STATE OF WEST VIRGINIA

BEFORE THE PUBLIC SERVICE COMMISSION

General investigation to determine whether West Virginia should adopt a plan for open access to the electric power supply market and for the development of a deregulated plan	)))))	Case No. 98-0452-E-GI

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

WEST VIRGINIA CONSUMER ADVOCATE

Resource Insight, Inc.

JULY 6, 1999

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EXHIBITS

I. Identification and Qualifications

Q: State your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 347 Broadway, Cambridge, Massachusetts 02139.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February, 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters. My work has considered, among other things, power supply planning, rate design, cost allocation, and utility industry restructuring. My resume is appended to this testimony as Exhibit___PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred and fifty times on utility issues before various regulatory, legislative, and judicial bodies, including the

Massachusetts Department of Public Utilities, Massachusetts Energy Facilities Siting Council, Vermont Public Service Board, Maine Public Utilities Commission, Rhode Island Public Utilities Commission, Connecticut Department of Public Utility Control, Texas Public Utilities Commission, New Mexico Public Service Commission, District of Columbia Public Service Commission, Michigan Public Service Commission, Minnesota Public Utilities Commission, Public Utilities Commission of Ohio, South Carolina Public Service Commission, North Carolina Utilities Commission, Florida Public Service Commission, Pennsylvania Public Utilities Commission, New York Public Service Commission, Arizona Commerce Commission, New Orleans City Council, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume.

Q: Have you testified previously on the estimation of stranded costs?

A: Yes. I have provided testimony related to stranded costs in the following cases:

- The rulemaking portion of New Hampshire PUC Case No. DR 96-150 on the definition and measurement of stranded costs.
- The adjudicatory portion of New Hampshire PUC Case No. DR 96-150 on the market value of power and interim stranded costs of Public Service of New Hampshire.
- Massachusetts DPU Docket 96-100 on the measurement and mitigation of stranded costs.
- NYPSC Docket 96-E-0897 on the estimation of Consolidated Edison's stranded costs.

- Maine PUC Docket 97-580 on the determination, mitigation, and allocation of Central Maine Power's stranded costs.
- Massachusetts DTE 97-120 on the stranded costs of Western Massachusetts Electric Company's Millstone shares.
- Maryland PSC Case No. 8794 on market prices and Baltimore Gas & Electric generation stranded costs.
- Maryland PSC Case No. 8795 on market prices and Delmarva Power and Light's generation stranded costs.
- Maryland PSC Case No. 8797 on the market prices and generation stranded costs of Potomac Edison, a subsidiary of Allegheny Energy.
- Connecticut DPUC Docket No. 99-02-03 on the market prices and generation stranded costs of Connecticut Light and Power.

Portions of some of my other testimony have addressed market prices, options for industry restructuring, and the implications for utility planning.

I also assisted the Vermont legislature in 1997 on issues relating to stranded costs and nuclear economics, in connection with the drafting of restructuring legislation.

II. Introduction and Summary

Q: On whose behalf are you testifying in this docket?

A: I am testifying on behalf of the West Virginia Consumer Advocate.

Q: What is the subject matter of your testimony?

A: For each of the utilities—Potomac Edison ("PE"), Monongahela Power ("Mon Power"), and Appalachian Power ("Apco")[1]—I present the Consumer

[1] I will refer to these utilities collectively as the "West Virginia utilities."

Advocate's projection of the market value of generating assets and the gain from restructuring.

Q: Please summarize the conclusions of your analysis.

A: Based on an analysis of the actual prices of comparable capacity sold for use in the competitive generation market, the market value of the generating assets of West Virginia utilities exceeds the book value of those assets by approximately **$2.8 billion**. I estimate that market value of generation plant and the resulting gain from restructuring for the three West Virginia utilities on a West Virginia jurisdictional basis are as follows (in million $):

	Market Value	Stranded Cost (Gain)
Appalachian Power	$1,830	($1,467)
Potomac Edison	$337	($244)
Monongahela Power	$1,493	($1,110)
Total		($2,821)

In addition, there is a positive stranded cost associated with Mon Power's three PURPA contracts, which I estimate to be between $55 and $194 million. This PURPA-related positive stranded cost is more than offset by the negative stranded costs associated with Mon Power's generating plant.

The analyses that I present in this testimony are estimates based on actual sales of generating assets in the open market. As discussed by other Consumer Advocate witnesses, the best way to determine and recover the true market value of the generating plant of West Virginia utilities is to require divestiture and sale of that generating plant on the open market.

Q: Does your analysis of stranded costs cover all investor-owned utilities serving retail customers in West Virginia?

A: No. My analysis omits distribution-only utilities, such as Wheeling Power Company and West Virginia Power. These companies own no generation assets and purchase all of their power from other entities pursuant to wholesale contracts of various terms.

III. Estimation of Market Value of Generation from Sales Results

Q: What is your estimate of West Virginia's share of the market value of Potomac Edison capacity?

A: Exhibit__PLC-2 shows the values I assigned to each Potomac Edison generator. I categorized Potomac Edison capacity as follows:

- High-quality coal plants at **$950/kW**: Fort Martin, Harrison, Hatfield, and Pleasants.
- Low-quality coal plants at **$400/kW**: Albright and Smith.
- Pumped storage at **$490/kW**: Bath County.
- Conventional hydro at **$1000/kW**: Potomac Edison's small hydro units.

Exhibit___PLC-2 projects the total market value of Potomac Edison capacity to be **$1,717 million**, or a weighted average of **$846/kW**. Assuming generation plant is allocated among jurisdictions based on average demand, Exhibit___PLC-3 shows that the West Virginia share of this value is **$337 million**. This market valuation would produce negative stranded costs of **$244 million**. In other words, the market value of PE's plants would result in a gain of $244 million over the net value of the plants as shown on the books of the Company.

Q: What is your estimate of West Virginia's share of the market value of Monongahela Power capacity?

A: Exhibit___PLC-4 shows the values I assigned to each Monongahela Power generator. Most of these plants, and hence most of the valuations, are the same as for Potomac Edison. I categorized Monongahela Power capacity as follows:

- High-quality coal plants at **$950/kW**: Fort Martin, Harrison, Hatfield, and Pleasants.
- Low-quality coal plants at **$400/kW**: Albright, Rivesville, and Willow Island.[2]
- Pumped storage at **$490/kW**: Bath County.

Exhibit___PLC-4 projects the total market value of Monongahela Power capacity to be **$1,720 million**, or **$762/kW**. Exhibit___PLC-3 shows that, based on an average-demand allocation, the West Virginia portion is **$1,493 million**. This market valuation would result in a gain of **$1,110 million** over net plant.

Q: What is your estimate of West Virginia's share of the market value of Appalachian Power?

A: Exhibit___PLC-5 shows the values I assigned to each Appalachian Power generator. I categorized Appalachian Power capacity as follows:

- High-quality coal plants at **$950/kW**: Amos and Mountaineer.

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[2] Rivesville's operating costs may be so high that the future of the plant in a competitive environment is questionable. However, because Rivesville is so small, only 137 MW, it has little impact on my ultimate conclusions. For example, even if it were assumed that Rivesville had absolutely no value on the open market, Mon Power's negative stranded costs would be reduced by only $55 million.

- Medium-quality coal plants at **$600/kW**: Philip Sporn unit 5, Clinch River.[3]
- Low-quality coal plants at **$400/kW**: Glen Lyn, Kanawha River, and Philip Sporn units 1-4.[4]
- Pumped storage at **$490/kW**: Smith Mountain.
- Run of River Hydro at **$1000/kW**: small hydro.

Exhibit___PLC-5 projects the total market value of Appalachian Power capacity to be **$4,474 million**, or **$773/kW**. Exhibit___PLC-3 shows that, based on an average-demand allocation, the West Virginia portion is **$1,830 million.** This market valuation would result in a gain of **$1,467 million** over net plant.

Q: How did you use the results of actual generation asset sales to estimate the value of each type of generation owned by the West Virginia utilities?

A: I based my estimates on an examination of all 1996-1998 sales of generating assets to be used for operation in the competitive market. Sales of plants that were to be operated under rate-of-return regulation, or under long-term purchased-power contracts, are not relevant. Exhibit___PLC-6 provides detailed information on the market-to-book ratio for these sales, where available, as well as data on sales in the West. As can be seen from this table,

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[3] I have classified Clinch River as a medium-quality coal plant because, in spite of its age, it has a very low operating cost.

[4] Glen Lyn Unit 6 was classified as a low-quality unit because of its age. This represents a conservative estimate of its value. Due to its size, 235MW, it might instead be categorized as a medium quality plant, which would increase the overall Apco value by approximately $47 million.

the average capacity sold for about $400/kW. The best coal plants sold for roughly $1,000/kW.

My analysis of this data was essentially a two-step process. First, I divided the sold assets into groups according to the type and quality of the generating plant. These assignments took into account such characteristics as:

- the size of the plants and the units, both of which help determine the O&M costs and capital additions (including environmental compliance costs);
- age;
- the fuel type;
- operating costs;
- power-market conditions.

Second, I selected dollar-per-kW values by plant category. Since the asset sales prices reported are for the total portfolio purchased, not for each generation plant or unit separately, I had to infer a price for each plant type. I selected values that would closely reproduce the assets sales prices in my data set.[5]

Exhibit___PLC-7 provides a summary of the MW and estimated dollar-per-kW value of each type of generation sold by the utilities that have sold non-nuclear generation into the competitive market east of the Mississippi. In Exhibits___PLC-2, 4 and 5, I estimate the asset values for each of the West Virginia utilities by applying the dollar-per-kW values by plant type that I developed from the actual sales data.

Q: What generation asset sales do you include in your data set?

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[5] As explained below, Exhibit___PLC-10 tests the validity of my assignments of dollar-per-kW values to plant types.

A: I include a total of twenty-two announced sales and one revaluation, covering over 41,000 MW that sold for a total price of over $19 billion.[6] Of the sales in the Eastern Interconnection, I excluded only

- The minority share of Wyman 4 sold (for $147/kW) by EUA to FPL, which had already agreed to purchase the controlling interest in Wyman 4 from Central Maine Power. Little interest has been shown in minority shares of power plants, other than by joint owners (and then usually the lead owner). This sale appears to be depressed by this consideration.[7]
- The sale by Commonwealth Energy of its share of Wyman 4, the jets and cogeneration steam units at the Kendall plant in Cambridge, Massachusetts, and various diesels on Cape Cod and Martha's Vineyard (for $500/kW). The value of the cogeneration units is very sensitive to the contractual arrangements for their steam output, making comparisons to other sales difficult. This sale price was higher than would be expected for the mix of capacity involved.

I grouped the joint owners' sales of Homer City, Canal, and New Haven Harbor plants.

Q: Why did you exclude the sales in the Western Interconnection?

A: The prices for primarily gas-fired plants in California have generally been less than for comparable plants in the Northeast and Midwest, as can be seen

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[6]Although not a sale, I included Illinois Power's revaluation of their assets under its "quasi-reorganization" since it was an estimate of fair market value agreed upon by both SEC officials and Illinois Power Accountants. (Illinova 8-K, March 3, 1999, Item 5)

[7]I included the Maine Public Service and Bangor Hydro sales of capacity mixes including their shares of Wyman 4, as well as Duquesne's sale of its half of Fort Martin 1 (roughly a quarter of the Fort Martin station) to APS, even though these the sale prices may have been depressed by the minority-owner effect.

in Exhibit___PLC-6. This is particularly true for the Southern California Edison plants and the sale from PG&E to Duke. The exceptions to this rule are the more recent sales by PG&E to Southern and by SDG&E to the Dynergy-NRG joint venture, both which are not much different from prices paid in the East for capacity of similar fuel type, vintage, and unit capacity.

The recent sale of the jointly-owned Colstrip plant and Montana Power's other coal and hydro capacity brought in prices around $800/kW. While much greater than the prices of the gas-fired plants, this was still about 20% less than similar plants would fetch in the East. The low prices in the West may result in part from the periodic surpluses of hydro energy in the West, which can price even the best baseload coal plants (and even nuclear plants) out of the market for months at a time.

Q: Why is the experience in the Northeast and Midwest capacity markets a reasonable basis for projecting the market value of capacity in eastern ECAR, the area served by West Virginia utilities?

A: In the last year, ECAR East has been one of the highest-cost regions. The market price in the AEP region has been just slightly lower. As Exhibit___PLC-8 shows, market prices in both regions have been far greater than in New England, New York or PJM (where the major asset sales have occurred since July 1998). For this reason, plants in ECAR may sell for even more than the prices realized in the Northeast.

Q: What is your basis for believing that this regional pattern will be maintained in future market prices?

A: Forward contract prices indicate a similar pattern across regions. Cinergy is the only ECAR delivery point for which the forward prices are publicly available. As shown in Exhibit ___PLC-8, the Cinergy forward prices are comparable to or higher than the NY, NE, PJM or MAIN regions.

Q: How did you classify the capacity in each of the sales included in your analysis?

A: In Exhibit___PLC-9, I list the megawatts of summer capacity in each sale for each fuel or plant type (coal, oil and/or gas steam, CTs, modern combined-cycle, pumped-storage hydro, and conventional hydro). For the first three plant types, I divided capacity into quality groups, primarily based on the age and capacity of units, and the total capacity of each power station. Exhibit___PLC-9 also shows the age of each steam unit used in the analysis. Other than the age and size criteria, my assignments of capacity to quality groups were influenced by the following considerations:

- I downgraded New England coal units, to reflect the small differentials between the prices of coal and other fuels in New England. Coal units just are not as desirable in New England as they are in other regions.
- I treated New Boston Units 1 and 2 as Big-New oil/gas units, even though they are few years older than my cut-off point, because they were extensively rebuilt as part of a gas conversion in the early 1990s.
- Bowline Point would appear to be a Big-New oil/gas plant (large units, large plant, 1972 in-service date). I downgraded it to reflect its low capacity factors in recent years.
- I treated GPU's Gilbert combined-cycle plant, which entered service in 1974, as being comparable to older CTs, rather than new combined-cycles, due to its age and lower efficiency.

Q: How did you determine the value of each type of capacity?

A: I selected the dollars-per-kW values shown in the top row of Exhibit___PLC-7 for each generation type that would closely reproduce actual sales prices, including actual prices for portfolio sales.[8] The values I estimated are

- Coal plants: $950/kW for the best capacity, categorized as post-1968 units larger than 500MW, ranging down to $400/kW for pre-1962 units with less than 200MW of capacity (some of which entered service in the 1940s and are under 40 MW).
- Oil- and/or gas-fired steam plants: $400/kW for plants built after 1967 and larger than 350 MW ranging down to $150/kW for pre-1962 units that are smaller than 200MW.
- Combustion turbines: $350/kW for post-1990 units, $150/kW for older units (mostly installed in 1967-1972).[9]
- Post-1990 combined-cycle units (NEES's Ocean States and Manchester Street): $450/kW.
- Pumped-storage hydro units: $490/kW.[10]
- Conventional hydro units: $1,000/kW.

Q: How well do your assignments of dollar-per-kW values to plant type fit the actual sales data?

A: Overall, the actual sale prices closely match the estimates that result if each type of plant in the sale is given the dollar-per-kW value I selected.

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[8]All sales are the announced dollars and are assumed to be relevant for the year the sale was announced. The figure is subject to change via inflation or situational market forces.

[9]I also included a few old diesels in the "old CT" category.

[10]This value is based on the price paid by FirstEnergy for GPU's part ownership of the Seneca pumped-storage plant, and may be depressed by the limited competition for minority ownership.

Exhibit___PLC-10 shows the resulting estimated asset value in millions of dollars and in dollars per kW, and the difference between my estimate and the actual sale price, as a percentage of the estimate. The Exhibit also identifies those sales that required the purchaser to sell power back to the seller at below-market rates, and the one sale that required the purchaser to absorb the risks of the value of significant purchased-power contracts. The fit is quite good, with three exceptions:

- NEES, which was the first New England sale, prior to retail access, and which included a buyback obligation and responsibility for a large purchased-power obligation.
- Some sales in which more than 65% of the implied value results from hydro capacity (Maine Public Service, NiMo, Central Maine, and Bangor Hydro). The sales prices are overestimated for MPS and NiMo, and underestimated for CMP and BHE.[11] The value of hydro capacity varies widely with the amount of energy available, the extent to which the plant can follow load, its operating costs, and anticipated costs and operating limits associated with relicensing.[12]
- Two oil- and gas-fired plants, New Haven Harbor and Bowline, sold for about a third less than I would have expected. This is presumably due to plant-specific factors. As I noted above, Bowline has operated at very

[11]The variability in hydro value may also affect the value of the NEES capacity, for which a quarter of my estimated value is from conventional hydro.

[12]A number of other factors may be at work for MPS, which is connected to competitive markets only through the Canadian province of New Brunswick. The MPS hydro sold for $1,000/kW, even if its fossil capacity were valued at zero. In addition, the value of MPS's 21-MW share of Wyman 4 may have been depressed by the minority-owner effect.

low capacity factors, and might be more-realistically rated as a low-value plant.

The value of any type of plant varies with details I haven't considered explicitly, including plant-specific equipment condition, contracts, fuel prices, O&M, property taxes, environmental problems, and expansion opportunities. Even without compensating for these factors, my estimates are fairly close on most of the sales prices.

Overall, my estimates average about three percent greater than the actual sales price. Excluding NEES, the average estimate is less than a half of a percent above actual. Perhaps as importantly for Potomac Edison, Monongahela, and Appalachian, the coal-dominated sales (O&R, GPU, Homer City, NYSEG, EUA, NiMo and ComEd) fit quite well, with the average estimate within one percent of the actual sales price and only one of the estimates falling more than 10% from the actual sale price.[13] This confirms the validity of my valuation of coal plants, which comprise the bulk of the value of the Potomac Edison, Monongahela, and Appalachian portfolios.

Q: How do the dollar-per-kW values by plant type that you selected compare with those of other analysts

A: Resource Data International compiles sales prices by type of plant and has reported generation asset values as follows:[14]

[13]The 22% difference for NiMo may result from the inclusion in the valuation of two 90 MW units from the early 1950s, which NiMo had scheduled for retirement in 1999. Removing the capacity of these two units reduces the difference to 8%.

[14]Wagman, David. 1998. "Niagara Mohawk Sells Hydro Plants," *Energy Insights* (December 4, 1998).

- Coal plants: High-value plants about $1,000/kW, medium-value $300/kW-$700/kW, average of $518/kW.
- Hydro: Average of $507/kW.
- Oil and gas plants: Average just under $370/kW, highest in the Northeast, $29/kW-$200/kW in California.

Overall, RDI's estimates of coal values, the important values for Potomac Edison, Monongahela, and Appalachian, are consistent with mine.

Q: Why is it reasonable to assign most of the coal capacity of the three West Virginia utilities to the high-quality coal category?

A: In Exhibit___PLC-11 and Exhibit___PLC-12, I compare the size, age, and operating-cost characteristics of the APS and AEP coal plants with the sold coal plants in the PJM and NY regions, along with Somerset 6 in New England.[15] The two charts clearly show that the large APS and AEP coal plants are similar to—and in some ways superior to—the best coal plants that have been sold to date.

IV. Estimation of the Market Value of Monongahela Power's PURPA Contracts

Q: How did you estimate the stranded costs related to Mon Power's PURPA contracts?

A: Because I did not have access to any more recent analyses, I relied on the methodology the Company used to estimate stranded costs in its June 23, 1997 filing in Case No. 96-1491-E-GI. For its determination of stranded

[15] Somerset was the only New England coal plant sold in a transaction that was clearly dominated by coal value.

costs related to PURPA, the Company compared the costs produced each year for each contract with an estimated market price. While I have relied on the Company's calculation of costs under each contract, I reserve the right to modify my calculation if it later appears that changes should be made in any of the contract costs.

For its calculation of the market value of the contracts, the Company projected market price by applying a 2.5% escalation factor to a 1997 starting price of $19/MWh. I revised the starting price to reflect more recent market experience. I calculated stranded costs based on two different estimates of market price in 2000:

- the 1998 average firm price for ECAR East region escalated to 2000, or $36.5/MWh, and
- the midpoint of the Cinergy calendar-year-2000 forward prices, adjusted upward by 4% to reflect the ratio of ECAR East to Cinergy market price over the past twelve months, or $28.3/MWh.

Exhibit___PLC-13 and Exhibit___PLC-14 calculate the stranded costs to be $194 million and $55 million for the high and low starting prices, respectively, using a 10% discount rate.

Q: Does this conclude your testimony?

A: Yes.