always been eligible as sites for foreign trade zones, only recently have the agencies concerned with economic development in these areas taken an interest in making zones a part of their public services. The traditional association of customs-free zones with seaports, and major seaports at that, has undoubtedly been a psychological factor. Were it not for the provision in the U.S. Constitution that prohibits legislation favoring the ports of one state over those of another, the Foreign Trade Zones Act might well have perpetuated this stereotype. The fact that Congress did not find this narrower view appropriate and made all U.S. ports of entry eligible for zones gave the concept wider currency in the United States (there are more than 300 customs ports of entry in the United States, about 25 percent of which are involved with commercial shipments). This provided the legal foundation for the present growth in the U.S. zone program.

The spread of zones to inland U.S. ports has not been just a matter of overcoming a mental block. The very definition of a port has broadened in a dramatically changing world economy. International trade, direct investment, and transportation technology are weaving a new trade network. Most of the world's larger seaports retain their prominence but, throughout the network, inland centers of trade are growing and new ones are emerging. These communities, although smaller in size, are taking on the trappings of true port cities.

The products of modern technology are also affecting the role of inland ports. Multinational firms that produce and market these products have an unparalleled range of choices in the siting of plants and distribution centers. Industries are no longer as tied to certain locations as they once were. Mobility and flexibility are the rule. This places new and complex demands on port communities, including inland ports, which have become increasingly sensitive to the need for improved public services and facilities (1,2).

U.S. ZONES FROM 1934 TO 1970

The first U.S. foreign trade zones were, as expected, established as seaports. Through the late 1940s, New York, Mobile, New Orleans, San Francisco, Los Angeles, and Seattle were the only U.S. cities that were authorized zones. New York's zone was sponsored by the city government, which contracted the operation of its facility to a private firm. The other zones were from the outset owned and operated by seaport authorities, some of whom eventually took on private firms as zone operators. Both Los Angeles and Mobile closed their zones after a short time, apparently finding that customs-bonded facilities served their needs.

Even after the 1934 act was amended in 1950 to permit manufacturing, another decade passed before there were further zone efforts. During the 1960s, new zones were approved for Toledo, Ohio; Bay County, Michigan; Mayaguez, Puerto Rico; and Honolulu, Hawaii. All of these facilities were tied to ocean or Great Lakes ports.

EXPANSION WAVE OF THE 1970s

Interest in foreign trade zones intensified with the international economic developments of the