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

REBUTTAL TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

WEST VIRGINIA CONSUMER ADVOCATE

Resource Insight, Inc.

AUGUST 6, 1999

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Exhibits

I. Introduction

Q: Please 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: Are you the same Paul Chernick who previously filed testimony in this proceeding?

A: Yes.

Q: What is the purpose of this rebuttal testimony?

A: I respond to the testimony of Allegheny Power witness John R. Howells on the market value of APS's generating assets and the resulting stranded costs.

II. Summary

Q: What is the Company's estimate of the stranded cost of its generating assets?

A: APS projects positive stranded costs of $64.2 million and $17.1 million for the West Virginia jurisdictional share of the generating assets of Monongahela Power (MP) and Potomac Edison (PE), respectively.

Q: How does APS compute stranded costs?

A: In Mr. Howell's testimony, Allegheny estimates stranded cost for a generating asset as the difference between the asset's net investment cost and its value, where value is the present value of APS's projection of discounted cash flow (DCF). Mr. Howell presents stranded cost separately for PE's and

MP's ownership share of each coal unit, for the share of Bath County that Allegheny allocates to each utility, and for PE's small hydro plants.

Q: Please describe the Discounted Cash Flow approach to asset valuation.

A: The DCF approach determines the value of an asset as the present value of the expected future cash flows. For an electric generation plant, the annual cash flow is the after-tax annual operating margin. Operating margin is defined as the difference between (1) market energy and capacity revenues and (2) operating expenses.

Q: Do you believe that the Company's projection of positive stranded costs is supported by its DCF analysis?

A: No. Allegheny projects pessimistically low market prices over the 25-year analysis period; makes unrealistically pessimistic assumptions about the operating costs of two of its high-quality coal plants, the useful life of all four modern coal plants, and the nature of a possible future carbon-tax program; and includes fossil decommissioning costs that are unlikely to be incurred.

Q: Have you estimated the effect of Company's unrealistic input assumptions on its estimate of stranded costs?

A: Yes. I recalculated the Company's asset-valuation spreadsheet, revising some of the input assumptions. These changes alone resulted in negative stranded cost of $504.5 million and $110.6 million for the West Virginia jurisdictional share of the generating assets of MP and PE, respectively.

Exhibit___PLC-R-1 shows the effect of my changes to APS's input assumptions on the results of its asset-valuation spreadsheet.

Q: Would you recommend that the Commission use the results of the modified DCF analysis to determine the market value of APS's generating assets?

A: No. My recalculation is intended for illustrative purposes only. My purpose is to demonstrate that replacing just some of the Company's input assumptions with more plausible projections will result in much higher estimates of the market value of its generating assets. I have not developed an independent projection of market price nor corrected all of the errors I identified in the Company's analysis.

Q: Could any analysis of future costs and revenues, such as the DCF, accurately determine the market value of the Company's generation resources?

A: No. Such an analysis requires a series of assumptions about the many factors that determine the value of a generating asset in a competitive market. After the fact, the results of any DCF analysis could turn out to be high or low because of the uncertainty of these underlying forecasts. From the perspective of APS, once its generation is no longer regulated, the value of each plant is the greater of (1) APS's expectation of the present value of cash flow if it retains the plant, and (2) the price that would be paid by the buyer most optimistic about the market and operating conditions for that plant, or otherwise most eager to acquire the capacity.[1] As I stated in my direct testimony, the best way to determine and recover the true market value of the generating plant of West Virginia utilities is to require sale of that generating plant on the open market. To the extent that buyers unaffiliated with the incumbent utilities in the region purchase the plants, the sales would also reduce problems of market power.

[1] This determination can be made plant by plant, as PP&L Resources did in deciding to sell Sunbury but retain its other Pennsylvania generation.

III. Recalculation of Stranded Generation Costs from APS's Discounted Cash Flow Analysis

Q: What changes did you make to APS's DCF calculation?

A: I made the following changes to Allegheny's DCF analysis:

- Substituted more plausible projections of growth in market price,
- Eliminated CO_2 taxes,
- Reduced the direct operating and maintenance (O&M) expenses projected for high quality coal units,
- Reduced APS's estimate of A&G expense,
- Increased the remaining life of high-quality coal plants, and
- Eliminated decommissioning.

Q: What was the basis of the market prices Allegheny assumed in its analysis?

A: Allegheny based its market price projection on Market Assessment and Portfolio Strategies Software (MAPS) runs for four years, 2001, 2003, 2008 and 2010. Beyond 2010, it assumed that market price would remain constant in real terms at the 2010 level.

Q: What projected trend in market price results from APS's MAPS analysis?

A: Allegheny's model predicts a 2001 starting price (averaged over all of its units) of about $23/MWh (in 1999 dollars). (Pifer testimony at 18). After 2003, average market price for the baseload coal plants rises at a real escalation rate of 1.8% per year.[2] Between 2008 and 2010, this average

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[2] APS projects higher escalation from 2001 to 2003, 4% annually for baseload coal plants. The increase in that period reflects a one-time introduction of new NOx regulations.

market price rises more than 10% per year (in real terms) largely because of the assumed introduction of CO_2 taxes in 2010. Allegheny extrapolated the MAPS results beyond 2010 by assuming that market price would remain constant in real terms throughout the analysis period.

Q: What market prices did you use in your calculation?

A: I used the Company's projections for the period 2001 through 2008. I excluded the 2010 value in order to eliminate the effect of CO_2 taxes from my results. Beyond 2008, I projected that market price would continue to rise at the average annual rate that the Company predicts for the period 2003-2008, 1.8% per year, in real terms.

Q: With your adjustments, do you believe that APS's projection of market price is realistic?

A: No. Even with my adjustments to APS's projection of market price, I still do not believe it is a realistic projection. Stated simply, APS's assumed starting price of about $23/MWh in 2001 is too low and skews APS's entire analysis. As discussed in my direct testimony, use of actual current market data would result in a much higher starting market price. Since the market price used in APS's DCF analysis is perhaps the single most important determinant of stranded costs, a higher starting price would result in much greater future value for APS's generating assets.

Q: What is APS's assumption regarding CO_2 taxes?

A: Allegheny assumes that CO_2 controls, when they are enacted, would result in a cost to utilities equivalent to a tax, with any allowances given to some parties other than utilities. APS assumes that these CO_2 taxes on utilities will be imposed starting in 2010.

Q: Why do you reject APS's assumption that CO_2 taxes will be imposed starting in 2010?

A: The timing, form, and cost of the assumed limits are speculative and opportunistic. Given the success of the SO_2 allowance trading system, and the adoption of allowances, rather than taxes, for NOx control, any future controls are more likely to be cap-and-trade or allowance schemes than a tax approach. If the APS units are allocated CO_2 allowances, they may be worth as much or more with CO_2 regulation than without.

It is obvious that a carbon tax (or allowances) would tend to decrease demand for and prices of high-carbon fuels (such as coal) and increase the demand for and prices of low-carbon fuels (such as natural gas).[3] This pattern has occurred for high- and low-sulfur coals under the sulfur allowance system. It is not clear that APS includes this effect. Including a carbon tax without an offsetting decrease in coal price and increase in gas prices (and hence in market prices) would understate the value of APS's coal plants.

In any case, the Company's position smacks of special pleading. So far as I am aware, APS has never included CO_2 taxes in any other economic analyses such as rate design or the analysis of cost-effectiveness of DSM or reducing T&D losses. In addition, PHB did not include CO_2 taxes in the market price analysis it sponsored in Pennsylvania.[4] (Pifer Testimony at 20). Neither does PHB appear to have included CO_2 taxes in analyses for other utilities in the same time frame as its analyses for Allegheny.

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[3]This is the opinion of one of APS's referred fuel-price forecasters, WEFA (at 8.7–8.12), which predicts increased coal prices and decreased gas prices in its carbon-stabilization case. WEFA Group. 1998. "Natural Gas Outlook." Eddystone, Penn.: WEFA Group.

[4] PHB Hagler Bailly is the consulting firm used by Allegheny to present its forecast of market prices and environmental costs.

Q: Please explain why you did not accept APS's projection of O&M costs for Harrison and Pleasants.

A: APS's O&M projections for Harrison and Pleasants are inconsistent with its projections for its other large coal plants, as well as with general expectations for improved efficiency in the competitive market. APS projects that the O&M costs for 2004–2008 will be an average of 18% below 1981-97 historical levels for Albright, Ft. Martin, Hatfield, and R. Paul Smith,[5] but will rise substantially for Harrison and Pleasants, 82% and 34% above historical levels, respectively. These O&M rates are summarized in Exhibit___PLC-R-2.

The general expectation is that competitive pressures will reduce non-fuel O&M costs, not increase them. For example,

- The Energy Information Administration projects 25% reductions in O&M for its reference competition case, and 40% in its high-efficiency competitive case.[6]
- Southern Company expects to cut in half the number of employees at the State Line generating plant, which it recently purchased from Commonwealth Edison (Smock at 7).[7]
- Duke expects to reduce staffing 15% at the plants it acquired from PG&E (Seeley at 28).[8]

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[5] The declines are greatest for the large modern plants, Ft. Martin and Hatfield.

[6]Energy Information Administration. 1997. *Electricity Prices in a Competitive Environment: Marginal-Cost Pricing of Generation Services and Financial Status of Electric Utilities* DOE/EIA-614. Washington:EIA, at 32.

[7]Smock, Robert. 1997. "USGen Buys NEES Power Plants for $1.59 Billion" *Electric Light and Power* 75(9) (9/97):1, 4, 6–7.

[8]Seeley, Robert. 1998. "Under New Ownership" *Power Markets* May 1988:24–28.

Q: What O&M costs did you project for Harrison and Pleasants?

A: For Harrison I assumed an O&M cost in 2004 of $20/kW-yr, rising thereafter at the rate of inflation, the same as Potomac Edison's projection in its Maryland stranded cost filing.[9] For Pleasants, I projected an O&M cost of $23/kW (in 1999 dollars). I assumed that competitive pressures would result in the same 18% reduction from historical levels that APS assumed for four of its coal plants.

Q: Please describe your estimate of Administrative & General (A&G) expenses.

A: I estimate annual A&G for existing plant as 30% of annual direct O&M expenses. The 30% value is consistent with overhead costs for generation-only entities reporting to FERC. This adder seems quite high for a firm operating in a competitive market.

Q: How does your estimate of a 30% A&G adder compare to the Company's assumption?

A: In its stranded-cost computations, APS assumes that A&G costs will average more than 36% of O&M costs in the first ten years of the analysis period.

Q: What plant retirement dates did APS assume in its DCF analysis?

A: It retired one high-quality coal unit every year in the period 2007 through 2014, starting with the retirement of Ft. Martin 1 in 2007. The remaining modern coal units, Pleasants 1 and 2, are assumed to be retired in 2019 and 2020, respectively.

Q: How did you modify the retirement dates assumed by APS?

[9] This value is nearly equal to Harrison's historical O&M. The addition of scrubbers may offset competitive pressures for cost reductions.

A: I accepted the retirement dates assumed by APS for its older coal plants (Albright, Smith, Willow Island, and Rivesville), but assumed that the modern coal units would continue to operate at least through the end of the analysis.

Q: How long does the Company assume its plants will operate?

A: APS assumes a 60-year operating life for its older coal plants, Albright, Smith, Rivesville 6 and Willow Island, but a life of only 40 years for Fort Martin and its other newer, larger supercritical coal units.[10] As a result of these inconsistent assumptions, APS projects that Fort Martin, which entered service in 1967 and 1968, will be retired at the same time as Smith 3, which entered service in 1947, a few years earlier than Rivesville 5, which entered service in 1943, and ten years before Smith 4, which entered service in 1958.

Q: What is the record regarding the longevity of supercritical coal boilers?

A: The first supercritical boilers entered service around 1958, and are now 40 years old. So far as I can determine, none of the first generation of supercritical boilers has been retired. Nor can I find any evidence that any of these units is scheduled for retirement. If they actually had a 40-year average life, some of them would have been retired by now. APS's larger and more modern super-critical units of the late 1960s to early 1980s and beyond are likely to last even longer than the units of the late 1950s.

Q: Does APS believe the retirement assumptions used in its own DCF analysis are reasonable?

A: Apparently not. APS planning documents that I have reviewed clearly show that APS expects its supercritical units to last well beyond the end of the

[10] Allegheny assumes an even longer operating life of 68 years for Rivesville 5.

DCF analysis period presented in this case. In particular, for determining the cost-effectiveness of capital additions and in the Allegheny Solid Waste Planning Manual (September 1995), APS assumed much longer lives. It is entirely inconsistent for APS to base stranded cost claims on artificially short assumed plant lives, while it uses substantially longer assumed lives for its own internal planning purposes.

Q: Why did you assume that there would be no fossil decommissioning costs incurred at the end of the analysis period?

A: APS has not provided any historical evidence that retired power plants are likely to be dismantled at a net cost to the owner. The available information indicates that most fossil plants will be reused in ways that result in significant values for the sites and buildings.

Q: Is the inclusion of dismantlement costs in stranded costs comparable to past inclusion of those costs in depreciation rates, under regulation?

A: No. In the past, if Potomac Edison and MonPower's depreciation rates were overstated, its rate base declined faster. The Commission also had the option of reducing depreciation rates in future years. As a result, higher depreciation rates in the near term could lead to lower revenue requirements in the long term, and potentially to little change in the present value of revenue requirements over the remaining plant life. Depreciation rates under regulation may be more important in determining the timing of revenue requirements paid by ratepayers than in determining total revenue requirements over time.

The situation is quite different for inclusion of dismantlement in stranded costs during the transition to generation competition. Since the generation plants are passing out of regulation, ratepayers do not receive any reduction in future rates, either automatically through reduction in rate base or through future Commission ratemaking.

Q: Have you identified other APS assumptions that would tend to overstate stranded costs?

A: Yes. There are several such features, which I did not correct in my recalculation of APS's DCF analysis:

- In the Company's model, uneconomic generating units show negative net cash flows even though uneconomic units should be retired before the start of the analysis and incur no more costs. I do not adjust my calculation of market value to remove the net operating costs of uneconomic units.
- I did not include any net value for plant sites (and reuse of facilities) when units are retired. The sites are likely to be reused for generation (in which case the cooling system, step-transformers, and other equipment is also likely to be valuable) or for some other higher-value purpose. Existing generation sites near (or in) load centers are hard to find and especially desirable for generation developers.
- I did not impute any value to extra space at existing sites, for additional generation or other purposes.
- I accepted the Company's stranded cost estimates for plant that it identified as uneconomic, even though they may include imprudent expenditures.

Q: What other costs should APS have removed from its stranded cost when it eliminated generating units it identified as uneconomic to operate?

A: In addition to eliminating from stranded costs the operating costs of the identified uneconomic units, APS should have explained why its capital additions to these units over the past several years were prudent, and why it has not retired these units already. If these plants are not economic to run in the near future, it is hard to see how it could have been economic in much of the 1990s, when market prices were lower. APS should not receive any further cost recovery for uneconomic units until it can justify its investments in them.

Q: Does this complete your testimony?

A: Yes.

Comparison of DCF Results

	Market Value		Stranded Cost (Gain)		West Virginia Share of Stranded Cost (Gain)	
	RII	APS	RII	APS	RII	APS
MP	1,132	450	(587)	75	(505)	64
PE	1,155	443	(596)	92	(111)	17

Summary of O&M Costs and Projections

Coal Plant	Average O&M Cost, 1999$/kW				Allegheny Power Projections, 1999 $/kW						RII Projection for 2004 and After	
	1981-1997	last 4 years	last 6 years		1999-2003	2004-2008	Increase to 2002 from average annual O&M in the period:					
			total	w/o high and low years			1999-2001	1981-1997	Last 4 Years	Last 6 years		Basis
Albright	$43	$42	$49	$45	$ 35	$ 41	17%	-4%	-1%	-17%	$41	Same as APS
Ft. Martin	$30	$31	$31	$31	$ 21	$ 19	-9%	-38%	-40%	-39%	$19	Same as APS
Harrison	$18	$22	$21	$21	$ 28	$ 32	15%	82%	45%	58%	$20	Same as APS in Md.
Hatfield	$25	$25	$27	$26	$ 17	$ 19	7%	-24%	-25%	-31%	$19	Same as APS
Pleasants	$28	$30	$28	$27	$ 32	$ 37	16%	34%	24%	34%	$23	1981-97 avg *(1-18%)
R. Paul Smith	$47	$43	$50	$43	$ 38	$ 44	17%	-5%	3%	-11%	$44	Same as APS
Average projected reduction in O&M costs (excl Harrison and Hatfield)								-18%				

Notes:

[1] Assumes 2.5% inflation

[2] Hatfield data were not available from UDI for 1997, so Hatfield calculations exclude 1997. Harrison computed from 1994-1997.