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BEFORE THE ARIZONA CORPORATION COMMISSION

MARC SPITZER
CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
MIKE GLEASON
KRISTIN K. MAYES

In the matter of the Application of ARIZONA PUBLIC SERVICE COMPANY for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and for Approval of Purchased Power Contract.	Docket No. E-01345A-03-0437 **NOTICE OF FILING DIRECT TESTIMONY AND EXHIBITS**

Western Resource Advocates, through its undersigned counsel, hereby provides notice that it has this day filed the written direct testimony and exhibits of David Berry in connection with the above-captioned matter.

Arizona Corporation Commission
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DATED this 3rd day of February, 2004.

ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST

By

Timothy M. Hogan
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Attorneys for Western Resource Advocates

ORIGINAL and 13 COPIES of the foregoing filed this 3rd day of February, 2004, with:

Docketing Supervisor
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Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

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All Parties of Record

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MARC SPITZER, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	DOCKET NO. E-01345A-03-0437

Direct Testimony of

David Berry

Western Resource Advocates

February 3, 2004

Direct Testimony of David Berry
Docket No. E-01345A-03-0437

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Introduction

Q. Please state your name and business address.

A. My name is David Berry. My business address is P.O. Box 1064, Scottsdale, Arizona 85252-1064.

Q. By whom are you employed and in what capacity?

A. I am Senior Policy Advisor for Western Resource Advocates, formerly the Land and Water Fund of the Rockies.

Q. Please describe Western Resource Advocates.

A. Western Resource Advocates (WRA) works to protect and restore the natural environment of the Interior American West. Western Resource Advocates uses law, economics, and policy analysis to protect land and water resources, protect essential habitats for plants and animals, and assure that energy demands are met in environmentally sound and sustainable ways. We work with other environmental and community groups, taking into account the economic and cultural framework unique to the states of the Interior West. Western Resource Advocates has been involved in Arizona utility regulatory issues for over 12 years.

Q. What are your professional qualifications for presenting testimony in this docket?

A. Exhibit DB-1 summarizes my experience and education.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of WRA and I will address the following topics:

- hedging Arizona Public Service Company's (APS') exposure to increases in natural gas prices with low cost renewable energy so that ratepayers are less exposed to increases in natural gas prices,
- funding the Environmental Portfolio Standard, and
- improving APS' solar energy tariffs.

Hedging Natural Gas Price Increases

Q. Has Arizona Public Service Company indicated that natural gas price increases are an important component of its proposed rate increase?

A. Yes. Mr. Wheeler states on page 9 of his direct testimony that APS' fuel and purchased power costs have increased very significantly over the levels reflected in APS' current rates. In addition, on pages 10 and 11, Mr. Wheeler states that purchased power and gas generation components of APS' energy supply mix have exhibited volatile prices and that APS' average delivered cost of gas increased by 68 percent since the end of the test period. Mr. Robinson indicates (Attachment DGR-5, Page 7 of 27) that APS' normalized 2003 fuel and purchased power costs were $0.02371 per kWh and that the test year fuel and purchased power costs were $0.018033 per kWh, for an increase of $0.005137 kWh, which translates to an adjusted increase in costs of about $121 million.

Q. Has the electric industry generally faced natural gas price volatility?

A. Yes. Exhibit DB-2 shows prices paid by electric utilities nationally for natural gas. Historical data were taken from Energy Information Administration reports and forecasted prices for 2003 and 2004 were taken from the Energy Information Administration Short Term Energy Outlook for December 2003. Costs are presented in constant 2002 dollars, using the Gross Domestic Product Implicit Price Deflator. Gas prices have increased by as much as 60 percent from one year to the next. There is also a general upward trend in natural gas prices. The trend line shows an annual percentage price increase of about 3 percent per year in constant dollars. Of course the trend line does not account for the complexities of periods of great volatility.

Q. What has been APS' experience with natural gas consumption and prices?

A. The upper figure in Exhibit DB-3 shows natural gas generation (kWh) as a percentage of total APS kWh generation. Between 1997 and 2002, APS obtained, on average, 8 percent of its kWh generation from natural gas–fired power plants.[1] The lower figure in Exhibit DB-3 shows APS' natural gas costs from 1996 through September 2003.[2] For comparison, the prices paid by electric utilities for natural gas nationally are also

[1] *APS 2002 Statistical Supplement*, p. 122. APS also obtained electricity from purchased power, but the mix of generation resources underlying the purchased power is not reported. Some of the purchased power was likely to come from gas-fired resources. In 2002, APS purchased at least 2,315,000 MWH of energy from natural gas generation (APS response to WRA data request WRA 1-3).

[2] In response to WRA data request 1-7, APS indicated that it does not have gas price data prior to 1996.

shown in the figure. Prices paid by APS are similar to national prices except in 1996. APS is not immune to the volatility of natural gas prices.

Q. On January 27, 2004, APS submitted to the Commission a summary of responses to its power supply Request for Proposals dated December 3, 2003. What information does APS' summary provide about the role of natural gas in future generation and the price risk faced by APS and its customers?

A. APS' summary reinforces the concern that APS and its customers are and will be subject to natural gas price increases affecting the generation of a large portion of the electricity serving APS' retail customers. In particular, APS notes that:

- All of the asset-backed proposals involved natural gas-fired generation, and all the responses require APS and its customers to bear or assume gas price risk and gas transportation risk.
- The levelized prices (as calculated preliminarily by APS) range from $65 to $160 per MWH over the life of the proposed asset or purchased power agreement.
- None of the purchased power agreement proposals involves a fixed price bid.

Q. What are the impacts of continued exposure of APS and its ratepayers to natural gas price increases and price volatility?

A. Higher natural gas prices result in higher rates if the Commission permits APS to pass along to ratepayers increased electricity costs resulting from natural gas price increases. Highly volatile electricity prices make it harder for residential and non-residential consumers to budget for electricity expenditures and make it harder for those consumers to make decisions about energy efficiency.

Q. How can APS reduce its and its ratepayers' exposure to natural gas price volatility and price increases?

A. There are several ways a utility can protect itself and its ratepayers from natural gas price increases and price volatility. These include deployment of energy efficiency measures which reduce demand during periods when natural gas fired steam units, combustion turbines, and combined cycle units are running, fuel substitution, and financial hedges. In response to WRA data request 1-13, APS indicated that it uses both physical and financial contracts to manage the risks of natural gas price volatility. Such hedging mechanisms may be able to reduce volatility but, in general, they would not allow APS to avoid the trend in increases in natural gas prices over time. Further, even with its use of financial and physical hedges, APS still experienced price volatility (Exhibit DB-3).

Of particular interest is acquisition of significant quantities of energy from renewable resources which have stable prices. This energy could come from a variety of relatively low cost resources including landfill gas, geothermal projects, and wind resources. Such resources may be located in Arizona or elsewhere. Wind energy is the most rapidly growing renewable energy technology in the United States and wind energy contracts today exhibit prices around $0.03 per kWh or less[3] and typically incorporate stable prices.

Note that both energy efficiency and renewable energy resources, once installed, would not be subject to significant price increases because most of the cost is incurred as up-front capital costs or because contracts for purchases of renewable energy typically contain stable prices. In contrast, even well-hedged natural gas supplies would still be subject to long run price increases.

Q. Please describe how a wind energy resource could reduce APS' exposure to volatile natural gas prices.

A. Wind energy has stable costs and would displace APS' marginal gas-fired and coal-fired units that would otherwise be running at the time wind energy is available. If APS owns the wind project, most of the costs would be incurred up front. At present these costs are about $1,000 per kW. Variable operating and maintenance costs are very low. Thus APS would not be exposed to large fluctuations in costs from year to year. If APS purchases wind energy from a developer, the contract would probably resemble other contracts in the industry. These contracts typically have a fixed price or a price that varies according to a pre-determined schedule or a price that varies with inflation. Again, APS would not be exposed to large, unexpected fluctuations in costs from year to year.

Q. How much wind energy would APS need to acquire to provide a useful hedge against natural gas price increases?

A. In order to provide a significant hedge, capable of saving a million dollars or more per year during years of high natural gas prices, the amount of energy from renewable resources must be large. A small project would not provide a significant benefit.

For the three year period 2000 to 2002, APS' average annual sales to ultimate customers was 23,081 GWH (APS Standard Filing Requirements Schedule E-7). In an <u>initial</u> acquisition, at least about 2 percent of retail sales should be from stably priced renewable energy resources, or about 462 GWH. Assuming energy losses of 5

[3] These low prices are dependent on continuation of tax and other government incentives, including the production tax credit.

percent[4] a 175 MW wind energy project with a capacity factor of 32 percent could supply the target amount of energy on average. Subsequent acquisitions of wind or other renewable energy resources could increase the percentage, eventually perhaps reaching or exceeding 20 percent of APS' retail load.

Q. Wouldn't APS need to start with small demonstration projects before it could venture into larger acquisitions of wind energy?

A. No. There is significant experience with large wind energy projects in the Southwest. As of October 2003, the following wind generating capacity was in place in Southwestern states:

- California 1,988 MW
- Texas 1,096 MW
- Colorado 61 MW plus 162 MW under construction (this project was completed in December 2003)
- New Mexico 205 MW

In other western states, there were an additional 588 MW of wind generating capacity as of October 2003. The national total as of October 2003 was 5326 MW of wind generating capacity as reported on the American Wind Energy Association website.

With regard to recent or planned specific projects:

- Public Service Company of New Mexico (PNM) obtains about 200 MW of power from a wind project in east central New Mexico through a 25 year contract with the project developer. This project began operation during 2003. Previously PNM had little or no wind resources. Salt River Project purchases some of PNM's wind energy.
- A 162 MW wind project was under construction in late 2003 near Lamar, Colorado, with the energy to be purchased by Public Service Company of Colorado. The Lamar project was completed in December 2003.
- Texas-Caprock Wind, LP, an affiliate of Cielo Wind Power, announced plans in August 2003 to install up to 80 MW of wind generation capacity near Tucumcari, New Mexico within the next 12 months. Xcel Energy will purchase all the output of the turbines for at least 15 years.

Q. How large are utility wind projects in relation to utility peak demand?

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[4] APS 2002 FERC Form 1, page 401a, lines 27 and 28.

A. I estimated MW of wind generation capacity for Public Service Company of New Mexico, Public Service Company of Colorado, and PacifiCorp[5] as a percentage of 2002 peak demand as reported in the utilities' 2002 FERC Form 1, page 401b.[6] PNM's wind project capacity is about 14 percent of peak demand, Public Service Company of Colorado's wind project capacity is about 4 percent of peak demand, and PacifiCorp's wind project capacity is about 3.5 percent of peak demand.

Q. Did you prepare a calculation of the hedge value of wind energy for APS?

A. Yes, I examined a generic 175 MW wind project considering the following factors:

- The cost of wind energy plus the costs of integrating wind energy into the grid plus transmission and related costs for delivering wind energy to APS.
- Avoided conventional generation costs, including avoided fuel cost, avoided operating and maintenance cost, and avoided capacity cost.
- The benefits of reduced carbon dioxide, sulfur dioxide, and nitrogen oxide emissions due to displacement of fossil fuel generation by wind energy.

One could conduct a similar analysis for a specific project. To be a useful hedge, wind energy should be expected to be less costly to society than conventional generation in years when natural gas prices are high.

Q. Please describe how you estimated the cost of wind energy.

A. I reviewed costs of wind generation reported by Navigant Consulting, costs contained in several confidential contracts and costs for Texas wind projects.[7] For a good wind site, a long term contract price would be about $0.03 per kWh or less. In my analysis, I assumed a long term contract price of $0.028 per kWh in constant 2002 dollars. Thus, the assumed nominal price escalates at the rate of inflation.

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[5] For Public Service Company of New Mexico, the wind resource is the 200 MW FPL project cited above. For Public Service Company of Colorado, the wind resource consists of the company's share of the Foote Creek Rim project, the Ponnequin project, the Peetz Table Wind Farm, and the Lamar project completed in December 2003. For PacifiCorp, the wind resource consists of PacifiCorp's share of the Foote Creek project in Wyoming plus the Stateline projects in Washington and Oregon. The energy output of these projects is not reported in a readily available form.

[6] Peak demand excludes non-requirements sales for resale and associated losses.

[7] Navigant Consulting, Inc., 2003. *The Changing Face of Renewable Energy*, http://www.navigantconsulting.com. R. Wiser, R. and O. Langniss, "The Renewables Portfolio Standard in Texas: An Early Assessment." Berkeley, CA: Lawrence Berkeley National Laboratory LBNL-49107, 2001.

Because wind energy is intermittent, there are wind integration costs. Wind integration refers to maintaining reliability given an intermittent resource by dealing with reserves and imbalances, rescheduling, and load following. I reviewed three studies which estimated wind integration operating costs as follows: about $2.00 per MWH for 200 MW of wind generation capacity with a 32 percent capacity factor (PacifiCorp); $1.90 to $2.92 per MWH reflecting a range of wind plant capacities from 250 MW to 2000 MW (We Energies); and $1.85 per MWH for Northern States Power's existing 280 MW wind plant.[8] I assumed a cost of $2.00 per MWH, reflecting a low initial quantity of wind generation in APS' system.

Transmission costs depend on the transmission service used. I assumed that APS' transmission and ancillary service costs (excluding imbalance costs, which are considered in integration costs, and assuming that all ancillary services are required) would apply.[9] Costs for any new transmission facilities and costs for interconnecting to the grid are site specific and will vary depending on the project location. To account for these costs generically, I assumed a five mile 230 kV transmission line from the wind facility to the grid plus the costs of interconnection with the grid.[10] The combined transmission-related costs are $24.13 per kW per year.

Q. Please describe the environmental benefits of wind energy.

A. As will be described below, wind energy displaces fossil fuel generation. APS would back off marginal gas and coal fired generation when wind energy is available and, in doing so, emissions of carbon dioxide, nitrogen oxides, and sulfur dioxide would be reduced. Carbon dioxide is the major anthropogenic contributor to greenhouse gases which affect long term climate change. Nitrogen oxides contribute to haze and smog and contribute to the formation of ozone which impairs respiratory health. Sulfur

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[8] PacifiCorp, *Integrated Resource Plan 2003*. Portland, OR, Appendix L, 2003. Electrotek Concepts, "We Energies Energy System Operations Impacts of Wind Generation Integration Study," Knoxville, TN, 2003. Electrotek Concepts, "Characterizing the Impacts of Significant Wind Generation Facilities on Bulk Power System Operations Planning," Arlington, VA, 2003 (study of Northern States Power).

[9] Arizona Public Service Company, 2002. Pro Forma Open Access Transmission Tariff, Revision No. 11. APS' transmission costs are neither the highest nor the lowest in the Southwest. In addition, provisions are being revised to recognize the intermittent nature of wind energy and to reduce the penalties for short term imbalances, thereby making ancillary service costs less onerous: California Independent System Operator, *Status Report in Compliance with March 27, 2003 Order,* Report submitted to the Federal Energy Regulatory Commission, July 28, 2003.

[10] Cost data from Energy Information Administration, *Renewable Energy Annual 1995*, Tables 32 and 33, inflated to 2002 dollars and annualized assuming a 25 year life and a 10 percent interest rate. Similar costs are reported in Iowa Department of Natural Resources, *Delivering 2,000 MW of Wind Energy to the Metropolitan Centers in the Midwest*, March 2002, pp. 15 - 16. The Midwest study uses cost estimates from the MidContinent Area Power Pool.

dioxide impairs respiratory function, is a cause of acid rain, and reduces visibility.[11] I subtracted the value of the environmental benefits from the costs of wind energy.[12,13]

Q. How did you monetize the environmental benefits?

A. To determine the volume of avoided emissions, I used APS' nitrogen oxide, sulfur dioxide, and carbon dioxide emissions rates for specific power plants.

As measures of the value to society of reducing air emissions, I applied market prices for tradable credits for emissions where there are air quality standards in place or where regulation may occur in the future. These market prices are intended to represent values to society. APS may be able to capture these values through the sale of emissions credits or allowances or through avoided purchases of credits and allowances.

Markets for carbon dioxide emissions reductions are currently developing and prices range from about $1 per metric ton of CO_2 to about $11 or more per metric ton of CO_2.[14] These prices discount the actual costs of complying with future carbon regulation because of uncertainty about what carbon credits will be acceptable to

[11] As an example of the benefits to society of reducing air emissions, the *Governor's Brown Cloud Summit Final Report* (January 16, 2001) found that nitrogen dioxide and sulfur dioxide gases from burning fossil fuels contribute to the brown cloud in the Phoenix area. Reduction of air emissions and the consequent reduction in the brown cloud would benefit society by improving visibility and reducing respiratory health effects.

[12] Alternately, one could add environmental costs to the costs of conventional generation.

[13] There may be other environmental benefits as well, such as reduced emissions of particulates and mercury and reduced water consumption. However, I did not include those benefits in the analysis. I also assumed that wind facilities would be located so as to minimize aesthetic and avian impacts.

[14] There are several markets for emissions reductions and not a single exchange in which credits are bought and sold. Price data are taken from the following sources. Natsource, "Assessment of Private Sector Anticipatory Response to Greenhouse Gas Market Development," prepared for Environment Canada, 2002. Cantor Environmental Brokerage reported that as of June 1, 2003, prices of project-based reductions in greenhouse gases for the United States were in the range of $1.00 to $3.00 per metric ton of carbon dioxide equivalent and increase up to $8.00 depending on vintage year, risk guarantees, volume, and contract structure. The Chicago Climate Exchange reported carbon financial instrument closing prices on December 16, 2003 of $1.00 per metric ton of carbon dioxide. However, the Chicago Climate Exchange began trading in December 2003 and there have been few trades so far. In a news release dated December 4, 2003, Natsource reported weighted average prices in 2003 as follows: $2.55 per ton of carbon dioxide equivalent for emissions reductions made for reasons other than complying with future regulation of greenhouse gas emissions; $3.64 per ton of carbon dioxide equivalent for emissions reductions that are Kyoto compliant (with buyer liability for shortfalls in delivery of contractual commitments); and $4.88 per ton of carbon dioxide equivalent for emission reductions that are Kyoto compliant with seller liability for failure to deliver contractual commitments. Natsource indicated that trades during the first three quarters of 2003 involved 71 million tons of carbon dioxide equivalents.

regulators in the future, uncertainty about future carbon regulation compliance costs, and other factors. I assumed a value of carbon dioxide emission reduction credits of $3.64 per metric ton which is the weighted average price during 2003 for emission reductions that will meet expected regulatory requirements but put the liability for shortfalls in delivery on the buyer.

For sulfur dioxide credits, I assumed the average value in 2002 reported in the literature, $170 per ton.[15]

For nitrogen oxides, there is a wide range of values. APS provided prices of sales and purchases which average $825 per ton. Nationally, credit prices averaged around $2000 per ton in 2002.[16] Cantor Environmental Brokerage reported prices for Maricopa County in October 2002 of $12,000 per ton. To be conservative, I used the average value reported by APS.

Q. What are the costs of conventional generation that could be avoided by wind energy?

A. If APS takes wind energy under a typical long term contract, it would take the wind energy produced from the project and back off its most expensive units running at the time the wind energy is available. If APS owns the wind project, the variable costs of the wind energy would be small and APS would back off its most expensive units running at the time the wind energy is available. To maximize the value of wind generation, APS should seek wind resources with as much generation as possible during peak seasons and hours.

To estimate the variable costs of the marginal units running when wind energy is available, I assumed that wind energy would be available year round with a capacity factor of 32 percent. I assumed that APS' marginal units would be as follows:[17]

- The Saguaro gas-fired combustion turbines and steam units. These are not as expensive as the Ocotillo combustion turbines, but the Ocotillo combustion turbines may be running when there is not sufficient transmission capacity to bring wind energy into the Phoenix load center. I assumed the heat rates and fuel costs reported by APS in its 2002 FERC Form 1.
- The West Phoenix gas-fired combined cycle units 1, 2, and 3. I assumed the heat rate and fuel cost reported by APS in its 2002 FERC Form 1. These units

[15] R. Richter, "Where's the Green in Green Emissions Trading?" *Power and Gas Marketing*, July/August, 2002, pp. 20-21, www.powerandgasmarketing.com.

[16] R. Richter, *op. cit.*

[17] The percentage of time that each unit is assumed to be the marginal unit is not reported in this testimony in order to preserve the confidentiality of other data provided by APS.

were considered to be the marginal units only during hours when they were running and there was sufficient transmission capacity to deliver energy from remote plants into the Phoenix area.

- The Four Corners coal-fired units 1, 2, and 3. I assumed the heat rate and fuel cost reported by APS in its 2002 FERC Form 1. These units are assumed to be the marginal units when the gas fired units listed above are not running.

For variable operating and maintenance costs, I used confidential costs provided by APS.

Q. Please describe your assumptions about avoided capacity costs attributable to wind energy.

A. Wind energy is an intermittent resource and its capacity value would depend on wind conditions and utility system characteristics. Thus, capacity value would be site specific. The National Renewable Energy Laboratory has analyzed the capacity value of wind projects and a study by the National Renewable Energy Laboratory suggests that a wind project at a good site may have a capacity value that is about 30 percent of the nameplate capacity of the wind project.[18] To the extent that wind resources have capacity value, APS could reduce its need for additional capacity[19] or could sell system capacity in the market.

I assumed that wind energy would enable APS to avoid capacity costs of $63.07 per kW per year for 30 percent of the nameplate capacity of the wind energy project. The cost was calculated as the annualized cost of a new combustion turbine using cost assumptions from the Energy Information Administration.[20]

Q. What do your calculations show when gas prices are at 2002 levels?

A. The relative costs of wind and conventional generation are project specific. I examined a generic project using reasonable assumptions about the costs of wind

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[18] M. Milligan. "Variance Estimates of Wind Plant Capacity Credit." Boulder, CO, National Renewable Energy Laboratory, NREL/TP-440-21311, 1996. To analyze the capacity value of a specific wind energy resource in a specific utility system it is useful to systematically take into account the probabilities of wind generation occurring at specific times, demand reaching certain levels at those times, and the availability of other resources. Loss of load probability analysis is one way to prepare such an analysis.

[19] APS' summer supply and demand balance attached its response to the Arizona Competitive Power Alliance (December 24, 2003) shows APS needs considerable additional capacity in the next few years.

[20] Energy Information Administration, *Annual Energy Outlook 2003*. Washington, DC, Assumptions Section, Table 40, assuming a 25 year time horizon and 12 percent interest rate on capital. The costs include fixed operating and maintenance costs. Costs are inflated to 2002 dollars.

energy and the market prices of tradable credits in air emissions and assuming APS' costs of generating conventional energy in 2002. The analysis shows that, under these circumstances, wind energy is about $1.5 million less costly per year (in constant 2002 dollars) than conventional generation, including the environmental benefits of wind energy. Exhibit DB-4, columns a and b, shows the costs.

Q. What expectations about future natural gas prices are reasonable?

A. No one can be sure of the future price of natural gas, but the long run trend has been upward (Exhibit DB-2). The Energy Information Administration Annual Energy Outlook 2004 (Table A3) forecasts a real (inflation adjusted) average growth rate of 1.2 percent per year for the price of natural gas purchased by electric utilities over the period 2002 to 2025. As suggested by Exhibit DB-2, natural gas prices have also been volatile and they may very well continue to be volatile.

Q. Exhibit DB-3 shows that APS' gas prices increased in the first nine months of 2003 relative to 2002. What savings from wind energy would there have been if you substituted APS' 2003 gas prices for the 2002 gas prices used in the above analysis?

A. Applying the percentage increase from 2002 to 2003 in Exhibit DB-3 to the prices at individual power plants reported by APS in FERC Form 1 for 2002, wind energy would be about $2.8 million less costly per year than conventional generation, including environmental benefits (in constant 2002 dollars). The details are shown in Exhibit DB-4, columns a and c. When natural gas costs are high as they were in 2003, wind energy is less costly even when environmental benefits are not considered (avoided conventional generation costs are $19.0 million per year versus annual wind costs, excluding environmental benefits, of $18.9 million).

Q. Did you conduct any sensitivity analyses beyond that using 2003 natural gas prices?

A. Yes. I conducted sensitivity analyses to examine the robustness of the conclusions set forth above. Because wind energy could be used in the future as a hedge against natural gas price increases, I conducted the sensitivity analyses assuming that natural gas prices are at the 2004 level forecast by the Energy Information Administration in its December 2003 Short Term Energy Outlook, Table 4. Specifically, the fuel cost at each natural gas unit is assumed to be $4.86 per MMBtu in 2002 dollars.

To judge the sensitivity of the overall conclusion that wind energy is likely to be beneficial, on net, I changed one or a few variables at a time, leaving the other variables as specified above and assuming 2004 gas price levels. With gas prices changed to 2004 levels and changing no other assumptions, wind energy would be

$2.4 million per year less costly than conventional generation (Exhibit DB-4, columns a and d). Costs are presented in constant 2002 dollars, as above.

Of interest are cases where wind energy would be less advantageous than assumed above. For example, if the capacity value of wind energy were 15 percent of the nameplate capacity of the wind generation facility instead of 30 percent as assumed above, wind energy would be $0.8 million less costly per year than conventional generation. If the heat rate of the Saguaro combustion turbine were 10,000 Btu per kWh instead of 20,785 Btu/kWh as reported by APS in its 2002 FERC Form 1, wind energy would be $1.6 million less costly per year than conventional generation. If the wind integration cost were $4 per MWH instead of $2 per MWH as assumed above, wind energy would be $1.4 million less costly per year than conventional generation. If the environmental benefits were only half the values assumed above, wind energy would be $1.0 million less costly per year than conventional generation.

In light of the long term upward trend in natural gas prices, I conclude that the expectation of positive net benefits for wind energy is robust as long as the federal Production Tax Credit is continued.

Q. What do you conclude regarding the benefits and uses of wind energy?

A. Because of the long run historical tendency of natural gas prices to rise, wind energy is a useful hedge against natural gas price increases. Wind energy also provides price stability in lieu of the price volatility associated with generating electricity from natural gas. In addition, wind energy, and energy from renewable resources in general, have important environmental benefits.

Q. Does APS have any plans to acquire wind resources?

A. APS indicated, in response to WRA data request 2-18, that it is considering acquisition of wind energy from 15 MW of generating capacity that would be available in 2004. APS also indicated, in response to WRA data request 2-19 that it is not planning to acquire energy from renewable resources beyond that required by the Environmental Portfolio Standard unless such energy is cost competitive with conventional generation or until the Commission authorizes greater funding for renewable energy.

Q. Is the energy from 15 MW of wind generating capacity sufficient to provide a good hedge against natural gas prices increases?

A. No. It is much too small.

Q. What is the relationship between the use of renewable energy as a natural gas price hedge and the Environmental Portfolio Standard (EPS)?

A. The two renewable energy strategies serve different purposes. The natural gas price hedge requires large volumes of low cost renewable energy to displace conventional generation that is, in aggregate, higher cost much of the time. In contrast, the EPS is intended to promote development of environmentally friendly resources whose costs tend to be above market costs for conventional energy and capacity and it emphasizes development of solar energy projects. The EPS kWh requirements are too small to support an effective hedge against natural gas price volatility and price increases. WRA supports continuation of the EPS to foster solar energy projects.

Q. Is it in the public interest for APS to acquire large quantities of energy from renewable resources?

A. Yes. Renewable energy would provide the following benefits:

- It would provide a hedge against natural gas price increases and volatility.
- It would result in reduced air emissions, including carbon dioxide emissions which contribute to climate change.
- Along with energy efficiency, it would move APS toward a more diverse set of resources and technologies for meeting the demand for electric energy services.

Q. What do you recommend regarding renewable energy?

A. First, I recommend that the Commission order APS to immediately seek stably-priced energy from renewable resources amounting to at least 2 percent of APS' retail sales, with a target date of delivery of the energy no more than two years after the date of the decision in this Docket. APS should submit a written report to the Commission on its progress in acquiring such resources, with copies to all interested parties to this Docket, every six months, starting six months after the effective date of the Commission's order in this Docket. Two years after the decision in the Docket the Commission should review APS' progress and should conduct a hearing to determine how to proceed if APS believes that renewable energy cannot be practically used to hedge natural gas prices or has otherwise not obtained the recommended amount of energy from renewable resources. Note that this recommendation allows APS to bring to the Commission a recommendation that it not obtain at least 2 percent of its energy from renewable resources if the hedge value of that renewable energy is greatly diminished or to bring to the Commission a recommendation that the schedule for obtaining the targeted amount of renewable energy be modified. For example, if

Congress does not re-authorize the federal Production Tax Credit, the Commission may wish to reconsider the renewable energy schedule in a hearing.

Second, the Commission should address long term renewable energy goals that take into account the potential for low cost resources such as wind energy. In particular, the Commission should immediately open a docket to consider a renewable portfolio standard requiring that about 15 to 20 percent of retail kWh sales by jurisdictional electric utilities be met by energy from renewable resources by 2020.

Q. If the Commission adopts your recommendation that APS obtain large quantities of renewable energy immediately, how would APS recover the costs of that energy?

A. The costs of purchased energy from renewable resources would be recovered through the purchased power adjustor mechanism adopted in Decision No. 66567. Regardless of the cost recovery mechanism, revenues from the sale of environmental, renewable energy, or similar credits or allowances derived from renewable energy should be credited against the renewable energy cost.

Funding the Environmental Portfolio Standard

Q. How is the Environmental Portfolio Standard (EPS) currently funded?

A. A.A.C. R14-2-1618(A)(2) indicates that utilities are to use existing system benefit charges, including re-allocation of demand side management funding to EPS resources, plus a surcharge of $0.000875 per kWh. The surcharge is capped at $0.35 per month for residential customers, $13 per month for non-residential customers, and $39 per month for non-residential customers whose demand is 3 MW or more.

Q. What are the effective surcharge rates now being assessed?

A. The table below shows APS' 2002 revenues and MWH sales by class and the effective surcharge rates (revenues per kWh sold). Note that the surcharge caps result in the large industrial customers paying a much smaller effective rate than other customers.

Class	2002 Surcharge Revenues	2002 MWH Sales	Effective Rate $/kWh
Residential	$3,101,375	10,447,596	$0.0002969
Non-residential under 3 MW	$3,456,626	10,338,456	$0.0003343
Non-residential 3 MW +	$31,150	2,575,703	$0.0000121
Totals	$6,589,151	23,361,755	$0.0002820

Q. Is this sufficient revenue for APS to meet the EPS goals by 2011 or 2012?

A. No. In its June 30, 2003 report to the Commission, the Cost Evaluation Working Group indicated that there were insufficient surcharge revenues for APS to meet the Environmental Portfolio Standard by 2011 on the schedule set forth in A.A.C. R14-2-1618. Further, in response to data request WRA 1-16, APS indicated that it would need about $253 million to meet the 1.1 percent goal by 2011 but that it would receive only about $142 million over the period 2003 to 2011 from current funding sources (including revenues from redirection of demand side management programs to renewable energy).

Demand side management program funding that is now used to pay for EPS resources could and should be restored to demand side management programs. I, therefore, prepared an independent analysis of revenue needs for APS to meet the 1.1 percent goal in the EPS rule by 2012 that suggests that APS would need to spend about $222 million from 2004 through 2012 but would only obtain $71 million from the current surcharge (not including redirection of demand side management funds). To provide adequate funding from the surcharge alone, the caps would have to be removed from the current surcharge. That is, a surcharge rate of about $0.000875 per kWh with no caps would produce approximately the needed funding so that APS could meet the 1.1 percent goal, including the effects of the extra credit multipliers, by 2012.

Q. What do you recommend regarding funding for the EPS?

A. The current surcharge caps are inequitable and do not produce adequate revenue to fund the EPS. The simplest funding mechanism would be a surcharge of $0.000875 per kWh with no caps. The surcharge would be included in APS' proposed Schedule SBAC-1 or similar adjustor mechanism. The impact on major customer groups of the surcharge with no caps is as follows:

- $0.95 per month for the average residential customer
- $7.39 per month for the average commercial/industrial customer on Schedules E-32, E-32R, E-53, and E-54
- $2,977 per month for the average large industrial customer on Schedules E-34 and E-35.

The proposed surcharge would be about 1 percent of APS' proposed base rates plus the Competition Rules Compliance Charge for residential and general service customers.

Because the exact EPS costs and revenues are not known at this time, the EPS surcharge account in Schedule SBAC-1 should be reviewed by the Commission every three years to determine whether the surcharge rate should be adjusted. After 2012, any over- or under-collection should be addressed by the Commission to return excess funds to ratepayers or to reimburse APS for insufficiently funded projects.

I also recommend that demand side management program funding be restored to demand side management programs. Consistent with the proposed surcharge recommended above, any other funding for renewable energy currently in APS' rates, including Schedule SBAC-1, and used to help meet EPS requirements should be set to zero.

Q. What is WRA's position on mitigating the effect of the surcharge for some customer groups?

A. WRA does not object to surcharge caps or other mechanisms that would alleviate undue burdens on some customer groups while still pursuing the goals of the EPS. For example, large industrial customers (1 MW or larger) could be allowed by APS to opt out of the surcharge if the customer implements renewable energy projects such as solar hot water facilities, biomass facilities, or photovoltaic projects. APS should bring to the Commission, for Commission approval, all requests for opting out that it would like to grant. In their evaluations, APS and the Commission should consider the amount of surcharge revenue foregone, the amount of energy generated from the customer's renewable resource facilities, and the measurement and verification of that generation. APS should be able to count the energy and extra credit multipliers from these opt-out projects toward meeting its goal for renewable energy.

Improving Solar Energy Services

Q. Does APS propose to offer services to customers who generate their own electricity from solar energy?

A. Yes. APS proposes to continue its EPR-4 and EPR-2 tariffs. These schedules pertain to small power production facilities such as photovoltaic systems and set forth the rates for services purchased from APS and for sales of energy from the small power production facility to APS. Schedule EPR-2 is for qualifying facilities under 100 kW and Schedule EPR-4 is for renewable energy qualifying facilities 10 kW or less. In 2002, APS had no customers on Schedule EPR-2 and 10 customers on Schedule EPR-4.

Q. Do you have any recommendations regarding EPR-4 as filed by APS in this rate case docket?

A. Yes. Through the Environmental Portfolio Standard, the Commission is promoting solar energy, including solar energy projects on consumers' premises. APS' EPR-4 tariff should reinforce the Commission's policy by making customer-sited projects attractive. Therefore, I propose two changes to Schedule EPR-4:

- First, EPR-4 should apply to renewable energy systems up to 100 kW of DC capacity. Commercial customers interested in photovoltaic projects, for example, may wish to install facilities larger than the 10 kW limit in Schedule EPR-4. Such customers would now have to be served under Schedule EPR-2 which imposes a monthly service charge of between $7.34 and $18.31 while Schedule EPR-4 does not.
- Second, Schedule EPR-4 should incorporate a net metering option similar to that used in Tucson Electric Power Company's Pricing Plan PRS-101 approved by the Commission in Decision No. 65751, dated March 20, 2003. Under the parallel mode[21] inherent in Schedule EPR-4, any excess energy generated by the customer and delivered to APS would be carried forward and credited to the net kWh of the next billing cycle instead of being purchased by APS at the avoided cost rates shown in the Schedule EPR-4. All negative credits could be zeroed out annually to prevent a large build up of credits.

Summary of Recommendations

Q. Please summarize your recommendations.

A. APS and its ratepayers are exposed to natural gas price volatility and price increases. As a hedge against natural gas price increases, I recommend that the Commission order APS to immediately seek stably-priced energy from renewable resources amounting to at least 2 percent of APS' retail sales, with delivery of that energy starting within two years. I also recommend that APS report on its progress as described previously.

The Commission should immediately open a docket to consider a renewable portfolio standard requiring that about 15 to 20 percent of retail kWh sales by jurisdictional utilities be met by energy from renewable resources by 2020.

I recommend that a surcharge of $0.000875 per kWh without caps be included in APS' proposed Schedule SBAC-1 or similar adjustor mechanism to fully fund implementation of the Environmental Portfolio Standard. Because the exact EPS costs and revenues are not known at this time, the EPS surcharge account in Schedule SBAC-1 should be reviewed by the Commission every three years to determine whether the surcharge rate should be adjusted. After 2012, any over- or under-collection should be addressed by the Commission to return excess funds to

[21] Decision No. 52345 defines parallel mode as a system configuration where the customer's self generation facilities first supply his or her own electric requirements with any excess power being sold to the utility.

ratepayers or to reimburse APS for insufficiently funded projects. Demand side management program funding that is now used to pay for EPS resources should be restored to demand side management programs.

I recommend that Schedule EPR-4 apply to systems up to 100 kW of DC capacity. I also recommend that Schedule EPR-4 incorporate a net metering option such that any excess energy generated by the customer and delivered to APS would be carried forward and credited to the net kWh of the next billing cycle instead of being purchased by APS at the avoided cost rates shown in the Schedule EPR-4.

Q. Does that conclude your direct testimony?

A. Yes.

Qualifications of David Berry

Education:

B.A. Syracuse University (Geography)
M.A. University of Pennsylvania (Regional Science)
Ph.D. University of Pennsylvania (Regional Science)

Employment History:

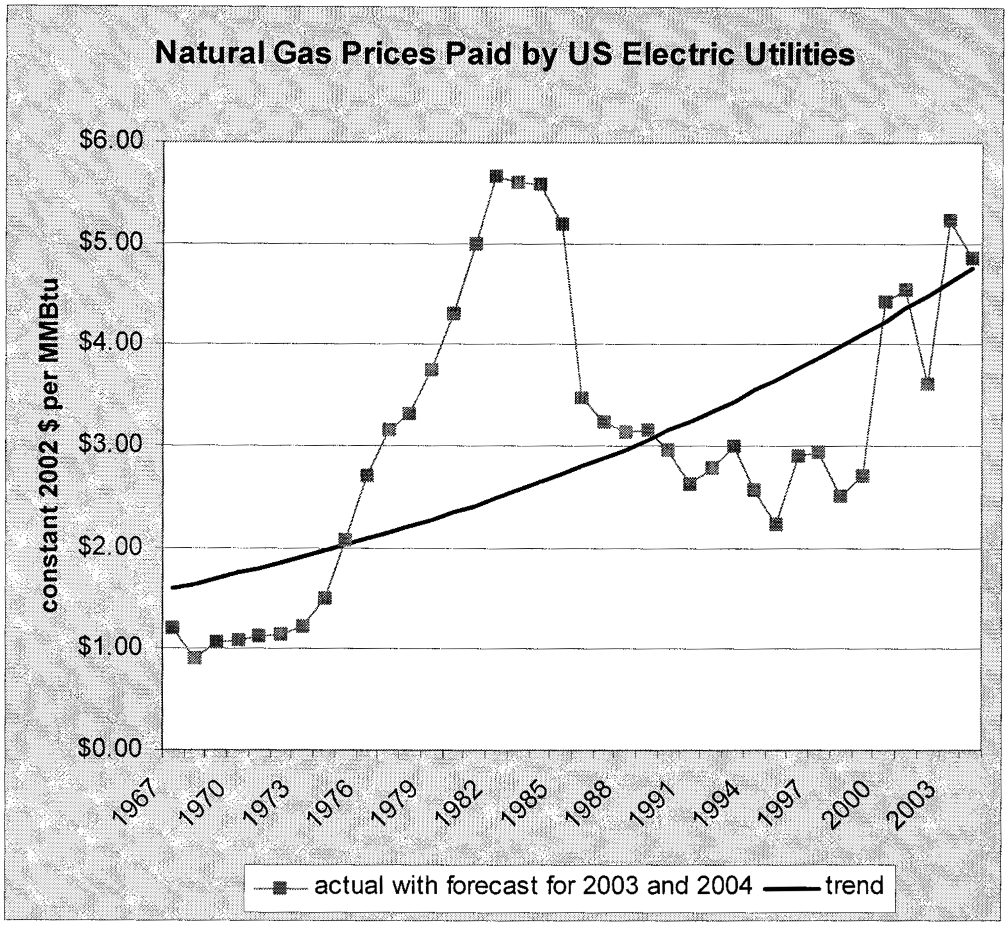
- Western Resource Advocates, Senior Policy Advisor (2001 - present)
- Navigant Consulting, Inc., Senior Engagement Manager (1997-2001)
- Arizona Corporation Commission, Chief Economist and Chief, Economics and Research (1985 – 1996)
- Boston University, Department of Urban Affairs and Planning, Lecturer (1981-1985)
- Abt Associates, Inc., Senior Analyst (1979-1985)
- University of Illinois, Department of Urban and Regional Planning, Visiting Assistant Professor (1977-1979)
- University of Pennsylvania, Regional Science Department, Lecturer (1974 –1977)
- Regional Science Research Institute, Research Associate (1972-1977)
- U.S. Army (1969-1971)

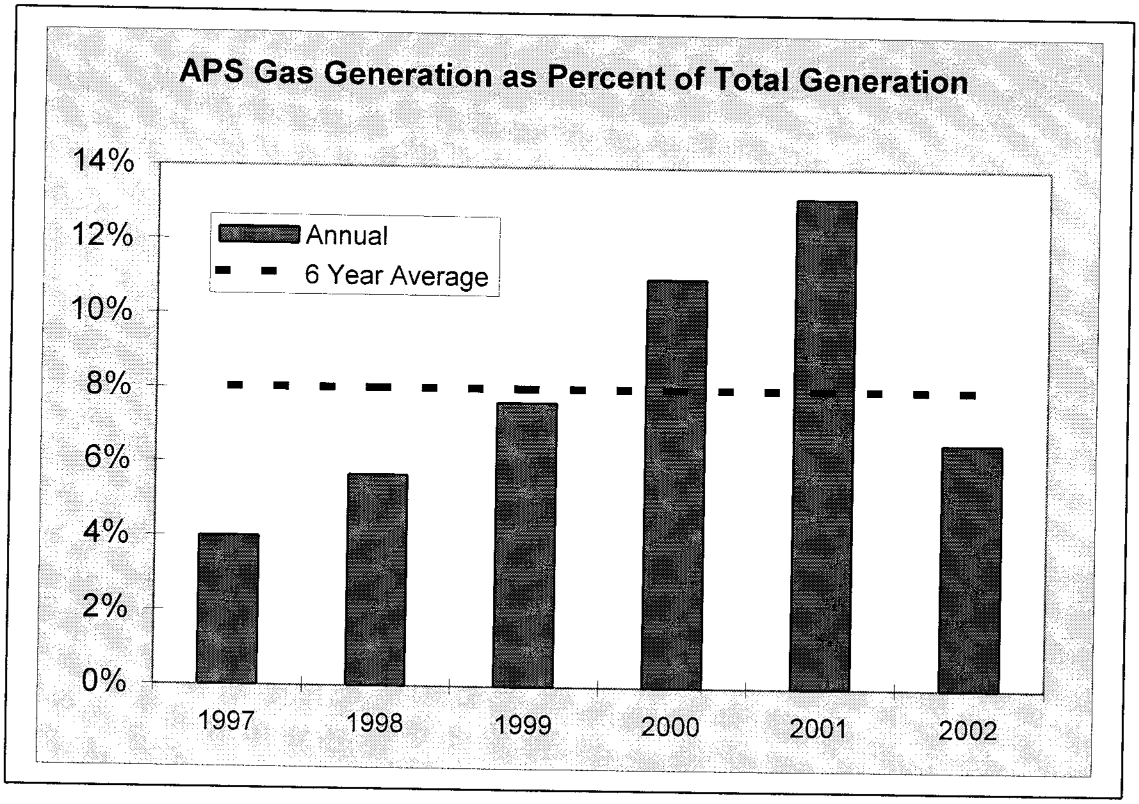
Testimony and Public Comment:

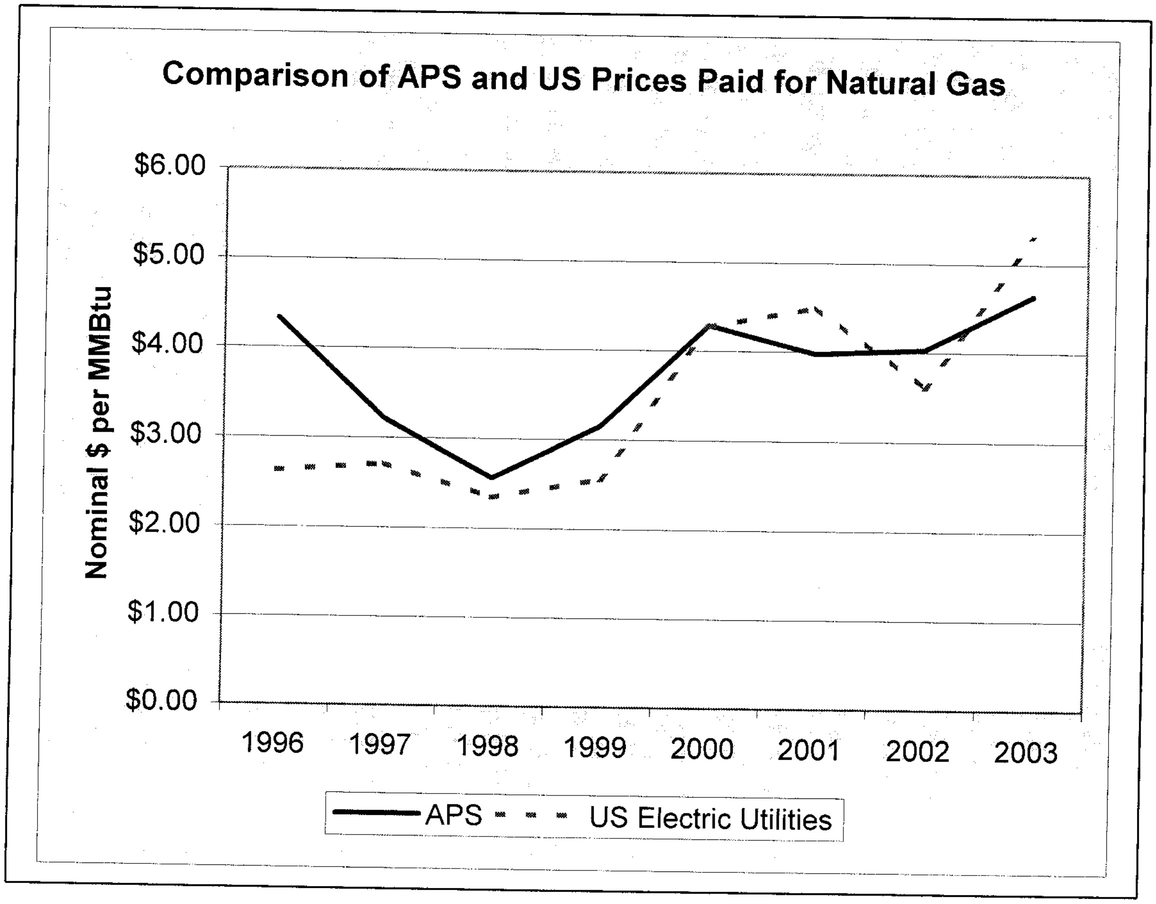
- Before the Maine Land Use Regulation Commission
- Before the Arizona Corporation Commission
- Before the New Mexico Public Regulation Commission

Publications in:

- *Ecological Economics*
- *Energy Policy*
- *Journal of the American Planning Association*
- *Business Economics*
- *Solar Today*
- *NRRI Quarterly Bulletin*
- *The Electricity Journal*
- *Journal of Economic Issues*
- *Public Utilities Fortnightly*
- *Journal of Environmental Management*
- *Public Management*
- *American Journal of Economics and Sociology*
- *Water Spectrum*
- *Geographical Perspectives*
- *Strategic Planning for Energy and the Environment*
- *National Tax Journal*
- *Policy Sciences*
- *Natural Resources Journal*
- *Water International*
- *Growth and Change*
- *Home Energy*
- *Professional Geographer*
- Chapters in books and proceedings


Natural Gas Prices Paid by US Electric Utilities
constant 2002 $ per MMBtu
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1967
1970
1973
1976
1979
1982
1985
1988
1991
1994
1997
2000
2003
actual with forecast for 2003 and 2004
trend


APS Gas Generation as Percent of Total Generation
14%
12%
10%
8%
6%
4%
2%
0%
Annual
6 Year Average
1997
1998
1999
2000
2001
2002


Comparison of APS and US Prices Paid for Natural Gas
Nominal $ per MMBtu
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1996
1997
1998
1999
2000
2001
2002
2003
APS
US Electric Utilities

(a) Component (all values in constant 2002 dollars)	(b) At 2002 Natural Gas Prices	(c) At 2003 Natural Gas Prices	(d) At 2004 Natural Gas Prices
1. Annual wind cost including transmission and integration	$18.9 million	$18.9 million	$18.9 million
2. Annual wind environmental benefits	$2.8 million	$2.8 million	$2.8 million
3. Annual net wind cost (= 1-2)	$16.2 million	$16.2 million	$16.2 million
4. Avoided annual conventional energy cost	$14.3 million	$15.7 million	$15.3 million
5. Avoided annualized conventional capacity cost	$3.3 million	$3.3 million	$3.3 million
6. Total annual avoided conventional generation cost (= 4 + 5)	$17.6 million	$19.0 million	$18.6 million
7. Annual wind energy savings (= 6 – 3)	**$1.5 million**	**$2.8 million**	**$2.4 million**

Notes to table

a. Components calculated assuming a 175 MW wind generation facility with a 32 percent capacity factor.

b. Because of rounding error, totals may differ from sums and differences of individual items shown in the table.