EXHIBIT
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JILL S. BAYLOR

AREAS OF QUALIFICATION

Integrated resource planning including generation and transmission planning; fuel market analysis, price forecasting, contract evaluation, and procurement; management audits and pre-audit preparation; non-utility generation, competitive bid evaluation, bidding issues, and economic, contracting, and fuel procurement due diligence reviews; merger and acquisition economic and regulatory support

EMPLOYMENT HISTORY

- Principal, RCG/Hagler Bailly, Boulder, CO, 1992-present
- Stone & Webster Management Consultants, Inc., Assistant Vice President, 1984-1992
- Mobil Oil Corporation, Planning Analyst, Mining and Coal Division, 1981-1984
- Duke Power Company, Planning Engineer, 1976-1981

EDUCATION

- University of North Carolina at Charlotte, MBA, 1979
- University of Virginia, BS, Applied Mathematics with a minor in Electrical Engineering, 1976

PROFESSIONAL EXPERIENCE

Ms. Baylor is a professional engineer who has specialized in utility planning, non-utility generation, and fuels issues during her career. She has managed projects covering a broad range of utility planning issues from: integrated resource planning, competitive bid evaluation, the economics and financial viability of non-utility generation, fuel procurement and contracting, and plant life management of aging power plants. Ms. Baylor brings to her consulting career the combination of utility and fuel supplier experience. Her projects reflect this background and have expanded on this foundation. Ms. Baylor has extensive experience in the use and application of the models utilized in integrated resource planning and economic analysis. In addition to her planning and fuels background, she has participated in preparing utilities to undergo management audits, conducted audits of utilities, and evaluated the economics of mergers and acquisitions within the utility and fuel procurement industries. Ms. Baylor has been published extensively in the areas of generation planning concerns and transmission planning concerns. She has testified in a variety of jurisdictions.

Ms. Baylor gained valuable experience while conducting generation planning studies during her employment in the System Planning Department at Duke Power Company. These studies

included production costing and capacity mix analyses using a wide array of sophisticated computer planning tools. She participated in a study to examine the economic and technological feasibility of alternative and renewable technologies. Ms. Baylor assisted in the fuel budget preparation, examined fuel use requirements, prepared a range of economic analyses, and evaluated maintenance scheduling and generation dispatching practices. She participated in the evaluation of direct load control strategies.

During the years that Ms. Baylor spent at Mobil Oil Corporation's Mining and Coal Division, she investigated the competitiveness of the various coal markets domestically and internationally, conducted utilization studies of coal for specific utilities and power plants, studied the feasibility of coal-fired generation at Mobil's enhanced oil recovery properties in California, and assessed the economics of pricing scenarios in coal contracts including the impacts on coal mining costs and profitability. She assisted in the development of the five-year strategic plan and associated budgets. In addition, Ms. Baylor actively assisted in the marketing efforts of Mobil to sell coal from its mine in the Wyoming Powder River Basin.

Ms. Baylor undertook consulting assignments in the areas of integrated resource planning and fuels issues while at Stone & Webster Management Consultants. Her projects included overseeing data required to conduct integrated resource planning studies; managing the financial, contract, and fuel concerns associated with due diligence reviews for non-utility generation and cogeneration projects; evaluating avoided costs of electric utilities across the country; assessing impacts and recommending strategies for dealing with the evolving nature of the transmission market; evaluating acid rain compliance planning strategies; conducting economic analyses for utility planning studies; and developing a methodology for plant life management of aging power plants. At Stone & Webster she participated in pre-audit counsels and management audits and was a key investigator in the evaluation of a proposed merger.

SELECTED PROJECTS

1994- **Non-Utility Generation Issues Support**
Client: Empire District Electric

Project manager of an evaluation of resource options for this utility client.

1993- **Reliability Standard Rulemaking**
1994 Clients: Commonwealth Edison, Central Illinois Public Service

Project manager and expert witness for a proceeding in Illinois with regard to a reliability rule proposed by the Staff of the Illinois Commerce Commission.

0132-27-88

1993- **Investigation of Scrubber Decision**
pres. Client: Kentucky Industrial Utility Customers

Examined the process used by Big Rivers Electric Corporation to determine that a scrubber should be installed at Henderson Station Two. Testified during a hearing on the proposed environmental surcharge.

1993- **Non-Utility Generation Expert**
1994 Client: Thermo-Electron

Project manager in providing assistance to the law firm of Skadden, Arps, Slate, Meagher & Flom in assisting South Florida Cogeneration Associates to show cause as to why it should not be categorized as a public utility for the initial years of its operation, 1987-1991.

1993 **South Bay 3 Repower Market Test**
Client: San Diego Gas & Electric

Project manager to evaluate the bids SDG&E received as part of its determination of the competitiveness of repowering its South Bay 3 unit.

1993 **Competitive Bid Evaluation**
Client: Northern States Power

Project manager for the independent evaluation of bids received by NSP for a 25-MW wind farm project.

1993 **Cost Evaluation Methodology Review**
Client: SaskPower

Project manager for a review of the cost evaluation process SaskPower used to evaluate bids received in response to its request for proposals for a 25-MW non-utility generation demonstration project.

1993 **Integrated Resource Planning Support**
Client: Black Hills Power & Light Company

Project manager for the evaluation and augmentation of the integrated resource planning analysis undertaken by Black Hills in support of a Certificate of Public Convenience and Necessity in Wyoming and a Rate Stability Plan in South Dakota. Specific areas of investigation included a demand-side potential evaluation study, extensive sensitivity analysis of the Company's integrated resource plan, an investigation into the availability and cost-effectiveness of wind generation, an examination of the Company's coal prices, and a

determination of the Company's avoided costs. Testimony was presented to the Wyoming Public Service Commission and the South Dakota Public Utilities Commission.

1992- **Provide Support in Hydro-Electric Project Licensing**
1993 Client: Bangor Hydro-Electric Company

Evaluated the integrated resource planning process used by Bangor Hydro-Electric Company in determining the optimal timing and the economic savings for the installation of several hydroelectric projects in its service territory. Alternative options examined including demand-side management options and other supply-side technologies were addressed. Testimony was provided to the Maine Department of Environmental Protection.

1992 **Provide Assistance in Evaluation of Cogeneration Project**
Client: Rhinelander Paper Company

Rhinelander Paper Company (RPC) and Wisconsin Public Service (WPS) announced in August 1992 that they intended to cooperate on a coal-fired cogeneration unit to be built on RPC's property to provide electricity and steam to RPC and generate additional electricity which WPS would use on its grid. Ms. Baylor conducted the economic evaluations to support RPC in its negotiation of the letter of intent with WPS. These evaluations included avoided cost calculations and determination of the cost of steam.

1991 **Independent Engineer for Cogeneration Project**
Client: Swiss Bank

Ms. Baylor served on the project team which provided independent engineering services for the Chambers Works Cogeneration Project being built at Du Pont's Chambers Works Facility in Carneys Point, New Jersey. This 282 MW facility will provide steam and electricity to Du Pont and electricity to Atlantic City Electric. Ms. Baylor's involvement included a review of business contracts including the power purchase agreement, the steam sales agreement, and the fuel agreement. In addition, she conducted economic evaluations of the project's viability and assisted in the process of the bank loan syndication.

1989- **Evaluate Merger Economics**
1990 Client: Tri-State Generation and Transmission and Colorado-Ute Electric Association

Colorado-Ute and Tri-State examined the economic ramifications of a friendly merger during the late months of 1989 and prior to Colorado-Ute's bankruptcy filing in 1990. Ms. Baylor examined the production costs, power purchases, power sales, and fuel contracts to ascertain the operational impacts of such a merger. Subsequent to the bankruptcy filing, Ms. Baylor again examined aspects of a hostile acquisition for Tri-State G&T and analyzed production costing impacts of such an acquisition.

1988- **Plant Life Management Options Project**
1990 Client: California Energy Commission

As project manager, Ms. Baylor oversaw a project for the California Energy Commission to develop a methodology for determining which plant life management option - run, reserve, replace, retire, refurbish, or repower - was the appropriate option to select for each oil/natural gas-fired unit in California. The work effort included a survey of retirement practices across the U S. and developed a methodology using parameters relative to each generating units' operating life and experience to determine which option was appropriate for that specific unit The work effort was conducted cooperatively with the utilities in California that own generating units.

SELECTED PUBLICATIONS/SPEECHES

"Estimating Air Conditioning Load Control Effectiveness Using an Engineering Model," Martin W. Gustafson, Jill S. Baylor, and Gary Epstein, IEEE 92 SM 420-0 PWRS, IEEE Transactions on Power Systems, Volume 8, Number 3, August 1993, pp 972-978.

"Direct Water Heater Load Control - Estimating Program Effectiveness Using an Engineering Model," Martin W. Gustafson, Jill S. Baylor, and Gary Epstein, IEEE 92 WM 130-5 - PWRS, IEEE Transactions on Power Systems, Volume 8, Number 1, February 1993, pp. 137-143.

"The Fair Access Debate," *Independent Energy*, September 1991

"Acid Rain Impacts on Utility Plans for Plant Life Extension," *Public Utilities Fortnightly*, March 1, 1990

"Power-System Loss Calculations Are Updated," *Transmission and Distribution*, November 1989, Jill S. Baylor and Martin W Gustafson.

"Wheeling - Issues and Challenges," 1989 Electric Utility Business Environment Conference and Exhibition, March 1989

"Approximating the System Losses Equation," Martin W. Gustafson and Jill S. Baylor, IEEE 89 WM 146-2 - PWRS, IEEE Transactions on Power Systems, Volume 4, Number 3, August 1989, pp. 850-855

"Power by Wire - Expectations and Realities," Coal Market Strategies Conference, November 1988.

"Operational Losses Savings Attributable to Load Management," Martin W. Gustafson and Jill S. Baylor, IEEE 88 SM 659-5, IEEE Transactions on Power Systems, Volume 4, Number 1, February 1989, pp. 229-235.

"The Equivalent Hours Loss Factor Revisited," Martin W. Gustafson, Jill S. Baylor and Steven S. Mulnix, IEEE 88 WM 166-1, IEEE Transactions on Power Systems, Volume 3, Number 4, November 1988, pp. 1502-1507.

"Considerations in the Formation of Power Pooling Arrangements, "*Public Utilities Fortnightly*, November 26, 1987, Jill S. Baylor and Leslie A. Buttorff.

"Transmission Loss Evaluation for Electric Systems," Martin W. Gustafson and Jill S. Baylor, IEEE 87 SM 467-4, IEEE Transactions on Power Systems, Volume 3, Number 3, August 1988, pp. 1026-1032.

TESTIMONY

Ms. Baylor has prepared testimony or affidavits for cases before the Federal Energy Regulatory Commission and before regulatory agencies in the states of Illinois, Kentucky, Maine, Missouri, Ohio, South Dakota, and Wyoming. Topics have included fuel procurement practices, policies, and procedures; integrated resource planning; non-utility generation markets; economic dispatch practices; avoided costs; fuel and purchased power expenses; and electric system reliability

TRAINING

Lecturer at Stone & Webster Management Consultants, Utility Management Development Program, 1986-1992. Topics included Coal Issues, Electric Fuel Management, Acid Rain, Fossil Issues, and Integrated Resource Planning.

Transmission System Engineering Fundamentals at Seminar titled Power Transmission Access, Pricing and Regulation, Infocast, Inc., September 1991.

Market Analysis, as part of a short course titled Geothermal Project Development and Management, Geothermal Resources Council, 1987.

PROFESSIONAL AFFILIATIONS AND HONORS

- Society of Women Engineers - 1991-92 National President, Fellow
- Institute of Electrical and Electronics Engineers, Power Engineering Society, Senior Member
- Registered Professional Engineer - Colorado
- 1990 Certificate of Honor - Colorado Engineering Council
- American Association of Engineering Societies - 1992 Board of Governors
- Tau Beta Pi, Virginia Alpha
- Listed in *Who's Who in Engineering* and *Who's Who in Science and Engineering*
- 1991 John E. Daly Award for Consulting Excellence - Stone & Webster Management Consultants
- Coal Market Strategies Conference Board of Advisors, 1990-1993
- Women in Engineering Program, University of Colorado - Boulder, External Advisory Board, 1993 - present
- Interdisciplinary Telecommunications Program, University of Colorado - Boulder, Executive Board, 1994 - present
- Colorado Women's Forum
- Rocky Mountain Electrical League Board of Directors, 1994-present
- Listed in *Who's Who in America* and *Who's Who of American Woman*

SELECTED PUBLICATIONS

Articles (Technical)

"Communicating the Value of Dipatchability for Non-Utility Generation Projects" (with D. Cotcher, K.D. Krauss, and D. Logan). January 1995. *IEEE 95 WM 123-0 - PWRS, IEEE Transactions on Power Systems.*

"Licensing a Coal-Fired Power Plant in the 1990s - A Utility's Success Story" (with Tom Ohlmacher, Douglas M. Logan, Ludwig Funke, and Scott Carpenter). 1993. *Power-Gen '93.*

"Estimating Air Conditioning Load Control Effectiveness Using an Engineering Model" (with Martin W. Gustafson and Gary Epstein). August 1993. *IEEE 92 SM 420-0 PWRS, IEEE Transactions on Power Systems*, 8(3):972-978.

Discussion for "Bulk Transmission System Loss Analysis." Nadira, Wu, Maratukulam, Weber, and Thomas (with Martin W. Gustafson). May 1993. *IEEE 92 WM 097-6 - PWRS, IEEE Transactions on Power Systems*, 8(2):414

"Direct Water Heater Load Control - Estimating Program Effectiveness Using an Engineering Model" (with Martin W. Gustafson and Gary Epstein). February 1993. *IEEE 92 WM 130-5 - PWRS, IEEE Transactions on Power Systems*, 8(1):137-143.

"The Fair Access Debate " 1991 *Independent Energy*. September.

"Making New Rules" (with Michael T. Burr, et al.). 1991. *Independent Energy*, July/August.

"Open Access " 1990. *Power-Gen '90* November.

"Plant Life Management Option Selection Decision Methodology" (with David S. Galpin and Roger L. Johnson). 1990 *Power-Gen '90*. December.

"Acid Rain Impacts on Utility Plans for Plant Life Extension " 1990 *Public Utilities Fortnightly*, March.

"Power-System Loss Calculations Are Updated" (with Martin W. Gustafson). 1989. *Transmission and Distribution*, November.

"Approximating the System Losses Equation" (with Martin W. Gustafson). 1989. *IEEE 89 WM 146-2 - PWRS, IEEE Transactions on Power Systems*, 4(3):850-855.

"Operational Losses Savings Attributable to Load Management" (with Martin W. Gustafson) *IEEE 88 WM 659-5, IEEE Transactions on Power Systems*, 4(1):229-235.

"The Equivalent Hours Loss Factor Revisited" (with Martin W. Gustafson and Steven S. Mulnix). *IEEE 88 WM 166-1, IEEE Transactions on Power Systems*, 3(4):1502-1507.

"Considerations in the Formation of Power Pooling Arrangements" (with Leslie A. Buttorff). 1987. *Public Utilities Fortnightly*, November 26.

"Transmission Loss Evaluation for Electric Systems" (with Martin W. Gustafson). *IEEE 87 SM 467-4, IEEE Transactions on Power Systems*, 3(3):1026-1032.

Articles (Non-technical)

"Turbines do kill raptors, but there's no free lunch." 1994. *The Denver Post*, Letter to the Editor, December 22.

"Engineers Can Be Leaders." 1994. *SWE Magazine of the Society of Women Engineers*, November/December.

"Women in Motion: Pioneers in Transportation" (with Alexis C Swoboda) 1994 *SWE Magazine of the Society of Women Engineers*, March/April.

"Living a Better Life" (with Alexis C. Swoboda). 1993. *U.S. Woman Engineer*, March/April.

"The Value of Networking." 1993. *U.S. Woman Engineer*, January/February.

"What I Wish I Had Known When I Graduated from College: Lessons Learned in the Corporate World." 1992. *U.S. Woman Engineer*, November/December.

"How about 'L.A. Engineer'?" 1992. *The News & Observer*, Raleigh, N.C., March 15.

"Encouraging girls in science, math: Steps are simple, vital." 1992. *The Cincinnati Post*, March 5.

"Let's stop discouraging girls from careers in engineering and science." 1992. *The Denver Post*, February 29.

"Today's society needs engineers of both sexes." 1992. *The Houston Chronicle*, February 27.

"Stepping Stones to Career Success." 1992. *Careers and the Engineer*, Spring.

"We Haven't Come Such a Long Way, Gary." 1992. *Business Week* (Letter to the Editor). January 20.

"Girls are not encouraged to be engineers." 1992. *The Denver Post* (Letter to the Editor). December 29.

"A Family Business: Opportunities for the Female Entrepreneur." 1991. *U.S. Woman Engineer*, July/August.

"Break Through The Glass Ceiling." 1991. *Woman Engineer* (SWE Column). Spring.

"Mathematics, Minerals and Molecules" (with Alexis C. Swoboda). MIDCON/90, September 1990.

"The SWE Achievement Award." 1990. *Woman Engineer*, SWE Column, Spring.

"Women Engineers on the Job." 1990. *Engineering Horizons*, Spring.

"SWE Highlights Women Achievers." 1989/1990. *Woman Engineer*, SWE Column, Winter.

"SWE Career-Guidance Programs." 1989. *The Woman Engineer*, SWE Column, April/May

"The 'Good Old Days': A Short Course in Appliance History." 1989. *U.S. Woman Engineer*, January/February.

"Nuclear Power Will Fill Energy Gap." 1980. *The Charlotte Observer*, Letter to the Editor, December 28.

"Nuclear Power." 1980. *The Charlotte Observer*, Letter to the Editor, October 16.

Articles (Featured in)

Quoted and pictured in an article titled "Manufacturing a New Engineer." *Science and Engineering Horizons*, 1994/1995 Women's Edition.

Quoted and pictured in an article titled "Hopper Inducted in National Women's Hall of Fame." *SWE Magazine of the Society of Women Engineers*, November/December 1994.

Featured in an article titled "Women Engineers Face Barriers, Opportunities." *National Business Employment Weekly*, February 26-March 4, 1993.

Featured in an article titled "Engineers break gender stereotypes." Seattle Times/Seattle Post-Intelligencer, October 18, 1992.

Featured in an article titled "Woman blazes a trail in field of engineering." *Journal-Bulletin*, Providence, RI, May 11, 1992.

Quoted in an article titled "Erasing Gender Stereotypes in Engineering." *Mechanical Advantage*, Spring 1992.

Featured in an article titled "Getting more women into the field of engineering." *Sentinel-Enterprise*, Fitchburg, MA, April 2, 1992.

Featured in an article titled "New careers open to women, but overall progress is slow." *Rocky Mountain News*, March 15, 1992.

Quoted in an article titled "The Pond Factor." *Graduating Engineer*, February 1992.

Quoted in an article titled "Job Opportunity Barometer." *Graduating Engineer*, February 1992.

Featured in an article titled "We Ask You: What is the toughest problem you've ever had to solve?" *Graduating Engineer*, February 1992.

Featured in an interview titled "Careers Unlimited." by Kathleen Groll Connolly, *Science and Engineering Horizons*, 1991/92 Women's Edition.

Profiled and pictured in an article titled "U.Va. Graduate is SWE President-Elect." Virginia Engineering, Spring 1991.

Profiled and pictured in an article titled "Women still rare in engineering." *Rocky Mountain News*, May 12, 1991.

Quoted in article titled "Taking Stock of Your Future." *Graduating Engineer*, February 1991.

Quoted in article titled "Dressing for Engineering Careers." *Engineering Horizons*, 1990/1991 Women's Edition.

Quoted in article titled "Networking." *Graduating Engineer*, October 1990.

Quoted in article titled "Nine Career Tips From Top Minority Managers." *Graduating Engineer*, April 1990.

Quoted in article titled "How We're Shortchanging Women Engineers." *Graduating Engineer*, February 1990.

Quoted in article titled "Engineering fails to break sex barriers." *The Dallas Morning News*, July 31, 1989.

Profiled in "Finding the Right Job." *The Woman Engineer*, Spring 1989.

One of 10 engineers profiled in "What We Wish We Had Known." *Graduating Engineer*, March 1988.

Conference Papers (Technical)

"Load Forecasting: Ensuring a Solid Foundation for Integrated Resource Planning" (with Douglas M. Logan and Chris Neil), *Proceedings of the Electric Systems Planning and Operations Conference*, 1-10, Denver, CO, sponsored by Electric Utilities Consultants, Inc., November 11-13, 1993.

"Modeling Renewable Energy Resources in Utility Planning Models" (with Douglas M. Logan, Alan Taylor, and Peter Lilienthal), *Proceedings of the National Regulatory Conference on Renewable Energy*, 315-329, Savannah, GA, sponsored by the National Association of Regulatory Utility Commissioners, October 3-6, 1993.

"Uncertainty Analysis Without Tears" (with Douglas M. Logan). Proceedings of EPRI's Ninth Electric Utility Forecasting Symposium, September 8-10, 1993.

"Transmission Access: Technical and Political Implications" (with Glenn A. Davidson), *Proceedings of the 2nd Annual Transmission & Wheeling Conference*, 127-134. Denver, CO, sponsored by Electric Utilities Consultants, Inc. and Stone & Webster Management Consultants, Inc., November 21-22, 1991.

"Engineering and Rate Making Fundamentals," *Power Transmission: Access, Pricing and Regulation*, San Francisco, CA, presented to Infocast, Inc., September 23, 1991.

"Decision Methodology for Plant Life Management Option Selection" (with David S. Galpin and Roger L. Johnson), *Proceedings of the American Power Conference*, Volume 53-I, 485-491, Chicago, IL, sponsored by the Illinois Institute of Technology, April 1991. (Awarded one of 10 best papers for 1991 for Stone & Webster employees.)

"Why Inter-Area Electric Transmission?" (with Fred E. Depenbrock), *Proceedings of the American Power Conference*, Volume 53-I, 588-591, Chicago, IL, sponsored by the Illinois Institute of Technology, April 1991.

"Transmission Access: Who Pays and How?" *Proceedings of the Transmission & Wheeling Conference*, 61-70, Denver, CO, sponsored by Electric Utilities Consultants, Inc. and Stone & Webster Management Consultants, Inc., November 8-9, 1990.

"Future Electric Generation: Clean Air At What Cost?" *Proceedings of the Fifteenth Annual Conferen - Issues in Gas, Electricity, and Telecommunications*, 5, July 18-20, 1990. (Awarde ne of 10 best papers for 1990 for Stone & Webster employees.)

"Transmission Pricing Policies and Access," *Proceedings of the 1990 Electric Utility Business Environment Conference and Exhibition*, 49-55, Denver, CO, sponsored by Electric Utilities Consultants, Inc. and RCG/Hagler Bailly, Inc., March 7-9, 1990.

"Air Quality Concerns: Impacts on Utility Plans for Life Extension of Coal-Fired Power Plants," *Proceedings of the Seventh Annual Coal Market Strategies Conference - Utility Coal Use, Acid Rain, and Other Uncertainties*, 3:1-16, Denver, CO, sponsored by Edison Electric Institute Western Coal Council, October 26, 1989. (Awarded one of 10 best papers for 1989 for Stone & Webster employees.)

"Wheeling - Issues and Challenges," *Proceedings of the 1989 Electric Utility Business Environment Conference and Exhibition*, 101-115, Denver, CO, sponsored by Electric Utilities Consultants, Inc. and RCG/Hagler Bailly, Inc., March 28-30, 1989.

"Power by Wire - Expectations and Realities," *Proceedings of the Sixth Annual Coal Market Strategies Conference - Dynamics of Utility Coal Use*, 2:1-21, Denver, CO, November 1-3, 1988. (Awarded one of 10 best papers for 1988 for Stone & Webster employees.)

"Geothermal Project Development and Management Market Analysis," (with Leslie A. Buttorff), presented to the Geothermal Resources Council as part of a short course, Sparks, NV, October 9-10, 1987.

Conference Papers (Non-technical)

"Women Who Made a Difference: Technological Bridges" (with Alexis C. Swoboda), *Proceedings of the Society of Women Engineers' National Convention and Student Conference - Engineering: A Bridge Into the 21st Century*, 69-74, Pittsburgh, PA, June 22-26, 1994.

"Women in Motion: Pioneers in Transportation" (with Alexis C. Swoboda), *Proceedings of the Society of Women Engineers' National Convention and Student Conference - Gear Up 2000, Women in Motion*, 312-316, Chicago, IL, June 21-27, 1993.

"Space: Women Challenge the Final Frontier" (with Cynthia Hesse), *Proceedings of the Society of Women Engineers' National Convention and Student Conference - Space Challenges: Earth and Beyond*, 1:4-8, Orlando, FL, June 22-27, 1992.

"Mathematics, Minerals and Molecules" (with Alexis C. Swoboda), *Proceedings of the Ninth International Conference of Women Engineers and Scientists*, University of Warwick, United Kingdom, July 14-20, 1991.

"Women in Engineering and Science: The Limited Past, A Limitless Future" (with Alexis C. Swoboda), *Proceedings of the Society of Women Engineers' National Convention and Student*

Conference - Engineering Our Future: Enhancing the Quality of Life, San Diego, CA, June 24-29, 1991.

"Living A Better Life" (with Alexis C. Swoboda), *Conference Record of MIDCON/90*, 554-557, Dallas, TX, sponsored by IEEE and ERA, September 11-13, 1990.

"Mathematics, Minerals and Molecules" (with Alexis C. Swoboda), *Proceedings of the Society of Women Engineers' National Convention and Student Conference - Building Tomorrow on Yesterday's Blueprints*, 308-316, New York, NY, June 25-July 1, 1990

"Living A Better Life" (with Alexis C. Swoboda), *Proceedings of the Society of Women Engineers' National Convention and Student Conference - Building Tomorrow on Yesterday's Blueprints*, 272-278, New York, NY, June 25-July 1, 1990.

"Interviewing Skills: Putting Yourself in the Driver's Seat," *Proceedings of the Society of Women Engineers' National Convention and Student Conference - Strength Through Diversity: Women & Technology*, 313-326, Oakland, CA, June 26-July 2, 1989

SELECTED PRESENTATIONS

Technical

"Natural Gas and Coal: Competition or Cooperation?" Presented at Denver Coal Club February 11, 1993

"Coal Issues and Electric Fuel Management." Stone & Webster Management Consultants' annual Utility Management Development Program, Annual lecture, 1986-1992

"New Transmission Lines. Do We Really Need Them?" (with Glenn A. Davidson). Presented at the Strategic Utility Planning Conference, June 25-26, 1992. (Awarded one of 10 best papers for 1992 for Stone & Webster employees.)

"Transmission Access and Wheeling." Presented at the Rocky Mountain Electrical League Spring Conference, May 1990

"Analyzing Utility System Losses." Presented at the T&D World Expo '90, March 1990

"How to Evaluate Utility Staff Resource Plans" (with Marlin W. Gustafson). Presented to the California Municipal Utilities Association, February 1987.

"Mechanical Performance of Surgical Sutures." Presented at the American Society of Mechanical Engineers Regional Student Conference, March 1976 (Awarded second place.)

"The Mechanical Performance of Polyglycolic Acid Sutures." Presented to the Virginia Academy of Science, May 1975.

Non-technical

"What I Wish I Had Known When I Graduated from College." Presented at Oklahoma State University, September 26, 1994.

"Tomorrow's Technical Workforce: Breaking the Mold." Presented to the American Business Women's Association, August 14, 1993.

"Historical Women in Engineering and Science: Unknown But Not Forgotten." Presented at U.S. West Advanced Technologies, March 1993.

"Developing Tomorrow's Technical Workforce." Presented at the Association for Women Geoscientists, September 12, 1992.

"The Changing Face of the Engineer: Breaking the Mold." Presented at Oklahoma State University, July 23, 1992.

"What I Wish I Had Known." Presented at the Society for Women Engineers' 1991-1992 Awards Banquet, Cornell University, April 22, 1992.

"Developing Tomorrow's Technical Workforce." Presented at the Rocky Mountain Regional Tech Prep Conference, March 26, 1992.

"What I Wish I had Known When I Graduated." Presented at the University of Colorado at Boulder, March 14, 1992.

"The Changing Face of the Engineer." Presented at the New York Academy of Sciences, Engineering Section, March 11, 1992.

"What I Wish I Had Known." Presented at Vanderbilt University, February 20, 1992.

"Is an Engineering Career in Your Future?" Presented as the Keynote Address for "Women In Engineering . . . A Winning Combination," University of Pittsburgh, November 22, 1991.

"Engineers of Tomorrow: Breaking the Mold." Presented at Power Supply USA, November 4-5, 1991.

"Engineers of Tomorrow: Breaking the Mold." Presented at the American Society of Mechanical Engineers Regional Conference, August 23, 1991.

"SWE in your future." Presented at the Society of Women Engineers' Region H Student Conference, October 20, 1990.

"What I Wish I Had Known When I Graduated From College." Presented at the University of Colorado at Boulder, September 20, 1989.

"What I Wish I Had Known." Presented at the University of Virginia, April 1989.

"What I Wish I Had Known When I Graduated." Presented at the Society of Women Engineers Region I Student Conference, Wichita State University, October 1, 1988.

EXHIBIT
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JILL S. BAYLOR

TESTIMONY AND DEPOSITION

Kentucky Public Service Commission, Big Rivers Electric Corporation PSC Case No 94-032. (On behalf of the Kentucky Industrial Utility Customers.) "Coal Price Forecasting and Markets." 1994.

Illinois Commerce Commission, Docket No. 92-0168. (On behalf of Commonwealth Edison and Central Illinois Public Service Company.) "Reliability Regulation and Measurement." 1993.

Federal Energy Regulatory Commission, Docket Nos. EL93-45-000 and QF83-248-002. (On behalf of Energy Systems Division of Thermo Electron Corp., et al.) 1993.

Missouri Public Service Commission, Case ER-93-41. (On behalf of St. Joseph Light and Power Company.) "Rebuttal Testimony on Production Cost Model, Fuel, and Interchange." 1993.

South Dakota Public Utilities Commission, Dockets Nos. EL92-026 and EL92-027. (On behalf of Black Hills Power & Light Company.) "Avoided Costs, Integrated Resource Planning, and Evaluation of Non-Utility Generation Markets." 1993.

Wyoming Public Service Commission, Docket No. 20002-EA-92-27. (On behalf of Black Hills Power & Light Company.) "Integrated Resource Planning." 1993.

Maine Department of Environmental Protection. (On behalf of Bangor Hydro-Electric Company.) "Net Benefit Analysis for the Veazie Development and the Basin Mills Development: Integrated Resource Planning." 1992.

Public Utilities Commission of Ohio. "Fuel Procurement Practices, Policies and Procedures, Toledo Edison." 1987.

Public Utilities Commission of Ohio. "Economic Dispatch Practices, Toledo Edison." 1985.

EXHIBIT
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INTEGRATED RESOURCE PLANNING ANALYSIS OF NEIL SIMPSON #2 FINAL REPORT

Prepared by:

Jill S. Baylor
Douglas M. Logan
RCG/Hagler, Bailly, Inc.
P.O. Drawer O
Boulder, CO 80306-1906

Prepared on behalf of:

BLACK HILLS POWER AND LIGHT COMPANY

February 26, 1993

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APPENDIX A4 Public Involvement Appendix

EXECUTIVE SUMMARY

This report describes the integrated resource planning (IRP) analysis of Neil Simpson #2 conducted for Black Hills Power and Light Company (Black Hills) by Black & Veatch and RCG/Hagler, Bailly, Inc. (Hagler, Bailly). It builds upon the analysis described in Ludwig F. Funke's testimony in Wyoming Public Service Commission Docket No. 20002-EA-92-27. The analysis documented herein examined a wide range of resource options and concluded that Neil Simpson #2 is substantially less expensive than the alternatives even under a wide range of possible future conditions. Neil Simpson #2 provides significant cost savings compared to alternative resources and results in the lowest cost for Black Hills' customers.

The objectives of this study were to:

(1) Identify the least-cost means of meeting electricity requirements of Black Hills' customers from among various generation options.

(2) Validate the selection of the technology choices determined in the analysis, including the installation of Neil Simpson #2, under a wide range of future conditions.

(3) Quantify the economic risk associated with the installation of Neil Simpson #2.

(4) Determine whether Neil Simpson #2 should be included in Black Hills' resource plan.

The key results of the study are summarized in Tables ES-1 and ES-2. Table ES-1 shows the net benefits of Neil Simpson #2 relative to six other options considered over the operating life of the projects. The net benefits of Neil Simpson #2 relative to an alternative resource are calculated as the difference between the total costs for two plans. The two plans are identical except for a given block of capacity starting in 1996. The first plan has Neil Simpson #2 filling this block. The second plan has Neil Simpson #2 deleted and replaced by some other resource option, for example, an 80 MW power purchase from PacifiCorp (also denoted as PPL). Transmission costs associated with an alternative resource are modeled, as is the gas pipeline required for the case with the combined cycle unit. The component labeled Net Emissions/Tax Cost includes all of the following:

(a) The value of allowances required for the net change in SO_2 emissions from the alternative resource and the rest of the system, less emissions from Neil Simpson #2,

Table ES-1
Net Cost of Alternative Resources
Relative to Neil Simpson #2
(Millions of $)

	PPL Purchase	Combustion Turbine	Combined Cycle	Wind	Photo-voltaics	Basin Purchase
Life of Alternative (years)	30	25	35	25	25	30
Alternative Resource Capital Cost	19.95	55.96	110.67	117.29	335.05	28.20
Alternative Resource Operating Cost	289.41	119.70	183.17	52.07	18.28	265.31
Neil Simpson #2 Capital Cost	141.55	136.42	144.64	136.42	136.42	141.55
Neil Simpson #2 Operating Cost	68.43	64.67	71.19	64.67	64.67	68.43
Net System Generation Cost	-14.15	154.33	14.29	340.60	-25.38	-20.23
Net Emissions/Tax Cost	5.02	21.41	-2.85	-15.97	-19.24	-2.19
Net Cost	90.25	150.31	89.45	92.89	107.61	61.10

Costs are expressed as present values, over the operating life of the alternative resource discounted to 1996.

Table ES-2
Probabilistic Analysis Results
Net Present Value of Savings from Neil Simpson #2
Relative to Alternative Resource Options
(Millions of $)

	PPL Purchase	Combustion Turbine	Combined Cycle	Wind	Photo-voltaics	Basin Purchase
Base Case	90.25	150.31	89.45	92.89	107.61	61.10
10% Fractile	13.06	96.94	41.11	49.03	52.74	10.55
50% Fractile	88.33	148.93	87.79	91.90	106.66	56.32
90% Fractile	141.02	184.77	121.99	137.01	160.57	103.87
Expected Value	81.15	143.25	85.01	94.21	107.57	52.00
Probability of Negative Net Present Value	0.8%	0.0%	0.2%	0.2%	0.0%	8.8%

Base case and fractile numbers are net present values, over the operating life of the alternative resource in millions of 1996 dollars.

(b) The additional cost imposed by the proposed federal energy tax, and

(c) The renewable energy tax credit, if applicable, which is represented as a negative cost.

The positive values of net cost for each of the alternative resources relative to Neil Simpson #2 indicates that the plan with Neil Simpson #2 is the lowest cost plan.

Table ES-2 shows the results of a probabilistic analysis of the costs and benefits over the operating life of an alternative resource. Both Tables ES-1 and ES-2 show the present value of net benefits to customers, or the reduction in revenue requirements, from Neil Simpson #2 relative to a case in which Neil Simpson #2 is deleted from the resource plan and replaced by an alternative resource. For example, the rates paid by Black Hills' customers over the life of a power purchase from PacifiCorp are expected to be higher by $81.15 million than they would have been had Neil Simpson #2 been built. The probability of positive net benefits from the installation of Neil Simpson #2 is very high -- 99%.

To perform this study, the work shown in Figure ES-1 was completed. The major components of this effort were the following:

(1) Construction of an optimized base case conventional resource plan that included Neil Simpson #2, combustion turbines, and other coal-fired units.

(2) Evaluation of the economic benefits provided in the base case resource plan by Neil Simpson #2. Black & Veatch's POWRPRO model was used to evaluate the production cost savings for each set of alternatives examined.

(3) Extensive sensitivity analysis of the production cost savings using POWRPRO.

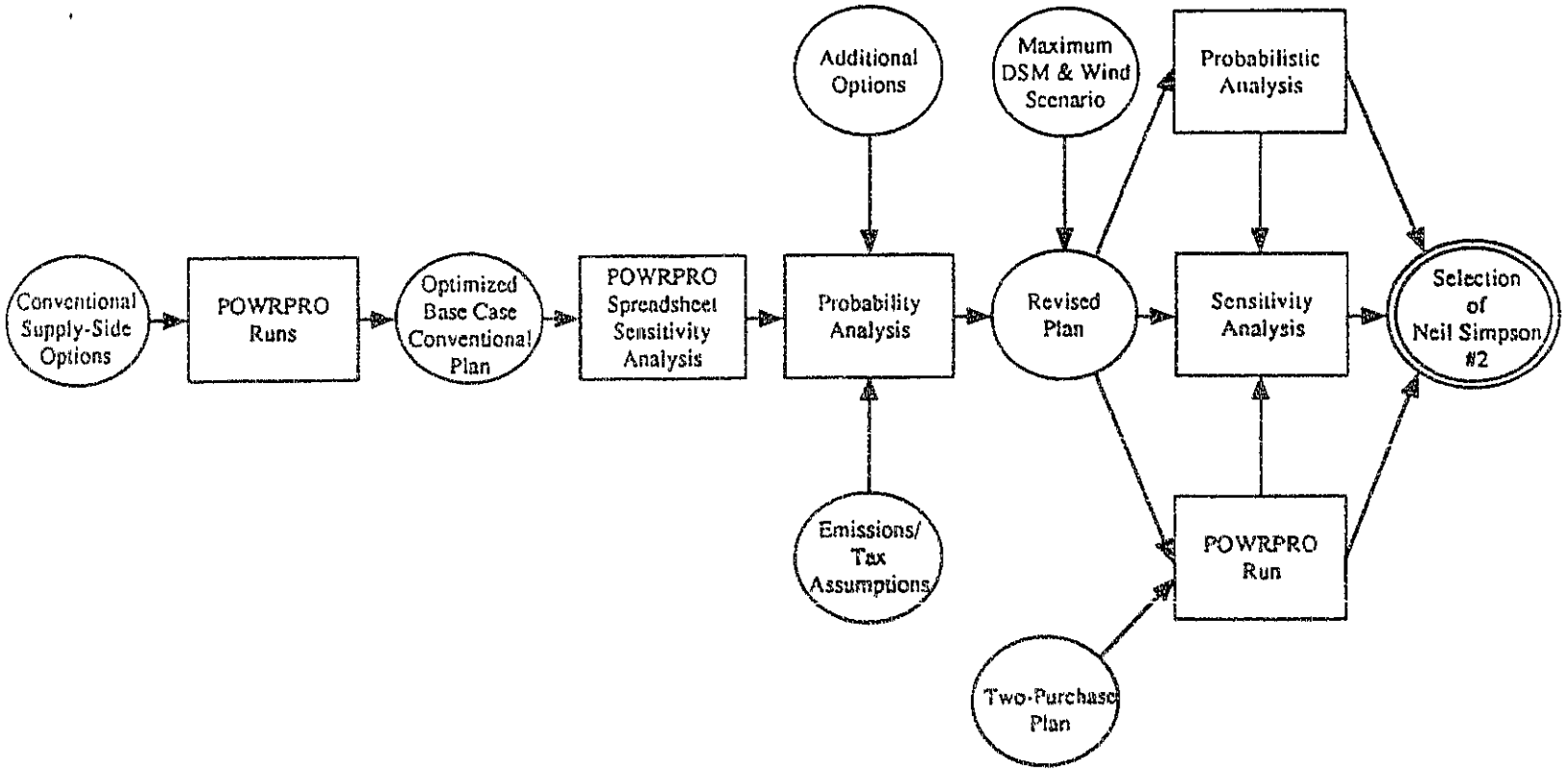
(4) Benchmark test of the results of the POWRPRO analysis using the ENPRO model, which Black Hills has in-house.

(5) Probabilistic analysis of the economic benefits using the results of the sensitivity analysis.

(6) Construction of a modified base case resource plan that includes large blocks of wind generation and additional DSM.

(7) Further POWRPRO analysis, sensitivity analysis, and probabilistic analysis around the modified base case.

Figure ES-1
Methodology For IRP Analysis of NS #2



(8) Probabilistic sensitivity analysis to determine the sensitivity of the probabilistic results to the input probability assumptions.

Two components that would be necessary parts of a comprehensive IRP process were not completed for this study. These two components are:

(a) Comprehensive assessment of DSM savings potential in Black Hills' service territory, and

(b) Construction of an integrated supply- and demand-side resource plan.

The DSM potential assessment, component (a), is underway but has not been completed. Construction of an integrated plan, component (b), cannot be started until the DSM potential assessment has been completed.

Although this study is not a comprehensive IRP process, the analysis that has been completed demonstrates unequivocally that Neil Simpson #2 would be an essential part of the integrated supply- and demand-side plan that would be obtained as the result of a comprehensive IRP process. It does so by showing that Neil Simpson #2 would be cost-effective even if prior commitment were made to aggressive levels of DSM and renewables.

The analysis conducted by Black & Veatch and described in Mr. Funke's testimony along with additional runs made later incorporated results of almost 30 different combinations of resource technologies which could meet the electricity requirements of Black Hills' customers over the planning horizon. These cases and their interrelationships are shown on Figure ES-2 and described in Table ES-3. The case identified as Case 106 has been called the base case because it results in the lowest present value of revenue requirements. Case 106 incorporates the installation of Neil Simpson #2 in 1996; followed by combustion turbines (CT) in 1997, 1998, 2001 and 2005; another coal-fired unit in 2007; followed by a CT in 2011; a coal unit in 2012; and another CT in the year 2013. The total cost of that case over the period 1996 to 2015 was $504.4 million discounted to 1993 dollars. All alternative cases examined, assuming the same peak demand and energy requirements with various combinations and timings associated with resource technologies, resulted in a higher present worth of revenue requirements.

In addition to the cases described above, further cases were run by Black & Veatch at the request of Hagler, Bailly, to allow the performance of a sensitivity analysis over a wide range of future conditions. As shown on Figure ES-3, these alternative future conditions included low and high fuel prices, low and high load growth, installation of wind energy resources, a high success rate for implementation of demand-side management resources (DSM), and combinations of various of these conditions. Table ES-4 provides a description of the cases analyzed and a cost comparison.

Figure ES-2
POWRPRO Cases

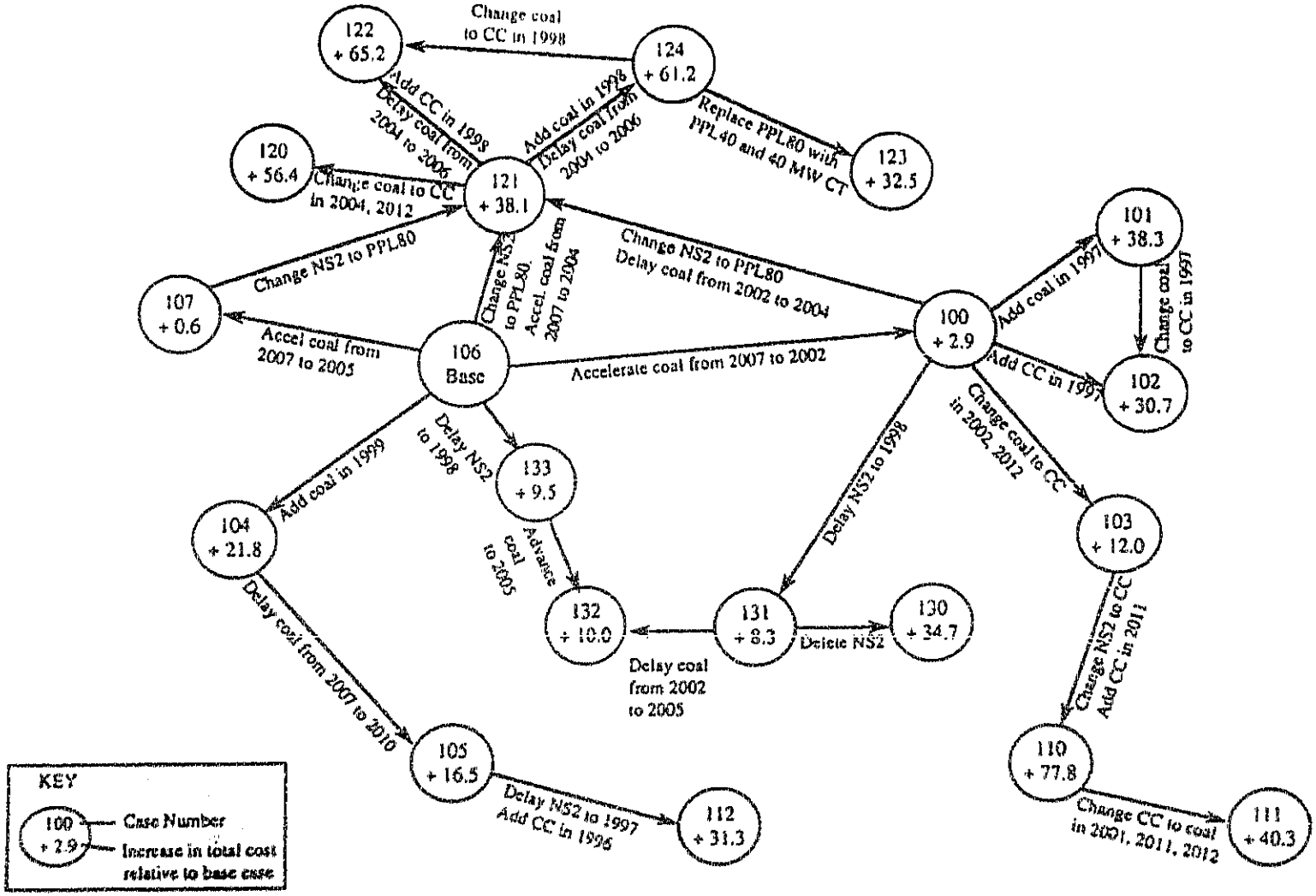


Table ES-3
Description of Cases
(Millions of $)

Case Number	NS#2	CT	CC	Coal	PP	Wind	DSM	Gas Pipe	Trans Cost	REC	QF	Total Cost M$	Comparison to Base M$	Levelized cents/kWh[1]
106	1996	1997, 1998, 2001, 2005, 2011, 2013		2007, 2012								504.4	BASE	3.83
107	1996	1997, 1998, 2001, 2010, 2011, 2013		2005, 2012								505.0	0.6	3.84
100	1996	1997, 1998, 2007, 2010, 2011, 2013		2002, 2012								507.3	2.9	3.86
133	1998	2-1996, 1997, 2001, 2005, 2011, 2013		2007, 2012								513.9	9.5	3.90
132	1998	2-1996, 2001, 2010, 2011, 2013		2005, 2012								514.4	10.0	3.91
103	1996	1997, 1998, 2007, 2010, 2011, 2013	2002, 2012					Yes				516.4	12.0	3.91
131	1998	2-1996, 2007, 2010, 2013		2002, 2012								516.7	12.3	3.93
Basin		1997, 1998, 2001, 2005, 2013		2007, 2012	80 MW 1996 Basin				Yes			521.6	17.2	3.95
105	1996	1997, 2005, 2007, 2-2013		1999, 2010, 2012								520.9	16.5	3.96
104	1996	1997, 2005, 2011, 2013		1999, 2007, 2012								526.2	21.8	4.00
102	1996	2007, 2010, 2011, 2013	1997	2002, 2012				Yes				535.1	30.7	4.08
112	1997	2000, 2003, 2007, 2008, 2015	1996	2011, 2012				Yes				535.7	31.3	4.08
123		1996, 2002, 2-2011, 2013		1998, 2006, 2012	40 MW 1996 PPL				Yes			536.9	32.5	4.08
130		2-1996, 1998, 1999, 2007, 2009, 2011, 2015		2002, 2012								539.1	34.7	4.09
121		1998, 2000, 2008, 2-2011, 2013		2004, 2012	80 MW 1996 PPL				Yes			542.5	38.1	4.12
101	1996	2007, 2010, 2011, 2013		1997, 2002, 2012								542.7	38.3	4.14

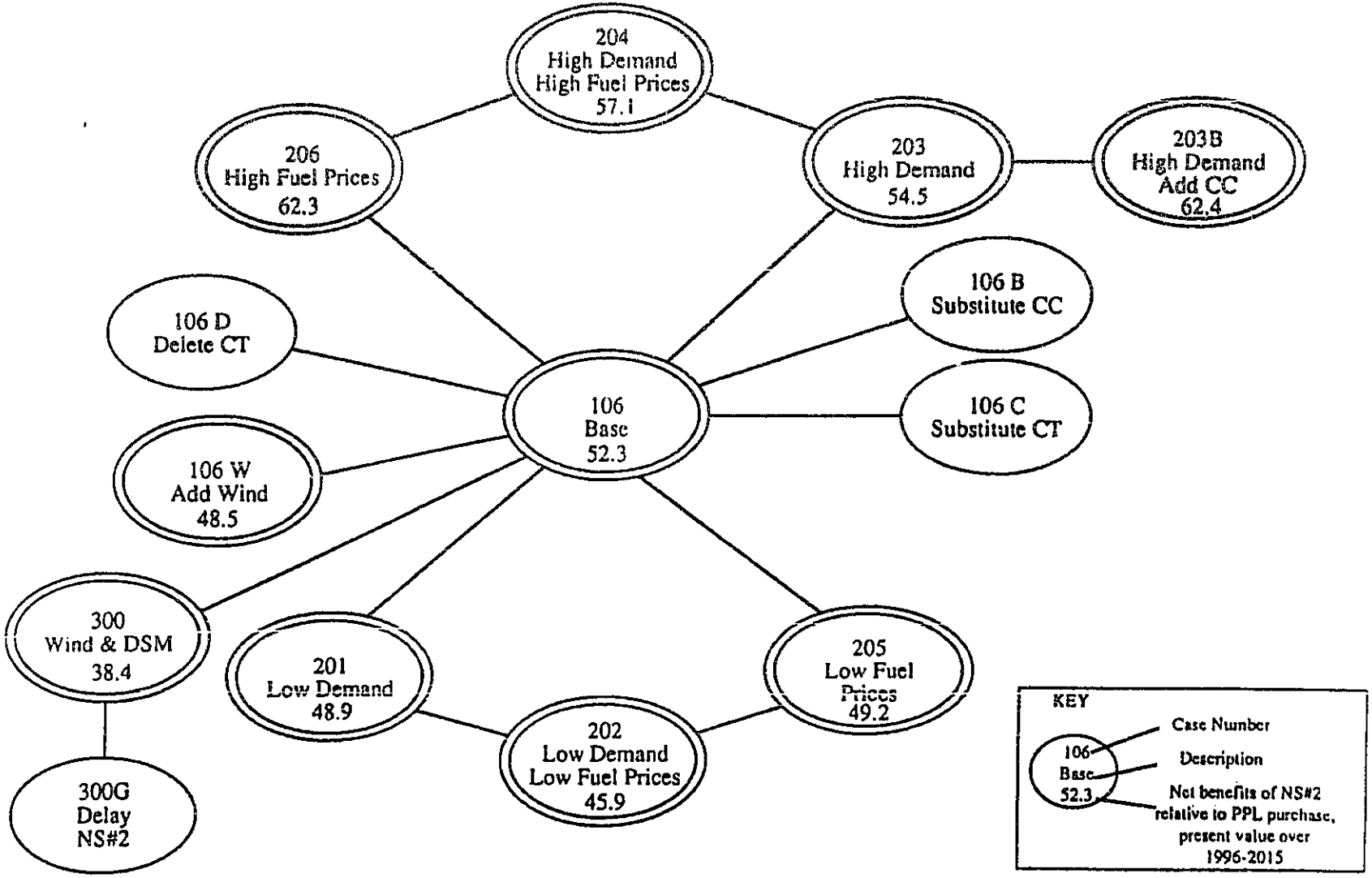
Table ES-3 (cont.)
Description of Cases
(Millions of $)

Case Number	NS#2	CT	CC	Coal	PP	Wind	DSM	Gas Pipe	Trans Cost	REC	QF	Total Cost M$	Comparison to Base M$	Levelized cents/kWh[1]
111		1997, 1998, 2007, 2008, 2015	1996	2001, 2011, 2012				Yes				544.7	40.3	4.14
121A		1998, 2000, 2010, 2011, 2013, 2015		2012	2-80 MW 1996, 2004				Yes			547.1	42.7	4.15
120		1998, 2000, 2008, 2-2011, 2013	2004, 2012		80 MW 1996 PPL			Yes	Yes			560.8	56.4	4.24
124		2002, 2-2011, 2014		1998, 2006, 2012	80 MW 1996 PPL				Yes			565.6	61.2	4.31
122		2002, 2-2011, 2014	1998	2006, 2012	80 MW 1996 PPL			Yes	Yes			569.6	65.2	4.36
110		1997, 1998, 2006, 2008, 2013, 2014	1996, 2001, 2011, 2012					Yes				582.2	77.8	4.40

Costs are expressed as present values discounted to 1993 dollars and are over the 20-year period 1996-2015.
Key: NS#2 - Neil Simpson #2, CT - Combustion Turbine, CC - Combined Cycle, Coal - Coal-fired unit, REC - Renewable Energy Production Credit, QF - Qualifying Facility, PP - Power Purchase, DSM - Demand-Side Management, Gas Pipe - Gas Pipeline, Trans Cost - Transmission Line Cost, Basin - Basin Electric, PPL - PacifiCorp.

(1) Costs derived by dividing annual revenue requirements by annual generation, taking the present value of the results and levelizing them.

Figure ES-3
POWRPRO Scenarios For Sensitivity Analysis



Double ovals indicate that a lettered scenario (e.g., 203A) was run in addition to the scenario with Neil Simpson #2.

Table ES-4
Description of Sensitivity Cases
(Millions of $)

Case Pair	Description	Alternative to Neil Simpson #2	Customer Savings from Installation of Neil Simpson #2
106-106A	Base case	PPL purchase and transmission costs	52.3
106-106B	Base case	CC and gas pipeline	56.1
106-106C	Base case	CT	92.1
106W-106WA	Wind and renewable energy production credit	PPL purchase and transmission costs	77.3
201-201A	Low demand	PPL purchase and transmission costs	49.0
202-202A	Low demand, low fuel prices	PPL purchase and transmission costs	45.9
203-203A	High demand	PPL purchase and transmission costs	44.6
203-203AB	High demand	PPL purchase and install additional CC, gas pipeline and transmission costs	116.9
204-204A	High demand, high fuel prices	PPL purchase and transmission costs	57.1
205-205A	Low fuel prices	PPL purchase and transmission costs	49.1
206-206A	High fuel prices	PPL purchase and transmission costs	62.1
300-300A	Wind and DSM, renewable energy production credit	PPL purchase and transmission costs	37.1
300-300G	Wind and DSM, renewable energy production credit	Delay NS#2 to 1997	4.0
300-300P	Wind and DSM, renewable energy production credit	NS#2 in 1997, CT + 20 MW photovoltaics in 1996	74.8
300-300W	Wind and DSM, renewable energy production credit	CT + 20 MW wind 1996, coal in 1999, CT-1998, 2006, 2011, 2014, coal-2008, 2012	18.2

* Costs are expressed as present values of production and incremental capital costs over 1996-2015, discounted to 1993.

The 300 series cases were run solely for sensitivity purposes and assumed different peak demand and energy requirements than the base case as blocks of additional DSM and wind generation were added and conventional supply-side resources other than Neil Simpson #2 were deferred, resulting in lower overall costs. These cases demonstrate that Neil Simpson #2 remains cost-effective, even with additional DSM and wind, because the case that has Neil Simpson#2 coming on-line in 1996 (Case 300) has lower total costs than either the case with Neil Simpson #2 deferred to 1998 (Case 300G) or replaced by the PPL purchase (Case 300A).

The results lead to the following conclusions:

(1) Neil Simpson #2 is substantially less expensive than the alternatives. This occurs both under base case assumptions and after accounting for uncertainty.

(2) The extensive uncertainty analysis shows that the probability that Neil Simpson #2 will be uneconomic is less than 1%. The values of negative benefits in these scenarios, however, are small and are overwhelmed by the large positive net benefits realized in the other scenarios, which account for 99% of potential future conditions.

Neil Simpson #2 was found to be economic even under low demand growth scenarios, in a scenario with renewable resources installed as well as aggressive DSM programs implemented, and in scenarios in which energy taxes and the economic costs of air emissions are accounted for. Therefore, Neil Simpson #2 would be included in the integrated supply- and demand-side resource plan obtained from a comprehensive IRP process.

1.0 INTRODUCTION

This report describes an integrated resource planning (IRP) analysis of Neil Simpson #2 for the Black Hills Power and Light Company (Black Hills) generation system.[1] Neil Simpson #2 is a proposed 80-MW pulverized coal unit which would be built in Gillette, Wyoming at the site of the Neil Simpson and Wyodak #1 units. It is scheduled for completion on January 1, 1996.

This study was performed to support filings in Wyoming (Certificate of Public Convenience and Necessity) and South Dakota (Rate Stability) for the Neil Simpson #2 project.

1.1 OBJECTIVES

The objectives of this study were to:

(1) Identify the least-cost means of meeting electricity requirements of Black Hills' customers from among various generation technologies.

(2) Validate the selection of the technology choices determined in the analysis, including the installation of Neil Simpson #2 under a wide range of future conditions.

(3) Quantify the economic risks associated with the installation of Neil Simpson #2. These risks include both uncertainty in the construction costs of the facility and uncertainty in various planning assumptions that determine the need for and the economic value to Black Hills of the project.

(4) Determine whether Neil Simpson #2 should be included in Black Hills' resource plan. The ultimate decision to approve the facility depends on whether the project provides net cost savings to Black Hills' customers compared to alternative resources.

[1] This study was performed in collaboration with Black Hills Power and Light Company and its consultant Black & Veatch. The assistance of Mr. Ludwig Funke and Mr. Scott Carpenter from Black & Veatch and Mr. Gary Svarstad from Black Hills was particularly valuable in providing background information and in performing the many computer model runs on which this analysis is based.

1.2 INTEGRATED RESOURCE PLANNING OVERVIEW

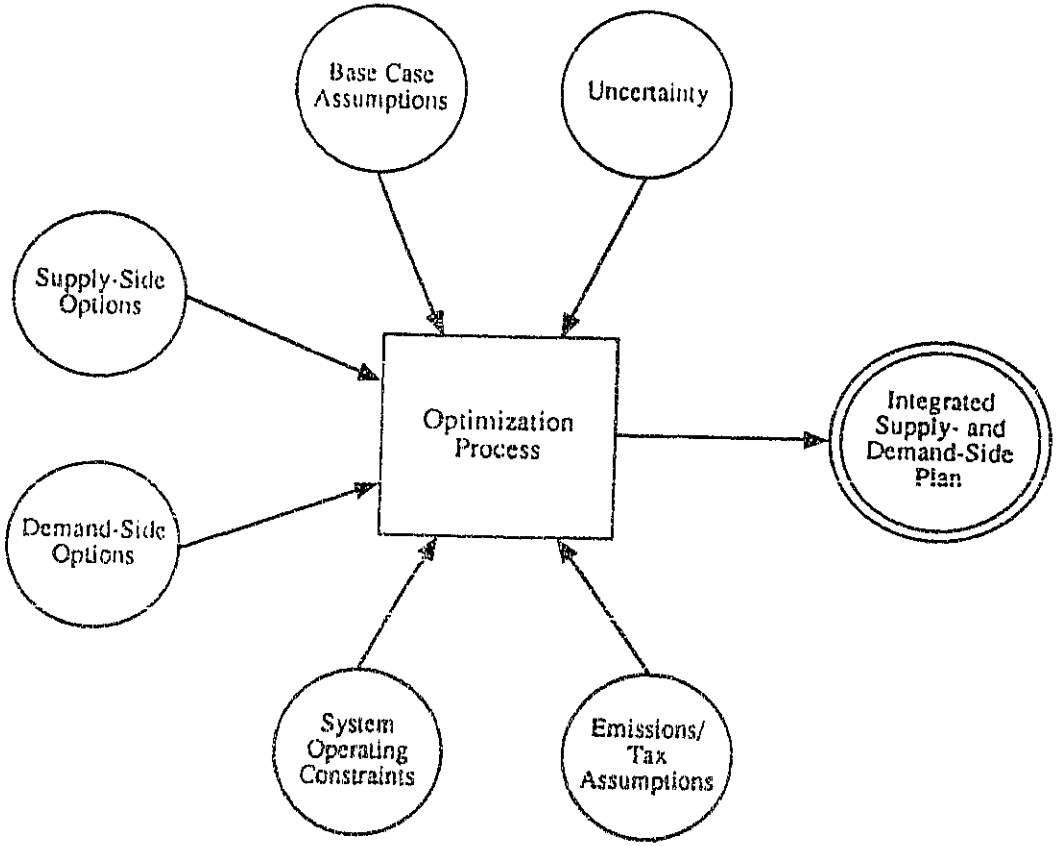
The fundamental concept of IRP is minimizing the total cost of energy services to the customer, where energy services are what the customer really wants such as lumens of light provided, pounds of clothes washed, or tons of metal heated. The total cost of these energy services incorporates all of the cost components included in calculating traditional revenue requirements. But it also includes expenditures on the customer side of the meter -- capital investment and labor that the customer combines with energy to produce the desired energy services. The utility's objective is not merely to select a mix of generation projects to minimize the cost of serving a given level of electricity demand at the meter, as it was in traditional generation planning. Rather, the utility's objective has expanded to look behind the meter and identify changes in end-use equipment and processes, which, together with a set of generation projects, will minimize this total cost. The next step is for the utility to identify the most efficient means to implement the end-use changes, whether through financial incentives, information programs, or standards.

Figure 1-1 shows an idealized IRP process. The integrated supply- and demand-side plan developed by the process specifies a combination of DSM options and generation projects, and the timing of these options. The optimization process simultaneously selects the optimal combination and timing of the supply- and demand-side options to satisfy the demand forecast and minimize total costs, taking into account the system operating constraints, assumptions regarding emissions regulations and taxes, and uncertainty.

The optimization process in Figure 1-1 is difficult, however. The ability of existing computer models to perform the optimization over a full set of demand- and supply-side options, taking full account of the system operating constraints and the regulatory environment, and recognizing uncertainty, is limited. A more practical approach is shown in Figure 1-2. The demand-side plan is constructed by assembling a set of DSM technologies and programs that is cost-effective given an initial set of avoided costs. Next, a supply-side plan is constructed to minimize the costs of meeting the net demand. Then, a new set of avoided costs is calculated for the supply-side plan. If the new avoided costs are substantially different from the set on which the demand-side plan is based, then the process reiterates, using the new set of avoided costs as the basis for a new demand-side plan. If the two sets of avoided costs are substantially the same, then the process has converged.

The demand-side and supply-side plans are constructed sequentially, rather than simultaneously, as in Figure 1-1. But the process passes through the sequence of constructing the demand-side and supply-side plans iteratively, using the avoided costs to coordinate the separate plans. The resulting combination of the demand-side and supply-side plans is equivalent to what would be obtained by a simultaneous process, if convergence is achieved.

Figure 1-1
Idealized IRP Methodology



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Figure 1-1
Idealized IRP Methodology

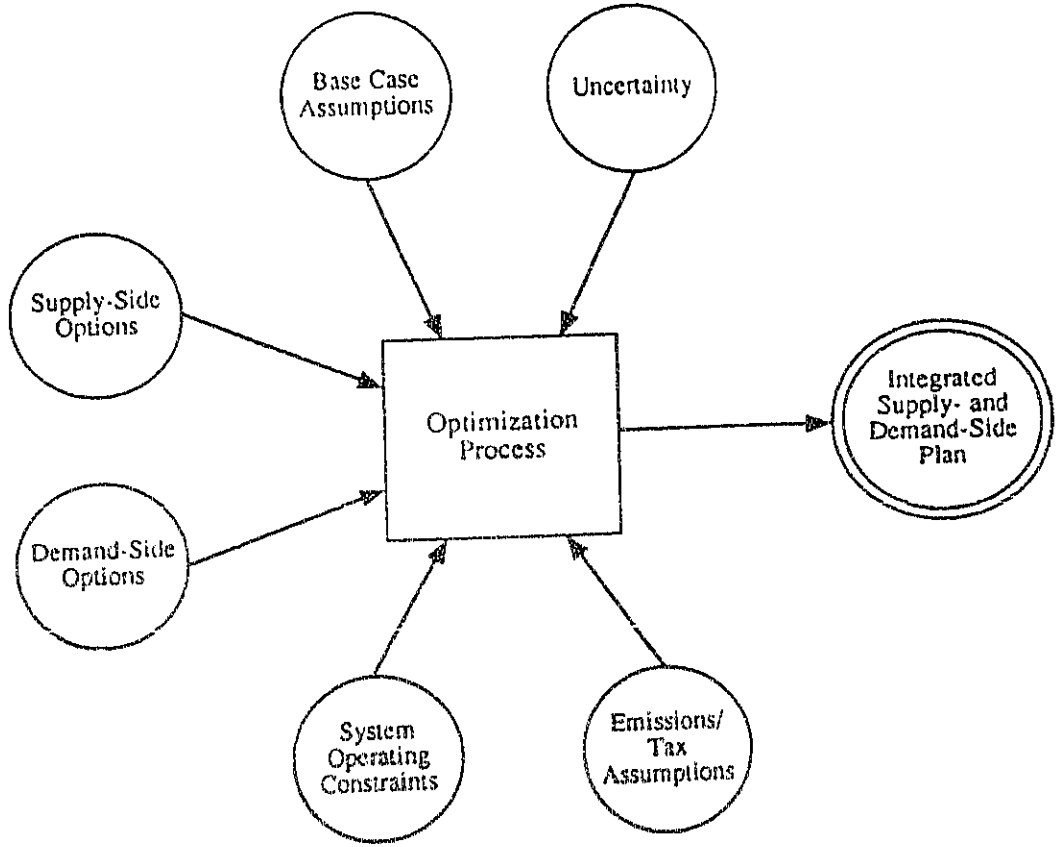
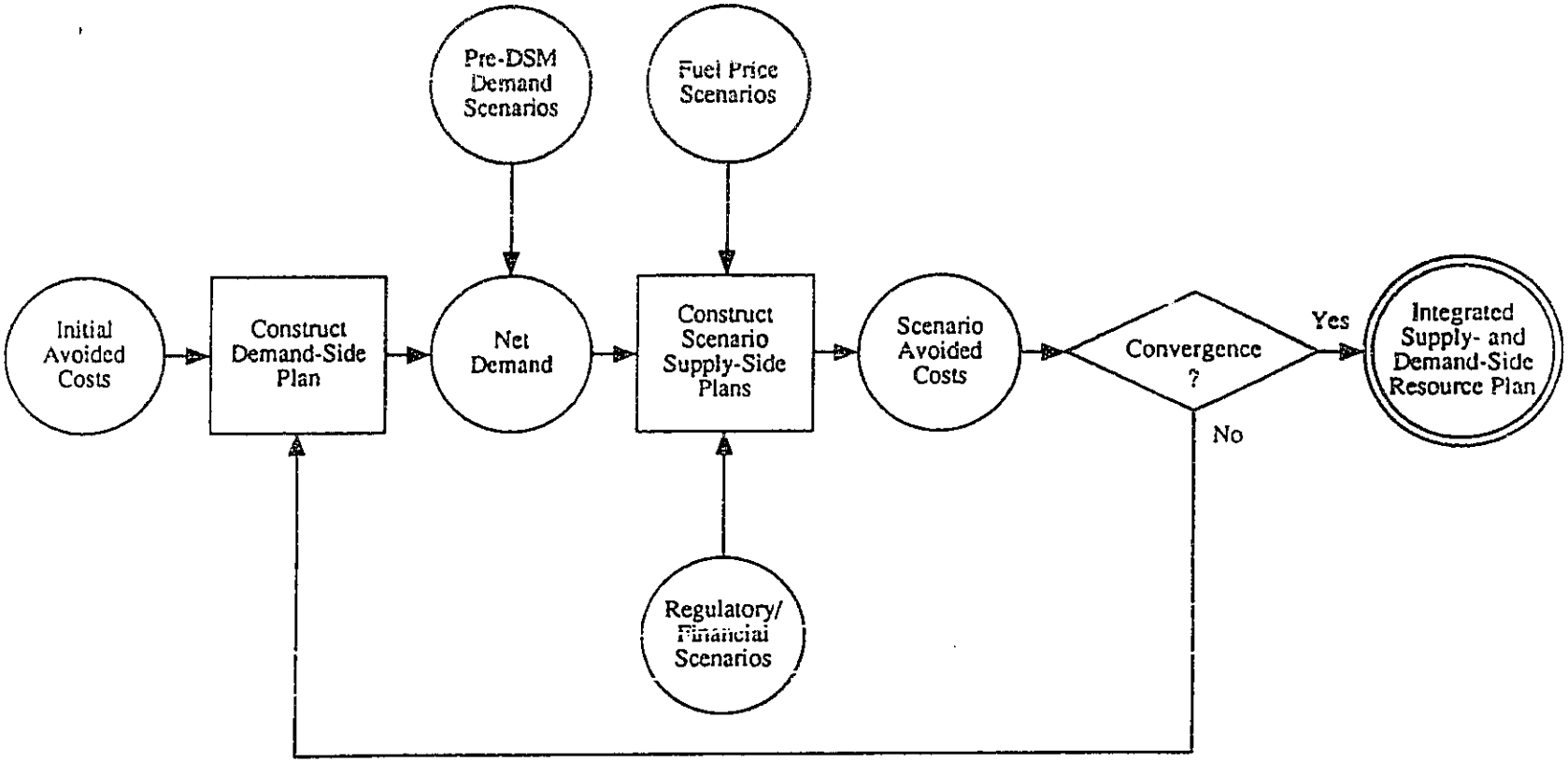


Figure 1-2
Practical IRP Methodology



This study's purpose was to evaluate whether the proposed Neil Simpson #2 should be part of an integrated supply- and demand-side resource plan without conducting a comprehensive IRP process. The approach followed is shown in Figure 1-3. This approach is equivalent to fixing the levels of DSM and renewable resources in the plan at high levels, then going through the iterative loop twice to find the conventional supply-side plan that minimizes the cost of meeting the remaining need for resources. This approach is described in greater detail in the following section.

1.3 APPROACH

This study examined the role of Neil Simpson #2 in Black Hills' resource plan under a variety of scenarios. First, the net savings to the customers from the project are compared to the next lowest cost options. The options examined included combustion turbines, combined cycle units, and purchased power based on the screening analysis conducted by Black & Veatch on behalf of Black Hills.[2] Extensive sensitivity analysis was then conducted to examine the impacts of changes in key parameters on the net savings which might be experienced by the customers of Black Hills.

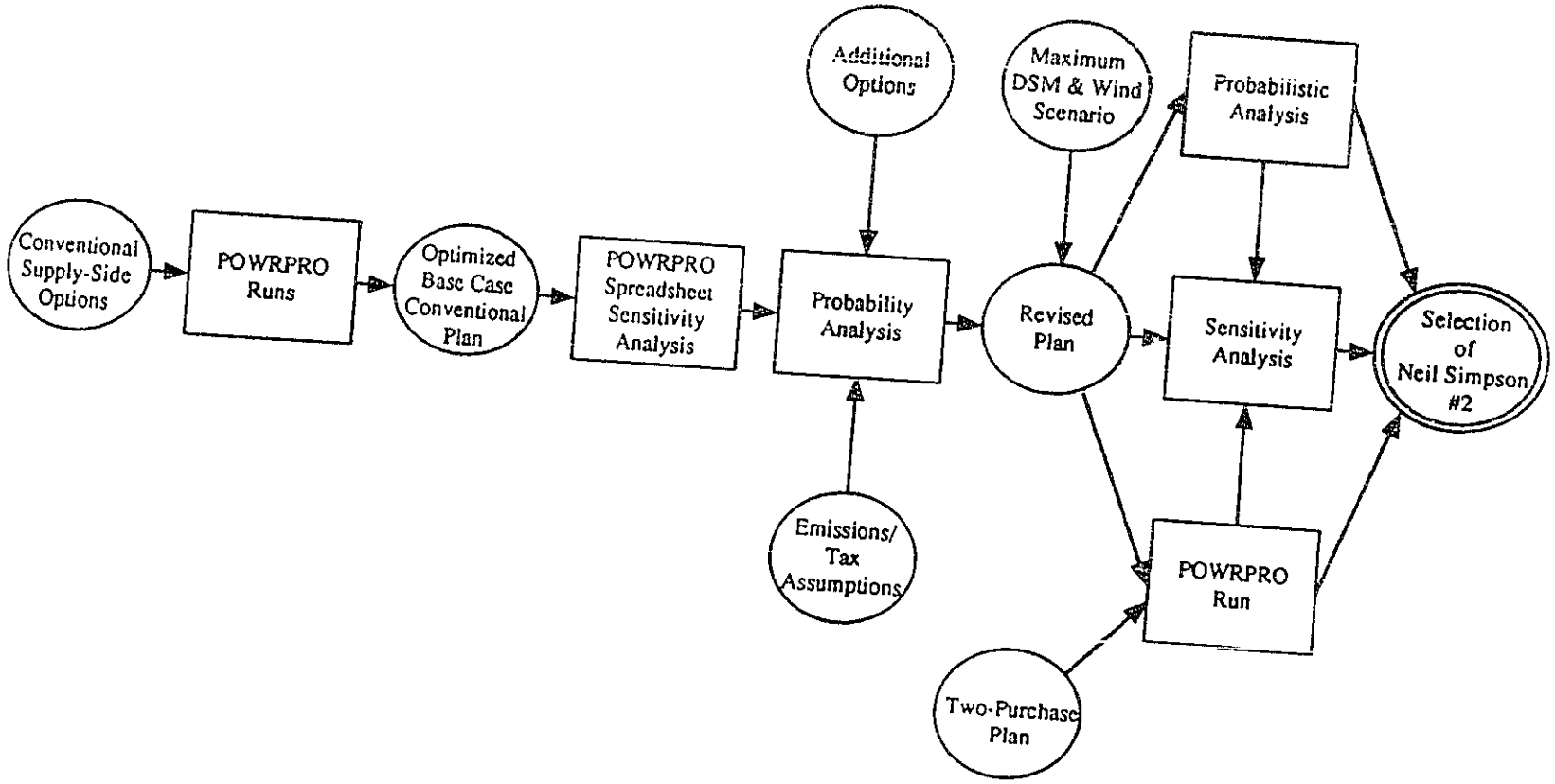
The following work, shown in Figure 1-3, was performed:

(1) A base case resource plan was constructed which incorporated the installation of Neil Simpson #2, followed by installation of combustion turbines and other capacity. This resource plan reflects a reasonable mix and appropriate timing of alternative capacity additions, given the load forecast and resulting need for capacity. Additional screening analysis was conducted and is documented herein.

(2) The net economic benefits provided in the base case resource plan by Neil Simpson #2 were evaluated. Black & Veatch's POWRPRO model was used to evaluate the production cost savings from Neil Simpson #2 relative to other resource alternatives. The production cost savings were calculated as the difference between two POWRPRO runs, one including Neil Simpson #2 in the resource plan and the other substituting alternative resource options for Neil Simpson #2. The net economic benefits were calculated in a spreadsheet that took the production cost savings from the POWRPRO runs and calculated the net change in fuel costs, capital-related costs, operation and maintenance (O&M) costs, and emission costs.

[2] Testimony of Ludwig F. Funke to the Wyoming Public Service Commission in Docket No. 20002-EA-92-7

Figure 1-3
Methodology For IRP Analysis of NS #2



(3) An extensive sensitivity analysis of the production cost savings was conducted using POWRPRO. The production cost savings attributable to Neil Simpson #2 were calculated for a number of scenarios representing a wide range of uncertainty and various combinations of deviations from the base case.

(4) The results of the POWRPRO analysis were validated by conducting a similar analysis on the in-house model used at Black Hills -- the ENPRO model.

(5) A probabilistic analysis of the economic benefits was conducted using the results of the sensitivity analysis. Probability distributions of the net economic benefits of the project were constructed to determine the likelihood of various outcomes.

(6) A modified base case resource plan was constructed that includes large blocks of wind generation and additional DSM.

(7) Further POWRPRO analysis, sensitivity analysis, and probabilistic analysis around the modified base case were conducted.

(8) Probabilistic sensitivity analysis to determine the sensitivity of the probabilistic results to the input probability assumptions was conducted.

Two components that would be necessary parts of a comprehensive IRP process were not completed for this study. These two components are:

(a) Comprehensive assessment of DSM savings potential in Black Hills' service territory, and

(b) Construction of an integrated supply- and demand-side resource plan.

The DSM potential assessment, component (a), is underway but has not been completed. Construction of an integrated plan, component (b), cannot be started until the DSM potential assessment has been completed.

Although this study is not a comprehensive IRP process, the analysis that has been performed demonstrates unequivocally that Neil Simpson #2 would be an essential part of the integrated supply- and demand-side plan that would be obtained as the result of a comprehensive IRP process. It does so by showing that Neil Simpson #2 would be cost-effective even if prior commitment was made to aggressive levels of DSM and renewables.

1.4 ORGANIZATION OF THIS REPORT

Section 2 describes the methodology, assumptions, and results of the eight parts of the analysis, including: construction of the base case resource plan, base case POWRPRO runs, base case economic analysis, POWRPRO sensitivity analysis, ENPRO comparisons, modified base case plan development, probabilistic analysis, and probabilistic sensitivity analysis. The conclusions are summarized in Section 3. The public involvement process for the project is discussed in Appendix A4.

2.0 ECONOMIC ANALYSIS

This section presents the methodology, assumptions, and results of the economic analysis of Neil Simpson #2 and alternatives.

2.1 BASE CASE RESOURCE PLAN

2.1.1 Process

The base case resource plan was constructed by analyzing the net present value of total revenue requirements under a variety of scenarios incorporating Neil Simpson #2, combustion turbines, combined cycle units, and purchased power to ascertain the case with the lowest net present value of revenue requirements. The lowest cost plan was with Neil Simpson #2 coming on-line in 1996; two additional 80-MW coal units - one in 2007, the other in 2012; and six, 40-MW combustion turbines coming on-line in various years. This plan is denoted as Case 106.

A diagram showing the cases analyzed and the relationships between the cases is in Figure 2-1. Table 2-1 shows the cases analyzed for developing the base case and the total operating and incremental investment costs associated with them. The levelized costs for each case are shown.

2.1.2 Assumptions

The key assumptions underlying the base case resource plan are listed in Table 2-2. These assumptions are consistent with Exhibit LFF-5 from the testimony of Ludwig F. Funke, Wyoming Public Service Commission Docket No. 20002-EA-92-27.

2.1.3 DSM Forecast

Hagler, Bailly reviewed Black Hills' DSM analysis as filed in Docket No. 20002-EA-92-27 and recommended that a detailed DSM potential study be undertaken. A draft report providing the results of that effort being conducted for Black Hills by Hagler, Bailly is targeted for completion in March 1993. The sensitivity analysis, which is described in detail later in this report, incorporates changes to the Black Hills' peak demand and energy forecast which represent the effects of various levels of DSM programs that might be implemented on Black Hills' system. It reflects an aggressive level of DSM programs, a presumed upper bound on the level of capacity and energy reductions that could be achieved by Black hills.

Figure 2-1
POWRPRO Cases

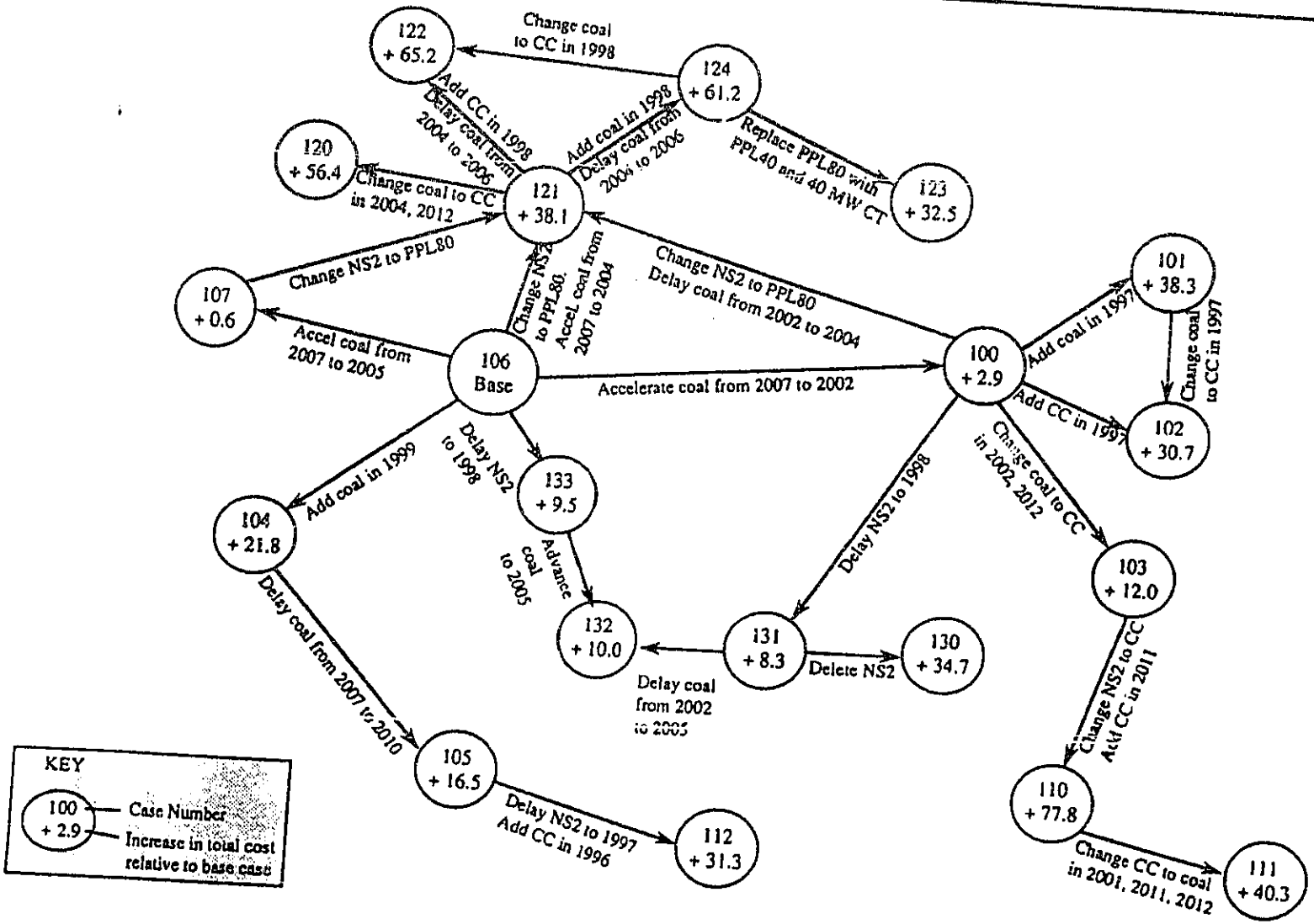


Table 2-1
Description of Cases
(Millions of $)

Case Number	NS#3	CT	CC	Coal	PP	Wind	DSM	Gas Pipe	Trans Cost	REC	QF	Total Cost M$	Comparison to Base M$	Levelized cents/kWh[1]
106	1996	1997, 1998, 2001, 2005, 2011, 2013		2007, 2012								504.4	BASE	3.83
107	1996	1997, 1998, 2001, 2010, 2011, 2013		2005, 2012								505.0	0.6	3.84
100	1996	1997, 1998, 2007, 2010, 2011, 2013		2002, 2012								507.3	2.9	3.86
133	1998	2-1996, 1997, 2001, 2005, 2011, 2013		2007, 2012								513.9	9.5	3.90
132	1998	2-1996, 2001, 2010, 2011, 2013		2005, 2012								514.4	10.0	3.91
103	1996	1997, 1998, 2007, 2010, 2011, 2013	2002, 2012					Yes				516.4	12.0	3.91
131	1998	2-1996, 2007, 2010, 2013		2002, 2012								516.7	12.3	3.93
Basin		1997, 1998, 2001, 2005, 2013		2007, 2012	80 MW 1996 Basin				Yes			521.6	17.2	3.95
105	1996	1997, 2005, 2007, 2-2013		1999, 2010, 2012								520.9	16.5	3.96
104	1996	1997, 2005, 2011, 2013		1999, 2007, 2012								526.2	21.8	4.00
102	1996	2007, 2010, 2011, 2013	1997	2002, 2012				Yes				535.1	30.7	4.06
112	1997	2000, 2003, 2007, 2008, 2015	1996	2011, 2012				Yes				535.7	31.3	4.08
123		1996, 2002, 2-2011, 2013		1998, 2006, 2012	40 MW 1996 PPL				Yes			536.9	32.5	4.08
130		2-1996, 1998, 1999, 2007, 2009, 2011, 2015		2002, 2012								539.1	34.7	4.09
121		1998, 2000, 2008, 2-2011, 2013		2004, 2012	80 MW 1996 PPL				Yes			542.5	38.1	4.12
101	1996	2007, 2010, 2011, 2013		1997, 2002, 2012								542.7	38.3	4.14

Table 2-1 (cont.)
Description of Cases
(Millions of $)

Case Number	NS#2	CT	CC	Coal	PP	Wind	DSM	Gas Pipe	Trans Cost	REC	QF	Total Cost M$	Comparison to Base M$	Levelized cents/kWh[1]
111		1997, 1998, 2007, 2008, 2015	1996	2001, 2011, 2012				Yes				544.7	40.3	4.14
121A		1998, 2000, 2010, 2011, 2013, 2015		2012	2-60 MW 1996, 2004				Yes			547.1	42.7	4.15
120		1998, 2000, 2008, 2-2011, 2013	2004, 2012		80 MW 1996 PPL			Yes	Yes			560.8	56.4	4.24
124		2002, 2-2011, 2014		1998, 2006, 2012	80 MW 1996 PPL				Yes			565.6	61.2	4.31
122		2002, 2-2011, 2014	1998	2006, 2012	80 MW 1996 PPL			Yes	Yes			569.6	65.2	4.36
110		1997, 1998, 2006, 2008, 2013, 2014	1996, 2001, 2011, 2012					Yes				582.2	77.8	4.40

Costs are expressed as present values discounted to 1993 dollars and are over the 20-year period 1996-2015.

Key: NS#2 - Neil Simpson #2, CT - Combustion Turbine, CC - Combined Cycle, Coal - Coal-fired unit, REC - Renewable Energy Production Credit, QF - Qualifying Facility, PP - Power Purchase, DSM - Demand-Side Management, Gas Pipe - Gas Pipeline, Trans Cost - Transmission Line Cost, Basin - Basin Electric, PPL - PacifiCorp.

(1) Costs derived by dividing annual revenue requirements by annual generation, taking the present value of the results and levelizing them.

Table 2-2
Key Assumptions of the Base Case Resource Plan

Input	Assumption
Demand Forecast	Black Hills Power and Light Company Load Forecast, April 1992, prepared by Black & Veatch.
Fuel Price Forecast	The coal price forecast was developed by Black Hills. Prices for the various power plants are provided in Ludwig Funke's testimony. The gas and oil price forecasts were developed by Black Hills in conjunction with Black & Veatch.
Reliability Constraints	Criterion 1 of the Western Systems Coordinating Council as applied to Black Hills translates into the largest risk plus 5% of the load responsibility.
Maintenance Schedule	Annual Maintenance Schedule dated June 26, 1992, titled 1994-2002 BHPL Generic Plant as provided by Black Hills.
Utility Generation Options	Black & Veatch and Black Hills in-house information.
Fixed Charge Rates	Calculated by Black & Veatch.
Other Financial Parameters	Testimony of Roxann Basham.
Discount Rate	Weighted cost of capital, 10.68%.

2.1.4 Additional Screening Analysis

To complement Black & Veatch's screening analysis which is documented in Exhibit LFF-5, and to be responsive to the Wyoming Public Service Commission, additional screening analysis was undertaken for technologies including:

- Wind
- Photovoltaics
- Power purchase/ownership purchase of Arizona power plant
- Coal gasification
- Power purchase/ownership purchase of Oregon power plant.

Each of these alternatives is discussed briefly below. The costs and other assumptions used for each are presented in Table 2-3. The screening curves, which result from application of the assumptions, are presented in Figure 2-2.

Table 2-3
Assumptions for Screening of Additional Technologies

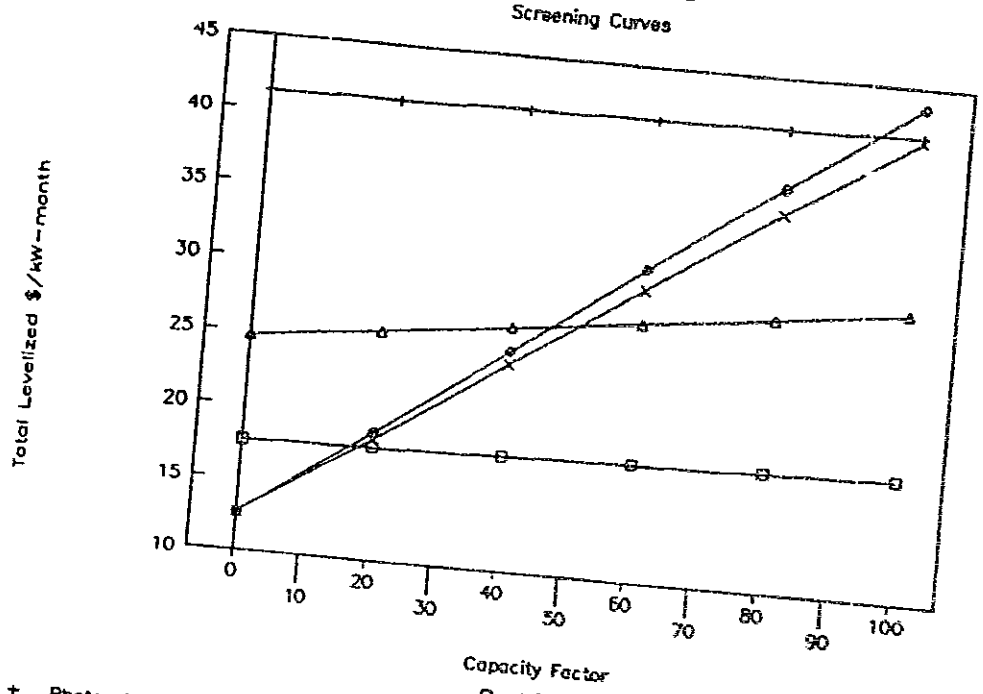
	Wind	Photo-voltaics	Arizona Power Plant	Coal Gasification	Oregon Power Plant
Net Capacity (MW)	20	10	80	80	50
Operating Life (years)	25	25	25	30	25
Capital Cost (1995$)	1115	3190	1000	1757	1000
Fixed O&M Cost (1996 $/Kw-yr)	9.00	8.24	-	43.14	-
Variable O&M Cost ($/MWh)	0.79 (2)	0.41	22.00 (1)	4.73	20.00
Fuel Cost (1996 $/MMBtu)	-	-	-	0.60	-
Equivalent Availability (%)	94.7	91.00	-	85.40	-
Forced Outage Rate (%)	5.00	5.40	-	10.6	-
Planned Outage (weeks/year)	-	2	-	2	-
Cost of Wheeling ($/MWh)	(3)	-	5	-	5
Losses, %	7	-	15	-	15
Construction Period, months	24	48	-	72	-

(1) Includes fuel and O&M costs.
(2) Excluding renewable energy production credit.
(3) Priced at $1.84/kw-month for payment to WAPA.

Wind

Wind resources have been identified in Wyoming, South Dakota, and Montana, as documented in the testimony of Dr. Donald Hardy. Several of the cases examined for this analysis assumed that wind would be installed, whether cost effective or not, to determine the impact on the economics and net benefits resulting from the installation of Neil Simpson #2. Before it can be determined if wind would be a beneficial resource for Black Hills' customers, serious issues need to be investigated, including: the availability of the resource by location, the requirements for transmission, net dependable capacity available from a wind resource, and the applicability and implementation of the renewable energy production credit.

Figure 2-2


Screening Curves
Total Levelized $/kW-month
45
40
35
30
25
20
15
10
0
10
20
30
40
50
60
70
80
90
100
Capacity Factor
+ Photovoltaics
◇ Arizona Power Plant
□ Wind
△ Coal Gasification
× Oregon Power Plant

Dr. Hardy's testimony addresses in detail the analysis to date of wind resources in the specific areas of Medicine Bow and Wheatland, Wyoming; Mission, South Dakota, and Livingston, Montana. Adequate data are not available in Black Hills' service territory to determine if a wind resource is viable. At least a year's worth of data at a suitable elevation would need to be obtained before such a determination could proceed.

The ability of the transmission system to deliver wind energy from wind resource locations, such as in the Medicine Bow area, needs to be more fully investigated and the costs of additional transmission quantified. We have endeavored to estimate a fair, yet conservative, value for the cost of additional transmission in our analysis. The wind resource, in this example, is assumed to only require utilization of the Western Area Power Administration's transmission lines at a cost of $1.84/kW-month. Power would be delivered to Stegall. Further investigation is required by Western to determine if transmission capacity is available on Western lines that would be needed to get the power to Stegall. Additional transmission might be required within Black Hills' service territory as well.

A renewable resource such as wind or the solar technologies cannot be counted on as dependable capacity to the same extent as a coal, natural gas or oil-fired facility due to one simple reason: the "fuel," i.e., sunlight or wind, cannot be guaranteed to be available. For our analysis, we have assumed that the dependable capacity of the wind resource varies in the range of 15% to 30%. That is, a 20-MW wind facility can be counted as reserve for either 3 MW (at 15%) or 6 MW (at 30%). It cannot be predicted with certainty that the wind resource will be available and generating at the time of system peak to its maximum capability. Pacific Gas and Electric, based on its experience to date, uses the 15% figure. PacifiCorp prefers 30%.

The renewable energy production credit appears to make wind projects more attractive. Significant additional investigation will be required on this topic, however. The current law contains some important limits that need to be incorporated in any economic analysis. The renewable energy production credit will only apply for ten years to wind or closed-loop biomass systems for facilities placed in service after December 31, 1993 and before July 1, 1999. The amount of the credit is to be 1.5 cents per kilowatt hour but is subject to phaseout based on the level of the price paid for the energy, the amount of grants provided by the federal or state government for construction of the project; the usage of tax-exempt financing; and any subsidies provided by a federal, state, or local program.

Photovoltaics

Energy from sunlight can be converted to electricity by using a chemically treated semiconductor material. The amount and availability of photovoltaic energy directly depends on the amount of sunshine hitting the surface of the equipment. This

technology is not expected to be commercially available on a utility scale until after the year 2000. Some small, remote locations, far from a utility's transmission grid, use solar photovoltaics to generate electricity today.

Power Purchase - Arizona Power Plant

The current overcapacity situation in the Arizona regional power market and resulting economic hard times for utilities in the area have led to the availability of power from Arizona and New Mexico. Hagler, Bailly contacted utilities in the area to determine the availability of power, the cost associated with that power, and the length of a contract that could be secured. The costs shown in Table 2-3 and underlying the screening curves in Figure 2-2 were derived from these conversations. Estimates of the necessary costs for wheeling and losses have been added to account for costs which would actually be incurred to move power into Black Hills' service territory.

Coal Gasification

A coal gasification facility incorporates a process at the front end to convert coal to gas. The back end of the facility is usually comparable to a combined cycle facility. Thus, the capital costs are higher than those for conventional combined cycle plants, the fixed and variable operating and maintenance costs are higher, but fuel costs are lower. These values are reflected in Table 2-3 and were derived from the Technical Assessment Guide.[3]

Power Purchase - Oregon Power Plant

A portion of the Boardman coal-fired power plant was recently sold to a California utility by its owner at a reported cost of about 4.5 cents/kWh. This information has been extrapolated to the numbers presented in Table 2-3 for screening purposes. Estimates of the necessary costs for wheeling and losses have been added to account for costs which would actually be incurred to move power into Black Hills' service territory.

Findings

The screening curves show that purchases of power from Arizona or Oregon as well as photovoltaics are clearly noncompetitive. A coal gasification facility needs to operate between an 80 and 100% capacity factor to be competitive. Coal gasification still would be more costly than Neil Simpson #2, although it would burn the same fuel; therefore it is screened out of the analysis. Of these additional technologies, only wind was

[3] TAG Technical Assessment Guide, Electric Power Research Institute, Electric Supply -1989, EPRI P-6587-L, Volume 1: Revision 6, Special Report, September 1989.

potentially competitive. Therefore, additional analysis incorporated wind as an alternative against which the net benefits of Neil Simpson #2 were evaluated.

2.1.5 Base Case Plan

The resulting base case plan incorporates the installation of Neil Simpson #2 in 1996 followed by combustion turbines (CT) installed in 1997, 1998, 2001, and 2005. A new coal unit is installed in 2007 followed by a CT in 2011, coal in 2012, and a CT in 2013. This plan is shown graphically in Figure 2-3.

2.2 BASE CASE POWRPRO RUNS

POWRPRO runs were performed to obtain the production costs for the following cases:

(a) Base Case Resource Plan including Neil Simpson #2.

(b) Base Case Resource Plan with Neil Simpson #2 deleted and replaced by a power purchase from PacifiCorp. Necessary transmission costs were incorporated in the analysis.

(c) Base Case Resource Plan with Neil Simpson #2 deleted and replaced by combustion turbine capacity.

(d) Base Case Resource Plan with Neil Simpson #2 deleted and replaced by combined cycle capacity. The costs associated with a gas pipeline required to provide fuel for the combined cycle unit were modeled.

The comparison of the net present value of revenue requirements for the 20-year period analyzed in the POWRPRO runs is shown on Table 2-4. The base case with Neil Simpson #2 installed in 1996 produces $52.3 million in customer savings compared to the power purchased from PPL.

2.3 BASE CASE ECONOMIC ANALYSIS

Table 2-5 shows the characteristics and cost assumptions for Neil Simpson #2 and other capacity alternatives. Additional details can be found in Exhibit LFF-5 from the testimony of Ludwig F. Funke, Wyoming Public Service Commission Docket No. 20002-EA-92-27. Project assumptions for wind, photovoltaics and a power purchase from Basin Electric can be found on page 5 of Appendix A1.

Figure 2 – 3

Base Case Capacity Expansion Plan

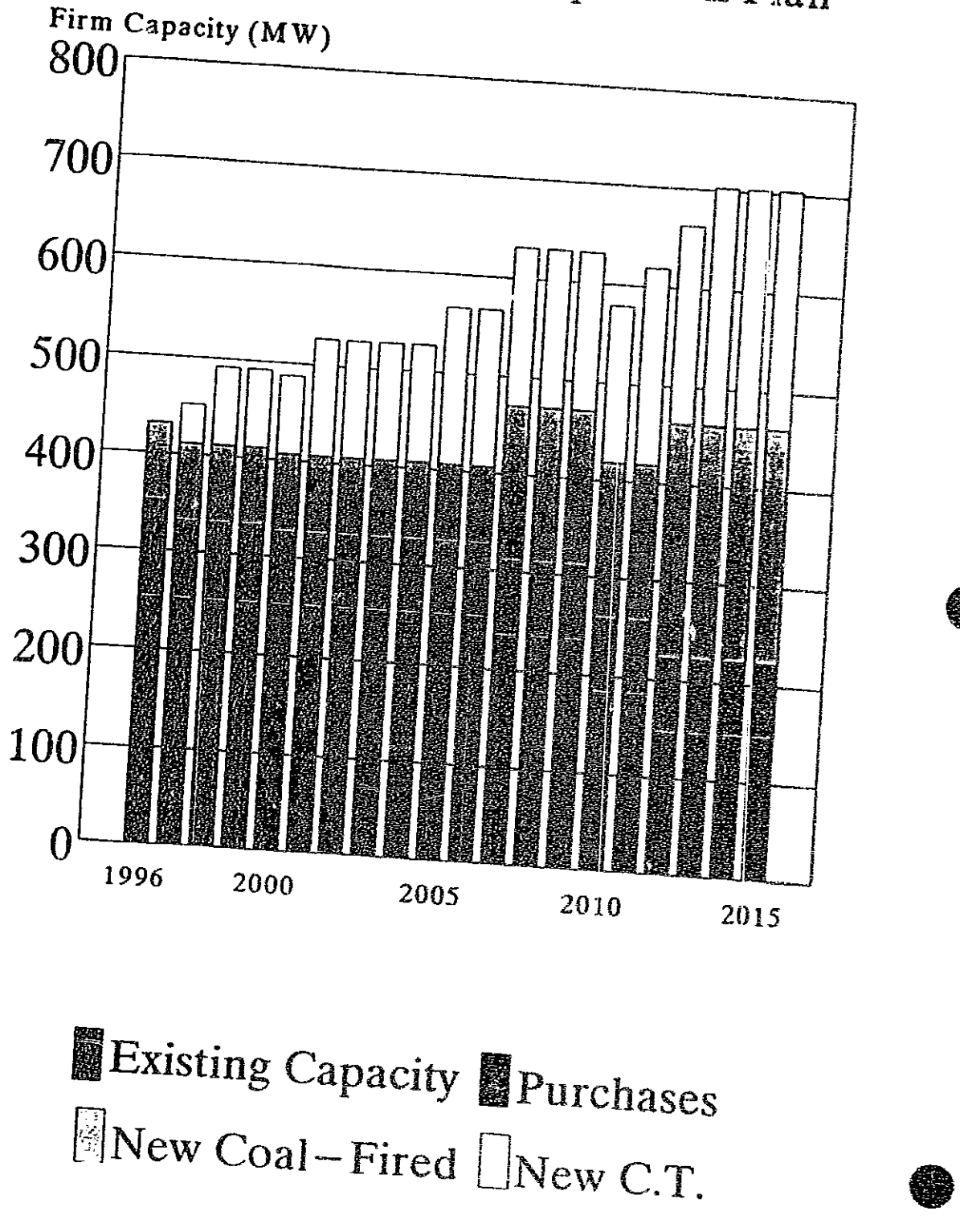


Table 2-4
Base Case Economic Analysis
(Millions of $)

	Neil Simpson #2	PPL Purchase	Combustion Turbine	Combined Cycle
20-Year Cost	504.4	556.7	596.5	560.5
Difference From Lowest Cost Plan	0	52.3	92.1	56.1

20-year cost is the present value of revenue requirements over the period 1996-2015 resulting from the POWRPRO analysis discounted to 1993.

Table 2-5
Project Assumptions

	Neil Simpson #2	Combustion Turbine	Combined Cycle	Purchased Power
Capacity (MW)	80	2×40	80	80
Installed Cost ($/kW)	1561	532	1023	220[1]
Fixed Operating Cost ($/kW-yr)	26.46	11.56	14.14	213.24[2]
Variable Operating Cost ($/MWh)	3.04	4.50	6.07	16.84[3]
On-line Date	1996	1996	1996	1996
Life (years)	50	25	35	30

Costs are in 1996 dollars.

[1] Cost of additional transmission facilities required.
[2] Purchased capacity demand charge starts at 17.77 $/kW-mo (213.24 $/kW-yr) in 1996 and escalates at an average annual rate of 0.5%.
[3] Purchased energy charge starts at 16.84 $/MWh in 1996 and escalates at an average annual rate of 5.1%.

The first column of Table 2-6 shows the net benefits to Black Hills' customers of Neil Simpson #2 relative to replacing it with the option of purchased power from PacifiCorp,[4] given the base case resource plan (Case 106). A listing of the spreadsheet model used to perform both the base case economic analysis and the probabilistic analysis in Section 2.5 is in Appendix A1. Detailed results for the project are in Appendix A2.

Table 2-6
Net Cost of Alternative Resources
Relative to Neil Simpson #2
(Millions of $)

	PPL Purchase	Combustion Turbine	Combined Cycle	Wind	Photo-voltaics	Basin Purchase
Life of Alternative (years)	30	25	35	25	25	30
Alternative Resource Capital Cost	19.95	55.96	110.67	117.29	335.05	28.20
Alternative Resource Operating Cost	289.41	119.70	183.17	52.07	13.28	265.31
Neil Simpson #2 Capital Cost	141.55	136.42	144.64	136.42	136.42	141.55
Neil Simpson #2 Operating Cost	68.43	64.67	71.19	64.67	64.67	68.43
Net System Generation Cost	-14.15	154.33	14.29	140.60	-25.38	-20.23
Net Emissions/Tax Cost	5.02	21.41	-2.85	-15.97	-19.24	-2.19
Net Cost	90.25	150.31	89.45	92.89	107.61	61.10

Costs are expressed as present values, over the operating life of the alternative resource discounted to 1996.

Neil Simpson #2 reduces the costs of the alternative resource, which is $309.36 million ($19.95 million capital plus $289.41 million operating), in terms of present value of 1996 dollars over the 30 years of the operating life of this alternative. The present value of capital-related costs, including depreciation, interest payments, and return to shareholders, net of income tax effects, is $141.55 million. O&M costs over the 30 years have a present value of $68.43 million.

[4] The term "net benefits" in this report is defined as customer benefits, or the reduction in utility revenue requirements.

The component labeled Net Emissions/Tax Cost includes all of the following:

- The value of allowances required for the net change in SO_2 emissions from the alternative resource and the rest of the system, less emissions from Neil Simpson #2
- The additional cost imposed by the proposed federal energy tax
- The renewable energy tax credit, if applicable, which is represented as a negative cost.

The net present value of the production cost savings and energy, demand and transmission benefits less the costs of Neil Simpson #2 is $90.25 million, in the base case. That is, total costs to customers would be higher by $90.25 million if Neil Simpson #2 were replaced by the alternative of purchased power from PacifiCorp. Table 2-6 shows the net cost relative to Neil Simpson #2 of several other alternative resources besides the PPL purchase. All of them have a higher net cost than the PPL purchase, except for the purchase from Basin Electric, which is still more costly than Neil Simpson #2. However, whether the power can be delivered to Black Hills from Basin Electric without substantial upgrades to the transmission system at increased cost in addition to the cost of the AC-DC-AC converter is uncertain. In addition, the power which could be procured from Basin is unit power, not system power as from PacifiCorp; it is not as reliable as it is not "firm" power. Therefore, the remainder of the study assumed that the PPL purchase is the next lowest cost alternative to Neil Simpson #2.

The POWRPRO runs extended only through 2015. Production cost savings values for the remaining 30 years were obtained by escalating the 2015 values. Production cost savings result because of the way various resources are used (usually called dispatched) to generate electricity. Daily load curve examples showing the way in which units are dispatched, on the Black Hills' system, are shown in Figure 2-4.

Table 2-7 compares the cost of power from Neil Simpson #2 and other resource options. Neil Simpson #2 is the lowest cost resource on a cents/kWh basis. The numbers on this table can be interpreted and related to the rest of the analysis as follows.

The levelized costs of power from various resource options in Table 2-7 are not comparable to the levelized average system costs in Table 2-1 for two reasons. First, the levelized costs in Table 2-7 represent only the costs of new generation and the costs of operating the existing system. They do not include any capital-related costs for the existing system. The costs in Table 2-7 include all costs associated with the resource options listed. Second, the costs in Table 2-7 for the individual resource options include

Figure 2-4
Economic Dispatch Example

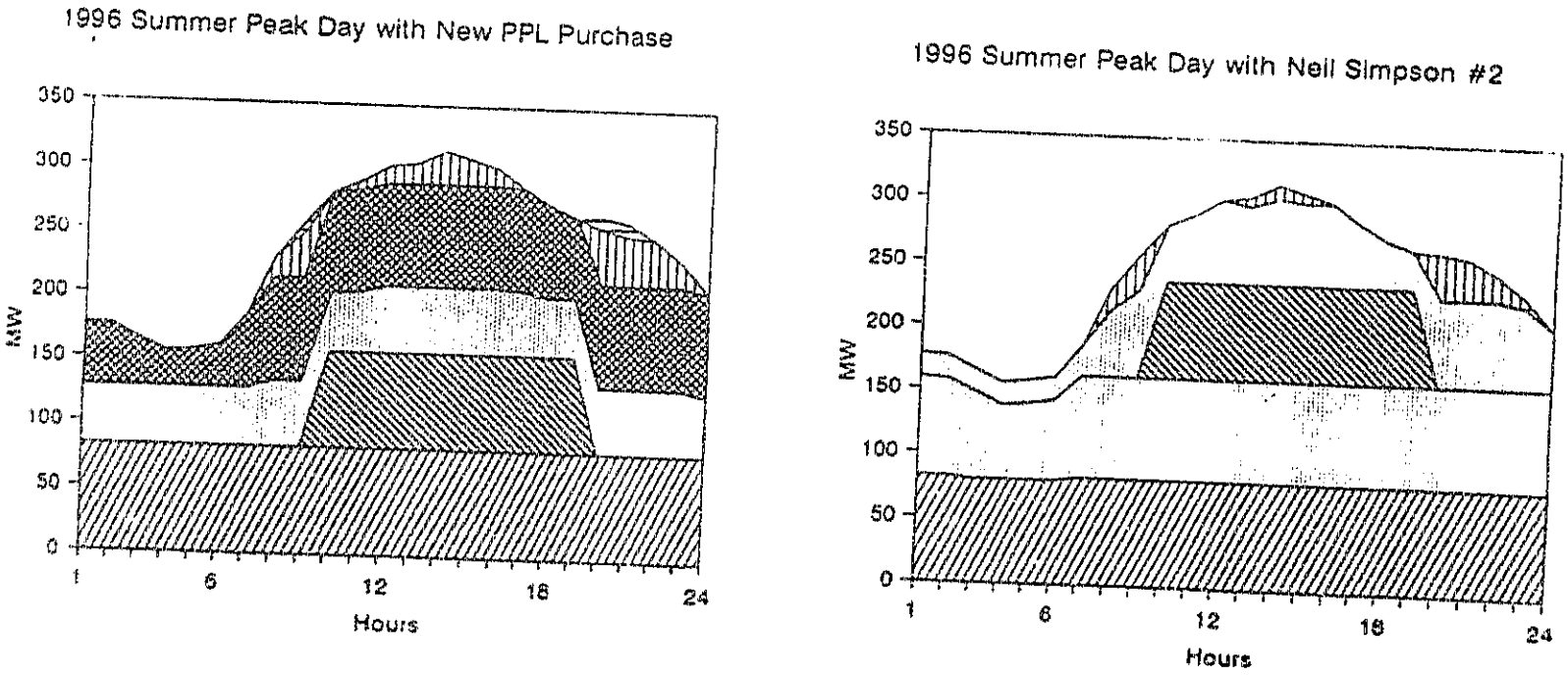
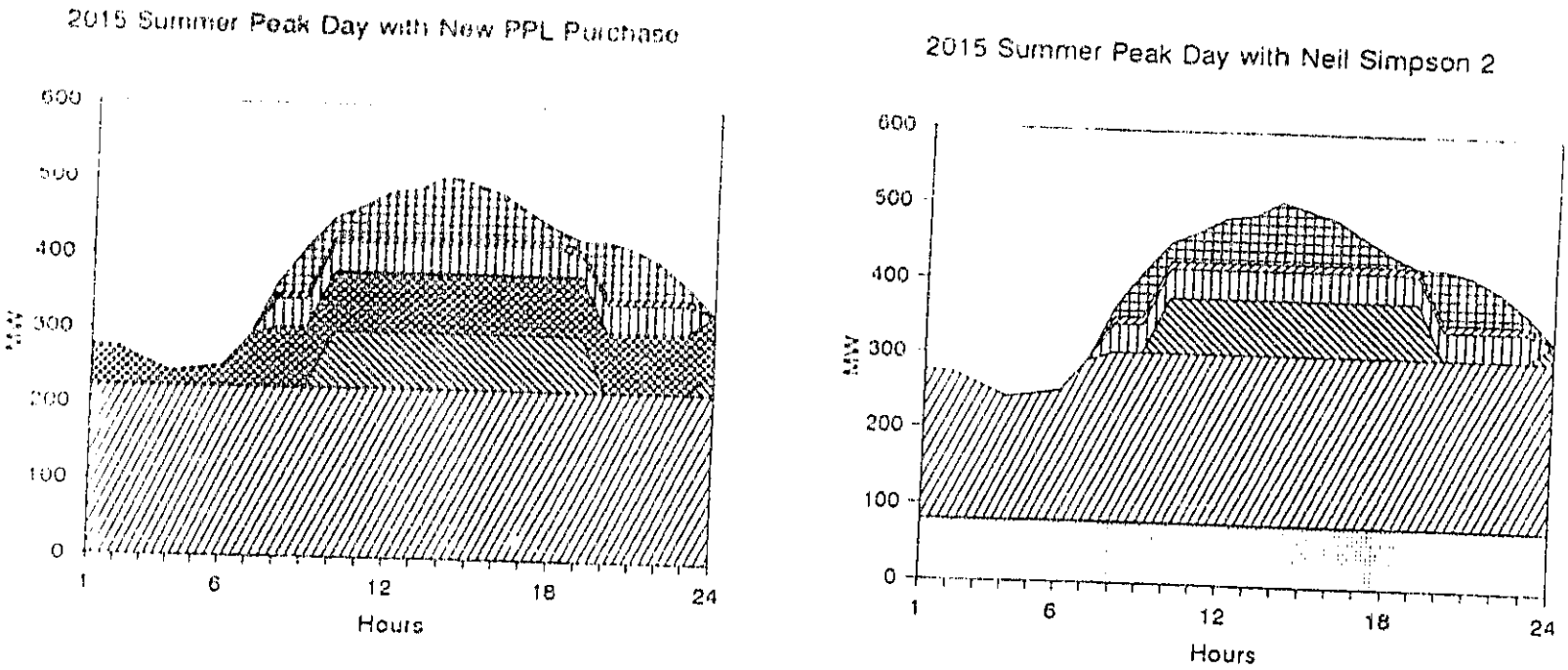


Figure 2-4 (continued)
Economic Dispatch Example



the proposed energy tax and the value of SO_2 allowances required.[5] These costs are not included in Table 2-1.

If the omitted costs were added to the numbers in Table 2-1, the total system costs, representing an average of the total costs of generation from existing and new generation, would still likely be lower than the costs of the new generation options in Table 2-7. This is because the capital-related costs of existing generation are generally much lower than those of new generation. The capital-related costs of existing generation are lower because they include only the remaining undepreciated portion of the original costs, which is quite small for old plants, and because the original costs are much lower on account of both general inflation and the additional environmental controls required on new plants. For utilities throughout the developed world the costs of new generation are often higher than the system average costs of existing generation.

The more relevant comparison for decision making is the relative costs of new generation options, which is a comparison between the options in Table 2-7 rather than a comparison between Tables 2-1 and 2-7.

However, a further caveat must be kept in mind when considering the numbers in Table 2-7, which represent the costs per kWh generated or per kW installed for each individual option. More specifically, the right column is the same total cost divided by the installed capacity of the option. Because of differences between the reliability of different options, a kW of one option is not comparable to a kW of another option. The difference is particularly important in the case of a resource with intermittent generation, like wind. The number in the left column is the total cost of an option divided by the total generation from that option. That number does not include the cost of generation from the rest of the system that would be required to make up for the difference in energy output between resources with high capacity factors, like Neil Simpson #2, and those with lower capacity factors, like wind. In some cases, the cost of generation from the rest of the system would be higher, increasing the average cost above the number in Table 2-7. In other cases, it would be lower. But in no case would the resulting average be lower than the cost of Neil Simpson #2, because the net cost, including the costs of both the alternative resource and the rest of the system, for each of the alternative resources in Table 2-6 base case economic results, is positive relative to Neil Simpson #2.

The conclusion of the base case analysis is that Neil Simpson #2 has very favorable benefits relative to costs when compared to any alternative. Sections 2.4 and 2.6 address the impact of uncertainty and show that uncertainty does not substantially modify this conclusion.

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[5] Costs also account for the federal renewable energy tax credit, if applicable.

Table 2-7
Cost of Power

	Cents/kWh	Dollars/kW-year
Neil Simpson #2	4.66	345.61
PPL Purchase	7.34	473.13
Basin Electric Purchase	6.29	446.01
Combined Cycle	8.08	421.61
Combustion Turbine	13.64	276.89
Wind	8.11	213.72
Photovoltaics	18.22	480.42

Levelized cost of energy and capacity in 1996 dollars. The values are not additive but mutually exclusive. Costs include net SO_2 allowances and impacts of federal renewable energy production credit and the proposed federal energy tax.

2.4 POWRPRO SENSITIVITY ANALYSIS

2.4.1 Scenarios

POWRPRO was run for 19 scenarios to evaluate the sensitivity of the production cost savings from Neil Simpson #2 to various assumptions. Table 2-8 lists the scenarios, and Figure 2-5 depicts them graphically. These scenarios were selected to examine the effects of varying one or two of the assumptions at a time. The effects of changing three or four of the assumptions at a time have been previously adequately approximated by adding together the effects of one- and two-at-a-time changes because the most significant interactions are between pairs of variables. Therefore, no scenarios with three or more assumptions changing at a time were included in Table 2-8.

These scenarios are designed to provide the information required to calibrate a response surface model for production cost savings from Neil Simpson #2. The response surface model is in the form of four equations, as described in Appendix A3. The independent variables of the response surface model are:

- Net demand
- General fuel price level
- Dispatch cost.

These variables are defined in Appendix A3.

The minimum number of pairs of scenarios required to estimate a quadratic with three independent variables is $3 + 3\times(3+1)/2 + 1 = 10$. This is the number of coefficients in the quadratic, plus one. However, some of the second-order effects have been found in previous work to be insignificant. The scenarios in Table 2-8 are sufficient to estimate the coefficients likely to be significant. Because we wanted a careful analysis of conditions in which project benefits are lower than anticipated, we constructed scenarios that incorporated combinations of assumptions that yielded more accurate production cost savings less than the median values. For example, scenarios 202 and 202A have low demand and low oil prices. Each of these changes from the base case reduces production cost savings. By taking these two downward effects together, we obtain better accuracy at the low end of production cost savings than if we had defined scenarios 202 and 202A as low demand and high oil price, or vice versa.

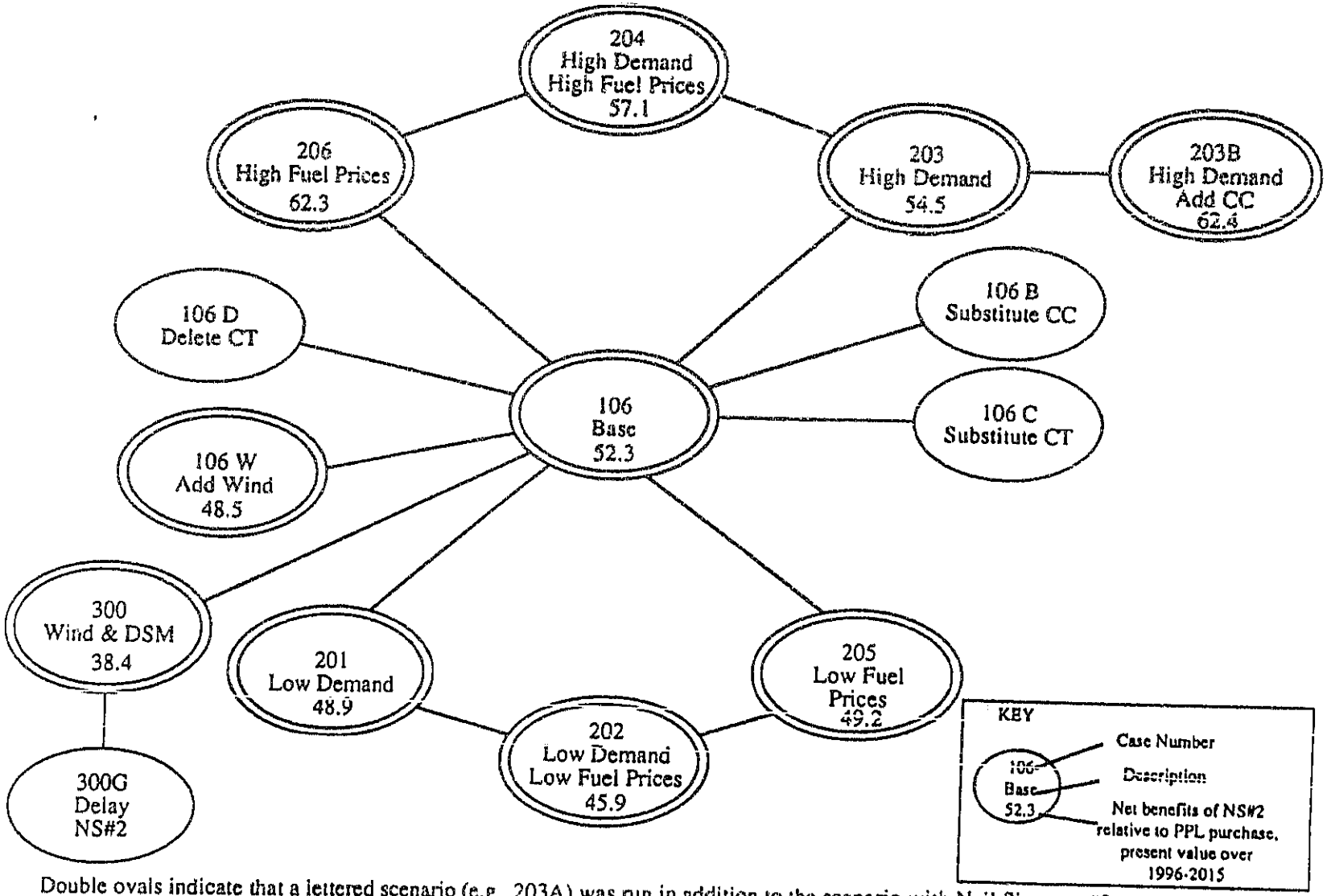
Table 2-8
POWRPRO Scenarios

Scenario	Demand	Fuel Price	Wind	Combination
106, 106A	. . . . . Base Case			
201, 201A	Low			
202, 202A	Low	Low		
203, 203A	High			
204, 204A	High	High		
205, 205A		Low		
206, 206A		High		
106W, 106WA			Installed	
300, 300A, 300G, 300P			Installed	Modeled

Base case assumptions were used for demand and fuel price unless otherwise indicated.

Numbered scenarios without letters have Neil Simpson #2 included in the resource plan; Neil Simpson #1 is out of the scenarios labeled with an A, and replaced by a power purchase from PacifiCorp.

Figure 2-5
POWRPRO Scenarios For Sensitivity Analysis



Double ovals indicate that a lettered scenario (e.g., 203A) was run in addition to the scenario with Neil Simpson #2.

The following paragraphs provide a brief discussion of the component scenarios that were assembled to construct the scenarios in Table 2-8.

Demand

The medium demand scenario was constructed as the net demand after DSM used for the IRP analysis conducted for Black Hills by Black & Veatch.

Uncertainty in the demand forecast is represented in the probabilistic analysis in Section 2.6. Sensitivity analysis to the level of DSM programs implemented has been incorporated in a separate set of scenarios. The high and low demand scenarios for POWRPRO sensitivity analysis were constructed to cover a wide range of possible scenarios of net demand. The construction of the low and high net demand forecasts started with the medium scenario and assumed that demand will be lower or higher in every year by an amount equal to 10% of the 1996 peak demand and energy forecast.

A more precise construction of the resource plan in, say, the high demand scenario would consider the evolution of expectations of future load growth year-by-year in response to the observation of actual load growth higher than previously forecasted, and the way that resource planning decisions are made in response to those expectations. If such conditions were actually to develop, resource commitments would always fall a little short of the level required to satisfy the target reliability constraint because actual demand in future years would always outstrip expectations from previous years. Even though high demand growth would have occurred in prior years, the expectation for future years would be that demand would grow more moderately. Additional resource commitments would be made to catch up with demand growth so far and to satisfy moderate growth in the future, but not to satisfy continued high demand growth.

General Fuel Price Level

The low and high fuel price scenarios were developed to encompass a wide range of fuel prices that might be experienced in the future. A change in the world price of oil was assumed to have impacts to the same or a lesser extent on other fuels, including coal and natural gas.

Wind

A scenario was constructed with 40 MW of additional wind capacity installed. To determine the economic impact on Neil Simpson #2 of adding wind capacity, without regard to any system operation problems that might arise from such a large block of wind generation relative to the size of the utility. Subsequent analyses used smaller blocks of wind capacity that were more appropriate to the size of the utility.

Combination

The impact of additional DSM on the economics of Neil Simpson #2 is captured by the low demand scenario. In a second round of sensitivity analysis, additional scenarios were constructed (the 300 series) to evaluate the net benefits of Neil Simpson #2 in the context of a resource plan that includes generous, but feasible, levels of both DSM and wind simultaneously. In addition, this series of analyses examined the impacts of a delay in the in-service date of Neil Simpson #2.

2.4.2 Scenario Analysis Results

Figure 2-5 and Table 2-9 show the present value of the production cost savings from Neil Simpson #2 for each pair of scenarios. The variations in benefits from Neil Simpson #2 between scenarios are consistent with what one would intuitively expect, increasing with higher demand and higher fuel prices, and decreasing with lower demand and lower fuel prices.

2.4.3 Response Surface Model

A simplified model was constructed to fit the year-by-year production cost savings results for the various scenarios. This "response surface model" summarizes the sensitivity of the benefits from Neil Simpson #2 to the independent variables.

This simplified model is used in the economic analysis spreadsheet to approximate the change relative to the base case of the production cost savings from Neil Simpson #2 in any scenario. Use of a response surface model makes it possible to interpolate between the results obtained from the POWRPRO scenario analysis.

Details of the response surface model are provided in Appendix A3.

2.4.4 Sensitivity Analysis of Neil Simpson #2 Assumptions

Additional analysis was conducted to determine the sensitivity of the economic analysis to particular assumptions about the performance of Neil Simpson #2, including the availability of the facility and its life. Table 2-10 shows the results.

Table 2-9
Description of Sensitivity Cases
(Millions of $)

Case Pair	Description	Alternative to Neil Simpson #2	Customer Savings from Installation of Neil Simpson #2
106-106A	Base case	PPL purchase and transmission costs	52.3
106-106B	Base case	CC and gas pipeline	56.1
106-106C	Base case	CT	92.1
106W-106WA	Wind and renewable energy production credit	PPL purchase and transmission costs	77.3
201-201A	Low demand	PPL purchase and transmission costs	49.0
202-202A	Low demand, low fuel prices	PPL purchase and transmission costs	45.9
203-203A	High demand	PPL purchase and transmission costs	44.6
203-203AB	High demand	PPL purchase and install additional CC, gas pipeline and transmission costs	116.9
204-204A	High demand, high fuel prices	PPL purchase and transmission costs	57.1
205-205A	Low fuel prices	PPL purchase and transmission costs	49.1
206-206A	High fuel prices	PPL purchase and transmission costs	62.1
300-300A	Wind and DSM, renewable energy production credit	PPL purchase and transmission costs	37.1
300-300G	Wind and DSM, renewable energy production credit	Delay NS#2 to 1997	4.0
300-300P	Wind and DSM, renewable energy production credit	NS#2 in 1997, CT + 20 MW photovoltaics in 1996	74.8
300-300W	Wind and DSM, renewable energy production credit	CT + 20 MW wind 1996, coal in 1999, CT-1998, 2006, 2011, 2014, coal-2008, 2012	18.2

* Costs are expressed as present values of production and incremental capital costs over 1996-2015, discounted to 1993.

Table 2-10
Sensitivity Analysis of
Neil Simpson #2 Performance Assumptions

	Net Cost (Millions of $)
Base Case EAF = 89.5% Life = 50 years	90.25
EAF = 85%	69.96
EAF = 80%	47.54
Life = 30 years	81.24

Net cost of the PPL purchase relative to Neil Simpson #2.

EAF = Equivalent Availability Factor

The base case assumptions are that the equivalent availability factor Equivalent Availability Factor (EAF) is 89.5% and that the life of Neil Simpson #2 is 50 years. When the EAF is changed to 85% or 80%, the net cost of the PPL purchase drops from $90.25 million to $69.96 million or $47.54 million, respectively. The net benefits are reduced if the unit is less reliable. The net benefits are sensitive to the availability assumption. Even with a degradation of 10% in EAF over the entire life of the project, Neil Simpson #2 has substantial positive net benefits.

If the life is reduced from 50 years to 30 years, the net cost of the PPL purchase drops from $90.25 million to $81.24 million. Clearly, the last 20 years of the plant's life do not have a large impact on the economics of Neil Simpson #2.

2.4.5 Sensitivity Analysis of Emissions and Tax Cost Assumptions

The Net Emissions/Tax Cost component modeled in the analysis represents the net effect value of net emissions of SO_2 at 500 $/ton; the proposed federal energy tax at 25.7 cents/MBtu on coal and natural gas, 59.9 cents/MBtu on oil, and nothing on wind and photovoltaic generation; and the renewable energy production tax credit.

Table 2-11 shows the effects of changing these assumptions. The proposed federal energy tax is equivalent to a tax on CO_2 emissions of about 1.00 $/ton CO_2. With either the energy tax or a $1.00/ton CO_2 tax, the PPL purchase, combined cycle, and wind options have about the same net cost. The combined cycle and wind options remain fairly competitive with each other throughout the range of tax rates and allowance prices considered in Table 2-11, except for the highest values, at which the combined cycle gets more credit for displacing a greater amount of coal generation.

Neil Simpson #2 remains the lowest cost option except for the highest values, at which both combined cycle and wind are more economic.

2.5 ENPRO RESULTS

Validation of the POWRPRO runs was conducted by Black Hills by running cases 106, 106A; 201, 201A; 203, 203A, and 205, 205A using the ENPRO model and comparing the results with those obtained from POWRPRO. The ENPRO model is a commercially available, hourly, chronological production simulation model that Black Hills uses for internal studies. The differences between the ENPRO cases and the POWRPRO cases were within the range of variation normally observed when comparing the results from different production simulation models. The difference between any pair of cases, using ENPRO, e.g., 203A and 203, was comparable to the differences obtained using POWRPRO. Table 2-12 shows the comparison between the production cost savings calculated using the two models. Attempts to reconcile differences between the two models were limited. The results in Table 2-12 are sufficiently close that no further effort to reconcile the two models was warranted.

2.6 PROBABILISTIC ANALYSIS

2.6.1 Probability Tree

A probabilistic analysis was performed on the economic analysis. The response surface model was used to estimate the production cost savings for each scenario.

Figure 2-6 depicts the structure of the probabilistic analysis. There are four independent variables with three possible values for each, for a total of $3^4 = 81$ end points. All of the variables were assumed to vary independently from one another.

The scenarios for each of the variables used in the probabilistic analysis are not necessarily the same as those used in the sensitivity analysis. The scenarios and probabilities are discussed briefly below.

Table 2-11
Sensitivity to Emissions/Net Cost of Alteration Responses
Relative to Neil Simpson #2/Tax Assumptions
(Millions of $)

Rates $/ton		PPL Purchase	Combustion Turbine	Combined Cycle	Wind
SO_2: $2000 CO_2: $30	Net Tax	2.26	32.10	-120.42	-121.97
	Net Cost	87.48	161.00	-28.13	-13.11
SO_2: $500 CO_2: $30	Net Tax	-25.73	-3.50	-129.71	-138.17
	Net Cost	59.50	125.40	-37.41	-29.31
SO_2: $500 CO_2: $10	Net Tax	-2.36	6.74	-41.17	-57.08
	Net Cost	82.87	135.65	51.12	51.78
SO_2: $500 CO_2: $2	Net Tax	6.99	10.84	-5.76	-24.64
	Net Cost	92.22	139.74	86.53	84.42
SO_2: $500 CO_2: $1	Net Tax	8.16	11.36	-1.33	-20.59
	Net Cost	93.38	140.26	90.96	88.28
SO_2: $500 Energy Tax (Base)	Net Tax	5.02	21.41	-2.85	-15.97
	Net Cost	90.25	150.31	89.45	92.89

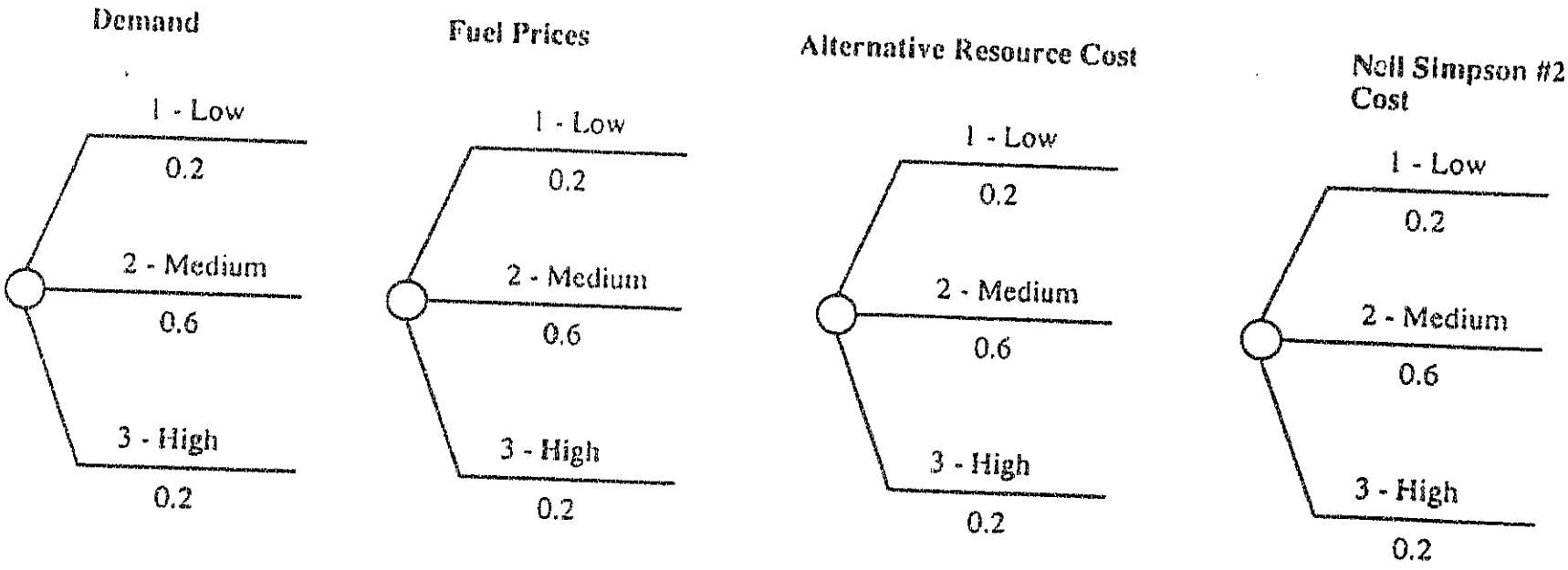
Note: Costs are expressed as present values, over the operating life of the alternative resource. The net tax line would replace the Net Emissions/Tax Cost line shown in Table 2-6. The Net Cost line would replace the Net Cost values shown in Table 2-6.

Table 2-12
ENPRO vs. POWRPRO Comparison
Production Cost Savings
(Millions of Dollars)

	Savings		Savings as a Percent of Total Production Costs	
	POWRPRO	ENPRO	POWRPRO	ENPRO
106, 106A	36.9	41.9	9.2%	11.2%
201, 201A	32.3	38.0	9.0%	11.1%
203, 203A	39.9	45.6	8.8%	10.9%
205, 205A	32.6	36.0	9.1%	10.4%

Differences are expressed in net present value of revenue requirements in 1996 dollars. Values are for production costs only. Percentage difference calculated relative to specified Neil Simpson #2 case as base.

Figure 2-6
Structure of Probabilistic Analysis



Demand

The demand and energy forecast was prepared in April 1992 by Black & Veatch on behalf of Black Hills. The sensitivity analysis used low and high demand forecasts which varied from the base case demand forecast by 10% of the 1996 value.

The probability analysis assigned probabilities of 20, 60, and 20% to the three scenarios. A probability of 20% is assigned to both the low and high demand cases. The remaining 60% is assigned to the base case demand. This distribution is generally consistent with the load forecast uncertainty studies conducted by other utilities.

Fuel Prices

The level of general fuel prices is indexed by world oil prices. The values of all other fuel prices are linked to world oil prices in the spreadsheet. The probabilities were assigned as 20% for low fuel prices as well as high fuel prices and the remaining 60% for base case fuel prices.

Alternative Resource Cost

The costs of Neil Simpson #2 and the alternative resources, except for fuel costs, which are linked to world oil prices, are allowed to vary independently in the probabilistic analysis. Capital-related costs (which include transmission costs for purchase alternatives), O&M costs, and purchased capacity costs all increase or decrease simultaneously in the three alternative resource cost scenarios. Capital-related costs vary over a range of ± 15%, and O&M costs at ± 20%, and purchased capacity costs ± 30%. The three scenarios are assigned probabilities of 20, 60, and 20%.

Neil Simpson #2

Capital-related costs, O&M costs, and purchased capacity costs all increase or decrease simultaneously in the three Neil Simpson #2 cost scenarios. Capital-related costs vary over a range of ± 15%, and O&M costs ± 20%. The three scenarios are assigned probabilities of 20, 60, and 20%.

2.6.2 Probabilistic Analysis Results

In the probabilistic analysis, the net benefits of Neil Simpson #2 relative to each of the alternatives were calculated for each of the 81 end points of the probability tree in Figure 2-6. These results are based on the base case resource plan (Case 106).

Figure 2-7 shows a cumulative distribution function of the customer savings obtained from the probabilistic analysis of Neil Simpson #2. The possible values of net benefits from Neil Simpson #2 range from -$28.0 to $175.6 million. Several numbers are transferred from this curve to Table 2-13. There is a 10% probability that net benefits will be less than the 10% fractile, or $13.06 million. There is a 10% probability that net benefits will be greater than the 90% fractile, or $141.02 million. Thus, there is an 80% probability that net benefits will be within the range of $13.06 to $141.02 million. There is a 50/50 chance that net benefits will be higher or lower than the 50% fractile, or $88.33 million, which is also called the median. The expected value of net benefits is $81.15 million. The expected value is different from the median because the distribution is not symmetrical.

Net benefits are positive for Neil Simpson #2 even in the low demand scenario. The difference between the base case and low demand forecasts is 37 MW, which is approximately equal to one combustion turbine. Because of the low coal costs for Neil Simpson #2, the plant still provides net benefits compared to any of the alternatives even under low demand growth.

The probabilistic analysis concluded that consideration of uncertainty does not substantially change the conclusion of the base case analysis. The downside risk of lower net benefits in some scenarios is offset by the upside potential of substantially greater benefits in other scenarios. The expected value is close to the base case value. The probability of negative net benefits is extremely small for Neil Simpson #2.

2.6.3 Probabilistic Sensitivity Analysis

A further analysis was performed to determine the sensitivity of the probabilistic results to the probability assumptions. The results are compared in Table 2-14.

The column labeled Base Values shows the results of probabilistic analysis of the net cost of the PPL purchase relative to Neil Simpson #2 using the probabilities given in Section 2.6.1. The results are the same as in Table 2-13.

The other columns show the results obtained from changes in various probability assumptions:

- Demand - The probabilities on the low, medium, and high demand scenarios are changed from 0.2, 0.6, and 0.2 to 0.333 for all three scenarios.
- Fuel Prices - The probabilities on the low, medium, and high fuel price scenarios are changed from 0.2, 0.6, and 0.2 to 0.333 for all three scenarios.

Figure 2-7

Net Simpson 2 Probabilistic Analysis

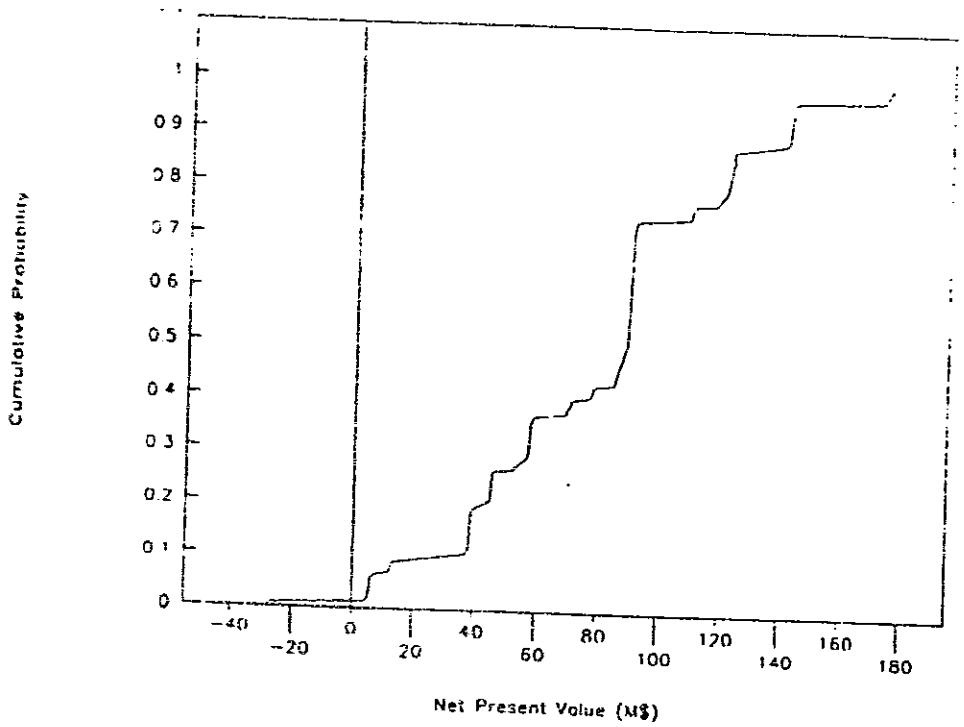


Table 2-13
Probabilistic Analysis Results
Net Present Value of Savings from Neil Simpson #1
Relative to Alternative Resource Options
(Millions of $)

	PPL Purchase	Combustion Turbine	Combined Cycle	Wind	Pumped-storage	Basin Purchase
Base Case	90.25	150.31	89.45	92.89	107.61	61.10
10% Fractile	13.06	96.94	41.11	49.03	52.74	10.55
50% Fractile	88.33	148.93	87.79	91.90	106.66	56.32
90% Fractile	141.02	184.77	121.99	137.01	160.57	103.87
Expected Value	81.15	143.25	85.01	94.21	107.57	52.00
Probability of Negative Net Present Value	0.8%	0.0%	0.2%	0.2%	0.0%	8.8%

Base case and fractile numbers are net present values, over the operating life of the alternative resource, in millions of 1996 dollars.

Table 2-14
Probabilistic Sensitivity Analysis
Net Present Value of Savings from Neil Simpson #2
Relative to Alternative Resource Options
(Millions of $)

	Base Values	Demand	Fuel Prices	Alternative Cost	Both Costs	NSJ Certain
Base Case	90.25	90.25	90.25	90.25	90.25	90.25
10% Fractile	13.06	12.29	13.06	6.00	5.82	13.06
50% Fractile	88.33	78.36	85.90	85.12	77.78	85.90
90% Fractile	141.02	123.71	140.20	142.12	142.46	141.02
Expected Value	81.15	75.33	80.95	81.15	81.32	81.20
Probability of Negative Net Present Value	0.8%	1.3%	0.8%	1.1%	2.2%	0.0%

Base case and fractile numbers are net present values, over the operating life of the project, in millions of 1996 dollars.

- Alternative Cost - The probabilities on the low, medium, and high alternative resource cost scenarios are changed from 0.2, 0.6, and 0.2 to 0.333 for all three scenarios.

- Both Costs - The probabilities on the low, medium, and high scenarios for both the alternative resource cost and Neil Simpson #2 cost are changed from 0.2, 0.6, and 0.2 to 0.333 for all three scenarios.

- NS2 Certain - The probabilities on the low, medium, and high scenarios for Neil Simpson #2 are changed from 0.2, 0.6, and 0.2 to 0, 1, and 0. The probabilities on the low, medium, and high alternative resource cost scenarios are changed from 0.2, 0.6, and 0.2 to 0.333 for all three scenarios.

The cases in which the probabilities of the high and low scenarios are increased from 0.2 to 0.333 represent increases in the variance of the corresponding uncertainty.

Table 2-14 shows that none of these changes in the probability assumptions has much effect on the results. The change that has the biggest effect on the results is the one involving both costs. The probability of negative net present value increases from 0.8% with base values to 2.2% if the variance of both cost assumptions is increased. None of the changes is sufficient to change the conclusion of the probabilistic analysis.

2.7 CASE WITH TWO 80 MW PURCHASES

At the request of the Wyoming Public Service Commission Staff, an additional case (Case 121A) was constructed in which both Neil Simpson #2 and the next planned coal unit after Neil Simpson #2 are deleted and replaced by power purchases.

This case was modeled by modifying Case 121, which has Neil Simpson #2 replaced by an 80 MW purchase in 1996, and coal units scheduled to come on-line in 2004 and 2012. Case 121 was modified by deleting the coal unit in 2004 and replacing it with a second 80-MW purchase in the same year. The second purchase was assumed to have the same prices as the first, which may understate the costs of this case, since it is likely that a second purchase would be priced at the higher cost of a new power plant.

An additional transmission upgrade is assumed to be required in 2004 to accommodate the second purchase, at a cost of $10 million in 1996 dollars. Currently, it is not possible to specify definitively what additional transmission upgrades would be required in this case, because no detailed studies have been done. It is unlikely that the transmission line that would be built for an 80-MW purchase in 1996 would be adequate for the second purchase as well without any additional upgrades. It is likely that the next upgrade required would be an AC-DC-AC converter in Rapid City, at a cost of $50 million.

However, a plausible scenario is that at least $10 million will need to be spent somewhere on the system.

Table 2-15 shows the results of Case 121A compared to the base case and the lowest cost case with only one 80-MW purchase.

Table 2-15
Net Cost of Alternative Resources Relative to Neil Simpson #2
Economic Analysis of 0, 1, and 2 Purchases
(Millions of $)

	Base Case No Purchases Case 106	One Purchase Case 121	Two Purchases Case 131A
20-Year Cost	504.4	542.5	547.1
Difference From Lowest Cost Plan	0	38.1	42.7

20-year cost is the present value of revenue requirements over the period 1996-2015 resulting from the POWRPRO analysis.

Clearly, the case with two purchases is more expensive than the cases with none or one purchase, if the additional transmission investment of $10 million is required in 2004. If a larger additional transmission investment is required, then the difference is even greater. If no additional transmission investment is required, then the two purchase case may cost less than the one-purchase case, but still more than the case with no purchases.

2.8 SECOND ITERATION ANALYSIS

A second iteration of POWRPRO runs, base case economic analysis, probabilistic analysis, and probabilistic sensitivity analysis was performed. The second iteration was based on a modified base case, which was constructed to represent an upper bound on the impact of DSM and renewable resources on the economics of Neil Simpson #2.

Table 2-16 compares the results from POWRPRO for the modified base case and two variations against Case 106, the original base case. Case 300 is defined, starting with Case 106, as follows:

Table 2-16
Modified Base Case Economic Analysis
(Millions of $)

	Original Base Case Case 106	Modified Base Case Case 300	PPL Purchase Case 300A	Delay NS #2 Case 300G	Combustion Turbine & Photovoltaics Case 300P	Combustion Turbine & Wind Case 300W
20-Year Cost	504.4	455.3	492.4	459.3	530.1	473.5
Difference From Modified Base Case	49.1	0	37.1	4.0	74.8	18.2
Difference From Original Base Case	0	-49.1	-12.0	-45.1	25.7	-30.9

20-year cost is the present value of revenue requirements over the period 1996-2015 resulting from the POWRPRO analysis.

- A block of additional DSM, with demand impact starting at zero in 1992, increasing to 10% of demand in 2003, then staying at the 2003 level for the remainder of the study. This block of DSM is assigned a cost equal to avoided costs, to establish an upper bound
- A 20-MW block of wind generation
- The 20-MW purchase from Tri-State in 1996 is deleted
- The timing of additional gas turbines is adjusted as needed to satisfy the reserve margin criterion.

Case 300A is identical to Case 300, except that Neil Simpson #2 is deleted and replaced by an 80-MW purchase from PPL.

The base case economic analysis for the modified base case is shown in Table 2-17. The probabilistic analysis for the modified base is shown in Table 2-18. The results for the PPL purchase are more sensitive to the modified base case than the other alternatives because it is assumed that the amount of capacity purchased can be renegotiated and capacity payments reduced after five years, if demand grows slower than anticipated, while the capacity provided by a combined cycle unit is the same regardless of the demand scenario. Figure 2-8 shows a cumulative distribution function of the customer savings obtained from the probabilistic analysis of Neil Simpson #2 assuming the modified base case plan.

Table 2-17
Net Cost of Alternative Resources
Relative to Neil Simpson #2 - Modified Base Case Plan
(Millions of $)

	PPL Purchase	Combustion Turbine	Combined Cycle	Wind	Photo-voltaics	Basin Purchase
Life of Alternative (years)	30	25	35	25	25	30
Alternative Resource Capital Cost	19.95	55.96	110.67	117.29	335.05	28.20
Alternative Resource Operating Cost	230.10	82.96	147.06	82.07	18.28	207.81
Neil Simpson #2 Capital Cost	141.55	136.42	144.64	136.42	136.42	141.55
Neil Simpson #2 Operating Cost	67.10	63.35	69.85	63.35	63.35	67.10
Net System Generation Cost	-2.71	158.94	25.26	122.45	-21.60	-10.11
Net Emissions/Tax Cost	6.56	20.07	1.14	-16.57	-19.80	-0.15
Net Cost	45.26	118.18	69.64	75.47	112.12	17.10

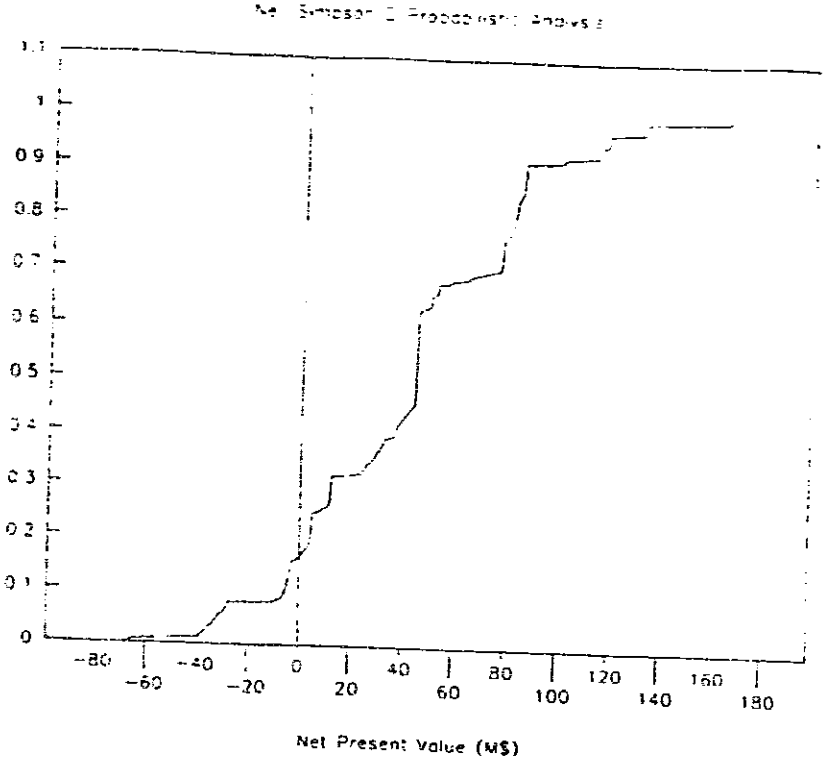
Costs are expressed as present values, over the operating life of the alternative resource discounted to 1996.

Table 2-18
Probabilistic Analysis Results
Net Present Value of Savings from Neil Simpson #2
Relative to Alternative Resource Options - Modified Base Case Plan
(Millions of $)

	PPL Purchase	Combustion Turbine	Combined Cycle	Wind	Photo-voltaics	Basin Purchase
Base Case	45.26	118.18	69.64	75.47	112.12	17.10
10% Fractile	-6.98	73.11	29.09	35.82	58.19	-38.76
50% Fractile	44.30	116.80	67.75	74.45	112.10	16.23
90% Fractile	84.86	153.84	102.15	118.15	166.01	53.01
Expected Value	42.65	113.98	65.89	76.57	112.18	14.99
Probability of Negative Net Present Value	16.5%	0.0%	1.3%	0.6%	0.0%	34.4%

Base case and fractile numbers are net present values, over the operating life of the alternative resources, in millions of 1996 dollars.

Figure 2-8


1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-80
-60
-40
-20
0
20
40
60
80
100
120
140
160
180
Net Present Value (M$)

The probabilistic sensitivity analysis change showing the greatest impact on the probabilistic analysis around Case 106 was redone for the modified base case. The results are shown in Table 2-19. This analysis reconfirms that reasonable changes in the probability assumptions will not materially affect the results of the analysis.

Table 2-19
Probabilistic Sensitivity Analysis for the Modified Base Case Net Present Value of Savings from Nail Simpson #2 #2 Relative to Alternative Resource Options
(Millions of $)

	Base Values	Risk Costs
Base Case	45.26	45.26
10% Fractile	-6.98	-21.50
50% Fractile	44.30	37.46
90% Fractile	84.86	115.19
Expected Value	42.65	41.60
Probability of Negative Net Present Value	16.5%	19.1%

Base case and fractile numbers are net present values, over the operating life of the alternative resource, in millions of 1996 dollars.

3.0 CONCLUSIONS

The integrated planning analysis for Neil Simpson #2 demonstrates that the project is substantially less expensive to customers than the alternatives. Neil Simpson #2 is expected to provide net benefits of $81.15 million, discounted to 1996, over its projected 50-year life under base case assumptions. Net benefits are measured relative to the costs of the next lowest cost alternative, power purchased from PacifiCorp. That is, costs to customers are expected to be $81.15 million higher if Neil Simpson #2 were not built but if power were purchased instead from PacifiCorp.

An extensive uncertainty analysis demonstrates that the favorable conclusions of the base case analysis are unlikely to be reversed by adverse scenarios or even by combinations of adverse scenarios. The uncertainty analysis considered uncertainty in demand, fuel prices, and construction and operating costs, any one of which could substantially increase or decrease net benefits. A total of 81 scenarios were considered in evaluating each development. The probability that actual net benefits will be zero from Neil Simpson #2 is small, being less than 1%. Further, the magnitude of the negative net benefits in these scenarios is small and is outweighed by the large positive benefits in other scenarios.

The net present value of benefits from Neil Simpson #2 will fall between $13.06 and $141.02 million, with a probability of 80%.

An analysis of the sensitivity of the results to the probabilistic assumptions shows that any reasonable alternative assumptions would not change the decision to proceed with Neil Simpson #2.

The public involvement process is documented in Appendix A4.

APPENDIX A1

Economic Analysis Spreadsheet

NEIL SIMPSON UNIT #2 ECONOMICANALYSIS
C:\LOGAN\BIPLE\ECONTRE3.WK1 2-25-93

Range: INDEX

This model calculates the net economic benefits of the Neil Simpson Unit No. 2 for various uncertainties, and calculates expected values.

INDEX

Range Name	Contents
INDEX	Index to the ranges in this spreadsheet
INSTRUCT	Instructions for using this spreadsheet
MODE	Model mode selection
FINPARM	Input data – Financial parameters
PROJECT	Input data – Project parameters
SCENARIO	Input data – Scenarios
TREEIN	Input data – Probability tree
RSMIN	Input data – Response surface model
SELECT	Calculations – Selection of scenarios and values
FUELCALC	Calculations – Fuel costs
RSMCALC	Calculations – Response surface model
ECONCALC	Calculations – Economic analysis
TREECALC	Calculations – Probability tree
ECONREPT	Output report – Economic analysis
TREEREPT	Output report – Probability tree calculations
MACROS	Macros

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

INSTRUCTIONS

Range: INSTRUCT

This s... sheet has two modes, which may be selected at the beginning of the Input Data – Probability Tree section:
Mo... 0, for probabilistic calculations. Press (F8) to do probabilistic calculations after
setting the value of mode to 0 and confirming that the specification of the branches is correct.
Mode = 1, for single scenario calculation. Specify the scenario just below the place where mode is selected.
Press (F9) to do single scenario calculations after confirming that the single scenario specified just below
the mode switch is correct.

All required input data are in the Input Data sections. Shaded values are input variables.
Unshaded values are calculated variables. The only change the user must make outside
of the Input Data sections is to assure that the size of the table in Calculations – Probability Tree corresponds
to the number of scenarios specified in Input Data – Probability Tree.

To print the entire spreadsheet, issue the command:
:PrintRangeSetALL{RETURN}Go
To print any of the named ranges listed in the contents above, issue the command:
:PrintRangeSet____{RETURN}Go
where the range name is typed into the blank.
Range RESULTS includes all of the ranges FUELCALC, RSMCALC, AND ECONCALC.
Range ALL includes the entire spreadsheet.

Macros
<Alt N> Creates a window at the top of the screen showing the value of Net Present Value
<Alt E> Creates a window at the top of the screen showing the value of Expected Value
<Alt D> Constructs cumulative distribution of Net Present Value
<Alt G> Displays graph of cumulative distribution of Net Present Value, and creates file CUMDIST.PIC for printing

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

MODEL MODE SELECTION

Range: MODE

Cost Mode: [1] 0 = Real 1996$
1 = Nominal $

Fixed Chg: [1] 0 = Use given fixed charge rate trajectory
1 = Use levelized fixed charge rate

Retirement: [1] 0 = Use Neil Simpson 2 retirement date for Neil Simpson 2
1 = Use Alternative retirement date for Neil Simpson 2

Tax: [1] 0 = Carbon Tax – Use CO2 Tax Rate
1 = Energy Tax – Use Energy Tax Rates

Project [6]

Mode: [0] 0 = Probabilistic: Press (F8) to perform calculations for all branches.
1 = Single Scenario: Make scenario selection below.

Single Scenario Selection

Node 1 – Demand Value	Node 2 – Fuel Price Value	Node 3 – Altern Cost Value	Node 4 – NS2 Cost Value
2	2	2	2

DSM scenario [2]

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

INPUT DATA – FINANCIAL PARAMETERS

Range: FINPARM

Nominal Discount Rate	10.68%
Escalation Rate	4.00%
Real Discount Rate	6.42%

Emissions

SO2 Allowance Price ($/ton)	300
CO2 Tax Rate ($/ton)	1
Renewable Credit Rate (cents/kWh)	1.5
Renewable Credit Term (years)	10

Energy Tax Rate

Fuel Type	cents/MBtu
0 Renewable	0
1 Coal	25.7
2 Gas	25.7
3 Oil	59.9
4 Other	25.7

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

INPUT DATA – PROJECT PARAMETERS

Range: PROJECT

Cost Reference Year [1996]

	Neil Simpson No. 2	Neil Simpson No. 2	Combustn Turbine 2x40 MW	Combined Cycle 80 MW	Wind	Photo-Voltaic	PPL Purchase 80 MW	Basin El Purchase 80 MW
Alternative Number	BASE	1	2	3	4	5	6	7
Name	NS2	NS2	CT	CC	Wind	PV	PPL	Basin
Capacity (MW)	80	80	80	80	80	80	80	80
Capacity Purchase Adjust Period	0	0	0	0	0	0	5	5
Capacity Equivalence Factor	0.950	0.950	0.950	0.970	0.150	1.000	1.000	1.000
Equivalent Availability	0.895	0.895	0.913	0.933	0.300	0.300	1.000	1.000
Installed Cost ($/kW) – Hi	1795	1795	612	1176	1282	3663	253	345
– Med	1561	1561	532	1023	1115	3185	220	300
– Lo	1327	1327	452	870	948	2707	187	255
Real Escalation Rate	3.8%	3.8%	0.0%	0.0%	-4.0%	0.0%	0.0%	0.0%
Fixed Charge Rate Pattern No.	1	1	2	3	2	2	1	5
Average Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	1000	1000
Capacity Price Trajectory No.	0	0	0	0	0	0	7	9
Fuel Price Trajectory No.	1	1	5	4	0	0	8	10
Fixed O&M ($/kW-yr) – Hi	31.75	31.75	13.87	16.97	65.43	22.97	0	28.80
– Med	26.46	26.46	11.56	14.14	54.53	19.14	0	24
– Lo	21.17	21.17	9.25	11.31	43.62	15.31	0	19.20
Real Escalation Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Var O&M ($/MWh) – Hi	3.65	3.65	5.40	7.28	0.00	0.00	0	0
– Med	3.04	3.04	4.5	6.07	0.00	0	0	0
– Lo	2.43	2.43	3.60	4.86	0.00	0.00	0	0
Real Escalation Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
SO2 Emissions Rate (tons/MWh)	0.0011	0.0011	0.0000	0.0000	0	0.0000	0.0028	0.0011
CO2 Emissions Rate (tons/MWh)	1.3438	1.3438	0.7070	0.4876	0	0.0000	1.1000	1.3438
Fuel Type	1	1	3	2	0	0	1	1
Tax Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	11000	11000
Renewable Tax Credit	0	0	0	0	1	1	0	0
Production Cost Selector	1	1	2	3	1	1	4	4
Start-up Year	1996	1996	1996	1996	1996	1996	1996	1996
Life (years)	50	50	25	35	25	25	30	30

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Notes on Project Parameters

Renewable Tax Credit = 1 if resource is eligible, 0 otherwise.
From [illegible] LFF–5, Tables 8–1 through 8–4.
Fixed O&M for Wind includes Variable O&M and transmission. Fixed O&M for PV includes Variable O&M.
Installed cost for PPL 80 MW purchase is the cost of transmission required.
Installed cost for Basin purchase is the cost of an AC–DC–AC converter. Fixed O&M includes transmission.

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Fixed Charge Rate Patterns

Year of Oper Life	1	2	3	4	5	6
Levelized	0.12593	0.15158	0.14702	0.13394	0.13052	
1	0.15499	0.19536	0.18448	0.17520	0.16798	
2	0.13437	0.16667	0.16268	0.15274	0.14618	
3	0.13441	0.16605	0.16153	0.15094	0.14503	
4	0.13423	0.16495	0.16017	0.14892	0.14367	
5	0.13386	0.16340	0.15863	0.14672	0.14213	
6	0.13332	0.16146	0.15690	0.14434	0.14040	
7	0.13261	0.15765	0.15501	0.14179	0.13851	
8	0.13174	0.15214	0.15296	0.13909	0.13646	
9	0.12929	0.14663	0.14934	0.13481	0.13284	
10	0.12654	0.14112	0.14540	0.13022	0.12890	
11	0.12378	0.13561	0.14147	0.12563	0.12497	
12	0.12103	0.13010	0.13753	0.12103	0.12103	
13	0.11828	0.12460	0.13360	0.11644	0.11710	
14	0.11552	0.11909	0.12966	0.11185	0.11316	
15	0.11277	0.11358	0.12573	0.10726	0.10923	
16	0.11001	0.12328	0.12179	0.10267	0.10529	
17	0.10726	0.13298	0.11786	0.09808	0.10136	
18	0.10450	0.12747	0.11393	0.09349	0.09743	
19	0.10175	0.12196	0.10999	0.08890	0.09349	
20	0.09900	0.11646	0.10606	0.08431	0.08956	
21	0.10774	0.11095	0.11362	0.09122	0.09712	
22	0.11647	0.10544	0.12117	0.09812	0.10467	
23	0.11372	0.09993	0.11724	0.09353	0.10074	
24	0.11097	0.09442	0.11330	0.08894	0.09680	
25	0.10821	0.08891	0.10937	0.08435	0.09287	
26	0.10546	0	0.10544	0.07976	0.08894	
27	0.10270	0	0.10150	0.07517	0.08500	
28	0.09995	0	0.09757	0.07058	0.08107	
29	0.09720	0	0.09363	0.06599	0.07713	
30	0.09444	0	0.08970	0.06140	0.07320	
31	0.09169	0	0.08576	0	0.06926	
32	0.08893	0	0.08183	0	0.06533	
33	0.08618	0	0.07789	0	0.06139	
34	0.08342	0	0.07396	0	0.05746	
35	0.08067	0	0.07002	0	0.05352	

36	0.07792	0	0	0	0
37	0.07516	0	0	0	0
38	0.07241	0	0	0	0
39	0.06965	0	0	0	0
40	0.06690	0	0	0	0
41	0.06414	0	0	0	0
42	0.06139	0	0	0	0
43	0.05864	0	0	0	0
44	0.05588	0	0	0	0
45	0.05313	0	0	0	0
46	0.05037	0	0	0	0
47	0.04762	0	0	0	0
48	0.04487	0	0	0	0
49	0.04211	0	0	0	0
50	0.03936	0	0	0	0
51	0	0	0	0	0
Life	50	25	35	30	35

Fixed Charge Rates from Black & Veatch Fixed Charge Rate Model
1 – Neil Simpson 2, 50 year
2 – Combustion turbine, 25 year
3 – Combined cycle, 35 year
4 – Neil Simpson 2, 30 year
5 – Transmission, 35 year
6 –

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Project Fuel and Purchased Power Prices

	(0) Null	(1) NS2 Fuel Cost $/MBtu	(2) Nat Gas Commodity $/MBtu	(3) Nat Gas Demand $/MBtu	(4) Nat Gas Total $/MBtu	(5) No. 2 Oil $/MBtu	(6) PPL Cap Price $/kW-mo	(7) PPL Cap Price $/kW-yr	(8) PPL Ener Price $/MWh	(9) Basin Cap Price $/kW-yr	(10) Basin Ener Price $/MWh
1996	0	0.6042	1.61	0.96	2.57	4.48	17.77	213.24	16.84	108.00	16.00
1997	0	0.6468	1.68	0.99	2.67	4.60	17.86	214.32	17.54	113.40	16.64
1998	0	0.5356	1.76	1.02	2.78	4.72	17.95	215.40	18.28	119.07	17.31
1999	0	0.5166	1.83	1.05	2.88	4.85	18.04	216.48	19.07	125.02	18.00
2000	0	0.3751	1.92	1.08	3.00	4.98	18.13	217.56	19.90	131.27	18.72
2001	0	0.3381	2.00	1.11	3.11	5.12	18.22	218.64	20.82	137.84	19.47
2002	0	0.2332	2.09	1.14	3.23	5.15	18.31	219.72	21.84	144.73	20.25
2003	0	0.2318	2.19	1.18	3.37	5.15	18.40	220.80	22.95	151.97	21.05
2004	0	0.1734	2.29	1.21	3.50	5.18	18.49	221.88	24.12	159.57	21.90
2005	0	0	2.39	1.25	3.64	5.23	18.59	223.08	25.41	167.54	22.77
2006	0	0	2.50	1.28	3.78	5.28	18.68	224.16	26.82	175.92	23.68
2007	0	0	2.61	1.32	3.93	5.35	18.77	225.24	28.34	184.72	24.63
2008	0	0	2.73	1.36	4.09	5.40	18.87	226.44	30.00	193.95	25.62
2009	0	0	2.85	1.40	4.25	5.40	18.96	227.52	31.74	203.65	26.64
2010	0	0	2.98	1.45	4.43	5.54	19.05	228.60	33.59	213.83	27.71
2011	0	0	3.12	1.49	4.61	5.77	19.15	229.80	35.54	224.52	28.82
2012	0	0	3.26	1.54	4.80	6.00	19.25	231.00	37.60	235.75	29.97
2013	0	0	3.40	1.59	4.99	6.26	19.35	232.16	39.78	247.54	31.17
2014	0	0	3.56	1.64	5.20	6.51	19.44	233.33	42.08	259.91	32.41
2015	0	0	3.72	1.69	5.41	6.77	19.54	234.50	44.52	272.91	33.71
Growth rate 2006-12							0.01		0.06		
Levelized Value			2.19	1.17							
	0	1	2	3	4	5	6	7	8	9	10
Real esc after 2015	0	0.0%	2.0%	2.0%	2.0%	2.0%	0.0%	0.0%	1.7%	0.0%	1.0%
Incr for high scenario	0	--	--	--	--	--	30.0%	30.0%	--	30.0%	--
Decr for low scenario	0	--	--	--	--	--	30.0%	30.0%	--	30.0%	--
Correl with oil price	0	25.0%	100.0%	0.0%	65.1%	100.0%	--	--	25.0%	--	25.0%

(1) from exhibit LFF-5, Appendix B, Case BHPL-106.
(2), (3), (5) from exhibit LFF-5, Tables 7-2 and 7-3. (4) calculated from (2) and (3).
(6), (8) from exhibit LFF-5, Table 8-4. Values for 2013-2015 calculated by applying average growth rate from 2006-2012 after 2012.

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

INPUT DATA – SCENARIOS

Range: SCENARIO

	Load (GWh)		
	1	2	3
	Low	Med	High
1996	1636.4	1818.2	2000.0
1997	1682.4	1864.2	2046.0
1998	1729.9	1911.7	2093.5
1999	1777.9	1959.7	2141.5
2000	1826.0	2007.8	2189.6
2001	1874.4	2056.2	2238.0
2002	1923.0	2104.8	2286.6
2003	1971.5	2153.3	2335.1
2004	2020.0	2201.8	2383.6
2005	2069.6	2251.4	2433.2
2006	2120.5	2302.3	2484.1
2007	2172.5	2354.3	2536.1
2008	2225.9	2407.7	2589.5
2009	2280.5	2462.3	2644.1
2010	2336.4	2518.2	2700.0
2011	2393.7	2575.5	2757.3
2012	2452.3	2634.1	2815.9
2013	2512.4	2694.2	2876.0
2014	2573.9	2755.7	2937.5
2015	2636.8	2818.6	3000.4

	DSM (GWh)		
	1	2	3
	Low	Med	High
1996	0.00	0.00	66.12
1997	0.00	0.00	84.74
1998	0.00	0.00	104.27
1999	0.00	0.00	124.71
2000	0.00	0.00	146.02
2001	0.00	0.00	168.23
2002	0.00	0.00	191.35
2003	0.00	0.00	215.33
2004	0.00	0.00	220.18
2005	0.00	0.00	225.14
2006	0.00	0.00	230.23
2007	0.00	0.00	235.43
2008	0.00	0.00	240.77
2009	0.00	0.00	246.23
2010	0.00	0.00	251.82
2011	0.00	0.00	257.55
2012	0.00	0.00	263.41
2013	0.00	0.00	269.42
2014	0.00	0.00	275.57
2015	0.00	0.00	281.86

	1752.08
	1779.46
	1807.42
	1834.99
	1861.77
	1887.96
	1913.45
	1937.97
	1981.62
	2026.26
	2072.07
	2118.87
	2166.93
	2216.07
	2266.38
	2317.95
	2370.69
	2424.78
	2480.13
	2536.74

Medium load scenario from exhibit LPF–5, Table 4–1.
Increment/decrement for Low and High scenarios is 10% of Medium value in 1996 = 181.82
DSM scenarios represent incremental DSM in addition to levels assumed in BHP's load forecast.

	Oil Price ($/MBtu)		
	1	2	3
	Low	Med	High
1996	2.69	4.48	6.27
1997	2.76	4.60	6.44
1998	2.83	4.72	6.61
1999	2.91	4.85	6.79
2000	2.99	4.98	6.97
2001	3.07	5.12	7.17
2002	3.09	5.15	7.21
2003	3.09	5.15	7.21
2004	3.11	5.18	7.25
2005	3.14	5.23	7.32
2006	3.17	5.28	7.39
2007	3.21	5.35	7.49
2008	3.24	5.40	7.56
2009	3.24	5.40	7.56
2010	3.32	5.54	7.76
2011	3.46	5.77	8.08
2012	3.60	6.00	8.40
2013	3.76	6.26	8.76
2014	3.91	6.51	9.11
2015	4.06	6.77	9.48

Medium oil price from exhibit LFF–5, Table 7–3 (No. 2 oil).
Decrement/increment for low/high scenarios is 40% of medium value in each year.

INPUT DATA – PROBABILITY TREE

Range: TREEIN

Branch ... ifications for Probabilistic Calculations

	Node 1 Demand	Node 2 Fuel Price	Node 3 Altern Cost	Node 4 NS2 Cost
1 Low	0.20	0.20	0.20	0.20
2 Med	0.60	0.60	0.60	0.60
3 High	0.20	0.20	0.20	0.20

	Node 1 – Demand		Node 2 – Fuel Price		Node 3 – Altern Cost		Node 4 – NS2 Cost	
	Value	Prob	Value	Prob	Value	Prob	Value	Prob
1	1	0.2	1	0.2	1	0.2	1	0.2
2	1	0.2	1	0.2	1	0.2	2	0.6
3	1	0.2	1	0.2	1	0.2	3	0.2
4	1	0.2	1	0.2	2	0.6	1	0.2
5	1	0.2	1	0.2	2	0.6	2	0.6
6	1	0.2	1	0.2	2	0.6	3	0.2
7	1	0.2	1	0.2	3	0.2	1	0.2
8	1	0.2	1	0.2	3	0.2	2	0.6
9	1	0.2	1	0.2	3	0.2	3	0.2
10	1	0.2	2	0.6	1	0.2	1	0.2
11	1	0.2	2	0.6	1	0.2	2	0.6
12	1	0.2	2	0.6	1	0.2	3	0.2
13	1	0.2	2	0.6	2	0.6	1	0.2
14	1	0.2	2	0.6	2	0.6	2	0.6
15	1	0.2	2	0.6	2	0.6	3	0.2
16	1	0.2	2	0.6	3	0.2	1	0.2
17	1	0.2	2	0.6	3	0.2	2	0.6
18	1	0.2	2	0.6	3	0.2	3	0.2
19	1	0.2	3	0.2	1	0.2	1	0.2
20	1	0.2	3	0.2	1	0.2	2	0.6
21	1	0.2	3	0.2	1	0.2	3	0.2
22	1	0.2	3	0.2	2	0.6	1	0.2
23	1	0.2	3	0.2	2	0.6	2	0.6
24	1	0.2	3	0.2	2	0.6	3	0.2
25	1	0.2	3	0.2	3	0.2	1	0.2
26	1	0.2	3	0.2	3	0.2	2	0.6
27	1	0.2	3	0.2	3	0.2	3	0.2

28	2	0.6	1	0.2	1	0.2	1	0.2
29	2	0.6	1	0.2	1	0.2	2	0.6
30	2	0.6	1	0.2	1	0.2	3	0.2
31	2	0.6	1	0.2	2	0.6	1	0.2
32	2	0.6	1	0.2	2	0.6	2	0.6
33	2	0.6	1	0.2	2	0.6	3	0.2
34	2	0.6	1	0.2	3	0.2	1	0.2
35	2	0.6	1	0.2	3	0.2	2	0.6
36	2	0.6	1	0.2	3	0.2	3	0.2
37	2	0.6	2	0.6	1	0.2	1	0.2
38	2	0.6	2	0.6	1	0.2	2	0.6
39	2	0.6	2	0.6	1	0.2	3	0.2
40	2	0.6	2	0.6	2	0.6	1	0.2
41	2	0.6	2	0.6	2	0.6	2	0.6
42	2	0.6	2	0.6	2	0.6	3	0.2
43	2	0.6	2	0.6	3	0.2	1	0.2
44	2	0.6	2	0.6	3	0.2	2	0.6
45	2	0.6	2	0.6	3	0.2	3	0.2
46	2	0.6	3	0.2	1	0.2	1	0.2
47	2	0.6	3	0.2	1	0.2	2	0.6
48	2	0.6	3	0.2	1	0.2	3	0.2
49	2	0.6	3	0.2	2	0.6	1	0.2
50	2	0.6	3	0.2	2	0.6	2	0.6
51	2	0.6	3	0.2	2	0.6	3	0.2
52	2	0.6	3	0.2	3	0.2	1	0.2
53	2	0.6	3	0.2	3	0.2	2	0.6
54	2	0.6	3	0.2	3	0.2	3	0.2

55	3	0.2	1	0.2	1	0.2	1	0.2
56	3	0.2	1	0.2	1	0.2	2	0.6
57	3	0.2	1	0.2	1	0.2	3	0.2
58	3	0.2	1	0.2	2	0.6	1	0.2
59	3	0.2	1	0.2	2	0.6	2	0.6
60	3	0.2	1	0.2	2	0.6	3	0.2
61	3	0.2	1	0.2	3	0.2	1	0.2
62	3	0.2	1	0.2	3	0.2	2	0.6
63	3	0.2	1	0.2	3	0.2	3	0.2
64	3	0.2	2	0.6	1	0.2	1	0.2
65	3	0.2	2	0.6	1	0.2	2	0.6
66	3	0.2	2	0.6	1	0.2	3	0.2
67	3	0.2	2	0.6	2	0.6	1	0.2
68	3	0.2	2	0.6	2	0.6	2	0.6
69	3	0.2	2	0.6	2	0.6	3	0.2
70	3	0.2	2	0.6	3	0.2	1	0.2
71	3	0.2	2	0.6	3	0.2	2	0.6
72	3	0.2	2	0.6	3	0.2	3	0.2
73	3	0.2	3	0.2	1	0.2	1	0.2
74	3	0.2	3	0.2	1	0.2	2	0.6
75	3	0.2	3	0.2	1	0.2	3	0.2
76	3	0.2	3	0.2	2	0.6	1	0.2
77	3	0.2	3	0.2	2	0.6	2	0.6
78	3	0.2	3	0.2	2	0.6	3	0.2
79	3	0.2	3	0.2	3	0.2	1	0.2
80	3	0.2	3	0.2	3	0.2	2	0.6
81	3	0.2	3	0.2	3	0.2	3	0.2

INPUT DATA – RESPONSE SURFACE MODEL – BASE CASE VALUES

Range: RSMIN

	(1) Net Demand GWh	(2) Oil Price $/MBtu	(3) Nat Gas Price $/MBtu	(4) NS2 Coal Price $/MBtu	(5) NS2 Var O&M $/MWh	(6) CT Var O&M $/MWh	(7) CC Var O&M $/MWh	(8) NS2 $/MWh PC Sel #1	(9) CT $/MWh PC Sel #2	(10) CC $/MWh PC Sel #3	(11) PPL $/MWh PC Sel #4	(12) Chg Peak MWh
							Heat Rate:	12499	12738	8785		
1996	1818.2	4.48	2.57	0.6042	3.04	4.50	6.07	10.59	61.57	28.65	16.84	18122
1997	1864.2	4.60	2.67	0.6468	3.16	4.68	6.31	11.25	63.27	29.77	17.54	20612
1998	1911.7	4.72	2.78	0.5356	3.29	4.87	6.57	9.98	64.99	30.99	18.28	22170
1999	1959.7	4.85	2.88	0.5166	3.42	5.06	6.83	9.88	66.84	32.13	19.07	28303
2000	2007.8	4.98	3.00	0.3751	3.56	5.26	7.10	8.24	68.70	33.46	19.90	29694
2001	2056.2	5.12	3.11	0.3381	3.70	5.47	7.39	7.92	70.69	34.71	20.82	32837
2002	2104.8	5.15	3.23	0.2332	3.85	5.69	7.68	6.76	71.29	36.06	21.84	32030
2003	2153.3	5.15	3.37	0.2318	4.00	5.92	7.99	6.90	71.52	37.59	22.95	33801
2004	2201.8	5.18	3.50	0.1734	4.16	6.16	8.31	6.33	72.14	39.05	24.12	34037
2005	2251.4	5.23	3.64	0	4.33	6.40	8.64	4.33	73.02	40.62	25.41	37923
2006	2302.3	5.28	3.78	0	4.50	6.66	8.99	4.50	73.92	42.19	26.82	39363
2007	2354.3	5.35	3.93	0	4.68	6.93	9.34	4.68	75.08	43.87	28.34	27847
2008	2407.7	5.40	4.09	0	4.87	7.20	9.72	4.87	75.99	45.65	30.00	24829
2009	2462.3	5.40	4.25	0	5.06	7.49	10.11	5.06	76.28	47.44	31.74	33891
2010	2518.2	5.54	4.43	0	5.26	7.79	10.51	5.26	78.36	49.43	33.59	28742
2011	2575.5	5.77	4.61	0	5.47	8.10	10.93	5.47	81.60	51.43	35.54	56248
2012	2634.1	6.00	4.80	0	5.69	8.43	11.37	5.69	84.86	53.54	37.60	22249
2013	2694.2	6.26	4.99	0	5.92	8.77	11.82	5.92	88.51	55.66	39.78	37395
2014	2755.7	6.51	5.20	0	6.16	9.12	12.30	6.16	92.04	57.98	42.08	38507
2015	2818.6	6.77	5.41	0	6.40	9.48	12.79	6.40	95.72	60.32	44.52	43026

(1), (2) are medium scenario values from input tables above.
(11) from exhibit LFF–5, Table 8–4.

Assumptions underlying Change in Peaking Gen and Coal Discount

Size of Block	80
Decrease in CEF Underlying Increase in Peaking Gen:	0.05
Sensitivity of Peaking Gen Cost to Fuel Price	1
Sensitivity of Coal Discount to Fuel Price	0.25
Real Escalation of Coal Discount after 2015	0

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Base Case Capacity Factors

	(1) CT Base Cost PC Sel #2	(2) CC Base Cost PC Sel #3	(3) PPL Base Cost PC Sel #4	(4) Peak Gen $/MWh	(5) Coal Discount $	(6) NS2 Avg CF PC Sel #1	(7) CT Avg CF PC Sel #2	(8) CC Avg CF PC Sel #3	(9) PPL Avg CF PC Sel #4	(10) NS2 CF' PC Sel #1	(11) CT CF' PC Sel #2	(12) CC CF' PC Sel #3	(13) PPL CF' PC Sel #4
									EAF:	0.895	0.915	0.933	1.000
1996	18.74	15.33	13.21	42.85	-1231909	0.750	0.209	0.497	0.606	1.61865	-1.1991	0.12963	0.42609
1997	22.37	16.37	13.89	48.72	-1344862	0.798	0.237	0.551	0.679	2.06749	-1.0384	0.36256	0.74097
1998	25.16	16.59	14.43	51.78	-1361310	0.792	0.196	0.551	0.681	2.00257	-1.2801	0.36256	0.75005
1999	27.98	18.52	15.21	50.90	-1481400	0.824	0.254	0.608	0.743	2.39524	-0.9423	0.61967	1.04893
2000	29.00	20.34	15.74	51.27	-1042232	0.834	0.259	0.609	0.749	2.54928	-0.9183	0.62434	1.08008
2001	33.89	21.36	16.62	50.97	-883378	0.855	0.286	0.657	0.792	2.96043	-0.7762	0.85750	1.31938
2002	36.78	23.01	17.09	52.20	-119725	0.858	0.308	0.634	0.779	3.03367	-0.6678	0.74337	1.24371
2003	48.36	26.23	18.17	52.55	-186729	0.869	0.456	0.684	0.821	3.35414	-0.0021	0.99862	1.50144
2004	81.98	21.05	18.48	54.49	150536	0.871	0.542	0.661	0.804	3.42420	0.37293	0.87787	1.39230
2005	61.17	22.40	19.26	55.01	154035	0.879	0.285	0.711	0.847	3.76250	-0.7838	1.14959	1.68473
2006	63.33	20.62	19.97	59.90	372014	0.881	0.274	0.709	0.831	3.86731	-0.8398	1.13601	1.56934
2007	51.35	15.70	16.91	56.44	4463222	0.888	0.131	0.450	0.634	4.34994	-1.7622	-0.0700	0.54364
2008	52.27	15.23	17.13	57.85	4420541	0.888	0.137	0.457	0.635	4.34994	-1.7069	-0.0403	0.54790
2009	54.82	17.42	18.04	58.34	4375229	0.891	0.173	0.516	0.684	4.65496	-1.4332	0.21087	0.76371
2010	56.07	16.70	18.69	62.12	4389169	0.891	0.169	0.502	0.665	4.65496	-1.4649	0.15096	0.67825
2011	70.21	25.30	15.03	66.57	4369221	0.893	0.370	0.769	0.904	4.92473	-0.3796	1.52300	2.19678
2012	56.29	13.05	10.15	67.83	4652912	0.893	0.112	0.431	0.649	4.92473	-1.9376	-0.1509	0.60811
2013	65.13	15.69	11.95	71.35	4508506	0.895	0.110	0.583	0.744	5.29330	-1.9525	0.50493	1.05409
2014	67.56	15.46	11.06	74.02	4553618	0.895	0.117	0.584	0.738	5.29330	-1.8892	0.50945	1.02332
2015	73.02	18.27	12.37	76.61	4539302	0.895	0.152	0.645	0.79	5.29330	-1.5869	0.79733	1.30753

0.23862

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

RSM Coefficients for NS2 Average Capacity Factor

	Linear	Demand	Oil Price
Linear	0	--	--
Cost Ratio	-3.6	--	--
Demand	6.9	0	--
Oil Price	0	0	0

B 0.99

RSM Coefficients for Production Cost Savings per MWh from NS2

	Linear	Demand	Oil Price
Linear	0		
Demand	0.9	0	
Oil Price	0.25	0	0

Real Escalation rate for savings after 2015 0

RSM Coefficients for Net Peaking Generation

	Linear
Linear	0
Demand	3.4

Parameters for Calculating Scenario Capacity Benefits

Annual Perfect Capacity Cost ($/kW-yr)	97.05
Ann Perfect Cap Cost Real Growth	0
Average load factor of demand	0.65

Rest-of-System Emissions Rates (tons/MWh)

	Peaking	Base	
		Early	Late
SO2	0.00000	0.00810	0.00106
CO2	0.72150	1.55250	1.34375

Last yr of early period 2010

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATION – SELECTION OF TREE VALUES AND PROJECT PARAMETERS

Range: SELECT

Selected Tree Values										Mode Selectors	
Branch	Node 1 – Demand Value	Prob	Node 2 – Fuel Price Value	Prob	Node 3 – Altern Cost Value	Prob	Node 4 – NS2 Cost Value	Prob	Branch Probability	Alternative	6 PPL
										Cost Mode	1
41	2 Med	0.6	2 Med	0.6	2 Med	0.6	2 Med	0.6	0.1296	FCR Mode	1
										Retirement	1
										Tax	1

Cost Scen #	NS2									Selected Project
	2					2				
0 Project Number	BASE	1	2	3	4	5	6	7	0	6
1 Name	NS2	NS2	CT	CC	Wind	PV	PPL	Basin	0	PPL
2 Capacity (MW)	80	80	80	80	80	80	80	80	0	80
3 Capacity Purchase Adjust Period	0	0	0	0	0	0	5	5	0	5
4 Capacity Equivalence Factor	0.95	0.95	0.95	0.97	0.15	1	1	1	0	1
5 Equivalent Availability	0.895	0.895	0.913	0.933	0.3	0.3	1	1	0	1
6 Installed Cost ($/kW)	1561	1561	532	1023	1115	3185	220	300	0	220
7 Real Escalation Rate	0.03846	0.03846	0	0	-0.04	0	0	0	0	0
8 Fixed Charge Rate Pattern No.	1	1	2	3	2	2	1	5	0	1
9 Average Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	1000	1000	0	1000
10 Capacity Price Trajectory No.	0	0	0	0	0	0	7	9	0	7
11 Fuel Price Trajectory No.	1	1	5	4	0	0	8	10	0	8
12 Fixed O&M Cost ($/kW-yr)	26.46	26.46	11.56	14.14	54.5289	19.1422	0	24	0	0
13 Real Escalation Rate	0	0	0	0	0	0	0	0	0	0
14 Var O&M Cost ($/kW-yr)	3.04	3.04	4.5	6.07	0	0	0	0	0	0
15 Real Escalation Rate	0	0	0	0	0	0	0	0	0	0
16 SO2 Emissions Rate (tons/MWh)	0.00106	0.00106	0.00000	0.00000	0	0	0.00275	0.00106	0	0.00275
17 CO2 Emissions Rate (tons/MWh)	1.34375	1.34375	0.70695	0.48756	0	0	1.1	1.34375	0	1.1
18 Fuel Type	1	1	3	2	0	0	1	1	0	1
19 Tax Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	11000	11000	0	11000
20 Renewable Tax Credit	0	0	0	0	1	1	0	0	0	0
21 Production Cost Selector	1	1	2	3	1	1	4	4	0	4
22 Start-up Year	1996	1996	1996	1996	1996	1996	1996	1996	0	1996
23 Life	50	50	25	35	25	25	30	30	0	30

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – SELECTION OF SCENARIOS AND ESCALATION

Scenario #	Demand 2	DSM 2	Net Demand	Oil Price 2
1996	1818.2	0.0	1818.2	4.48
1997	1864.2	0.0	1864.2	4.60
1998	1911.7	0.0	1911.7	4.72
1999	1959.7	0.0	1959.7	4.85
2000	2007.8	0.0	2007.8	4.98
2001	2056.2	0.0	2056.2	5.12
2002	2104.8	0.0	2104.8	5.15
2003	2153.3	0.0	2153.3	5.15
2004	2201.8	0.0	2201.8	5.18
2005	2251.4	0.0	2251.4	5.23
2006	2302.3	0.0	2302.3	5.28
2007	2354.3	0.0	2354.3	5.35
2008	2407.7	0.0	2407.7	5.40
2009	2462.3	0.0	2462.3	5.40
2010	2518.2	0.0	2518.2	5.54
2011	2575.5	0.0	2575.5	5.77
2012	2634.1	0.0	2634.1	6.00
2013	2694.2	0.0	2694.2	6.26
2014	2755.7	0.0	2755.7	6.51
2015	2818.6	0.0	2818.6	6.77

	Escalation Rate	Annual Escalation	Compound Escalation
1996	0.0400	1.0400	1.0000
1997	0.0400	1.0400	1.0400
1998	0.0400	1.0400	1.0816
1999	0.0400	1.0400	1.1249
2000	0.0400	1.0400	1.1699
2001	0.0400	1.0400	1.2167
2002	0.0400	1.0400	1.2653
2003	0.0400	1.0400	1.3159
2004	0.0400	1.0400	1.3686
2005	0.0400	1.0400	1.4233
2006	0.0400	1.0400	1.4802
2007	0.0400	1.0400	1.5395
2008	0.0400	1.0400	1.6010
2009	0.0400	1.0400	1.6651
2010	0.0400	1.0400	1.7317
2011	0.0400	1.0400	1.8009
2012	0.0400	1.0400	1.8730
2013	0.0400	1.0400	1.9479
2014	0.0400	1.0400	2.0258
2015			2.1068
Beyond	0.0400	1.0400	

(Escalation is zero, with real cost mode.)

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – PROJECT FUEL AND PURCHASED POWER COSTS

Range: FUELCALC

	Cap Price	Fuel Price
Real esc after 2015	0	0.01723
Incr for high scenario	0.3	– –
Decr for low scenario	0.3	– –
Correl with oil price	– –	0.25
Cap price factor	1	

Mode Selectors		Scenario	
Alternative	6 PPL	Node 1 – Demand	2 Med
Cost Mode	1	Node 2 – Fuel Price	2 Med
FCR Mode	1	Node 3 – Altern Cost	2 Med
Retirement	1	Node 4 – NS2 Cost	2 Med
Tax	1		

	Change In Oil Price %	NS2 Coal Price	NS2 Var O&M	NS2 Disp Cost	NS2 Fixd O&M	Alternative Cap Price	Alternative Fuel Price	Alternative Var O&M	Alternative Disp Cost	Alternative Fixd O&M
1996	0.00%	0.60	3.04	10.59	26.46	213.24	16.84	0.00	16.84	0.00
1997	0.00%	0.65	3.16	11.25	27.52	214.32	17.54	0.00	17.54	0.00
1998	0.00%	0.54	3.29	9.98	28.62	215.40	18.28	0.00	18.28	0.00
1999	0.00%	0.52	3.42	9.88	29.76	216.48	19.07	0.00	19.07	0.00
2000	0.00%	0.38	3.56	8.24	30.95	217.56	19.90	0.00	19.90	0.00
2001	0.00%	0.34	3.70	7.92	32.19	218.64	20.82	0.00	20.82	0.00
2002	0.00%	0.23	3.85	6.76	33.48	219.72	21.84	0.00	21.84	0.00
2003	0.00%	0.23	4.00	6.90	34.82	220.80	22.95	0.00	22.95	0.00
2004	0.00%	0.17	4.16	6.33	36.21	221.88	24.12	0.00	24.12	0.00
2005	0.00%	0.00	4.33	4.33	37.66	223.08	25.41	0.00	25.41	0.00
2006	0.00%	0.00	4.50	4.50	39.17	224.16	26.82	0.00	26.82	0.00
2007	0.00%	0.00	4.68	4.68	40.73	225.24	28.34	0.00	28.34	0.00
2008	0.00%	0.00	4.87	4.87	42.36	226.44	30.00	0.00	30.00	0.00
2009	0.00%	0.00	5.06	5.06	44.06	227.52	31.74	0.00	31.74	0.00
2010	0.00%	0.00	5.26	5.26	45.82	228.60	33.59	0.00	33.59	0.00
2011	0.00%	0.00	5.47	5.47	47.65	229.80	35.54	0.00	35.54	0.00
2012	0.00%	0.00	5.69	5.69	49.56	231.00	37.60	0.00	37.60	0.00
2013	0.00%	0.00	5.92	5.92	51.54	232.16	39.78	0.00	39.78	0.00
2014	0.00%	0.00	6.16	6.16	53.60	233.33	42.08	0.00	42.08	0.00
2015	0.00%	0.00	6.40	6.40	55.75	234.50	44.52	0.00	44.52	0.00

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – RESPONSE SURFACE MODEL

Range: RSMCALC

Prod Cost Selector # 4

	Base	Demand	Oil Price	NS2 Cost	Alt Cost	D*D	D*OP	OP*OP
CF Coefs	Alt Cost	6.9	0	−3.6	−3.6	0	0	0
Ben Coefs		0.9	0.25	--	--	0	0	0
1996	16.84	0	0	0	0	0	0	0
1997	17.54	0	0	0	0	0	0	0
1998	18.28	0	0	0	0	0	0	0
1999	19.07	0	0	0	0	0	0	0
2000	19.90	0	0	0	0	0	0	0
2001	20.82	0	0	0	0	0	0	0
2002	21.84	0	0	0	0	0	0	0
2003	22.95	0	0	0	0	0	0	0
2004	24.12	0	0	0	0	0	0	0
2005	25.41	0	0	0	0	0	0	0
2006	26.82	0	0	0	0	0	0	0
2007	28.34	0	0	0	0	0	0	0
2008	30.00	0	0	0	0	0	0	0
2009	31.74	0	0	0	0	0	0	0
2010	33.59	0	0	0	0	0	0	0
2011	35.54	0	0	0	0	0	0	0
2012	37.60	0	0	0	0	0	0	0
2013	39.78	0	0	0	0	0	0	0
2014	42.08	0	0	0	0	0	0	0
2015	44.52	0	0	0	0	0	0	0

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Dispatch and Production Cost

Net Peak Gen Factor 1

	NS2 CF				Alt CF				Energy (GWh)			
	Linear Sum	Quadratic Sum	Exp(CF')	CF	Linear Sum	Quadratic Sum	Exp(CF')	CF	NS2	Alt	Net Peak	Net Base
1996	0	0	5.04627	75.6%	0	0	1.53126	60.6%	525.6	424.7	-18.1	119.0
1997	0	0	7.90502	79.8%	0	0	2.09798	67.9%	559.2	475.8	-20.6	104.0
1998	0	0	7.40809	79.2%	0	0	2.11710	68.1%	555.0	477.2	-22.2	100.0
1999	0	0	10.9708	82.4%	0	0	2.85460	74.3%	577.5	520.7	-28.3	85.1
2000	0	0	12.7978	83.4%	0	0	2.94492	74.9%	584.5	524.9	-29.7	89.3
2001	0	0	19.3062	85.5%	0	0	3.74113	79.2%	599.2	555.0	-32.8	77.0
2002	0	0	20.7735	85.8%	0	0	3.46847	77.9%	601.3	545.9	-32.0	87.4
2003	0	0	28.6210	86.9%	0	0	4.48817	82.1%	609.0	575.4	-33.8	67.4
2004	0	0	30.6982	87.1%	0	0	4.02411	80.4%	610.4	563.4	-34.0	81.0
2005	0	0	43.0561	87.9%	0	0	5.39100	84.7%	616.0	593.6	-37.9	60.3
2006	0	0	47.8137	88.1%	0	0	4.80349	83.1%	617.4	582.4	-39.4	74.4
2007	0	0	77.4743	88.8%	0	0	1.72227	63.4%	622.3	444.3	-27.8	205.9
2008	0	0	77.4743	88.8%	0	0	1.72963	63.5%	622.3	445.0	-24.8	202.1
2009	0	0	105.105	89.1%	0	0	2.14623	68.4%	624.4	479.3	-33.9	179.0
2010	0	0	105.105	89.1%	0	0	1.97044	66.5%	624.4	466.0	-28.7	187.1
2011	0	0	137.652	89.3%	0	0	8.99600	90.4%	625.8	633.5	-56.2	48.5
2012	0	0	137.652	89.3%	0	0	1.83695	64.9%	625.8	454.8	-22.2	193.2
2013	0	0	199	89.5%	0	0	2.86937	74.4%	627.2	521.4	-37.4	143.2
2014	0	0	199	89.5%	0	0	2.78243	73.8%	627.2	517.2	-38.5	148.5
2015	0	0	199	89.5%	0	0	3.69704	79.0%	627.2	553.6	-43.0	116.6

Production Cost and Capacity Surplus Calculations

	Base Gen Cost					Pk Cost
	Base Val $/MWh	Linear Sum	Quadratic Sum	Exp(Q)	Adj Val $/MWh	Adj Val $/MWh
1996	13.21	0	0	1	13.21	42.85
1997	13.89	0	0	1	13.89	48.72
1998	14.43	0	0	1	14.43	51.78
1999	15.21	0	0	1	15.21	50.90
2000	15.74	0	0	1	15.74	51.27
2001	16.62	0	0	1	16.62	50.97
2002	17.09	0	0	1	17.09	52.20
2003	18.17	0	0	1	18.17	52.55
2004	18.48	0	0	1	18.48	54.49
2005	19.26	0	0	1	19.26	55.01
2006	19.97	0	0	1	19.97	59.90
2007	16.91	0	0	1	16.91	56.44
2008	17.13	0	0	1	17.13	57.85
2009	18.04	0	0	1	18.04	58.34
2010	18.69	0	0	1	18.69	62.12
2011	15.03	0	0	1	15.03	66.57
2012	10.15	0	0	1	10.15	67.85
2013	11.95	0	0	1	11.95	71.35
2014	11.06	0	0	1	11.06	74.02
2015	12.37	0	0	1	12.37	76.61

	Capacity Surplus	Lagged Capacity Surplus
1996	0.00	0.00
1997	0.00	0.00
1998	0.00	0.00
1999	0.00	0.00
2000	0.00	0.00
2001	0.00	0.00
2002	0.00	0.00
2003	0.00	0.00
2004	0.00	0.00
2005	0.00	0.00
2006	0.00	0.00
2007	0.00	0.00
2008	0.00	0.00
2009	0.00	0.00
2010	0.00	0.00
2011	0.00	0.00
2012	0.00	0.00
2013	0.00	0.00
2014	0.00	0.00
2015	0.00	0.00

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Emissions Calculations

	Emissions (tons)							
	NS2		Alternative		Net Peaking		Net Base	
	SO2	CO2	SO2	CO2	SO2	CO2	SO2	CO2
1996	558	706275	1168	467153	-0	-13075	964	184805
1997	594	751477	1309	523428	-0	-14872	842	161471
1998	590	745826	1312	524969	-0	-15996	810	155186
1999	614	775961	1432	572764	-0	-20421	689	132068
2000	621	785378	1443	577389	-0	-21424	723	138579
2001	637	805154	1526	610537	-0	-23692	624	119523
2002	639	807979	1501	600816	-0	-23110	708	135678
2003	647	818337	1582	632892	-0	-24387	546	104700
2004	649	820221	1549	619788	-0	-24558	656	125738
2005	655	827754	1632	652935	-0	-27361	489	93691
2006	656	829638	1602	640601	-0	-28400	603	115511
2007	661	836230	1222	488738	-0	-20092	1667	319582
2008	661	836230	1224	489509	-0	-17914	1637	313809
2009	663	839055	1318	527282	-0	-24452	1450	277830
2010	663	839055	1282	512635	-0	-20737	1516	290508
2011	665	840938	1742	696876	-0	-40583	52	65225
2012	665	840938	1251	500301	-0	-16053	205	259672
2013	666	842822	1434	573535	-0	-26980	152	192446
2014	666	842822	1422	568909	-0	-27783	158	199591
2015	666	842822	1522	608995	-0	-31043	124	156695

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – ECONOMIC ANALYSIS

Range: ECONCALC

Alternative	6 PPL
Cost Mode	1
FCR Mode	1
Retirement	1
Tax	1

Node 1 – Demand	2 Med
Node 2 – Fuel Price	2 Med
Node 3 – Altern Cost	2 Med
Node 4 – NS2 Cost	2 Med

INTERMEDIATE CALCULATIONS

INITIAL COSTS		ESCALATION RATES	
Neil Simpson 2			
Construction Cost (M$)	124.88	NS2 Fuel Cost	1.000
		Variable O&M Cost	1.000
Retirement Year	2026	Fixed O&M Cost	1.000
Alternative			
Construction Cost (M$)	17.60	Fuel Cost	1.017
		Variable O&M Cost	1.000
Retirement Year	2026	Fixed O&M / Capacity Price	1.000
Last Year of Renewable Credit	0		
System			
		Net Prod Cost Savings, after 2020	1.000
		Cost Discount	1.000
Net Reliability Cost (M$)	−0.388	Net Reliability Cost	1.000

		Energy Tax Rates ($/MWh)	
Discount Rate	0.107	Neil Simpson 2	3.21
Annual Discount Factor	0.904	Alternative	2.83
Discount From 2015 to 1996	0.145	Net Peaking	7.79
		Net Base	3.34

Neil Simpson values are scaled to the size of the alternative project.

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De-escal	NS2						Alternative					
	Factor	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total
1996	1.000	3.97	1.60	2.12	15.73	1.97	25.38	7.15	0.00	17.06	2.22	1.78	28.21
1997	1.000	4.52	1.77	2.20	15.73	2.18	26.39	8.35	0.00	17.15	2.22	2.08	29.79
1998	1.000	3.72	1.82	2.29	15.73	2.25	25.80	8.72	0.00	17.23	2.22	2.17	30.34
1999	1.000	3.73	1.97	2.38	15.73	2.43	26.24	9.93	0.00	17.32	2.22	2.46	31.93
2000	1.000	2.74	2.08	2.48	15.73	2.56	25.58	10.45	0.00	17.40	2.22	2.58	32.65
2001	1.000	2.53	2.22	2.58	15.73	2.73	25.78	11.56	0.00	17.49	2.22	2.84	34.10
2002	1.000	1.75	2.31	2.68	15.73	2.85	25.32	11.92	0.00	17.58	2.22	2.90	34.62
2003	1.000	1.76	2.44	2.79	15.73	3.00	25.71	13.20	0.00	17.66	2.22	3.18	36.27
2004	1.000	1.32	2.54	2.90	15.73	3.13	25.61	13.59	0.00	17.75	2.22	3.24	36.80
2005	1.000	0.00	2.67	3.01	15.73	3.28	24.69	15.08	0.00	17.85	2.22	3.55	38.70
2006	1.000	0.00	2.78	3.13	15.73	3.42	25.06	15.62	0.00	17.93	2.22	3.62	39.39
2007	1.000	0.00	2.91	3.26	15.73	3.59	25.48	12.59	0.00	18.02	2.22	2.87	35.70
2008	1.000	0.00	3.03	3.39	15.73	3.73	25.87	13.35	0.00	18.12	2.22	2.99	36.68
2009	1.000	0.00	3.16	3.52	15.73	3.89	26.30	15.21	0.00	18.20	2.22	3.35	38.99
2010	1.000	0.00	3.29	3.67	15.73	4.05	26.73	15.65	0.00	18.29	2.22	3.39	39.55
2011	1.000	0.00	3.43	3.81	15.73	4.22	27.18	22.52	0.00	18.38	2.22	4.79	47.91
2012	1.000	0.00	3.56	3.96	15.73	4.39	27.64	17.10	0.00	18.48	2.22	3.58	41.38
2013	1.000	0.00	3.71	4.12	15.73	4.57	28.14	20.74	0.00	18.57	2.22	4.27	45.80
2014	1.000	0.00	3.86	4.29	15.73	4.76	28.63	21.76	0.00	18.67	2.22	4.40	47.05
2015	1.000	0.00	4.02	4.46	15.73	4.95	29.15	24.65	0.00	18.76	2.22	4.90	50.53
20 yr NPV		17.71	19.27	22.56	127.90	23.73	211.17	98.28	0.00	143.25	18.03	23.02	282.57

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De-escal	NS2						Alternative					
	Factor	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total
2016	1.000	0.00	4.18	4.64	15.73	5.14	29.69	26.08	0.00	19.51	2.22	5.10	52.90
2017	1.000	0.00	4.35	4.82	15.73	5.35	30.25	27.59	0.00	20.29	2.22	5.30	55.39
2018	1.000	0.00	4.52	5.02	15.73	5.56	30.83	29.18	0.00	21.10	2.22	5.51	58.02
2019	1.000	0.00	4.70	5.22	15.73	5.79	31.43	30.87	0.00	21.95	2.22	5.73	60.77
2020	1.000	0.00	4.89	5.43	15.73	6.02	32.06	32.66	0.00	22.82	2.22	5.96	63.67
2021	1.000	0.00	5.08	5.64	15.73	6.26	32.71	34.55	0.00	23.74	2.22	6.20	66.71
2022	1.000	0.00	5.29	5.87	15.73	6.51	33.39	36.56	0.00	24.69	2.22	6.45	69.91
2023	1.000	0.00	5.50	6.10	15.73	6.77	34.10	38.67	0.00	25.67	2.22	6.71	73.27
2024	1.000	0.00	5.72	6.35	15.73	7.04	34.83	40.91	0.00	26.70	2.22	6.98	76.81
2025	1.000	0.00	5.95	6.60	15.73	7.32	35.60	43.28	0.00	27.77	2.22	7.26	80.52
2026	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30 yr NPV		0.00	4.22	4.68	13.65	5.19	27.74	28.20	0.00	19.69	1.92	5.14	54.95
50 yr NPV		17.71	23.49	27.24	141.55	28.92	238.91	126.48	0.00	162.94	19.95	28.16	337.52

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Rel Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
1996	-0.39	-0.78	1.57	1.25	0.74	2.40	5.23	4.83	317.22	6.64	352.65	1.00	65.41
1997	-0.40	-1.00	1.44	1.34	0.63	2.01	5.41	4.72	329.93	6.26	372.35	0.97	67.59
1998	-0.42	-1.15	1.44	1.36	0.61	1.85	6.39	4.65	322.55	6.36	379.27	1.15	79.82
1999	-0.44	-1.44	1.29	1.48	0.46	1.36	7.04	4.54	328.03	6.13	399.07	1.22	88.00
2000	-0.45	-1.52	1.41	1.04	0.50	0.97	8.04	4.38	319.76	6.22	408.09	1.38	100.47
2001	-0.47	-1.67	1.28	0.88	0.38	0.40	8.72	4.30	322.24	6.14	426.26	1.44	109.00
2002	-0.49	-1.67	1.49	0.12	0.50	-0.05	9.25	4.21	316.48	6.34	432.74	1.54	115.66
2003	-0.51	-1.78	1.23	0.19	0.31	-0.57	9.99	4.22	321.41	6.30	453.33	1.64	124.86
2004	-0.53	-1.85	1.50	-0.15	0.46	-0.58	10.60	4.20	320.16	6.53	459.97	1.74	132.51
2005	-0.55	-2.09	1.16	-0.15	0.21	-1.42	12.59	4.01	308.58	6.52	483.70	2.04	157.41
2006	-0.57	-2.36	1.49	-0.37	0.36	-1.46	12.87	4.06	313.24	6.76	492.38	2.08	160.91
2007	-0.60	-1.57	3.48	-4.46	2.01	-1.14	9.07	4.10	318.55	8.04	446.27	1.46	113.44
2008	-0.62	-1.44	3.46	-4.42	2.08	-0.93	9.87	4.16	323.42	8.24	458.45	1.59	123.35
2009	-0.65	-1.98	3.23	-4.38	1.76	-2.01	10.67	4.21	328.80	8.13	487.33	1.71	133.43
2010	-0.67	-1.79	3.50	-4.39	2.01	-1.34	11.48	4.28	334.08	8.49	494.37	1.84	143.51
2011	-0.70	-3.74	0.73	-4.37	-0.45	-8.53	12.19	4.34	339.80	7.56	598.88	1.95	152.40
2012	-0.73	-1.51	1.96	-4.65	1.08	-3.85	9.88	4.42	345.53	9.10	517.21	1.58	123.55
2013	-0.76	-2.67	1.71	-4.51	0.51	-5.71	11.95	4.49	351.72	8.78	572.46	1.91	149.38
2014	-0.79	-2.85	1.64	-4.55	0.56	-5.99	12.43	4.57	357.92	9.10	588.12	1.98	155.33
2015	-0.82	-3.30	1.44	-4.54	0.25	-6.97	14.41	4.65	364.38	9.13	631.56	2.30	180.12
20 yr NPV	-4.14	-13.04	13.55	-2.96	5.53	-1.06	70.34	35.97	2639.62	55.54	3532.14	11.81	879.27

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Rel Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
2016	-0.85	-3.43	1.50	-4.72	0.26	-7.24	15.97	4.73	371.09	9.55	661.24	2.55	199.60
2017	-0.88	-3.57	1.56	-4.91	0.27	-7.53	17.61	4.82	378.07	10.01	692.42	2.81	220.19
2018	-0.92	-3.71	1.62	-5.11	0.28	-7.83	19.35	4.91	385.33	10.48	725.19	3.09	241.93
2019	-0.96	-3.86	1.69	-5.31	0.29	-8.15	21.19	5.01	392.88	10.98	759.63	3.38	264.90
2020	-1.00	-4.01	1.76	-5.52	0.30	-8.47	23.13	5.11	400.73	11.50	795.83	3.69	289.17
2021	-1.03	-4.17	1.83	-5.74	0.31	-8.81	25.18	5.22	408.90	12.05	833.87	4.02	314.81
2022	-1.08	-4.34	1.90	-5.97	0.32	-9.17	27.35	5.32	417.39	12.63	873.86	4.36	341.90
2023	-1.12	-4.51	1.97	-6.21	0.34	-9.53	29.64	5.44	426.22	13.23	915.90	4.73	370.52
2024	-1.16	-4.69	2.05	-6.46	0.35	-9.91	32.06	5.55	435.41	13.87	960.09	5.11	400.76
2025	-1.21	-4.88	2.14	-6.72	0.36	-10.31	34.62	5.68	444.96	14.54	1006.55	5.52	432.71
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30 yr NPV	-0.86	-3.46	1.51	-4.76	0.26	-7.31	19.90	4.42	346.73	9.93	686.89	3.17	248.79
50 yr NPV	-5.00	-16.50	15.07	-7.72	5.78	-8.37	90.25	40.40	2986.35	65.46	4219.02	14.98	1128.07
Levelized								4.53	334.89	7.34	473.13	1.68	126.50

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – PROBABILITY TREE

Project: 6

Range: TREECALC

	+NPV	+PROB	Weighted NPV
1	37.1677	0.0016	0.0595
2	4.8388	0.0048	0.0232
3	-27.7500	0.0016	-0.0444
4	77.2108	0.0048	0.3706
5	44.8820	0.0144	0.6463
6	12.2931	0.0048	0.0590
7	117.2539	0.0016	0.1876
8	84.9251	0.0048	0.4076
9	52.3362	0.0016	0.0837
10	38.3154	0.0048	0.1839
11	5.8171	0.0144	0.0838
12	-26.9881	0.0048	-0.1295
13	78.3586	0.0144	1.1284
14	45.8602	0.0432	1.9812
15	13.0550	0.0144	0.1880
16	118.4017	0.0048	0.5683
17	85.9033	0.0144	1.2370
18	53.0981	0.0048	0.2549
19	37.7419	0.0016	0.0604
20	5.0312	0.0048	0.0241
21	-28.0391	0.0016	-0.0449
22	77.7850	0.0048	0.3734
23	45.0743	0.0144	0.6491
24	12.0040	0.0048	0.0576
25	117.8281	0.0016	0.1885
26	85.1175	0.0048	0.4086
27	52.0471	0.0016	0.0833

Cum Prob	Sorted Scen No.	Sorted NPV	Sorted Prob	Cum Prob
0		-1000		0
0.0016	21	-28.0391	0.0016	0.0016
0.0032	3	-27.7500	0.0016	0.0032
0.0080	12	-26.9881	0.0048	0.0080
0.0128	30	4.1337	0.0048	0.0128
0.0176	2	4.8388	0.0048	0.0176
0.0224	20	5.0312	0.0048	0.0224
0.0240	57	5.1780	0.0016	0.0240
0.0384	11	5.8171	0.0144	0.0384
0.0528	39	5.8770	0.0144	0.0528
0.0576	48	6.0012	0.0048	0.0576
0.0624	66	6.8395	0.0048	0.0624
0.0640	75	7.2794	0.0016	0.0640
0.0688	24	12.0040	0.0048	0.0688
0.0736	6	12.2931	0.0048	0.0736
0.0880	15	13.0550	0.0144	0.0880
0.1024	29	36.4539	0.0144	0.1024
0.1040	1	37.1677	0.0016	0.1040
0.1088	56	37.2734	0.0048	0.1088
0.1104	19	37.7419	0.0016	0.1104
0.1152	10	38.3154	0.0048	0.1152
0.1584	38	38.3715	0.0432	0.1584
0.1728	47	38.7175	0.0144	0.1728
0.1872	65	39.0613	0.0144	0.1872
0.1920	74	39.6664	0.0048	0.1920
0.2064	5	44.8820	0.0144	0.2064
0.2208	23	45.0743	0.0144	0.2208
0.2640	14	45.8602	0.0432	0.2640

28	68.5736	0.0048	0.3292
29	36.4539	0.0144	0.5249
30	4.1337	0.0048	0.0198
31	120.4473	0.0144	1.7344
32	88.3277	0.0432	3.8158
33	56.0075	0.0144	0.8065
34	172.3211	0.0048	0.8271
35	140.2014	0.0144	2.0189
36	107.8812	0.0048	0.5178
37	70.6250	0.0144	1.0170
38	38.3715	0.0432	1.6577
39	5.8770	0.0144	0.0846
40	122.4987	0.0432	5.2919
41	90.2453	0.1296	11.6958
42	57.7507	0.0432	2.4948
43	174.3724	0.0144	2.5110
44	142.1190	0.0432	6.1395
45	109.6245	0.0144	1.5786
46	71.1446	0.0048	0.3415
47	38.7175	0.0144	0.5575
48	6.0012	0.0048	0.0288
49	123.0183	0.0144	1.7715
50	90.5912	0.0432	3.9135
51	57.8749	0.0144	0.8334
52	174.8921	0.0048	0.8395
53	142.4650	0.0144	2.0515
54	109.7487	0.0048	0.5268

0.2656	27	52.0471	0.0016	0.2656
0.2672	9	52.3362	0.0016	0.2672
0.2720	18	53.0981	0.0048	0.2720
0.2864	33	56.0075	0.0144	0.2864
0.2912	60	57.0518	0.0048	0.2912
0.3344	42	57.7507	0.0432	0.3344
0.3488	51	57.8749	0.0144	0.3488
0.3632	69	58.7132	0.0144	0.3632
0.3680	78	59.1531	0.0048	0.3680
0.3728	28	68.5736	0.0048	0.3728
0.3744	55	69.2255	0.0016	0.3744
0.3888	37	70.6250	0.0144	0.3888
0.3936	64	71.1084	0.0048	0.3936
0.3984	46	71.1446	0.0048	0.3984
0.4000	73	71.8398	0.0016	0.4000
0.4048	4	77.2108	0.0048	0.4048
0.4096	22	77.7850	0.0048	0.4096
0.4240	13	78.3586	0.0144	0.4240
0.4288	8	84.9251	0.0048	0.4288
0.4336	26	85.1175	0.0048	0.4336
0.4480	17	85.9033	0.0144	0.4480
0.4912	32	88.3277	0.0432	0.4912
0.5056	59	89.1472	0.0144	0.5056
0.6352	41	90.2453	0.1296	0.6352
0.6784	50	90.5912	0.0432	0.6784
0.7216	68	90.9351	0.0432	0.7216
0.7360	77	91.5401	0.0144	0.7360

55	69.2255	0.0016	0.11076
56	37.2734	0.0048	0.17891
57	5.1780	0.0016	0.00828
58	121.0993	0.0048	0.58127
59	89.1472	0.0144	1.28371
60	57.0518	0.0048	0.27384
61	172.9730	0.0016	0.27675
62	141.0209	0.0048	0.67690
63	108.9255	0.0016	0.17428
64	71.1084	0.0048	0.34132
65	39.0613	0.0144	0.56248
66	6.8395	0.0048	0.03282
67	122.9821	0.0144	1.77094
68	90.9351	0.0432	3.92839
69	58.7132	0.0144	0.84547
70	174.8558	0.0048	0.83930
71	142.8088	0.0144	2.05644
72	110.5870	0.0048	0.53081
73	71.8398	0.0016	0.11494
74	39.6664	0.0048	0.19039
75	7.2794	0.0016	0.01164
76	123.7135	0.0048	0.59382
77	91.5401	0.0144	1.31817
78	59.1531	0.0048	0.28393
79	175.5873	0.0016	0.28093
80	143.4138	0.0048	0.68838
81	111.0268	0.0016	0.1776
UV		1	81.1312

0.7408	36	107.8812	0.0048	0.7408
0.7424	63	108.9255	0.0016	0.7424
0.7568	45	109.6245	0.0144	0.7568
0.7616	54	109.7487	0.0048	0.7616
0.7664	72	110.5870	0.0048	0.7664
0.7680	81	111.0268	0.0016	0.7680
0.7696	7	117.2539	0.0016	0.7696
0.7712	25	117.8281	0.0016	0.7712
0.7760	16	118.4017	0.0048	0.7760
0.7904	31	120.4473	0.0144	0.7904
0.7952	58	121.0993	0.0048	0.7952
0.8384	40	122.4987	0.0432	0.8384
0.8528	67	122.9821	0.0144	0.8528
0.8672	49	123.0183	0.0144	0.8672
0.8720	76	123.7135	0.0048	0.8720
0.8864	35	140.2014	0.0144	0.8864
0.8912	62	141.0209	0.0048	0.8912
0.9344	44	142.1190	0.0432	0.9344
0.9488	53	142.4650	0.0144	0.9488
0.9632	71	142.8088	0.0144	0.9632
0.9680	80	143.4138	0.0048	0.9680
0.9728	34	172.3211	0.0048	0.9728
0.9744	61	172.9730	0.0016	0.9744
0.9888	43	174.3724	0.0144	0.9888
0.9936	70	174.8558	0.0048	0.9936
0.9984	52	174.8921	0.0048	0.9984
1.0000	79	175.5873	0.0016	1.0000

OUTPUT REPORT – ECONOMIC ANALYSIS

Range: ECONREPT

Alternative	6 PPL	Node 1 – Demand	2 Med
Cost Mode	1	Node 2 – Fuel Price	2 Med
FCR Mode	1	Node 3 – Altern Cost	2 Med
Retirement	1	Node 4 – NS2 Cost	2 Med
Tax	1		

	Present Value (M$)			
	NS2 Alternative		System	Net
Fuel/Energy Cost	17.71	126.48	−9.16	99.61
Variable O&M Cost	23.49	0.00	--	−23.49
Fixed O&M/Capacity Cost	27.24	162.94	−5.00	130.70
Investment Cost	141.55	19.95	--	−121.60
Emissions / Tax Cost	28.92	28.16	5.78	5.02
Total	238.91	337.52	−8.37	90.25

	Present Value (M$)
Alternative Resource Capital Cost	19.95
Alternative Resource Operating Cost	289.41
Neil Simpson #2 Capital Cost	141.55
Neil Simpson #2 Operating Cost	68.43
Net System Generation & Reliability Cost	−14.15
Net Emissions / Tax Cost	5.02
Net Cost	90.25

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

OUTPUT REPORT – PROBABILITY TREE CALCULATIONS

Range: TREEREPT

	NPV Savings (M$)
Base Case	90.25
10% Fractile	13.06
50% Fractile	88.33
90% Fractile	141.02
Expected Value	81.15
Prob of Negative NPV	0.8%

Alternative	6 PPL
Cost Mode	1
FCR Mode	1
Retirement	1
Tax	1

MACROS

Range: MACROS

Macro to create window for Net Present Value
\n {Home}{Down}/WWH{Goto}npvlabel~{Window}

Macro to create window for Expected Value
\e {Home}{Down}/WWH{Goto}evlabel~{Window}

Macro to construct cumulative distribution of results
\d /RVtreetabl~treesort~/DSDtreesort~Papvsort~A~G{Calc}

Macro to graph cumulative distribution
\g /GRGTX
Xxrange~Ayrange~
OFGNGLQ
TFFigure 2-7~
TSNeil Simpson 2 Probabilistic Analysis~
TXNet Present Value (M$)~
TYCumulative Probability~
OV
Scumdist~RQ

APPENDIX A2

Base Case Economic Analysis Results

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

OUTPUT REPORT - ECONOMIC ANALYSIS

Range: ECONREPT

Alternative	2 CT	Node 1 - Demand	2 Med
Cost Mode	1	Node 2 - Fuel Price	2 Med
FCR Mode	1	Node 3 - Altern Cost	2 Med
Retirement	1	Node 4 - NS2 Cost	2 Med
Tax	1		

	Present Value (M$)			
	NS2 Alternative		System	Net
Fuel/Energy Cost	17.71	99.62	154.33	236.25
Variable O&M Cost	21.70	9.04	--	-12.66
Fixed O&M/Capacity Cost	25.27	11.04	0.00	-14.23
Investment Cost	136.42	55.96	--	-80.46
Emissions / Tax Cost	26.73	15.34	32.80	21.41
Total	227.82	191.00	187.13	150.31

	Present Value (M$)
Alternative Resource Capital Cost	55.96
Alternative Resource Operating Cost	119.70
Neil Simpson #2 Capital Cost	136.42
Neil Simpson #2 Operating Cost	64.67
Net System Generation & Reliability Cost	154.33
Net Emissions / Tax Cost	21.41
Net Cost	150.31

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATION – SELECTION OF TREE VALUES AND PROJECT PARAMETERS

Range: SELECT

Selected Tree Values										Mode Selectors	
Branch	Node 1 – Demand Value	Prob	Node 2 – Fuel Price Value	Prob	Node 3 – Altern Cost Value	Prob	Node 4 – NS2 Cost Value	Prob	Branch Probability	Alternative	2 CT
										Cost Mode	1
										FCR Mode	1
41	2	0.6	2	0.6	2	0.6	2	0.6	0.1296	Retirement	1
	Med		Med		Med		Med			Tax	1

	NS2									Selected
Cost Scen #	2					2				Project
0 Project Number	BASE	1	2	3	4	5	6	7	0	2
1 Name	NS2	NS2	CT	CC	Wind	PV	PPL	Basin	0	CT
2 Capacity (MW)	80	80	80	80	80	80	80	80	0	80
3 Capacity Purchase Adjust Period	0	0	0	0	0	0	5	5	0	0
4 Capacity Equivalence Factor	0.95	0.95	0.95	0.97	0.15	1	1	1	0	0.95
5 Equivalent Availability	0.895	0.895	0.913	0.933	0.3	0.3	1	1	0	0.913
6 Installed Cost ($/kW)	1561	1561	532	1023	1115	3185	220	300	0	532
7 Real Escalation Rate	0.03846	0.03846	0	0	−0.04	0	0	0	0	0
8 Fixed Charge Rate Pattern No.	1	1	2	3	2	2	1	5	0	2
9 Average Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	1000	1000	0	12738
10 Capacity Price Trajectory No.	0	0	0	0	0	0	7	9	0	0
11 Fuel Price Trajectory No.	1	1	5	4	0	0	8	10	0	5
12 Fixed O&M Cost ($/kW−yr)	26.46	26.46	11.56	14.14	54.5289	19.1422	0	24	0	11.56
13 Real Escalation Rate	0	0	0	0	0	0	0	0	0	0
14 Var O&M Cost ($/kW−yr)	3.04	3.04	4.5	6.07	0	0	0	0	0	4.5
15 Real Escalation Rate	0	0	0	0	0	0	0	0	0	0
16 SO2 Emissions Rate (tons/MWh)	0.00106	0.00106	0.00000	0.00000	0	0	0.00275	0.00106	0	0.00000
17 CO2 Emissions Rate (tons/MWh)	1.34375	1.34375	0.70695	0.48756	0	0	1.1	1.34375	0	0.70695
18 Fuel Type	1	1	3	2	0	0	1	1	0	3
19 Tax Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	11000	11000	0	12738
20 Renewable Tax Credit	0	0	0	0	1	1	0	0	0	0
21 Production Cost Selector	1	1	2	3	1	1	4	4	0	2
22 Start−up Year	1996	1996	1996	1996	1996	1996	1996	1996	0	1996
23 Life	50	50	25	35	25	25	30	30	0	25

CALCULATIONS – SELECTION OF SCENARIOS AND ESCALATION

Scenario #	Demand 2	DSM 2	Net Demand	Oil Price 2
1996	1818.2	0.0	1818.2	4.48
1997	1864.2	0.0	1864.2	4.60
1998	1911.7	0.0	1911.7	4.72
1999	1959.7	0.0	1959.7	4.85
2000	2007.8	0.0	2007.8	4.98
2001	2056.2	0.0	2056.2	5.12
2002	2104.8	0.0	2104.8	5.15
2003	2153.3	0.0	2153.3	5.15
2004	2201.8	0.0	2201.8	5.18
2005	2251.4	0.0	2251.4	5.23
2006	2302.3	0.0	2302.3	5.28
2007	2354.3	0.0	2354.3	5.35
2008	2407.7	0.0	2407.7	5.40
2009	2462.3	0.0	2462.3	5.40
2010	2518.2	0.0	2518.2	5.54
2011	2575.5	0.0	2575.5	5.77
2012	2634.1	0.0	2634.1	6.00
2013	2694.2	0.0	2694.2	6.26
2014	2755.7	0.0	2755.7	6.51
2015	2818.6	0.0	2818.6	6.77

	Escalation Rate	Annual Escalation	Compound Escalation
1996	0.0400	1.0400	1.0000
1997	0.0400	1.0400	1.0400
1998	0.0400	1.0400	1.0816
1999	0.0400	1.0400	1.1249
2000	0.0400	1.0400	1.1699
2001	0.0400	1.0400	1.2167
2002	0.0400	1.0400	1.2653
2003	0.0400	1.0400	1.3159
2004	0.0400	1.0400	1.3686
2005	0.0400	1.0400	1.4233
2006	0.0400	1.0400	1.4802
2007	0.0400	1.0400	1.5395
2008	0.0400	1.0400	1.6010
2009	0.0400	1.0400	1.6651
2010	0.0400	1.0400	1.7317
2011	0.0400	1.0400	1.8009
2012	0.0400	1.0400	1.8730
2013	0.0400	1.0400	1.9479
2014	0.0400	1.0400	2.0258
2015			2.1068
Beyond	0.0400	1.0400	

(Escalation is zero, with real cost mode.)

CALCULATIONS - PROJECT FUEL AND PURCHASED POWER COSTS

Range: FUELCALC

	Cap Price	Fuel Price
Real esc after 2015	0	0.02
Incr for high scenario	0	--
Decr for low scenario	0	--
Correl with oil price	0	1
Cap price factor	1	

Mode Selectors		Scenario	
Alternative	2 CT	Node 1 - Demand	2 Med
Cost Mode	1	Node 2 - Fuel Price	2 Med
FCR Mode	1	Node 3 - Altern Cost	2 Med
Retirement	1	Node 4 - NS2 Cost	2 Med
Tax	1		

	Change In Oil Price %	NS2 Coal Price	NS2 Var O&M	NS2 Disp Cost	NS2 Fixd O&M	Alternative Cap Price	Alternative Fuel Price	Alternative Var O&M	Alternative Disp Cost	Alternative Fixd O&M
1996	0.00%	0.60	3.04	10.59	26.46	0.00	4.48	4.50	61.57	11.56
1997	0.00%	0.65	3.16	11.25	27.52	0.00	4.60	4.68	63.27	12.02
1998	0.00%	0.54	3.29	9.98	28.62	0.00	4.72	4.87	64.99	12.50
1999	0.00%	0.52	3.42	9.88	29.76	0.00	4.85	5.06	66.84	13.00
2000	0.00%	0.38	3.56	8.24	30.95	0.00	4.98	5.26	68.70	13.52
2001	0.00%	0.34	3.70	7.92	32.19	0.00	5.12	5.47	70.69	14.06
2002	0.00%	0.23	3.85	6.76	33.48	0.00	5.15	5.69	71.29	14.63
2003	0.00%	0.23	4.00	6.90	34.82	0.00	5.15	5.92	71.52	15.21
2004	0.00%	0.17	4.16	6.33	36.21	0.00	5.18	6.16	72.14	15.82
2005	0.00%	0.00	4.33	4.33	37.66	0.00	5.23	6.40	73.02	16.45
2006	0.00%	0.00	4.50	4.50	39.17	0.00	5.28	6.66	73.92	17.11
2007	0.00%	0.00	4.68	4.68	40.73	0.00	5.35	6.93	75.08	17.80
2008	0.00%	0.00	4.87	4.87	42.36	0.00	5.40	7.20	75.99	18.51
2009	0.00%	0.00	5.06	5.06	44.06	0.00	5.40	7.49	76.28	19.25
2010	0.00%	0.00	5.26	5.26	45.82	0.00	5.54	7.79	78.36	20.02
2011	0.00%	0.00	5.47	5.47	47.65	0.00	5.77	8.10	81.60	20.82
2012	0.00%	0.00	5.69	5.69	49.56	0.00	6.00	8.43	84.86	21.65
2013	0.00%	0.00	5.92	5.92	51.54	0.00	6.26	8.77	88.51	22.52
2014	0.00%	0.00	6.16	6.16	53.60	0.00	6.51	9.12	92.04	23.42
2015	0.00%	0.00	6.40	6.40	55.75	0.00	6.77	9.48	95.72	24.36

CALCULATIONS – RESPONSE SURFACE MODEL

Range: RSMCALC

Prod Cost Selector # 2

	Base	Demand	Oil Price	NS2 Cost	Alt Cost	D*D	D*OP	OP*OP
CF Coefs	Alt Cost	6.9	0	-3.6	-3.6	0	0	0
Ben Coefs		0.9	0.25	--	--	0	0	0
1996	61.57	0	0	0	0	0	0	0
1997	63.27	0	0	0	0	0	0	0
1998	64.99	0	0	0	0	0	0	0
1999	66.84	0	0	0	0	0	0	0
2000	68.70	0	0	0	0	0	0	0
2001	70.69	0	0	0	0	0	0	0
2002	71.29	0	0	0	0	0	0	0
2003	71.52	0	0	0	0	0	0	0
2004	72.14	0	0	0	0	0	0	0
2005	73.02	0	0	0	0	0	0	0
2006	73.92	0	0	0	0	0	0	0
2007	75.08	0	0	0	0	0	0	0
2008	75.99	0	0	0	0	0	0	0
2009	76.28	0	0	0	0	0	0	0
2010	78.36	0	0	0	0	0	0	0
2011	81.60	0	0	0	0	0	0	0
2012	84.86	0	0	0	0	0	0	0
2013	88.51	0	0	0	0	0	0	0
2014	92.04	0	0	0	0	0	0	0
2015	95.72	0	0	0	0	0	0	0

Dispatch and Production Cost

Net Peak Gen Factor 0

	NS2 CF				Alt CF				Energy (GWh)			
	Linear Sum	Quadratic Sum	Exp(CF')	CF	Linear Sum	Quadratic Sum	Exp(CF')	CF	NS2	Alt	Net Peak	Net Base
1996	0	0	5.04627	75.0%	0	0	0.30145	20.9%	525.6	146.5	0.0	379.1
1997	0	0	7.90502	79.8%	0	0	0.35392	23.7%	559.2	165.7	0.0	393.5
1998	0	0	7.40809	79.2%	0	0	0.27800	19.6%	555.0	137.4	0.0	417.7
1999	0	0	10.9708	82.4%	0	0	0.38970	25.4%	577.5	178.0	0.0	399.5
2000	0	0	12.7978	83.4%	0	0	0.39919	25.9%	584.5	181.2	0.0	403.3
2001	0	0	19.3062	85.5%	0	0	0.46011	28.6%	599.2	200.4	0.0	398.8
2002	0	0	20.7735	85.8%	0	0	0.51280	30.8%	601.3	215.8	0.0	385.4
2003	0	0	28.6210	86.9%	0	0	0.99783	45.6%	609.0	319.6	0.0	289.4
2004	0	0	30.6982	87.1%	0	0	1.45199	54.2%	610.4	379.5	0.0	230.9
2005	0	0	43.0561	87.9%	0	0	0.45665	28.5%	616.0	199.4	0.0	416.6
2006	0	0	47.8137	88.1%	0	0	0.43177	27.4%	617.4	191.7	0.0	425.7
2007	0	0	77.4743	88.8%	0	0	0.17165	13.1%	622.3	91.5	0.0	530.9
2008	0	0	77.4743	88.8%	0	0	0.18141	13.7%	622.3	96.0	0.0	526.3
2009	0	0	105.105	89.1%	0	0	0.23852	17.3%	624.4	121.2	0.0	503.2
2010	0	0	105.105	89.1%	0	0	0.23108	16.9%	624.4	118.1	0.0	506.3
2011	0	0	137.652	89.3%	0	0	0.68408	37.0%	625.8	259.3	0.0	366.5
2012	0	0	137.652	89.3%	0	0	0.14403	11.1%	625.8	78.1	0.0	547.7
2013	0	0	199	89.5%	0	0	0.14191	11.0%	627.2	77.1	0.0	550.1
2014	0	0	199	89.5%	0	0	0.15117	11.7%	627.2	81.6	0.0	545.6
2015	0	0	199	89.5%	0	0	0.20455	15.2%	627.2	106.5	0.0	520.7

Production Cost and Capacity Surplus Calculations

	Base Gen Cost					Pk Cost
	Base Val $/MWh	Linear Sum	Quadratic Sum	Exp(Q)	Adj Val $/MWh	Adj Val $/MWh
1996	18.74	0	0	1	18.74	42.85
1997	22.37	0	0	1	22.37	48.72
1998	25.16	0	0	1	25.16	51.78
1999	27.98	0	0	1	27.98	50.90
2000	29.00	0	0	1	29.00	51.27
2001	33.89	0	0	1	33.89	50.97
2002	36.78	0	0	1	36.78	52.20
2003	48.36	0	0	1	48.36	52.55
2004	81.98	0	0	1	81.98	54.49
2005	61.17	0	0	1	61.17	55.01
2006	63.33	0	0	1	63.33	59.90
2007	51.35	0	0	1	51.35	56.44
2008	52.27	0	0	1	52.27	57.85
2009	54.82	0	0	1	54.82	58.34
2010	56.07	0	0	1	56.07	62.12
2011	70.21	0	0	1	70.21	66.57
2012	56.29	0	0	1	56.29	67.85
2013	65.13	0	0	1	65.13	71.35
2014	67.56	0	0	1	67.56	74.02
2015	73.02	0	0	1	73.02	76.61

	Capacity Surplus	Lagged Capacity Surplus
1996	0.00	0.00
1997	0.00	0.00
1998	0.00	0.00
1999	0.00	0.00
2000	0.00	0.00
2001	0.00	0.00
2002	0.00	0.00
2003	0.00	0.00
2004	0.00	0.00
2005	0.00	0.00
2006	0.00	0.00
2007	0.00	0.00
2008	0.00	0.00
2009	0.00	0.00
2010	0.00	0.00
2011	0.00	0.00
2012	0.00	0.00
2013	0.00	0.00
2014	0.00	0.00
2015	0.00	0.00

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Emissions Calculations

	Emissions (tons)							
	NS2		Alternative		Net Peaking		Net Base	
	SO2	CO2	SO2	CO2	SO2	CO2	SO2	CO2
1996	558	706275	1	103546	0	0	3071	588604
1997	594	751477	1	117171	0	0	3187	610908
1998	590	745826	0	97106	0	0	3383	648443
1999	614	775961	1	125841	0	0	3236	620155
2000	621	785378	1	128070	0	0	3267	626139
2001	637	805154	1	141695	0	0	3230	619067
2002	639	807979	1	152595	0	0	3122	598396
2003	647	818337	1	225919	0	0	2344	449341
2004	649	820221	1	268279	0	0	1870	358493
2005	655	827754	1	140952	0	0	3375	646811
2006	656	829638	1	135502	0	0	3448	660955
2007	661	836230	0	64655	0	0	4300	824154
2008	661	836230	0	67875	0	0	4263	817082
2009	663	839055	0	85711	0	0	4076	781178
2010	663	839055	0	83481	0	0	4101	786074
2011	665	840938	1	183312	0	0	389	492509
2012	665	840938	0	55241	0	0	582	735939
2013	666	842822	0	54498	0	0	585	739235
2014	666	842822	0	57718	0	0	580	733113
2015	666	842822	0	75306	0	0	553	699683

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – ECONOMIC ANALYSIS

Range: ECONCALC

Alternative	2 CT
Cost Mode	1
PCR Mode	1
Retirement	1
Tax	1

Node 1 – Demand	2 Med
Node 2 – Fuel Price	2 Med
Node 3 – Altern Cost	2 Med
Node 4 – NS2 Cost	2 Med

INTERMEDIATE CALCULATIONS

INITIAL COSTS		ESCALATION RATES	
Neil Simpson 2			
Construction Cost (M$)	124.88	NS2 Fuel Cost	1.000
		Variable O&M Cost	1.000
Retirement Year	2021	Fixed O&M Cost	1.000
Alternative			
Construction Cost (M$)	42.56	Fuel Cost	1.020
		Variable O&M Cost	1.000
Retirement Year	2021	Fixed O&M / Capacity Price	1.000
Last Year of Renewable Credit	0		
System			
		Net Prod Cost Savings, after 2020	1.000
		Coal Discount	1.000
Net Reliability Cost (M$)	0.000	Net Reliability Cost	1.000

Discount Rate	0.107
Annual Discount Factor	0.904
Discount From 2015 to 1996	0.145

Energy Tax Rates ($/MWh)	
Neil Simpson 2	3.21
Alternative	7.63
Net Peaking	7.79
Net Base	3.34

Neil Simpson values are scaled to the size of the alternative project.

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De-escal	NS2						Alternative					
	Factor	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total
1996	1.000	3.97	1.60	2.12	15.73	1.97	25.38	8.36	0.66	0.92	6.45	1.12	17.51
1997	1.000	4.52	1.77	2.20	15.73	2.18	26.39	9.71	0.78	0.96	6.45	1.32	19.22
1998	1.000	3.72	1.82	2.29	15.73	2.25	25.80	8.26	0.67	1.00	6.45	1.13	17.51
1999	1.000	3.73	1.97	2.38	15.73	2.43	26.24	11.00	0.90	1.04	6.45	1.53	20.92
2000	1.000	2.74	2.08	2.48	15.73	2.56	25.58	11.49	0.95	1.08	6.45	1.62	21.60
2001	1.000	2.53	2.22	2.58	15.73	2.73	25.78	13.07	1.10	1.13	6.45	1.86	23.61
2002	1.000	1.75	2.31	2.68	15.73	2.85	25.32	14.16	1.23	1.17	6.45	2.08	25.09
2003	1.000	1.76	2.44	2.79	15.73	3.00	25.71	20.96	1.89	1.22	6.45	3.21	33.73
2004	1.000	1.32	2.54	2.90	15.73	3.13	25.61	25.04	2.34	1.27	6.45	3.96	39.06
2005	1.000	0.00	2.67	3.01	15.73	3.28	24.69	13.28	1.28	1.32	6.45	2.17	24.49
2006	1.000	0.00	2.78	3.13	15.73	3.42	25.06	12.89	1.28	1.37	6.45	2.17	24.15
2007	1.000	0.00	2.91	3.26	15.73	3.59	25.48	6.23	0.63	1.42	6.45	1.07	15.82
2008	1.000	0.00	3.03	3.39	15.73	3.73	25.87	6.60	0.69	1.48	6.45	1.17	16.40
2009	1.000	0.00	3.16	3.52	15.73	3.89	26.30	8.34	0.91	1.54	6.45	1.54	18.78
2010	1.000	0.00	3.29	3.67	15.73	4.05	26.73	8.33	0.92	1.60	6.45	1.56	18.87
2011	1.000	0.00	3.43	3.81	15.73	4.22	27.18	19.06	2.10	1.67	6.45	3.56	32.84
2012	1.000	0.00	3.56	3.96	15.73	4.39	27.64	5.97	0.66	1.73	6.45	1.12	15.93
2013	1.000	0.00	3.71	4.12	15.73	4.57	28.14	6.15	0.68	1.80	6.45	1.15	16.22
2014	1.000	0.00	3.86	4.29	15.73	4.76	28.63	6.77	0.74	1.87	6.45	1.26	17.10
2015	1.000	0.00	4.02	4.46	15.73	4.95	29.15	9.19	1.01	1.95	6.45	1.71	20.31
20 yr NPV		17.71	19.27	22.56	127.90	23.73	211.17	93.73	8.43	9.86	52.47	14.30	178.78

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De-escal	NS2						Alternative					
	Factor	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total
2016	1.000	0.00	4.18	4.64	15.73	5.14	29.69	9.74	1.05	2.03	6.45	1.78	21.05
17	1.000	0.00	4.35	4.82	15.73	5.35	30.25	10.34	1.09	2.11	6.45	1.85	21.84
2018	1.000	0.00	4.52	5.02	15.73	5.56	30.83	10.97	1.14	2.19	6.45	1.93	22.67
2019	1.000	0.00	4.70	5.22	15.73	5.79	31.43	11.63	1.18	2.28	6.45	2.00	23.55
2020	1.000	0.00	4.89	5.43	15.73	6.02	32.06	12.34	1.23	2.37	6.45	2.08	24.47
2021	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30 yr NPV		0.00	2.43	2.70	8.52	3.00	16.65	5.89	0.61	1.18	3.50	1.04	12.22
50 yr NPV		17.31	21.70	25.27	136.42	26.73	227.82	99.62	9.04	11.04	55.96	15.34	191.06

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Rel Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
1996	0.00	0.00	7.10	1.25	2.80	11.16	3.29	4.83	317.22	11.96	218.89	0.63	41.15
1997	0.00	0.00	8.80	1.34	3.02	13.17	5.99	4.72	329.93	11.59	240.20	1.07	74.91
1998	0.00	0.00	10.51	1.36	3.34	15.21	6.92	4.65	322.55	12.75	218.90	1.25	86.44
1999	0.00	0.00	11.18	1.48	3.32	15.98	10.66	4.54	328.03	11.75	261.47	1.85	133.20
2000	0.00	0.00	11.70	1.04	3.49	16.23	12.24	4.38	319.76	11.92	269.95	2.09	153.01
2001	0.00	0.00	13.51	0.88	3.59	17.98	15.81	4.30	322.24	11.78	295.08	2.64	197.62
2002	0.00	0.00	14.18	0.12	3.60	17.90	17.68	4.21	316.48	11.63	313.68	2.94	220.97
2003	0.00	0.00	14.00	0.19	2.82	17.00	25.02	4.22	321.41	10.56	421.67	4.11	312.74
2004	0.00	0.00	18.93	−0.15	2.34	21.12	34.56	4.20	320.16	10.29	488.21	5.66	432.01
2005	0.00	0.00	25.49	−0.15	4.38	29.71	29.52	4.01	308.58	12.28	306.16	4.79	369.01
2006	0.00	0.00	26.96	−0.37	4.66	31.25	30.34	4.06	313.24	12.60	301.92	4.91	379.25
2007	0.00	0.00	27.26	−4.46	6.04	28.84	19.17	4.10	318.55	17.29	197.69	3.08	239.59
2008	0.00	0.00	27.51	−4.42	6.23	29.32	19.84	4.16	323.42	17.08	205.01	3.19	248.03
2009	0.00	0.00	27.59	−4.38	6.19	29.40	21.88	4.21	328.80	15.49	234.75	3.50	273.48
2010	0.00	0.00	28.39	−4.39	6.48	30.48	22.62	4.28	334.08	15.98	235.83	3.62	282.73
2011	0.00	0.00	25.73	−4.37	2.56	23.92	29.58	4.34	339.80	12.67	410.50	4.73	369.70
2012	0.00	0.00	30.83	−4.65	3.97	30.15	18.44	4.42	345.53	20.39	199.14	2.95	230.49
2013	0.00	0.00	35.83	−4.51	4.15	35.47	23.56	4.49	351.72	21.04	202.77	3.76	294.44
2014	0.00	0.00	36.86	−4.55	4.28	36.58	25.05	4.57	357.92	20.95	213.77	3.99	313.15
2015	0.00	0.00	38.02	−4.54	4.25	37.73	28.89	4.65	364.38	19.07	253.86	4.61	361.13
20 yr NPV	0.00	0.00	137.01	−2.95	30.22	164.28	131.89	35.97	2639.62	106.18	2234.77	21.82	1648.61

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Ref Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
2016	0.00	0.00	39.54	-4.72	4.42	39.24	30.61	4.73	371.09	19.76	263.17	4.88	382.60
2017	0.00	0.00	41.13	-4.91	4.59	40.81	32.41	4.82	378.07	20.50	273.01	5.17	405.08
2018	0.00	0.00	42.77	-5.11	4.78	42.44	34.29	4.91	385.33	21.28	283.39	5.47	428.61
2019	0.00	0.00	44.48	-5.31	4.97	44.14	36.26	5.01	392.88	22.11	294.35	5.78	453.24
2020	0.00	0.00	46.26	-5.52	5.17	45.91	38.32	5.11	400.73	22.98	305.92	6.11	479.03
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30 yr NPV	0.00	0.00	23.03	-2.75	2.57	22.85	18.42	2.65	208.15	11.47	152.71	2.94	230.22
50 yr NPV	0.00	0.00	160.04	-5.71	12.80	187.13	150.31	38.63	2847.77	117.65	2387.48	24.76	1878.83
Levelized								4.48	310.27	13.64	276.89	2.87	217.90

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

OUTPUT REPORT – ECONOMIC ANALYSIS

Range: ECONRPT

Alternative	3 CC	Node 1 – Demand	2 Med
Cost Mode	1	Node 2 – Fuel Price	2 Med
FCR Mode	1	Node 3 – Altern Cost	2 Med
Retirement	1	Node 4 – NS2 Cost	2 Med
Tax	1		

	Present Value (M$)			
	NS2	Alternative	System	Net
Fuel/Energy Cost	17.71	133.13	16.39	131.82
Variable O&M Cost	24.79	34.71	--	9.92
Fixed O&M/Capacity Cost	28.69	15.33	-2.10	-15.46
Investment Cost	144.64	110.67	--	-33.98
Emissions / Tax Cost	30.53	12.92	14.77	-2.85
Total	246.36	306.75	29.05	89.45

	Present Value (M$)
Alternative Resource Capital Cost	110.67
Alternative Resource Operating Cost	183.17
Neil Simpson #2 Capital Cost	144.64
Neil Simpson #2 Operating Cost	71.19
Net System Generation & Reliability Cost	14.29
Net Emissions / Tax Cost	-2.85
Net Cost	89.45

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATION = SELECTION OF TREE VALUES AND PROJECT PARAMETERS

Range: SELECT

Selected Tree Values										Mode Selectors	
Branch	Node 1 – Demand Value	Prob	Node 2 – Fuel Price Value	Prob	Node 3 – Altern Cost Value	Prob	Node 4 – NS2 Cost Value	Prob	Branch Probability	Alternative	3 CC
										Cost Mode	1
										FCR Mode	1
41	2	0.6	2	0.6	2	0.6	2	0.6	0.1296	Retirement	1
	Med		Med		Med		Med			Tax	1

	NS2									Selected
Cost Scen #	2					2				Project
0 Project Number	BASE	1	2	3	4	5	6	7	0	3
1 Name	NS2	NS2	CT	CC	Wind	PV	PPL	Basin	0	CC
2 Capacity (MW)	80	80	80	80	80	80	80	80	0	80
3 Capacity Purchase Adjust Period	0	0	0	0	0	0	5	5	0	0
4 Capacity Equivalence Factor	0.95	0.95	0.95	0.97	0.15	1	1	1	0	0.97
5 Equivalent Availability	0.895	0.895	0.913	0.933	0.3	0.3	1	1	0	0.933
6 Installed Cost ($/kW)	1561	1561	532	1023	1115	3185	220	300	0	1023
7 Real Escalation Rate	0.03846	0.03846	0	0	−0.04	0	0	0	0	0
8 Fixed Charge Rate Pattern No.	1	1	2	3	2	2	1	5	0	3
9 Average Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	1000	1000	0	8785
10 Capacity Price Trajectory No.	0	0	0	0	0	0	7	9	0	0
11 Fuel Price Trajectory No.	1	1	5	4	0	0	8	10	0	4
12 Fixed O&M Cost ($/kW−yr)	26.46	26.46	11.56	14.14	54.5289	19.1422	0	24	0	14.14
13 Real Escalation Rate	0	0	0	0	0	0	0	0	0	0
14 Var O&M Cost ($/kW−yr)	3.04	3.04	4.5	6.07	0	0	0	0	0	6.07
15 Real Escalation Rate	0	0	0	0	0	0	0	0	0	0
16 SO2 Emissions Rate (tons/MWh)	0.00106	0.00106	0.00000	0.00000	0	0	0.00275	0.00106	0	0.00000
17 CO2 Emissions Rate (tons/MWh)	1.34375	1.34375	0.70695	0.48756	0	0	1.1	1.34375	0	0.48756
18 Fuel Type	1	1	3	2	0	0	1	1	0	2
19 Tax Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	11000	11000	0	8785
20 Renewable Tax Credit	0	0	0	0	1	1	0	0	0	0
21 Production Cost Selector	1	1	2	3	1	1	4	4	0	3
22 Start−up Year	1996	1996	1996	1996	1996	1996	1996	1996	0	1996
23 Life	50	50	25	35	25	25	30	30	0	35

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – SELECTION OF SCENARIOS AND ESCALATION

Scenario #	Demand 2	DSM 2	Net Demand	Oil Price 2
1996	1818.2	0.0	1818.2	4.48
1997	1864.2	0.0	1864.2	4.60
1998	1911.7	0.0	1911.7	4.72
1999	1959.7	0.0	1959.7	4.85
2000	2007.8	0.0	2007.8	4.98
2001	2056.2	0.0	2056.2	5.12
2002	2104.8	0.0	2104.8	5.15
2003	2153.3	0.0	2153.3	5.15
2004	2201.8	0.0	2201.8	5.18
2005	2251.4	0.0	2251.4	5.23
2006	2302.3	0.0	2302.3	5.28
2007	2354.3	0.0	2354.3	5.35
2008	2407.7	0.0	2407.7	5.40
2009	2462.3	0.0	2462.3	5.40
2010	2518.2	0.0	2518.2	5.54
2011	2575.5	0.0	2575.5	5.77
2012	2634.1	0.0	2634.1	6.00
2013	2694.2	0.0	2694.2	6.26
2014	2755.7	0.0	2755.7	6.51
2015	2818.6	0.0	2818.6	6.77

	Escalation Rate	Annual Escalation	Compound Escalation
1996	0.0400	1.0400	1.0000
1997	0.0400	1.0400	1.0400
1998	0.0400	1.0400	1.0816
1999	0.0400	1.0400	1.1249
2000	0.0400	1.0400	1.1699
2001	0.0400	1.0400	1.2167
2002	0.0400	1.0400	1.2653
2003	0.0400	1.0400	1.3159
2004	0.0400	1.0400	1.3686
2005	0.0400	1.0400	1.4233
2006	0.0400	1.0400	1.4802
2007	0.0400	1.0400	1.5395
2008	0.0400	1.0400	1.6010
2009	0.0400	1.0400	1.6651
2010	0.0400	1.0400	1.7317
2011	0.0400	1.0400	1.8009
2012	0.0400	1.0400	1.8730
2013	0.0400	1.0400	1.9479
2014	0.0400	1.0400	2.0258
2015			2.1068
Beyond	0.0400	1.0400	

(Escalation is zero, with real cost mode.)

CALCULATIONS – PROJECT FUEL AND PURCHASED POWER COSTS

Range: FUELCALC

	Cap Price	Fuel Price
Real esc after 2015	0	0.02
Incr for high scenario	0	--
Decr for low scenario	0	--
Correl with oil price	0	0.65137
Cap price factor	1	

Mode Selectors		Scenario	
Alternative	3 CC	Node 1 – Demand	2 Med
Cost Mode	1	Node 2 – Fuel Price	2 Med
FCR Mode	1	Node 3 – Altern Cost	2 Med
Retirement	1	Node 4 – NS2 Cost	2 Med
Tax	1		

	Change In Oil Price %	NS2 Coal Price	NS2 Var O&M	NS2 Disp Cost	NS2 Fixd O&M	Alternative Cap Price	Alternative Fuel Price	Alternative Var O&M	Alternative Disp Cost	Alternative Fixd O&M
1996	0.00%	0.60	3.04	10.59	26.46	0.00	2.57	6.07	28.65	14.14
1997	0.00%	0.65	3.16	11.25	27.52	0.00	2.67	6.31	29.77	14.71
1998	0.00%	0.54	3.29	9.98	28.62	0.00	2.78	6.57	30.99	15.29
1999	0.00%	0.52	3.42	9.88	29.76	0.00	2.88	6.83	32.13	15.91
2000	0.00%	0.38	3.56	8.24	30.95	0.00	3.00	7.10	33.46	16.54
2001	0.00%	0.34	3.70	7.92	32.19	0.00	3.11	7.39	34.71	17.20
2002	0.00%	0.23	3.85	6.76	33.48	0.00	3.23	7.68	36.06	17.89
2003	0.00%	0.23	4.00	6.90	34.82	0.00	3.37	7.99	37.59	18.61
2004	0.00%	0.17	4.16	6.33	36.21	0.00	3.50	8.31	39.05	19.35
2005	0.00%	0.00	4.33	4.33	37.66	0.00	3.64	8.64	40.62	20.13
2006	0.00%	0.00	4.50	4.50	39.17	0.00	3.78	8.99	42.19	20.93
2007	0.00%	0.00	4.68	4.68	40.73	0.00	3.93	9.34	43.87	21.77
2008	0.00%	0.00	4.87	4.87	42.36	0.00	4.09	9.72	45.65	22.64
2009	0.00%	0.00	5.06	5.06	44.06	0.00	4.25	10.11	47.44	23.54
2010	0.00%	0.00	5.26	5.26	45.82	0.00	4.43	10.51	49.43	24.49
2011	0.00%	0.00	5.47	5.47	47.65	0.00	4.61	10.93	51.43	25.47
2012	0.00%	0.00	5.69	5.69	49.56	0.00	4.80	11.37	53.54	26.48
2013	0.00%	0.00	5.92	5.92	51.54	0.00	4.99	11.82	55.66	27.54
2014	0.00%	0.00	6.16	6.16	53.60	0.00	5.20	12.30	57.98	28.65
2015	0.00%	0.00	6.40	6.40	55.75	0.00	5.41	12.79	60.32	29.79

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – RESPONSE SURFACE MODEL

Range: RSMCALC

Prod Cost Selector # 3

	Base	Demand	Oil Price	NS2 Cost	Alt Cost	D*D	D*OP	OP*OP
CF Coefs	Alt Cost	6.9	0	-3.6	-3.6	0	0	0
Den Coefs		0.9	0.25	--	--	0	0	0
1996	28.65	0	0	0	0	0	0	0
1997	29.77	0	0	0	0	0	0	0
1998	30.99	0	0	0	0	0	0	0
1999	32.13	0	0	0	0	0	0	0
2000	33.46	0	0	0	0	0	0	0
2001	34.71	0	0	0	0	0	0	0
2002	36.06	0	0	0	0	0	0	0
2003	37.59	0	0	0	0	0	0	0
2004	39.05	0	0	0	0	0	0	0
2005	40.62	0	0	0	0	0	0	0
2006	42.19	0	0	0	0	0	0	0
2007	43.87	0	0	0	0	0	0	0
2008	45.65	0	0	0	0	0	0	0
2009	47.44	0	0	0	0	0	0	0
2010	49.43	0	0	0	0	0	0	0
2011	51.43	0	0	0	0	0	0	0
2012	53.54	0	0	0	0	0	0	0
2013	55.66	0	0	0	0	0	0	0
2014	57.98	0	0	0	0	0	0	0
2015	60.32	0	0	0	0	0	0	0

Dispatch and Production Cost

Net Peak Gen Factor 0.4

	NS2 CF				Alt CF				Energy (GWh)			
	Linear Sum	Quadratic Sum	Exp(CF*)	CF	Linear Sum	Quadratic Sum	Exp(CF*)	CF	NS2	Alt	Net Peak	Net Base
1996	0	0	5.04627	75.0%	0	0	1.13841	49.7%	525.6	348.3	−7.2	184.6
1997	0	0	7.90502	79.8%	0	0	1.43701	55.1%	559.2	386.1	−8.2	181.3
1998	0	0	7.40809	79.2%	0	0	1.43701	55.1%	555.0	386.1	−8.9	177.8
1999	0	0	10.9708	82.4%	0	0	1.85832	60.8%	577.5	426.1	−11.3	162.7
2000	0	0	12.7978	83.4%	0	0	1.86702	60.9%	584.5	426.8	−11.9	169.6
2001	0	0	19.3062	85.5%	0	0	2.35726	65.7%	599.2	460.4	−13.1	151.9
2002	0	0	20.7735	85.8%	0	0	2.10301	63.4%	601.3	444.3	−12.8	169.8
2003	0	0	28.6210	86.9%	0	0	2.71454	68.4%	609.0	479.3	−13.5	143.2
2004	0	0	30.6982	87.1%	0	0	2.40579	66.1%	610.4	463.2	−13.6	160.8
2005	0	0	43.0561	87.9%	0	0	3.15692	71.1%	616.0	498.3	−15.2	132.9
2006	0	0	47.8137	88.1%	0	0	3.12056	70.9%	617.4	496.9	−15.7	136.3
2007	0	0	77.4743	88.8%	0	0	0.93233	45.0%	622.3	315.4	−11.1	318.1
2008	0	0	77.4743	88.8%	0	0	0.96047	45.7%	622.3	320.3	−9.9	312.0
2009	0	0	105.105	89.1%	0	0	1.23475	51.6%	624.4	361.6	−13.6	276.4
2010	0	0	105.105	89.1%	0	0	1.16295	50.2%	624.4	351.8	−11.5	284.1
2011	0	0	137.652	89.3%	0	0	4.58599	76.9%	625.8	538.9	−22.5	109.4
2012	0	0	137.652	89.3%	0	0	0.85988	43.1%	625.8	302.0	−8.9	332.7
2013	0	0	199	89.5%	0	0	1.65687	58.3%	627.2	408.6	−15.0	233.6
2014	0	0	199	89.5%	0	0	1.66438	58.4%	627.2	409.3	−15.4	233.4
2015	0	0	199	89.5%	0	0	2.21962	64.5%	627.2	452.0	−17.2	192.4

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Production Cost and Capacity Surplus Calculations

	Base Gen Cost					Pk Cost
	Base Val $/MWh	Linear Sum	Quadratic Sum	Exp(Q)	Adj Val $/MWh	Adj Val $/MWh
1996	15.33	0	0	1	15.33	42.85
1997	16.37	0	0	1	16.37	48.72
1998	16.59	0	0	1	16.59	51.78
1999	18.52	0	0	1	18.52	50.90
2000	20.34	0	0	1	20.34	51.27
2001	21.36	0	0	1	21.36	50.97
2002	23.01	0	0	1	23.01	52.20
2003	26.23	0	0	1	26.23	52.55
2004	21.05	0	0	1	21.05	54.49
2005	22.40	0	0	1	22.40	55.01
2006	20.62	0	0	1	20.62	59.90
2007	15.70	0	0	1	15.70	56.44
2008	15.23	0	0	1	15.23	57.85
2009	17.42	0	0	1	17.42	58.34
2010	16.70	0	0	1	16.70	62.12
2011	25.30	0	0	1	25.30	66.57
2012	13.05	0	0	1	13.05	67.85
2013	15.69	0	0	1	15.69	71.35
2014	15.46	0	0	1	15.46	74.02
2015	18.27	0	0	1	16.27	76.61

	Capacity Surplus	Lagged Capacity Surplus
1996	0.00	0.00
1997	0.00	0.00
1998	0.00	0.00
1999	0.00	0.00
2000	0.00	0.00
2001	0.00	0.00
2002	0.00	0.00
2003	0.00	0.00
2004	0.00	0.00
2005	0.00	0.00
2006	0.00	0.00
2007	0.00	0.00
2008	0.00	0.00
2009	0.00	0.00
2010	0.00	0.00
2011	0.00	0.00
2012	0.00	0.00
2013	0.00	0.00
2014	0.00	0.00
2015	0.00	0.00

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Emissions Calculations

	Emissions (tons)							
	NS2		Alternative		Net Peaking		Net Base	
	SO2	CO2	SO2	CO2	SO2	CO2	SO2	CO2
1996	558	706275	1	169819	-0	-5230	1495	286516
1997	594	751477	1	188270	-0	-5949	1469	281534
1998	590	745826	1	188270	-0	-6398	1440	275974
1999	614	775961	1	207746	-0	-8168	1318	252582
2000	621	785378	1	208088	-0	-8570	1373	263238
2001	637	805154	1	224489	-0	-9477	1230	235814
2002	639	807979	1	216630	-0	-9244	1375	263601
2003	647	818337	1	233714	-0	-9755	1160	222269
2004	649	820221	1	225855	-0	-9823	1302	249615
2005	655	827754	1	242940	-0	-10945	1077	206333
2006	656	829638	1	242256	-0	-11360	1104	211579
2007	661	836230	1	153759	-0	-8037	2577	493833
2008	661	836230	1	156151	-0	-7166	2527	484343
2009	663	839055	1	176311	-0	-9781	2238	429043
2010	663	839055	1	171527	-0	-8295	2301	441078
2011	665	840938	1	262758	-0	-16233	116	147004
2012	665	840938	1	147267	-0	-6421	353	447024
2013	666	842822	1	199204	-0	-10792	248	313910
2014	666	842822	1	199545	-0	-11113	248	313566
2015	666	842822	1	220388	-0	-12417	204	258551

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – ECONOMIC ANALYSIS

Range: ECONCALC

Alternative	3 CC
Cost Mode	1
FCR Mode	1
Retirement	1
Tax	1

Node 1 – Demand	2 Med
Node 2 – Fuel Price	2 Med
Node 3 – Altern Cost	2 Med
Node 4 – NS2 Cost	2 Med

INTERMEDIATE CALCULATIONS

INITIAL COSTS	
Neil Simpson 2	
Construction Cost (M$)	124.88
Retirement Year	2031
Alternative	
Construction Cost (M$)	81.84
Retirement Year	2031
Last Year of Renewable Credit	0
System	
Net Reliability Cost (M$)	-0.155

ESCALATION RATES	
NS2 Fuel Cost	1.000
Variable O&M Cost	1.000
Fixed O&M Cost	1.000
Fuel Cost	1.020
Variable O&M Cost	1.000
Fixed O&M / Capacity Price	1.000
Net Prod Cost Savings, after 2020	1.000
Coal Discount	1.000
Net Reliability Cost	1.000

Discount Rate	0.107
Annual Discount Factor	0.904
Discount From 2015 to 1990	0.141

Energy Tax Rate (mills/kWh)	
Neil Simpson 2	3.21
Alternative	2.26
Net Peaking	2.79
Net Base	3.84

Neil Simpson values are scaled to the size of the alternative project

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De-escal	NS2						Alternative					
	Factor	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total
1996	1.000	3.97	1.60	2.12	15.73	1.97	25.38	7.86	2.11	1.13	12.03	0.79	23.93
1997	1.000	4.52	1.77	2.20	15.73	2.18	26.39	9.06	2.44	1.18	12.03	0.91	25.61
1998	1.000	3.72	1.82	2.29	15.73	2.25	25.80	9.43	2.54	1.22	12.03	0.94	26.16
1999	1.000	3.73	1.97	2.38	15.73	2.43	26.24	10.78	2.91	1.27	12.03	1.08	28.08
2000	1.000	2.74	2.08	2.48	15.73	2.56	25.58	11.25	3.03	1.32	12.03	1.13	28.76
2001	1.000	2.53	2.22	2.58	15.73	2.73	25.78	12.58	3.40	1.38	12.03	1.27	30.65
2002	1.000	1.75	2.31	2.68	15.73	2.85	25.32	12.61	3.41	1.43	12.03	1.27	30.75
2003	1.000	1.76	2.44	2.79	15.73	3.00	25.71	14.19	3.83	1.49	12.03	1.42	32.97
2004	1.000	1.32	2.54	2.90	15.73	3.13	25.61	14.24	3.85	1.55	12.03	1.43	33.10
2005	1.000	0.00	2.67	3.01	15.73	3.28	24.69	15.93	4.30	1.61	12.03	1.60	35.48
2006	1.000	0.00	2.78	3.13	15.73	3.42	25.06	16.50	4.46	1.67	12.03	1.66	36.33
2007	1.000	0.00	2.91	3.26	15.73	3.59	25.48	10.89	2.95	1.74	12.03	1.10	28.71
2008	1.000	0.00	3.03	3.39	15.73	3.73	25.87	11.51	3.11	1.81	12.03	1.16	29.62
2009	1.000	0.00	3.16	3.52	15.73	3.89	26.30	13.50	3.65	1.88	12.03	1.36	32.43
2010	1.000	0.00	3.29	3.67	15.73	4.05	26.73	13.69	3.70	1.96	12.03	1.38	32.76
2011	1.000	0.00	3.43	3.81	15.73	4.22	27.18	21.83	5.89	2.04	12.03	2.19	43.98
2012	1.000	0.00	3.56	3.96	15.73	4.39	27.64	12.74	3.43	2.12	12.03	1.28	31.60
2013	1.000	0.00	3.71	4.12	15.73	4.57	28.14	17.91	4.83	2.20	12.03	1.80	38.77
2014	1.000	0.00	3.86	4.29	15.73	4.76	28.63	18.70	5.03	2.29	12.03	1.87	39.93
2015	1.000	0.00	4.02	4.46	15.73	4.95	29.15	21.48	5.78	2.38	12.03	2.15	43.83
20 yr NPV		17.71	19.27	22.56	127.90	23.73	211.17	99.19	26.76	12.06	97.86	9.96	245.83

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De-escal	NS2						Alternative					
	Factor	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total
2016	1.000	0.00	4.18	4.64	15.73	5.14	29.69	22.79	6.01	2.48	12.03	2.24	45.55
2017	1.000	0.00	4.35	4.82	15.73	5.35	30.25	24.17	6.25	2.58	12.03	2.33	47.36
2018	1.000	0.00	4.52	5.02	15.73	5.56	30.83	25.64	6.50	2.68	12.03	2.42	49.28
2019	1.000	0.00	4.70	5.22	15.73	5.79	31.43	27.20	6.76	2.79	12.03	2.52	51.30
2020	1.000	0.00	4.89	5.43	15.73	6.02	32.06	28.86	7.03	2.90	12.03	2.62	53.44
2021	1.000	0.00	5.08	5.64	15.73	6.26	32.71	30.61	7.31	3.02	12.03	2.72	55.70
2022	1.000	0.00	5.29	5.87	15.73	6.51	33.39	32.47	7.61	3.14	12.03	2.83	58.08
2023	1.000	0.00	5.50	6.10	15.73	6.77	34.10	34.45	7.91	3.26	12.03	2.94	60.60
2024	1.000	0.00	5.72	6.35	15.73	7.04	34.83	36.54	8.23	3.39	12.03	3.06	63.26
2025	1.000	0.00	5.95	6.60	15.73	7.32	35.60	38.76	8.56	3.53	12.03	3.18	66.07
2026	1.000	0.00	6.18	6.87	15.73	7.62	36.39	41.12	8.90	3.67	12.03	3.31	69.03
2027	1.000	0.00	6.43	7.14	15.73	7.92	37.22	43.62	9.25	3.82	12.03	3.44	72.17
2028	1.000	0.00	6.69	7.43	15.73	8.24	38.08	46.27	9.63	3.97	12.03	3.58	75.48
2029	1.000	0.00	6.96	7.72	15.73	8.57	38.97	49.09	10.01	4.13	12.03	3.73	78.98
2030	1.000	0.00	7.23	8.03	15.73	8.91	39.90	52.07	10.41	4.29	12.03	3.87	82.68
2031	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30 yr NPV		0.00	3.52	4.13	15.74	4.80	15.19	31.94	7.94	3.28	12.81	2.96	60.93
50 yr NPV		17.71	24.79	28.09	144.64	30.13	246.36	133.13	34.71	15.33	110.62	12.92	306.75

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Rel Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
1996	-0.16	-0.31	2.83	1.25	1.31	4.92	3.47	4.83	317.22	6.87	299.10	0.66	43.40
1997	-0.16	-0.40	2.97	1.34	1.33	5.08	4.29	4.72	329.93	6.63	320.14	0.77	53.67
1998	-0.17	-0.46	2.95	1.36	1.35	5.03	5.39	4.65	322.55	6.78	327.06	0.97	67.37
1999	-0.17	-0.58	3.01	1.48	1.25	5.00	6.83	4.54	328.03	6.59	350.96	1.18	85.39
2000	-0.18	-0.61	3.45	1.04	1.36	5.06	8.24	4.38	319.76	6.74	359.53	1.41	102.98
2001	-0.19	-0.67	3.24	0.88	1.24	4.51	9.39	4.30	322.24	6.66	383.17	1.57	117.32
2002	-0.20	-0.67	3.91	0.12	1.46	4.62	10.06	4.21	316.48	6.92	384.42	1.67	125.73
2003	-0.20	-0.71	3.76	0.19	1.25	4.28	11.54	4.22	321.41	6.88	412.08	1.89	144.19
2004	-0.21	-0.74	3.38	-0.15	1.48	3.76	11.25	4.20	320.16	7.15	413.80	1.84	140.64
2005	-0.22	-0.83	2.98	-0.15	1.23	3.00	13.79	4.01	308.58	7.12	443.53	2.24	172.42
2006	-0.23	-0.94	2.81	-0.37	1.31	2.57	13.85	4.06	313.24	7.31	454.15	2.24	173.09
2007	-0.24	-0.63	5.00	-4.46	3.49	3.15	6.37	4.10	318.55	9.10	358.81	1.02	79.64
2008	-0.25	-0.57	4.75	-4.42	3.57	3.07	6.82	4.16	323.42	9.25	370.27	1.10	85.27
2009	-0.26	-0.79	4.81	-4.38	3.23	2.61	8.74	4.21	328.80	8.97	405.40	1.40	109.28
2010	-0.27	-0.71	4.74	-4.39	3.48	2.85	8.88	4.28	334.08	9.31	409.46	1.42	111.04
2011	-0.28	-1.50	2.77	-4.37	0.45	-2.93	13.86	4.34	339.80	8.16	549.73	2.22	173.30
2012	-0.29	-0.60	4.34	-4.65	2.28	1.08	5.04	4.42	345.53	10.46	394.99	0.80	62.95
2013	-0.30	-1.07	3.66	-4.51	1.54	-0.68	9.96	4.49	351.72	9.49	484.68	1.59	124.48
2014	-0.31	-1.14	3.61	-4.55	1.59	-0.81	10.48	4.57	357.92	9.76	499.07	1.67	130.99
2015	-0.33	-1.32	3.52	-4.54	1.29	-1.38	13.30	4.65	364.38	9.70	547.88	2.12	166.22
20 yr NPV	-1.66	-5.22	27.79	-2.96	13.00	30.95	65.62	35.97	2639.62	60.05	3072.90	10.98	820.22

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Rel Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
2016	-0.34	-1.37	3.66	-4.72	1.34	-1.44	14.42	4.73	371.09	10.08	569.36	2.30	180.30
2017	-0.35	-1.43	3.80	-4.91	1.39	-1.50	15.62	4.82	378.07	10.48	592.05	2.49	195.29
2018	-0.37	-1.48	3.95	-5.11	1.45	-1.56	16.90	4.91	385.33	10.90	616.00	2.69	211.23
2019	-0.38	-1.54	4.11	-5.31	1.51	-1.62	18.26	5.01	392.88	11.35	641.29	2.91	228.20
2020	-0.40	-1.60	4.28	-5.52	1.57	-1.68	19.70	5.11	400.73	11.82	668.00	3.14	246.24
2021	-0.41	-1.67	4.45	-5.74	1.63	-1.75	21.24	5.22	408.90	12.32	696.21	3.39	265.44
2022	-0.43	-1.74	4.63	-5.97	1.69	-1.82	22.87	5.32	417.39	12.85	726.00	3.65	285.87
2023	-0.45	-1.80	4.81	-6.21	1.76	-1.89	24.61	5.44	426.22	13.41	757.46	3.92	307.59
2024	-0.47	-1.88	5.00	-6.46	1.83	-1.97	26.46	5.55	435.41	13.99	790.70	4.22	330.70
2025	-0.48	-1.95	5.20	-6.72	1.91	-2.05	28.42	5.68	444.96	14.62	825.82	4.53	355.27
2026	-0.50	-2.03	5.41	-6.99	1.98	-2.13	30.51	5.80	454.90	15.27	862.91	4.86	381.41
2027	-0.52	-2.11	5.63	-7.27	2.06	-2.21	32.74	5.93	465.23	15.97	902.10	5.22	409.21
2028	-0.54	-2.20	5.85	-7.56	2.14	-2.30	35.10	6.07	475.97	16.70	943.51	5.60	438.76
2029	-0.57	-2.28	6.09	-7.86	2.23	-2.39	37.62	6.21	487.15	17.47	987.27	6.00	470.19
2030	-0.59	-2.37	6.33	-8.18	2.32	-2.49	40.29	6.36	498.77	18.29	1033.50	6.42	503.61
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10 yr NPV	-0.45	-1.81	4.63	-6.24	1.77	-1.90	21.83	5.61	439.88	13.48	761.53	3.80	297.89
30 yr NPV	-2.10	-7.03	15.62	-9.20	14.77	29.05	89.45	41.58	3079.50	73.53	3834.43	14.78	1118.11
Levelized								4.37	338.60	5.08	421.61	1.63	132.96

OUTPUT REPORT – ECONOMIC ANALYSIS

Range: ECONREPT

Alternative	4 Wind	Node 1 – Demand	2 Med
Cost Mode	1	Node 2 – Fuel Price	2 Med
FCR Mode	1	Node 3 – Altern Cost	2 Med
Retirement	1	Node 4 – NS2 Cost	2 Med
Tax	1		

	Present Value (M$)			
	NS2 Alternative		System	Net
Fuel/Energy Cost	17.71	0.00	66.46	48.76
Variable O&M Cost	21.70	0.00	--	-21.70
Fixed O&M/Capacity Cost	25.27	52.07	74.14	100.94
Investment Cost	136.42	117.29	--	-19.13
Emissions / Tax Cost	26.73	-21.93	32.69	-15.97
Total	227.82	147.43	173.29	92.89

	Present Value (M$)
Alternative Resource Capital Cost	117.29
Alternative Resource Operating Cost	52.07
Neil Simpson #2 Capital Cost	136.42
Neil Simpson #2 Operating Cost	64.67
Net System Generation & Reliability Cost	140.60
Net Emissions / Tax Cost	-15.97
Net Cost	92.89

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATION – SELECTION OF TREE VALUES AND PROJECT PARAMETERS

Range: SELECT

Selected Tree Values										Mode Selectors	
Branch	Node 1 – Demand		Node 2 – Fuel Price		Node 3 – Altern Cost		Node 4 – NS2 Cost		Branch	Alternative	4 Wind
	Value	Prob	Value	Prob	Value	Prob	Value	Prob	Probability	Cost Mode	1
										FCR Mode	1
41	2	0.6	2	0.6	2	0.6	2	0.6	0.1296	Retirement	1
	Med		Med		Med		Med			Tax	1

Cost Scen #	NS2		2							Selected
	2									Project
0 Project Number	BASE	1	2	3	4	5	6	7	0	4
1 Name	NS2	NS2	CT	CC	Wind	PV	PPL	Basin	0	Wind
2 Capacity (MW)	80	80	80	80	80	80	80	80	0	80
3 Capacity Purchase Adjust Period	0	0	0	0	0	0	5	5	0	0
4 Capacity Equivalence Factor	0.95	0.95	0.95	0.97	0.15	1	1	1	0	0.15
5 Equivalent Availability	0.895	0.895	0.913	0.933	0.3	0.3	1	1	0	0.3
6 Installed Cost ($/kW)	1561	1561	532	1023	1115	3185	220	300	0	1115
7 Real Escalation Rate	0.03846	0.03846	0	0	−0.04	0	0	0	0	−0.04
8 Fixed Charge Rate Pattern No.	1	1	2	3	2	2	1	5	0	2
9 Average Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	1000	1000	0	0
10 Capacity Price Trajectory No.	0	0	0	0	0	0	7	9	0	0
11 Fuel Price Trajectory No.	1	1	5	4	0	0	8	10	0	0
12 Fixed O&M Cost ($/kW−yr)	26.46	26.46	11.56	14.14	54.5289	19.1422	0	24	0	54.5289
13 Real Escalation Rate	0	0	0	0	0	0	0	0	0	0
14 Var O&M Cost ($/kW−yr)	3.04	3.04	4.5	6.07	0	0	0	0	0	0
15 Real Escalation Rate	0	0	0	0	0	0	0	0	0	0
16 SO2 Emissions Rate (tons/MWh)	0.00106	0.00106	0.00000	0.00000	0	0	0.00275	0.00106	0	0
17 CO2 Emissions Rate (tons/MWh)	1.34375	1.34375	0.70695	0.48756	0	0	1.1	1.34375	0	0
18 Fuel Type	1	1	3	2	0	0	1	1	0	0
19 Tax Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	11000	11000	0	0
20 Renewable Tax Credit	0	0	0	0	1	1	0	0	0	1
21 Production Cost Selector	i	i	2	3	i	i	4	4	0	i
22 Start−up Year	1996	1996	1996	1996	1996	1996	1996	1996	0	1996
23 Life	50	50	25	35	25	25	30	30	0	25

CALCULATIONS – SELECTION OF SCENARIOS AND ESCALATION

Scenario #	Demand 2	DSM 2	Net Demand	Oil Price 2
1996	1818.2	0.0	1818.2	4.48
1997	1864.2	0.0	1864.2	4.60
1998	1911.7	0.0	1911.7	4.72
1999	1959.7	0.0	1959.7	4.85
2000	2007.8	0.0	2007.8	4.98
2001	2056.2	0.0	2056.2	5.12
2002	2104.8	0.0	2104.8	5.15
2003	2153.3	0.0	2153.3	5.15
2004	2201.8	0.0	2201.8	5.18
2005	2251.4	0.0	2251.4	5.23
2006	2302.3	0.0	2302.3	5.28
2007	2354.3	0.0	2354.3	5.35
2008	2407.7	0.0	2407.7	5.40
2009	2462.3	0.0	2462.3	5.40
2010	2518.2	0.0	2518.2	5.54
2011	2575.5	0.0	2575.5	5.77
2012	2634.1	0.0	2634.1	6.00
2013	2694.2	0.0	2694.2	6.26
2014	2755.7	0.0	2755.7	6.51
2015	2818.6	0.0	2818.6	6.77

	Escalation Rate	Annual Escalation	Compound Escalation
1996	0.0400	1.0400	1.0000
1997	0.0400	1.0400	1.0400
1998	0.0400	1.0400	1.0816
1999	0.0400	1.0400	1.1249
2000	0.0400	1.0400	1.1699
2001	0.0400	1.0400	1.2167
2002	0.0400	1.0400	1.2653
2003	0.0400	1.0400	1.3159
2004	0.0400	1.0400	1.3686
2005	0.0400	1.0400	1.4233
2006	0.0400	1.0400	1.4802
2007	0.0400	1.0400	1.5395
2008	0.0400	1.0400	1.6010
2009	0.0400	1.0400	1.6651
2010	0.0400	1.0400	1.7317
2011	0.0400	1.0400	1.8009
2012	0.0400	1.0400	1.8730
2013	0.0400	1.0400	1.9479
2014	0.0400	1.0400	2.0258
2015			2.1068
Beyond	0.0400	1.0400	

(Escalation is zero, with real cost mode.)

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – PROJECT FUEL AND PURCHASED POWER COSTS

Range: FUELCALC

	Cap Price	Fuel Price
Real esc after 2015	0	0
Incr for high scenario	0	0
Decr for low scenario	0	0
Correl with oil price	0	0
Cap price factor	1	

Mode Selectors		Scenario	
Alternative	4 Wind	Node 1 – Demand	2 Med
Cost Mode	1	Node 2 – Fuel Price	2 Med
FCR Mode	1	Node 3 – Altern Cost	2 Med
Retirement	1	Node 4 – NS2 Cost	2 Med
Tax	1		

	Change In Oil Price %	NS2 Cost Price	NS2 Var O&M	NS2 Disp Cost	NS2 Fixd O&M	Alternative Cap Price	Alternative Fuel Price	Alternative Var O&M	Alternative Disp Cost	Alternative Fixd O&M
1996	0.00%	0.60	3.04	10.59	26.46	0.00	0.00	0.00	0.00	54.53
1997	0.00%	0.65	3.16	11.25	27.52	0.00	0.00	0.00	0.00	56.71
1998	0.00%	0.54	3.29	9.98	28.62	0.00	0.00	0.00	0.00	58.98
1999	0.00%	0.52	3.42	9.88	29.76	0.00	0.00	0.00	0.00	61.34
2000	0.00%	0.38	3.56	8.24	30.95	0.00	0.00	0.00	0.00	63.79
2001	0.00%	0.34	3.70	7.92	32.19	0.00	0.00	0.00	0.00	66.34
2002	0.00%	0.23	3.85	6.76	33.48	0.00	0.00	0.00	0.00	69.00
2003	0.00%	0.23	4.00	6.90	34.82	0.00	0.00	0.00	0.00	71.76
2004	0.00%	0.17	4.16	6.33	36.21	0.00	0.00	0.00	0.00	74.63
2005	0.00%	0.00	4.33	4.33	37.66	0.00	0.00	0.00	0.00	77.61
2006	0.00%	0.00	4.50	4.50	39.17	0.00	0.00	0.00	0.00	80.72
2007	0.00%	0.00	4.68	4.68	40.73	0.00	0.00	0.00	0.00	83.94
2008	0.00%	0.00	4.87	4.87	42.36	0.00	0.00	0.00	0.00	87.30
2009	0.00%	0.00	5.06	5.06	44.06	0.00	0.00	0.00	0.00	90.79
2010	0.00%	0.00	5.26	5.26	45.82	0.00	0.00	0.00	0.00	94.43
2011	0.00%	0.00	5.47	5.47	47.65	0.00	0.00	0.00	0.00	98.20
2012	0.00%	0.00	5.69	5.69	49.56	0.00	0.00	0.00	0.00	102.13
2013	0.00%	0.00	5.92	5.92	51.54	0.00	0.00	0.00	0.00	106.22
2014	0.00%	0.00	6.16	6.16	53.60	0.00	0.00	0.00	0.00	110.47
2015	0.00%	0.00	6.40	6.40	55.75	0.00	0.00	0.00	0.00	114.88

CALCULATIONS – RESPONSE SURFACE MODEL

Range: RSMCALC

Prod Cost Selector # 1

	Base	Demand	Oil Price	NS2 Cost	Alt Cost	D*D	D*OP	OP*OP
CF Coefs	Alt Cost	6.9	0	-3.6	-3.6	0	0	0
Ben Coefs		0.9	0.25	- -	- -	0	0	0
1996	10.59	0	0	0	-1	0	0	0
1997	11.25	0	0	0	-1	0	0	0
1998	9.98	0	0	0	-1	0	0	0
1999	9.88	0	0	0	-1	0	0	0
2000	8.24	0	0	0	-1	0	0	0
2001	7.92	0	0	0	-1	0	0	0
2002	6.76	0	0	0	-1	0	0	0
2003	6.90	0	0	0	-1	0	0	0
2004	6.33	0	0	0	-1	0	0	0
2005	4.33	0	0	0	-1	0	0	0
2006	4.50	0	0	0	-1	0	0	0
2007	4.68	0	0	0	-1	0	0	0
2008	4.87	0	0	0	-1	0	0	0
2009	5.06	0	0	0	-1	0	0	0
2010	5.26	0	0	0	-1	0	0	0
2011	5.47	0	0	0	-1	0	0	0
2012	5.69	0	0	0	-1	0	0	0
2013	5.92	0	0	0	-1	0	0	0
2014	6.16	0	0	0	-1	0	0	0
2015	6.40	0	0	0	-1	0	0	0

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Dispatch and Production Cost

Net Peak Gen Factor -4.8

	NS2 CF				Alt CF				Energy (GWh)			
	Linear Sum	Quadratic Sum	Exp(CF')	CF	Linear Sum	Quadratic Sum	Exp(CF')	CF	NS2	Alt	Net Peak	Net Base
1996	0	0	5.04627	75.0%	3.6	0	184.684	30.0%	525.6	210.2	87.0	228.5
1997	0	0	7.90502	79.8%	3.6	0	289.310	30.0%	559.2	210.6	98.9	249.7
1998	0	0	7.40809	79.2%	3.6	0	271.123	30.0%	555.0	210.5	106.4	238.1
1999	0	0	10.9708	82.4%	3.6	0	401.513	30.1%	577.5	210.8	135.9	230.8
2000	0	0	12.7978	83.4%	3.6	0	468.380	30.1%	584.5	210.8	142.5	231.1
2001	0	0	19.3062	85.5%	3.6	0	706.576	30.1%	599.2	211.0	157.6	230.6
2002	0	0	20.7735	85.8%	3.6	0	760.273	30.1%	601.3	211.0	153.7	236.5
2003	0	0	28.6210	86.9%	3.6	0	1047.47	30.1%	609.0	211.1	162.2	235.7
2004	0	0	30.6982	87.1%	3.6	0	1123.50	30.1%	610.4	211.1	163.4	235.9
2005	0	0	43.0561	87.9%	3.6	0	1575.77	30.1%	616.0	211.2	182.0	222.8
2006	0	0	47.8137	88.1%	3.6	0	1749.89	30.1%	617.4	211.2	188.9	217.3
2007	0	0	77.4743	88.8%	3.6	0	2835.42	30.1%	622.3	211.2	133.7	277.4
2008	0	0	77.4743	88.8%	3.6	0	2835.42	30.1%	622.3	211.2	119.2	291.9
2009	0	0	105.105	89.1%	3.6	0	3846.67	30.1%	624.4	211.2	162.7	250.5
2010	0	0	105.105	89.1%	3.6	0	3846.67	30.1%	624.4	211.2	138.0	275.2
2011	0	0	137.652	89.3%	3.6	0	5037.82	30.1%	625.8	211.3	270.0	144.6
2012	0	0	137.652	89.3%	3.6	0	5037.82	30.1%	625.8	211.3	106.8	307.8
2013	0	0	199	89.5%	3.6	0	7283.04	30.1%	627.2	211.3	179.5	236.4
2014	0	0	199	89.5%	3.6	0	7283.04	30.1%	627.2	211.3	184.8	231.1
2015	0	0	199	89.5%	3.6	0	7283.04	30.1%	627.2	211.3	206.5	209.4

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Production Cost and Capacity Surplus Calculations

	Base Gen Cost					Pk Cost
	Base Val $/MWh	Linear Sum	Quadratic Sum	Exp(Q)	Adj Val $/MWh	Adj Val $/MWh
1996	0.00	0	0	1	0.00	42.85
1997	0.00	0	0	1	0.00	48.72
1998	0.00	0	0	1	0.00	51.78
1999	0.00	0	0	1	0.00	50.90
2000	0.00	0	0	1	0.00	51.27
2001	0.00	0	0	1	0.00	50.97
2002	0.00	0	0	1	0.00	52.20
2003	0.00	0	0	1	0.00	52.55
2004	0.00	0	0	1	0.00	54.49
2005	0.00	0	0	1	0.00	55.01
2006	0.00	0	0	1	0.00	59.90
2007	0.00	0	0	1	0.00	56.44
2008	0.00	0	0	1	0.00	57.85
2009	0.00	0	0	1	0.00	58.34
2010	0.00	0	0	1	0.00	62.12
2011	0.00	0	0	1	0.00	66.57
2012	0.00	0	0	1	0.00	67.85
2013	0.00	0	0	1	0.00	71.35
2014	0.00	0	0	1	0.00	74.02
2015	0.00	0	0	1	0.00	76.61

	Capacity Surplus	Lagged Capacity Surplus
1996	0.00	0.00
1997	0.00	0.00
1998	0.00	0.00
1999	0.00	0.00
2000	0.00	0.00
2001	0.00	0.00
2002	0.00	0.00
2003	0.00	0.00
2004	0.00	0.00
2005	0.00	0.00
2006	0.00	0.00
2007	0.00	0.00
2008	0.00	0.00
2009	0.00	0.00
2010	0.00	0.00
2011	0.00	0.00
2012	0.00	0.00
2013	0.00	0.00
2014	0.00	0.00
2015	0.00	0.00

Emissions Calculations

	Emissions (tons)							
	NS2		Alternative		Net Peaking		Net Base	
	SO2	CO2	SO2	CO2	SO2	CO2	SO2	CO2
1996	558	706275	0	0	0	62760	1850	354678
1997	594	751477	0	0	0	71383	2023	387707
1998	590	745826	0	0	0	76779	1929	369644
1999	614	775961	0	0	1	98019	1870	358364
2000	621	785378	0	0	1	102836	1872	358762
2001	637	805154	0	0	1	113721	1868	357952
2002	639	807979	0	0	1	110926	1916	367197
2003	647	818337	0	0	1	117060	1909	365848
2004	649	820221	0	0	1	117877	1911	366244
2005	655	827754	0	0	1	131335	1805	345906
2006	656	829638	0	0	1	136322	1760	337330
2007	661	836230	0	0	0	96440	2247	430691
2008	661	836230	0	0	0	85988	2364	453181
2009	663	839055	0	0	1	117371	2029	388885
2010	663	839055	0	0	1	99539	2229	427255
2011	665	840938	0	0	1	194798	154	194258
2012	665	840938	0	0	0	77053	327	413552
2013	666	842822	0	0	1	129506	251	317726
2014	666	842822	0	0	1	133357	246	310554
2015	666	842822	0	0	1	149008	223	281406

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – ECONOMIC ANALYSIS

Range: ECONCALC

Alternative	4 Wind
Cost Mode	1
FCR Mode	1
Retirement	1
Tax	1

Node 1 – Demand	2 Med
Node 2 – Fuel Price	2 Med
Node 3 – Altern Cost	2 Med
Node 4 – NS2 Cost	2 Med

INTERMEDIATE CALCULATIONS

INITIAL COSTS		ESCALATION RATES	
Neil Simpson 2			
Construction Cost (M$)	124.88	NS2 Fuel Cost	1.000
		Variable O&M Cost	1.000
Retirement Year	2021	Fixed O&M Cost	1.000
Alternative			
Construction Cost (M$)	89.20	Fuel Cost	1.000
		Variable O&M Cost	1.000
Retirement Year	2021	Fixed O&M / Capacity Price	1.000
Last Year of Renewable Credit	2005		
System			
		Net Prod Cost Savings, after 2020	1.000
		Coal Discount	1.000
Net Reliability Cost (M$)	6.211	Net Reliability Cost	1.000

Discount Rate	0.107
Annual Discount Factor	0.904
Discount From 2015 to 1996	0.345

Energy Tax Rates ($/MWh)	
Neil Simpson 2	3.21
Alternative	0.00
Net Peaking	7.79
Net Base	3.34

Neil Simpson values are scaled to the size of the alternative project.

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De-escal	NS2						Alternative					
	Factor	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total
1996	1.000	3.97	1.60	2.12	15.73	1.97	25.38	0.00	0.00	4.36	13.52	-3.15	14.73
1997	1.000	4.52	1.77	2.20	15.73	2.18	26.39	0.00	0.00	4.54	13.52	-3.28	14.77
1998	1.000	3.72	1.82	2.29	15.73	2.25	25.80	0.00	0.00	4.72	13.52	-3.42	14.82
1999	1.000	3.73	1.97	2.38	15.73	2.43	26.24	0.00	0.00	4.91	13.52	-3.56	14.87
2000	1.000	2.74	2.08	2.48	15.73	2.56	25.58	0.00	0.00	5.10	13.52	-3.70	14.92
2001	1.000	2.53	2.22	2.58	15.73	2.73	25.78	0.00	0.00	5.31	13.52	-3.85	14.98
2002	1.000	1.75	2.31	2.68	15.73	2.85	25.32	0.00	0.00	5.52	13.52	-4.01	15.04
2003	1.000	1.76	2.44	2.79	15.73	3.00	25.71	0.00	0.00	5.74	13.52	-4.17	15.09
2004	1.000	1.32	2.54	2.90	15.73	3.13	25.61	0.00	0.00	5.97	13.52	-4.33	15.16
2005	1.000	0.00	2.67	3.01	15.73	3.28	24.69	0.00	0.00	6.21	13.52	-4.51	15.22
2006	1.000	0.00	2.78	3.13	15.73	3.42	25.06	0.00	0.00	6.46	13.52	0.00	19.98
2007	1.000	0.00	2.91	3.26	15.73	3.59	25.48	0.00	0.00	6.72	13.52	0.00	20.24
2008	1.000	0.00	3.03	3.39	15.73	3.73	25.87	0.00	0.00	6.98	13.52	0.00	20.51
2009	1.000	0.00	3.16	3.52	15.73	3.89	26.30	0.00	0.00	7.26	13.52	0.00	20.78
2010	1.000	0.00	3.29	3.67	15.73	4.05	26.73	0.00	0.00	7.55	13.52	0.00	21.08
2011	1.000	0.00	3.43	3.81	15.73	4.22	27.18	0.00	0.00	7.86	13.52	0.00	21.38
2012	1.000	0.00	3.56	3.96	15.73	4.39	27.64	0.00	0.00	8.17	13.52	0.00	21.69
2013	1.000	0.00	3.71	4.12	15.73	4.57	28.14	0.00	0.00	8.50	13.52	0.00	22.02
2014	1.000	0.00	3.86	4.29	15.73	4.76	28.63	0.00	0.00	8.84	13.52	0.00	22.36
2015	1.000	0.00	4.02	4.46	15.73	4.95	29.15	0.00	0.00	9.19	13.52	0.00	22.71
20 yr NPV		17.71	19.27	22.56	127.90	23.73	211.17	0.00	0.00	46.50	109.97	-21.93	134.53

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De-escal Factor	NS2 Fuel Cost	NS2 Var Cost	NS2 Fixed Cost	NS2 Invst Cost	NS2 Tax Cost	NS2 Total	Alternative Fuel Cost	Alternative Var Cost	Alternative Fixed Cost	Alternative Invst Cost	Alternative Tax Cost	Alternative Total
	1.000	0.00	4.18	4.64	15.73	5.14	29.69	0.00	0.00	9.56	13.52	0.00	23.08
2017	1.000	0.00	4.35	4.82	15.73	5.35	30.25	0.00	0.00	9.94	13.52	0.00	23.46
2018	1.000	0.00	4.52	5.02	15.73	5.56	30.83	0.00	0.00	10.34	13.52	0.00	23.86
2019	1.000	0.00	4.70	5.22	15.73	5.79	31.43	0.00	0.00	10.75	13.52	0.00	24.27
2020	1.000	0.00	4.89	5.43	15.73	6.02	32.06	0.00	0.00	11.18	13.52	0.00	24.70
2021	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30 yr NPV		0.00	2.43	2.70	8.52	3.00	16.65	0.00	0.00	5.57	7.33	0.00	12.89
50 yr NPV		17.71	21.70	25.27	136.42	26.73	227.82	0.00	0.00	52.07	117.29	-21.93	147.43

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Rel Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
1996	6.21	3.73	0.00	1.25	2.37	13.56	2.91	4.83	317.22	7.01	184.14	0.55	36.38
1997	6.46	4.82	0.00	1.34	2.72	15.35	3.73	4.72	329.93	7.02	184.66	0.67	46.56
1998	6.72	5.51	0.00	1.36	2.80	16.39	5.41	4.65	322.55	7.04	185.30	0.97	67.63
1999	6.99	6.91	0.00	1.48	3.11	18.49	7.12	4.54	328.03	7.06	185.90	1.23	89.02
2000	7.27	7.31	0.00	1.04	3.30	18.91	8.26	4.38	319.76	7.08	186.56	1.41	103.21
2001	7.56	8.03	0.00	0.88	3.57	20.04	9.24	4.30	322.24	7.10	187.22	1.54	115.51
2002	7.86	8.03	0.00	0.12	3.73	19.73	9.45	4.21	316.48	7.13	187.95	1.57	118.12
2003	8.17	8.53	0.00	0.19	3.95	20.84	10.22	4.22	321.41	7.15	188.68	1.68	127.79
2004	8.50	8.90	0.00	-0.15	4.13	21.38	10.92	4.20	320.16	7.18	189.47	1.79	136.55
2005	8.84	10.01	0.00	-0.15	4.36	23.06	13.60	4.01	308.58	7.21	190.27	2.21	169.96
2006	9.19	11.32	0.00	-0.37	4.56	24.70	19.62	4.06	313.24	9.46	249.73	3.18	245.20
2007	9.56	7.54	0.00	-4.46	4.76	17.40	12.16	4.10	318.55	9.58	252.96	1.95	151.94
2008	9.94	6.89	0.00	-4.42	4.94	17.36	11.99	4.16	323.42	9.71	256.32	1.93	149.87
2009	10.34	9.49	0.00	-4.38	5.19	20.65	15.13	4.21	328.80	9.84	259.81	2.42	189.14
2010	10.76	8.57	0.00	-4.39	5.38	20.32	14.67	4.28	334.08	9.98	263.44	2.35	183.35
2011	11.19	17.97	0.00	-4.37	4.80	29.59	23.78	4.34	339.80	10.12	267.22	3.80	297.26
2012	11.63	7.25	0.00	-4.65	3.79	18.02	12.07	4.42	345.53	10.27	271.15	1.93	150.82
2013	12.10	12.81	0.00	-4.51	4.51	24.90	18.79	4.49	351.72	10.42	275.23	3.00	234.82
2014	12.58	13.68	0.00	-4.55	4.73	26.44	20.16	4.57	357.92	10.58	279.48	3.21	252.06
2015	13.09	15.82	0.00	-4.54	5.10	29.47	23.03	4.65	364.38	10.75	283.90	3.67	287.86
20 yr NPV	66.21	62.59	0.00	-2.96	29.60	155.44	78.81	35.97	2639.62	63.79	1681.67	13.07	985.08

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Rel Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
2016	13.61	16.45	0.00	-4.72	5.30	30.65	24.04	4.73	371.09	10.92	288.49	3.83	300.47
2017	14.15	17.11	0.00	-4.91	5.51	31.87	25.09	4.82	378.07	11.10	293.27	4.00	313.60
2018	14.72	17.80	0.00	-5.11	5.73	33.15	26.18	4.91	385.33	11.29	298.24	4.17	327.24
2019	15.31	18.51	0.00	-5.31	5.96	34.47	27.31	5.01	392.88	11.49	303.41	4.35	341.43
2020	15.92	19.25	0.00	-5.52	6.20	35.85	28.50	5.11	400.73	11.69	308.79	4.54	356.19
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30 yr NPV	7.93	9.58	0.00	-2.78	3.09	17.85	14.09	2.65	208.15	6.10	161.17	2.25	176.10
50 yr NPV	74.14	72.17	0.00	-5.71	32.69	173.29	92.89	18.63	2847.77	69.89	1842.84	15.31	1161.18
Levelized								4.48	350.27	8.11	213.72	1.76	134.67

OUTPUT REPORT – ECONOMIC ANALYSIS

Range: ECONRPT

Alternative	5 PV	Node 1 – Demand	2 Med
Cost Mode	1	Node 2 – Fuel Price	2 Med
FCR Mode	1	Node 3 – Altern Cost	2 Med
Retirement	1	Node 4 – NS2 Cost	2 Med
Tax	1		

	Present Value (M$)			
	NS2 Alternative		System	Net
Fuel/Energy Cost	17.71	0.00	−20.75	−38.45
Variable O&M Cost	21.70	0.00	--	−21.70
Fixed O&M/Capacity Cost	25.27	18.28	−4.63	−11.62
Investment Cost	136.42	335.05	--	198.63
Emissions / Tax Cost	26.73	−21.93	29.42	−19.24
Total	227.82	331.39	4.04	107.61

	Present Value (M$)
Alternative Resource Capital Cost	335.05
Alternative Resource Operating Cost	18.28
Neil Simpson #2 Capital Cost	136.42
Neil Simpson #2 Operating Cost	64.67
Net System Generation & Reliability Cost	−25.38
Net Emissions / Tax Cost	−19.24
Net Cost	107.61

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATION - SELECTION OF TREE VALUES AND PROJECT PARAMETERS

Range: SELECT

Selected Tree Values										Mode Selectors	
Branch	Node 1 – Demand Value	Prob	Node 2 – Fuel Price Value	Prob	Node 3 – Altern Cost Value	Prob	Node 4 – NS2 Cost Value	Prob	Branch Probability	Alternative	5 PV
										Cost Mode	1
										FCR Mode	1
41	2	0.6	2	0.6	2	0.6	2	0.6	0.1296	Retirement	1
	Med		Med		Med		Med			Tax	1

											Selected
Cost Scen #	NS2 2					2					Project
0 Project Number	BASE	1	2	3	4	5	6	7	0		5
1 Name	NS2	NS2	CT	CC	Wind	PV	PPL	Basin	0		PV
2 Capacity (MW)	80	80	80	80	80	80	80	80	0		80
3 Capacity Purchase Adjust Period	0	0	0	0	0	0	5	5	0		0
4 Capacity Equivalence Factor	0.95	0.95	0.95	0.97	0.15	1	1	1	0		1
5 Equivalent Availability	0.895	0.895	0.913	0.933	0.3	0.3	1	1	0		0.3
6 Installed Cost ($/kW)	1561	1561	532	1023	1115	3185	220	300	0		3185
7 Real Escalation Rate	0.03846	0.03846	0	0	-0.04	0	0	0	0		0
8 Fixed Charge Rate Pattern No.	1	1	2	3	2	2	1	5	0		2
9 Average Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	1000	1000	0		0
10 Capacity Price Trajectory No.	0	0	0	0	0	0	7	9	0		0
11 Fuel Price Trajectory No.	1	1	5	4	0	0	8	10	0		0
12 Fixed O&M Cost ($/kW-yr)	26.46	26.46	11.56	14.14	54.5289	19.1422	0	24	0		19.1422
13 Real Escalation Rate	0	0	0	0	0	0	0	0	0		0
14 Var O&M Cost ($/kW-yr)	3.04	3.04	4.5	6.07	0	0	0	0	0		0
15 Real Escalation Rate	0	0	0	0	0	0	0	0	0		0
16 SO2 Emissions Rate (tons/MWh)	0.00106	0.00106	0.00000	0.00000	0	0	0.00275	0.00106	0		0
17 CO2 Emissions Rate (tons/MWh)	1.34375	1.34375	0.70695	0.48756	0	0	1.1	1.34375	0		0
18 Fuel Type	1	1	3	2	0	0	1	1	0		0
19 Tax Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	11000	11000	0		0
20 Renewable Tax Credit	0	0	0	0	1	1	0	0	0		1
21 Production Cost Selector	1	1	2	3	1	1	4	4	0		1
22 Start-up Year	1996	1996	1996	1996	1996	1996	1996	1996	0		1996
23 Life	50	50	25	35	25	25	30	30	0		25

CALCULATIONS – SELECTION OF SCENARIOS AND ESCALATION

Scenario #	Demand 2	DSM 2	Net Demand	Oil Price 2
1996	1818.2	0.0	1818.2	4.48
1997	1864.2	0.0	1864.2	4.60
1998	1911.7	0.0	1911.7	4.72
1999	1959.7	0.0	1959.7	4.85
2000	2007.8	0.0	2007.8	4.98
2001	2056.2	0.0	2056.2	5.12
2002	2104.8	0.0	2104.8	5.15
2003	2153.3	0.0	2153.3	5.15
2004	2201.8	0.0	2201.8	5.18
2005	2251.4	0.0	2251.4	5.23
2006	2302.3	0.0	2302.3	5.28
2007	2354.3	0.0	2354.3	5.35
2008	2407.7	0.0	2407.7	5.40
2009	2462.3	0.0	2462.3	5.40
2010	2518.2	0.0	2518.2	5.54
2011	2575.5	0.0	2575.5	5.77
2012	2634.1	0.0	2634.1	6.00
2013	2694.2	0.0	2694.2	6.26
2014	2755.7	0.0	2755.7	6.51
2015	2818.6	0.0	2818.6	6.77

	Escalation Rate	Annual Escalation	Compound Escalation
1996	0.0400	1.0400	1.0000
1997	0.0400	1.0400	1.0400
1998	0.0400	1.0400	1.0816
1999	0.0400	1.0400	1.1249
2000	0.0400	1.0400	1.1699
2001	0.0400	1.0400	1.2167
2002	0.0400	1.0400	1.2653
2003	0.0400	1.0400	1.3159
2004	0.0400	1.0400	1.3686
2005	0.0400	1.0400	1.4233
2006	0.0400	1.0400	1.4802
2007	0.0400	1.0400	1.5395
2008	0.0400	1.0400	1.6010
2009	0.0400	1.0400	1.6651
2010	0.0400	1.0400	1.7317
2011	0.0400	1.0400	1.8009
2012	0.0400	1.0400	1.8730
2013	0.0400	1.0400	1.9479
2014	0.0400	1.0400	2.0258
2015			2.1068
Beyond	0.0400	1.0400	

(Escalation is zero, with real cost mode.)

CALCULATIONS – PROJECT FUEL AND PURCHASED POWER COSTS

Range: FUELCALC

	Cap Price	Fuel Price
Real esc after 2015	0	0
Incr for high scenario	0	0
Decr for low scenario	0	0
Correl with oil price	0	0
Cap price factor	1	

Mode Selectors		Scenario	
Alternative	5 PV	Node 1 – Demand	2 Med
Cost Mode	1	Node 2 – Fuel Price	2 Med
FCR Mode	1	Node 3 – Altern Cost	2 Med
Retirement	1	Node 4 – NS2 Cost	2 Med
Tax	1		

	Change In Oil Price %	NS2 Coal Price	NS2 Var O&M	NS2 Disp Cost	NS2 Fixd O&M	Alternative Cap Price	Alternative Fuel Price	Alternative Var O&M	Alternative Disp Cost	Alternative Fixd O&M
1996	0.00%	0.60	3.04	10.59	26.46	0.00	0.00	0.00	0.00	19.14
1997	0.00%	0.65	3.16	11.25	27.52	0.00	0.00	0.00	0.00	19.91
1998	0.00%	0.54	3.29	9.98	28.62	0.00	0.00	0.00	0.00	20.70
1999	0.00%	0.52	3.42	9.88	29.76	0.00	0.00	0.00	0.00	21.53
2000	0.00%	0.38	3.56	8.24	30.95	0.00	0.00	0.00	0.00	22.39
2001	0.00%	0.34	3.70	7.92	32.19	0.00	0.00	0.00	0.00	23.29
2002	0.00%	0.23	3.85	6.76	33.48	0.00	0.00	0.00	0.00	24.22
2003	0.00%	0.23	4.00	6.90	34.82	0.00	0.00	0.00	0.00	25.19
2004	0.00%	0.17	4.16	6.33	36.21	0.00	0.00	0.00	0.00	26.20
2005	0.00%	0.00	4.33	4.33	37.66	0.00	0.00	0.00	0.00	27.25
2006	0.00%	0.00	4.50	4.50	39.17	0.00	0.00	0.00	0.00	28.34
2007	0.00%	0.00	4.68	4.68	40.73	0.00	0.00	0.00	0.00	29.47
2008	0.00%	0.00	4.87	4.87	42.36	0.00	0.00	0.00	0.00	30.65
2009	0.00%	0.00	5.06	5.06	44.06	0.00	0.00	0.00	0.00	31.87
2010	0.00%	0.00	5.26	5.26	45.82	0.00	0.00	0.00	0.00	33.15
2011	0.00%	0.00	5.47	5.47	47.65	0.00	0.00	0.00	0.00	34.47
2012	0.00%	0.00	5.69	5.69	49.56	0.00	0.00	0.00	0.00	35.85
2013	0.00%	0.00	5.92	5.92	51.54	0.00	0.00	0.00	0.00	37.29
2014	0.00%	0.00	6.16	6.16	53.60	0.00	0.00	0.00	0.00	38.78
2015	0.00%	0.00	6.40	6.40	55.75	0.00	0.00	0.00	0.00	40.33

CALCULATIONS – RESPONSE SURFACE MODEL

Range: RSMCALC

Prod Cost Selector # 1

	Base	Demand	Oil Price	NS2 Cost	Alt Cost	D*D	D*OP	OP*OP
CF Coefs	Alt Cost	6.9	0	−3.6	−3.6	0	0	0
Ben Coefs		0.9	0.25	– –	– –	0	0	0
1996	10.59	0	0	0	−1	0	0	0
1997	11.25	0	0	0	−1	0	0	0
1998	9.98	0	0	0	−1	0	0	0
1999	9.88	0	0	0	−1	0	0	0
2000	8.24	0	0	0	−1	0	0	0
2001	7.92	0	0	0	−1	0	0	0
2002	6.76	0	0	0	−1	0	0	0
2003	6.90	0	0	0	−1	0	0	0
2004	6.33	0	0	0	−1	0	0	0
2005	4.33	0	0	0	−1	0	0	0
2006	4.50	0	0	0	−1	0	0	0
2007	4.68	0	0	0	−1	0	0	0
2008	4.87	0	0	0	−1	0	0	0
2009	5.06	0	0	0	−1	0	0	0
2010	5.26	0	0	0	−1	0	0	0
2011	5.47	0	0	0	−1	0	0	0
2012	5.69	0	0	0	−1	0	0	0
2013	5.92	0	0	0	−1	0	0	0
2014	6.16	0	0	0	−1	0	0	0
2015	6.40	0	0	0	−1	0	0	0

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Dispatch and Production Cost

Net Peak Gen Factor 1

	NS2 CF				Alt CF				Energy (GWh)			
	Linear Sum	Quadratic Sum	Exp(CF)	CF	Linear Sum	Quadratic Sum	Exp(CF)	CF	NS2	Alt	Net Peak	Net Base
1996	0	0	5.04627	75.0%	3.6	0	184.684	30.0%	525.6	210.2	−18.1	333.6
1997	0	0	7.90502	79.8%	3.6	0	289.310	30.0%	559.2	210.6	−20.6	369.3
1998	0	0	7.40809	79.2%	3.6	0	271.123	30.0%	555.0	210.5	−22.2	366.7
1999	0	0	10.9709	82.4%	3.6	0	401.513	30.1%	577.5	210.8	−28.3	395.0
2000	0	0	12.7978	83.4%	3.6	0	468.380	30.1%	584.5	210.8	−29.7	403.3
2001	0	0	19.3062	85.5%	3.6	0	706.576	30.1%	599.2	211.0	−32.8	421.0
2002	0	0	20.7735	85.8%	3.6	0	760.273	30.1%	601.3	211.0	−32.0	422.3
2003	0	0	28.6210	86.9%	3.6	0	1047.47	30.1%	609.0	211.1	−33.8	431.7
2004	0	0	30.6982	87.1%	3.6	0	1123.50	30.1%	610.4	211.1	−34.0	433.3
2005	0	0	43.0561	87.9%	3.6	0	1575.77	30.1%	616.0	211.2	−37.9	442.8
2006	0	0	47.8137	88.1%	3.6	0	1749.89	30.1%	617.4	211.2	−39.4	445.6
2007	0	0	77.4743	88.8%	3.6	0	2835.42	30.1%	622.3	211.2	−27.8	438.9
2008	0	0	77.4743	88.8%	3.6	0	2835.42	30.1%	622.3	211.2	−24.8	435.9
2009	0	0	105.105	89.1%	3.6	0	3846.67	30.1%	624.4	211.2	−33.9	447.1
2010	0	0	105.105	89.1%	3.6	0	3846.67	30.1%	624.4	211.2	−28.7	441.9
2011	0	0	137.652	89.3%	3.6	0	5037.82	30.1%	625.8	211.3	−56.2	470.8
2012	0	0	137.652	89.3%	3.6	0	5037.82	30.1%	625.8	211.3	−22.2	436.8
2013	0	0	199	89.5%	3.6	0	7283.04	30.1%	627.2	211.3	−37.4	453.3
2014	0	0	199	89.5%	3.6	0	7283.04	30.1%	627.2	211.3	−38.5	454.5
2015	0	0	199	89.5%	3.6	0	7283.04	30.1%	627.2	211.3	−43.0	459.0

Production Cost and Capacity Surplus Calculations

	Base Gen Cost					Pk Cost
	Base Val $/MWh	Linear Sum	Quadratic Sum	Exp(Q)	Adj Val $/MWh	Adj Val $/MWh
1996	0.00	0	0	1	0.00	42.85
1997	0.00	0	0	1	0.00	48.72
1998	0.00	0	0	1	0.00	51.78
1999	0.00	0	0	1	0.00	50.90
2000	0.00	0	0	1	0.00	51.27
2001	0.00	0	0	1	0.00	50.97
2002	0.00	0	0	1	0.00	52.20
2003	0.00	0	0	1	0.00	52.55
2004	0.00	0	0	1	0.00	54.49
2005	0.00	0	0	1	0.00	55.01
2006	0.00	0	0	1	0.00	59.90
2007	0.00	0	0	1	0.00	56.44
2008	0.00	0	0	1	0.00	57.85
2009	0.00	0	0	1	0.00	58.34
2010	0.00	0	0	1	0.00	62.12
2011	0.00	0	0	1	0.00	66.57
2012	0.00	0	0	1	0.00	67.85
2013	0.00	0	0	1	0.00	71.35
2014	0.00	0	0	1	0.00	74.02
2015	0.00	0	0	1	0.00	76.61

	Capacity Surplus	Lagged Capacity Surplus
1996	0.00	0.00
1997	0.00	0.00
1998	0.00	0.00
1999	0.00	0.00
2000	0.00	0.00
2001	0.00	0.00
2002	0.00	0.00
2003	0.00	0.00
2004	0.00	0.00
2005	0.00	0.00
2006	0.00	0.00
2007	0.00	0.00
2008	0.00	0.00
2009	0.00	0.00
2010	0.00	0.00
2011	0.00	0.00
2012	0.00	0.00
2013	0.00	0.00
2014	0.00	0.00
2015	0.00	0.00

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Emissions Calculations

	Emissions (tons)							
	NS2		Alternative		Net Peaking		Net Base	
	SO2	CO2	SO2	CO2	SO2	CO2	SO2	CO2
1996	558	706275	0	0	−0	−13075	2702	517858
1997	594	751477	0	0	−0	−14872	2991	573307
1998	590	745826	0	0	−0	−15996	2970	569274
1999	614	775961	0	0	−0	−20421	3199	613219
2000	621	785378	0	0	−0	−21424	3267	626142
2001	637	805154	0	0	−0	−23692	3410	653632
2002	639	807979	0	0	−0	−23110	3421	655611
2003	647	818337	0	0	−0	−24387	3497	670209
2004	649	820221	0	0	−0	−24558	3510	672731
2005	655	827754	0	0	−0	−27361	3586	687383
2006	656	829638	0	0	−0	−28400	3609	691774
2007	661	836230	0	0	−0	−20092	3555	681440
2008	661	836230	0	0	−0	−17914	3531	676754
2009	663	839055	0	0	−0	−24452	3621	694056
2010	663	839055	0	0	−0	−20737	3579	686062
2011	665	840938	0	0	−0	−40583	500	632641
2012	665	840938	0	0	−0	−16053	464	586955
2013	666	842822	0	0	−0	−26980	482	609173
2014	666	842822	0	0	−0	−27783	483	610668
2015	666	842822	0	0	−0	−31043	488	616740

CALCULATIONS – ECONOMIC ANALYSIS

Range: ECONCALC

Alternative	5 PV
Cost Mode	1
PCR Mode	1
Retirement	1
Tax	1

Node 1 – Demand	2 Med
Node 2 – Fuel Price	2 Med
Node 3 – Altern Cost	2 Med
Node 4 – NS2 Cost	2 Med

INTERMEDIATE CALCULATIONS

INITIAL COSTS	
Neil Simpson 2	
Construction Cost (M$)	124.88
Retirement Year	2021
Alternative	
Construction Cost (M$)	254.80
Retirement Year	2021
Last Year of Renewable Credit	2005
System	
Net Reliability Cost (M$)	−0.388

ESCALATION RATES	
NS2 Fuel Cost	1.000
Variable O&M Cost	1.000
Fixed O&M Cost	1.000
Fuel Cost	1.000
Variable O&M Cost	1.000
Fixed O&M / Capacity Price	1.000
Net Prod Cost Savings, after 2020	1.000
Cost Discount	1.000
Net Reliability Cost	1.000

Discount Rate	0.107
Annual Discount Factor	0.904
Discount From 2015 to 1996	0.145

Energy Tax Rates ($/MWh)	
Neil Simpson 2	3.21
Alternative	0.00
Net Peaking	7.79
Net Base	3.34

Neil Simpson values are scaled to the size of the alternative project.

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De-escal	NS2						Alternative					
	Factor	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total
1996	1.000	3.97	1.60	2.12	15.73	1.97	25.38	0.00	0.00	1.53	38.62	-3.15	37.00
1997	1.000	4.52	1.77	2.20	15.73	2.18	26.39	0.00	0.00	1.59	38.62	-3.28	36.93
1998	1.000	3.72	1.82	2.29	15.73	2.25	25.80	0.00	0.00	1.66	38.62	-3.42	36.86
1999	1.000	3.73	1.97	2.38	15.73	2.43	26.24	0.00	0.00	1.72	38.62	-3.56	36.79
2000	1.000	2.74	2.08	2.48	15.73	2.56	25.58	0.00	0.00	1.79	38.62	-3.70	36.71
2001	1.000	2.53	2.22	2.58	15.73	2.73	25.78	0.00	0.00	1.86	38.62	-3.85	36.64
2002	1.000	1.75	2.31	2.68	15.73	2.85	25.32	0.00	0.00	1.94	38.62	-4.01	36.56
2003	1.000	1.76	2.44	2.79	15.73	3.00	25.71	0.00	0.00	2.02	38.62	-4.17	36.47
2004	1.000	1.32	2.54	2.90	15.73	3.13	25.61	0.00	0.00	2.10	38.62	-4.33	36.39
2005	1.000	0.00	2.67	3.01	15.73	3.28	24.69	0.00	0.00	2.18	38.62	-4.51	36.29
2006	1.000	0.00	2.78	3.13	15.73	3.42	25.06	0.00	0.00	2.27	38.62	0.00	40.89
2007	1.000	0.00	2.91	3.26	15.73	3.59	25.48	0.00	0.00	2.36	38.62	0.00	40.98
2008	1.000	0.00	3.03	3.39	15.73	3.73	25.87	0.00	0.00	2.45	38.62	0.00	41.07
2009	1.000	0.00	3.16	3.52	15.73	3.89	26.30	0.00	0.00	2.55	38.62	0.00	41.17
2010	1.000	0.00	3.29	3.67	15.73	4.05	26.73	0.00	0.00	2.65	38.62	0.00	41.27
2011	1.000	0.00	3.43	3.81	15.73	4.22	27.18	0.00	0.00	2.76	38.62	0.00	41.38
2012	1.000	0.00	3.56	3.96	15.73	4.39	27.64	0.00	0.00	2.87	38.62	0.00	41.49
2013	1.000	0.00	3.71	4.12	15.73	4.57	28.14	0.00	0.00	2.98	38.62	0.00	41.61
2014	1.000	0.00	3.86	4.29	15.73	4.76	28.63	0.00	0.00	3.10	38.62	0.00	41.73
2015	1.000	0.00	4.02	4.46	15.73	4.95	29.15	0.00	0.00	3.23	38.62	0.00	41.85
20 yr NPV		17.71	19.27	22.56	127.90	23.73	211.17	0.00	0.00	16.32	314.12	-21.93	308.51

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De - escal	NS2						Alternative					
	Factor	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total
2016	1.000	0.00	4.18	4.64	15.73	5.14	29.69	0.00	0.00	3.36	38.62	0.00	41.98
2017	1.000	0.00	4.35	4.82	15.73	5.35	30.25	0.00	0.00	3.49	38.62	0.00	42.11
2018	1.000	0.00	4.52	5.02	15.73	5.56	30.83	0.00	0.00	3.63	38.62	0.00	42.25
2019	1.000	0.00	4.70	5.22	15.73	5.79	31.43	0.00	0.00	3.77	38.62	0.00	42.40
2020	1.000	0.00	4.89	5.43	15.73	6.02	32.06	0.00	0.00	3.93	38.62	0.00	42.55
2021	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30 yr NPV		0.00	2.43	2.70	9.52	3.69	16.65	0.00	0.00	1.95	20.93	0.00	22.88
40 yr NPV		17.71	21.70	25.27	136.42	26.73	227.82	0.00	0.00	18.25	335.05	-21.94	431.39

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Rel Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
1996	-0.39	-0.78	0.00	1.25	2.32	2.41	14.04	4.83	317.22	17.61	462.53	2.67	175.45
1997	-0.40	-1.00	0.00	1.34	2.67	2.61	13.15	4.72	329.93	17.54	461.64	2.35	164.31
1998	-0.42	-1.15	0.00	1.36	2.74	2.54	13.60	4.65	322.55	17.51	460.80	2.45	169.98
1999	-0.44	-1.44	0.00	1.48	3.04	2.64	13.19	4.54	328.03	17.45	459.87	2.28	164.84
2000	-0.45	-1.52	0.00	1.04	3.22	2.28	13.42	4.38	319.76	17.41	458.93	2.30	167.70
2001	-0.47	-1.67	0.00	0.88	3.47	2.21	13.07	4.30	322.24	17.36	457.94	2.18	163.36
2002	-0.49	-1.67	0.00	0.12	3.63	1.59	12.83	4.21	316.48	17.32	456.95	2.13	160.34
2003	-0.51	-1.78	0.00	0.19	3.85	1.75	12.51	4.22	321.41	17.28	455.89	2.05	156.39
2004	-0.53	-1.85	0.00	-0.15	4.02	1.48	12.26	4.20	320.16	17.23	454.81	2.01	153.20
2005	-0.55	-2.09	0.00	-0.15	4.24	1.44	13.05	4.01	308.58	17.19	453.68	2.12	163.15
2006	-0.57	-2.36	0.00	-0.37	4.42	1.12	16.95	4.06	313.24	19.36	511.12	2.74	211.84
2007	-0.60	-1.57	0.00	-4.46	4.66	-1.97	13.52	4.10	318.55	19.40	512.26	2.17	169.06
2008	-0.62	-1.44	0.00	-4.42	4.85	-1.63	13.57	4.16	323.42	19.45	513.44	2.18	169.64
2009	-0.65	-1.98	0.00	-4.38	5.06	-1.94	12.93	4.21	328.80	19.49	514.66	2.07	161.66
2010	-0.67	-1.79	0.00	-4.39	5.27	-1.58	12.97	4.28	334.08	19.54	515.94	2.08	162.11
2011	-0.70	-3.74	0.00	-4.37	2.49	-6.32	7.88	4.34	339.80	19.59	517.26	1.26	98.48
2012	-0.73	-1.51	0.00	-4.65	2.84	-4.05	9.80	4.42	345.53	19.64	518.64	1.57	122.54
2013	-0.76	-2.67	0.00	-4.51	2.85	-5.08	8.39	4.49	351.72	19.69	520.08	1.34	104.85
2014	-0.79	-2.85	0.00	-4.55	2.96	-5.23	7.86	4.57	357.92	19.75	521.57	1.25	98.23
2015	-0.82	-3.30	0.00	-4.54	3.04	-5.62	7.08	4.65	364.38	19.81	523.12	1.13	88.55
20 yr NPV	-4.14	-13.04	0.00	-2.96	27.58	7.45	104.78	35.97	2639.62	146.29	3856.36	17.92	1309.81

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Rel Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
	-0.85	-3.43	0.00	-4.72	3.16	-5.84	6.45	4.73	371.09	19.87	524.73	1.03	80.65
2017	-0.88	-3.57	0.00	-4.91	3.29	-6.07	5.79	4.82	378.07	19.93	526.41	0.92	72.42
2018	-0.92	-3.71	0.00	-5.11	3.42	-6.32	5.11	4.91	385.33	20.00	528.15	0.81	63.87
2019	-0.96	-3.86	0.00	-5.31	3.55	-6.57	4.40	5.01	392.88	20.07	529.97	0.70	54.98
2020	-1.00	-4.01	0.00	-5.52	3.70	-6.83	3.66	5.11	400.73	20.14	531.86	0.58	45.73
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30 yr NPV	-0.50	-2.00	0.00	-2.75	1.84	-3.40	2.83	2.65	208.15	10.83	286.04	0.45	35.38
50 yr NPV	-4.63	-15.06	0.00	-5.71	29.42	4.04	107.61	38.63	2847.77	157.12	4142.40	18.37	1348.19
Levelized								4.48	330.27	18.22	480.42	2.13	156.01

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

OUTPUT REPORT – ECONOMIC ANALYSIS

Range: ECONREPT

Alternative	6 PPL	Node 1 – Demand	2 Med
Cost Mode	1	Node 2 – Fuel Price	2 Med
FCR Mode	1	Node 3 – Altern Cost	2 Med
Retirement	1	Node 4 – NS2 Cost	2 Med
Tax	1		

	Present Value (M$)			
	NS2 Alternative		System	Net
Fuel/Energy Cost	17.71	126.48	−9.16	99.61
Variable O&M Cost	23.49	0.00	--	−23.49
Fixed O&M/Capacity Cost	27.24	162.94	−5.00	130.70
Investment Cost	141.55	19.95	--	−121.60
Emissions / Tax Cost	28.92	28.16	5.78	5.02
Total	238.91	337.52	−8.37	90.25

	Present Value (M$)
Alternative Resource Capital Cost	19.95
Alternative Resource Operating Cost	289.41
Neil Simpson #2 Capital Cost	141.55
Neil Simpson #2 Operating Cost	68.43
Net System Generation & Reliability Cost	−14.15
Net Emissions / Tax Cost	5.02
Net Cost	90.25

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATION – SELECTION OF TREE VALUES AND PROJECT PARAMETERS

Range: SELECT

Selected Tree Values										Mode Selectors	
Branch	Node 1 – Demand Value	Prob	Node 2 – Fuel Price Value	Prob	Node 3 – Altern Cost Value	Prob	Node 4 – NS2 Cost Value	Prob	Branch Probability	Alternative	6 PPL
										Cost Mode	1
										FCR Mode	1
41	2	0.6	2	0.6	2	0.6	2	0.6	0.1296	Retirement	1
	Med		Med		Med		Med			Tax	1

	NS2									Selected
Cost Scen #	2					2				Project
0 Project Number	BASE	1	2	3	4	5	6	7	0	6
1 Name	NS2	NS2	CT	CC	Wind	PV	PPL	Basin	0	PPL
2 Capacity (MW)	80	80	80	80	80	80	80	80	0	80
3 Capacity Purchase Adjust Period	0	0	0	0	0	0	5	5	0	5
4 Capacity Equivalence Factor	0.95	0.95	0.95	0.97	0.15	1	1	1	0	1
5 Equivalent Availability	0.895	0.895	0.913	0.933	0.3	0.3	1	1	0	1
6 Installed Cost ($/kW)	1561	1561	532	1023	1115	3185	220	300	0	220
7 Real Escalation Rate	0.03846	0.03846	0	0	−0.04	0	0	0	0	0
8 Fixed Charge Rate Pattern No.	1	1	2	3	2	2	1	5	0	1
9 Average Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	1000	1000	0	1000
10 Capacity Price Trajectory No.	0	0	0	0	0	0	7	9	0	7
11 Fuel Price Trajectory No.	1	1	5	4	0	0	8	10	0	8
12 Fixed O&M Cost ($/kW−yr)	26.46	26.46	11.56	14.14	54.5289	19.1422	0	24	0	0
13 Real Escalation Rate	0	0	0	0	0	0	0	0	0	0
14 Var O&M Cost ($/kW−yr)	3.04	3.04	4.5	6.07	0	0	0	0	0	0
15 Real Escalation Rate	0	0	0	0	0	0	0	0	0	0
16 SO2 Emissions Rate (tons/MWh)	0.00106	0.00106	0.00000	0.00000	0	0	0.00275	0.00106	0	0.00275
17 CO2 Emissions Rate (tons/MWh)	1.34375	1.34375	0.70695	0.48756	0	0	1.1	1.34375	0	1.1
18 Fuel Type	1	1	3	2	0	0	1	1	0	1
19 Tax Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	11000	11000	0	11000
20 Renewable Tax Credit	0	0	0	0	1	1	0	0	0	0
21 Production Cost Selector	1	1	2	3	1	1	4	4	0	4
22 Start−up Year	1996	1996	1996	1996	1996	1996	1996	1996	0	1996
23 Life	50	50	25	35	25	25	30	30	0	30

CALCULATIONS – SELECTION OF SCENARIOS AND ESCALATION

Scenario #	Demand 2	DSM 2	Net Demand	Oil Price 2
1996	1818.2	0.0	1818.2	4.48
1997	1864.2	0.0	1864.2	4.60
1998	1911.7	0.0	1911.7	4.72
1999	1959.7	0.0	1959.7	4.85
2000	2007.8	0.0	2007.8	4.98
2001	2056.2	0.0	2056.2	5.12
2002	2104.8	0.0	2104.8	5.15
2003	2153.3	0.0	2153.3	5.15
2004	2201.8	0.0	2201.8	5.18
2005	2251.4	0.0	2251.4	5.23
2006	2302.3	0.0	2302.3	5.28
2007	2354.3	0.0	2354.3	5.35
2008	2407.7	0.0	2407.7	5.40
2009	2462.3	0.0	2462.3	5.40
2010	2518.2	0.0	2518.2	5.54
2011	2575.5	0.0	2575.5	5.77
2012	2634.1	0.0	2634.1	6.00
2013	2694.2	0.0	2694.2	6.26
2014	2755.7	0.0	2755.7	6.51
2015	2818.6	0.0	2818.6	6.77

	Escalation Rate	Annual Escalation	Compound Escalation
1996	0.0400	1.0400	1.0000
1997	0.0400	1.0400	1.0400
1998	0.0400	1.0400	1.0816
1999	0.0400	1.0400	1.1249
2000	0.0400	1.0400	1.1699
2001	0.0400	1.0400	1.2167
2002	0.0400	1.0400	1.2653
2003	0.0400	1.0400	1.3159
2004	0.0400	1.0400	1.3686
2005	0.0400	1.0400	1.4233
2006	0.0400	1.0400	1.4802
2007	0.0400	1.0400	1.5395
2008	0.0400	1.0400	1.6010
2009	0.0400	1.0400	1.6651
2010	0.0400	1.0400	1.7317
2011	0.0400	1.0400	1.8009
2012	0.0400	1.0400	1.8730
2013	0.0400	1.0400	1.9479
2014	0.0400	1.0400	2.0258
2015			2.1068
Beyond	0.0400	1.0400	

(Escalation is zero, with real cost mode.)

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – PROJECT FUEL AND PURCHASED POWER COSTS

Range: FUELCALC

	Cap Price	Fuel Price
Real esc after 2015	0	0.01723
Incr for high scenario	0.3	--
Decr for low scenario	0.3	--
Correl with oil price	--	0.25
Cap price factor	1	

Mode Selectors		Scenario	
Alternative	6 PPL	Node 1 – Demand	2 Med
Cost Mode	1	Node 2 – Fuel Price	2 Med
FOR Mode	1	Node 3 – Altern Cost	2 Med
Retirement	1	Node 4 – NS2 Cost	2 Med
Tax	1		

	Change In Oil Price %	NS2 Cont Price	NS2 Var O&M	NS2 Disp Cost	NS2 Fixd O&M	Alternative Cap Price	Alternative Fuel Price	Alternative Var O&M	Alternative Disp Cost	Alternative Fixd O&M
1996	0.00%	0.60	3.04	10.59	26.46	213.24	16.84	0.00	16.84	0.00
1997	0.00%	0.65	3.16	11.25	27.52	214.32	17.54	0.00	17.54	0.00
1998	0.00%	0.54	3.29	9.98	28.62	215.40	18.28	0.00	18.28	0.00
1999	0.00%	0.52	3.42	9.88	29.76	216.48	19.07	0.00	19.07	0.00
2000	0.00%	0.38	3.56	8.24	30.95	217.56	19.90	0.00	19.90	0.00
2001	0.00%	0.34	3.70	7.92	32.19	218.64	20.82	0.00	20.82	0.00
2002	0.00%	0.23	3.85	6.76	33.48	219.72	21.84	0.00	21.84	0.00
2003	0.00%	0.23	4.00	6.90	34.82	220.80	22.95	0.00	22.95	0.00
2004	0.00%	0.17	4.16	6.33	36.21	221.88	24.12	0.00	24.12	0.00
2005	0.00%	0.00	4.33	4.33	37.66	223.08	25.41	0.00	25.41	0.00
2006	0.00%	0.00	4.50	4.50	39.17	224.16	26.82	0.00	26.82	0.00
2007	0.00%	0.00	4.68	4.68	40.73	225.24	28.34	0.00	28.34	0.00
2008	0.00%	0.00	4.87	4.87	42.36	226.44	30.00	0.00	30.00	0.00
2009	0.00%	0.00	5.06	5.06	44.06	227.52	31.74	0.00	31.74	0.00
2010	0.00%	0.00	5.26	5.26	45.82	228.60	33.59	0.00	33.59	0.00
2011	0.00%	0.00	5.47	5.47	47.65	229.80	35.54	0.00	35.54	0.00
2012	0.00%	0.00	5.69	5.69	49.56	231.00	37.60	0.00	37.60	0.00
2013	0.00%	0.00	5.92	5.92	51.54	232.16	39.78	0.00	39.78	0.00
2014	0.00%	0.00	6.16	6.16	53.60	233.33	42.08	0.00	42.08	0.00
2015	0.00%	0.00	6.40	6.40	55.75	234.50	44.52	0.00	44.52	0.00

CALCULATIONS – RESPONSE SURFACE MODEL

Range: RSMCALC

Prod Cost Selector # 4

	Base	Demand	Oil Price	NS2 Cost	Alt Cost	D*D	D*OP	OP*OP
CF Costs	Alt Cost	6.9	0	-3.6	-3.6	0	0	0
Ben Costs		0.9	0.25	--	--	0	0	0
1996	16.84	0	0	0	0	0	0	0
1997	17.54	0	0	0	0	0	0	0
1998	18.28	0	0	0	0	0	0	0
1999	19.07	0	0	0	0	0	0	0
2000	19.90	0	0	0	0	0	0	0
2001	20.82	0	0	0	0	0	0	0
2002	21.84	0	0	0	0	0	0	0
2003	22.95	0	0	0	0	0	0	0
2004	24.12	0	0	0	0	0	0	0
2005	25.41	0	0	0	0	0	0	0
2006	26.82	0	0	0	0	0	0	0
2007	28.34	0	0	0	0	0	0	0
2008	30.00	0	0	0	0	0	0	0
2009	31.74	0	0	0	0	0	0	0
2010	33.59	0	0	0	0	0	0	0
2011	35.54	0	0	0	0	0	0	0
2012	37.60	0	0	0	0	0	0	0
2013	39.78	0	0	0	0	0	0	0
2014	42.08	0	0	0	0	0	0	0
2015	44.52	0	0	0	0	0	0	0

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Dispatch and Production Cost

Net Peak Gen Factor 1

	NS2 CF				Alt CF				Energy (GWh)			
	Linear Sum	Quadratic Sum	Exp(CF')	CF	Linear Sum	Quadratic Sum	Exp(CF')	CF	NS2	Alt	Net Peak	Net Base
1996	0	0	5.04627	75.0%	0	0	1.53126	60.6%	525.6	424.7	-18.1	119.0
1997	0	0	7.90502	79.8%	0	0	2.09798	67.9%	559.2	475.8	-20.6	104.0
1998	0	0	7.40809	79.2%	0	0	2.11710	68.1%	555.0	477.2	-22.2	100.0
1999	0	0	10.9708	82.4%	0	0	2.85460	74.3%	577.5	520.7	-28.3	85.1
2000	0	0	12.7978	83.4%	0	0	2.94492	74.9%	584.5	524.9	-29.7	89.3
2001	0	0	19.3062	85.5%	0	0	3.74113	79.2%	599.2	555.0	-32.8	77.0
2002	0	0	20.7735	85.8%	0	0	3.46847	77.9%	601.3	545.9	-32.0	87.4
2003	0	0	28.6210	86.9%	0	0	4.48817	82.1%	609.0	575.4	-33.8	67.4
2004	0	0	30.6982	87.1%	0	0	4.02411	80.4%	610.4	563.4	-34.0	81.0
2005	0	0	43.0561	87.9%	0	0	5.39100	84.7%	616.0	593.6	-37.9	60.3
2006	0	0	47.8137	88.1%	0	0	4.80349	83.1%	617.4	582.4	-39.4	74.4
2007	0	0	77.4743	88.8%	0	0	1.72227	63.4%	622.3	444.3	-27.8	205.9
2008	0	0	77.4743	88.8%	0	0	1.72963	63.5%	622.3	445.0	-24.8	202.1
2009	0	0	105.105	89.1%	0	0	2.14623	68.4%	624.4	479.3	-33.9	179.0
2010	0	0	105.105	89.1%	0	0	1.97044	66.5%	624.4	466.0	-28.7	187.1
2011	0	0	137.652	89.3%	0	0	8.99600	90.4%	625.8	633.5	-56.2	48.5
2012	0	0	137.652	89.3%	0	0	1.83695	64.9%	625.8	454.8	-22.2	193.2
2013	0	0	199	89.5%	0	0	2.86937	74.4%	627.2	521.4	-37.4	143.2
2014	0	0	199	89.5%	0	0	2.78243	73.8%	627.2	517.2	-38.5	148.5
2015	0	0	199	89.5%	0	0	3.69704	79.0%	627.2	553.6	-43.0	116.6

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Production Cost and Capacity Surplus Calculations

	Base Gen Cost					Pk Cost
	Base Val $/MWh	Linear Sum	Quadratic Sum	Exp(Q)	Adj Val $/MWh	Adj Val $/MWh
1996	13.21	0	0	1	13.21	42.85
1997	13.89	0	0	1	13.89	48.72
1998	14.43	0	0	1	14.43	51.78
1999	15.21	0	0	1	15.21	50.90
2000	15.74	0	0	1	15.74	51.27
2001	16.62	0	0	1	16.62	50.97
2002	17.09	0	0	1	17.09	52.20
2003	18.17	0	0	1	18.17	52.55
2004	18.48	0	0	1	18.48	54.49
2005	19.26	0	0	1	19.26	55.01
2006	19.97	0	0	1	19.97	59.90
2007	16.91	0	0	1	16.91	56.44
2008	17.13	0	0	1	17.13	57.85
2009	18.04	0	0	1	18.04	58.34
2010	18.69	0	0	1	18.69	62.12
2011	15.03	0	0	1	15.03	66.57
2012	10.15	0	0	1	10.15	67.85
2013	11.95	0	0	1	11.95	71.35
2014	11.06	0	0	1	11.06	74.02
2015	12.37	0	0	1	12.37	76.61

	Capacity Surplus	Lagged Capacity Surplus
1996	0.00	0.00
1997	0.00	0.00
1998	0.00	0.00
1999	0.00	0.00
2000	0.00	0.00
2001	0.00	0.00
2002	0.00	0.00
2003	0.00	0.00
2004	0.00	0.00
2005	0.00	0.00
2006	0.00	0.00
2007	0.00	0.00
2008	0.00	0.00
2009	0.00	0.00
2010	0.00	0.00
2011	0.00	0.00
2012	0.00	0.00
2013	0.00	0.00
2014	0.00	0.00
2015	0.00	0.00

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Emissions Calculations

	Emissions (tons)							
	NS2		Alternative		Net Penking		Net Base	
	SO2	CO2	SO2	CO2	SO2	CO2	SO2	CO2
1996	558	706275	1168	467153	−0	−13075	964	184805
1997	594	751477	1309	523428	−0	−14872	842	161471
1998	590	745826	1312	524969	−0	−15996	810	155186
1999	614	775961	1432	572764	−0	−20421	689	132068
2000	621	785378	1443	577389	−0	−21424	723	138579
2001	637	805154	1526	610537	−0	−23692	624	119523
2002	639	807979	1501	600516	−0	−23110	708	135678
2003	647	818337	1582	632892	−0	−24387	546	104700
2004	649	820221	1549	619788	−0	−24558	656	125738
2005	655	827754	1632	652935	−0	−27361	489	93691
2006	656	829638	1602	640601	−0	−28400	603	115511
2007	661	836230	1222	488738	−0	−20092	1667	319582
2008	661	836230	1224	489509	−0	−17914	1637	313809
2009	663	839055	1318	527282	−0	−24452	1450	277830
2010	663	839055	1282	512635	−0	−20737	1516	290508
2011	665	840938	1742	696876	−0	−40583	52	65225
2012	665	840938	1251	500301	−0	−16053	205	259672
2013	666	842822	1434	573535	−0	−26980	152	192446
2014	666	842822	1422	568909	−0	−27783	158	199591
2015	666	842822	1522	608995	−0	−31043	124	156695

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – ECONOMIC ANALYSIS

Range: ECONCALC

Alternative	6 PPL
Cost Mode	1
FCR Mode	1
Retirement	1
Tax	1

Node 1 – Demand	2 Med
Node 2 – Fuel Price	2 Med
Node 3 – Altern Cost	2 Med
Node 4 – NS2 Cost	2 Med

INTERMEDIATE CALCULATIONS

INITIAL COSTS	
Neil Simpson 2	
Construction Cost (M$)	124.88
Retirement Year	2026
Alternative	
Construction Cost (M$)	17.60
Retirement Year	2026
Last Year of Renewable Credit	0
System	
Net Reliability Cost (M$)	−0.388

ESCALATION RATES	
NS2 Fuel Cost	1.000
Variable O&M Cost	1.000
Fixed O&M Cost	1.000
Fuel Cost	1.017
Variable O&M Cost	1.000
Fixed O&M / Capacity Price	1.000
Net Prod Cost Savings, after 2020	1.000
Cost Discount	1.000
Net Reliability Cost	1.000

Discount Rate	0.107
Annual Discount Factor	0.906
Discount From 2015 to 1996	0.145

Energy Tax Rates ($/MWh)	
Neil Simpson 2	3.21
Alternative	2.83
Net Peaking	7.79
Net Base	3.34

Neil Simpson values are scaled to the size of the alternative project.

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De-escal	NS2						Alternative					
	Factor	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total
1996	1.000	3.97	1.60	2.12	15.73	1.97	25.38	7.15	0.00	17.06	2.22	1.78	28.21
1997	1.000	4.52	1.77	2.20	15.73	2.18	26.39	8.35	0.00	17.15	2.22	2.08	29.79
1998	1.000	3.72	1.82	2.29	15.73	2.25	25.80	8.72	0.00	17.23	2.22	2.17	30.34
1999	1.000	3.73	1.97	2.38	15.73	2.43	26.24	9.93	0.00	17.32	2.22	2.46	31.93
2000	1.000	2.74	2.08	2.48	15.73	2.56	25.58	10.45	0.00	17.40	2.22	2.58	32.65
2001	1.000	2.53	2.22	2.58	15.73	2.73	25.78	11.56	0.00	17.49	2.22	2.84	34.10
2002	1.000	1.75	2.31	2.68	15.73	2.85	25.32	11.92	0.00	17.58	2.22	2.90	34.62
2003	1.000	1.76	2.44	2.79	15.73	3.00	25.71	13.20	0.00	17.66	2.22	3.18	36.27
2004	1.000	1.32	2.54	2.90	15.73	3.13	25.61	13.59	0.00	17.75	2.22	3.24	36.80
2005	1.000	0.00	2.67	3.01	15.73	3.28	24.69	15.08	0.00	17.85	2.22	3.55	38.70
2006	1.000	0.00	2.78	3.13	15.73	3.42	25.06	15.62	0.00	17.93	2.22	3.62	39.39
2007	1.000	0.00	2.91	3.26	15.73	3.59	25.48	12.59	0.00	18.02	2.22	2.87	35.70
2008	1.000	0.00	3.03	3.39	15.73	3.73	25.87	13.35	0.00	18.12	2.22	2.99	36.68
2009	1.000	0.00	3.16	3.52	15.73	3.89	26.30	15.21	0.00	18.20	2.22	3.35	38.99
2010	1.000	0.00	3.29	3.67	15.73	4.05	26.73	15.65	0.00	18.29	2.22	3.39	39.55
2011	1.000	0.00	3.43	3.81	15.73	4.22	27.18	22.52	0.00	18.38	2.22	4.79	47.91
2012	1.000	0.00	3.56	3.96	15.73	4.39	27.64	17.10	0.00	18.48	2.22	3.58	41.38
2013	1.000	0.00	3.71	4.12	15.73	4.57	28.14	20.74	0.00	18.57	2.22	4.27	45.80
2014	1.000	0.00	3.86	4.29	15.73	4.76	28.63	21.76	0.00	18.67	2.22	4.40	47.05
2015	1.000	0.00	4.02	4.46	15.73	4.95	29.15	24.65	0.00	18.76	2.22	4.90	50.53
20 yr NPV		17.71	19.27	22.56	127.90	23.73	211.17	98.28	0.00	143.25	18.03	23.02	282.57

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De-escal	NS2						Alternative					
	Factor	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total
2016	1.000	0.00	4.18	4.64	15.73	5.14	29.69	26.08	0.00	19.51	2.22	5.10	52.90
2017	1.000	0.00	4.35	4.82	15.73	5.35	30.25	27.59	0.00	20.29	2.22	5.30	55.39
2018	1.000	0.00	4.52	5.02	15.73	5.56	30.83	29.18	0.00	21.10	2.22	5.51	58.02
2019	1.000	0.00	4.70	5.22	15.73	5.79	31.43	30.87	0.00	21.95	2.22	5.73	60.77
2020	1.000	0.00	4.89	5.43	15.73	6.02	32.06	32.66	0.00	22.82	2.22	5.96	63.67
2021	1.000	0.00	5.08	5.64	15.73	6.26	32.71	34.55	0.00	23.74	2.22	6.20	66.71
2022	1.000	0.00	5.29	5.87	15.73	6.51	33.39	36.56	0.00	24.69	2.22	6.45	69.91
2023	1.000	0.00	5.50	6.10	15.73	6.77	34.10	38.67	0.00	25.67	2.22	6.71	73.27
2024	1.000	0.00	5.72	6.35	15.73	7.04	34.83	40.91	0.00	26.70	2.22	6.98	76.81
2025	1.000	0.00	5.95	6.60	15.73	7.32	35.60	43.28	0.00	27.77	2.22	7.26	80.52
2026	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30 yr NPV		0.00	4.22	4.68	13.65	5.19	27.74	25.20	0.00	19.69	1.92	5.14	54.95
50 yr NPV		17.71	23.49	27.24	141.55	28.92	238.91	126.48	0.00	162.94	19.95	28.16	337.52

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Rel Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
1996	-0.39	-0.78	1.57	1.25	0.74	2.40	5.23	4.83	317.22	6.64	352.65	1.00	65.41
1997	-0.40	-1.00	1.44	1.34	0.63	2.01	5.41	4.72	329.93	6.26	372.35	0.97	67.59
1998	-0.42	-1.15	1.44	1.36	0.61	1.85	6.39	4.65	322.55	6.36	379.27	1.15	79.82
1999	-0.44	-1.44	1.29	1.48	0.46	1.36	7.04	4.54	328.03	6.13	399.07	1.22	88.00
2000	-0.45	-1.52	1.41	1.04	0.50	0.97	8.04	4.38	319.76	6.22	408.09	1.38	100.47
2001	-0.47	-1.67	1.28	0.88	0.38	0.40	8.72	4.30	322.24	6.14	426.26	1.46	109.00
2002	-0.49	-1.67	1.49	0.12	0.50	-0.05	9.25	4.21	316.48	6.34	432.74	1.54	115.66
2003	-0.51	-1.78	1.23	0.19	0.31	-0.57	9.99	4.22	321.41	6.30	453.33	1.64	124.86
2004	-0.53	-1.85	1.50	-0.15	0.46	-0.58	10.60	4.20	320.16	6.53	459.97	1.74	132.51
2005	-0.55	-2.09	1.16	-0.15	0.21	-1.42	12.59	4.01	308.58	6.52	483.70	2.04	157.41
2006	-0.57	-2.36	1.49	-0.37	0.36	-1.46	12.87	4.06	313.24	6.76	492.38	2.08	160.91
2007	-0.60	-1.57	3.48	-4.46	2.01	-1.14	9.07	4.10	318.55	8.04	446.27	1.46	113.44
2008	-0.62	-1.44	3.46	-4.42	2.08	-0.93	9.87	4.16	323.42	8.24	458.45	1.59	123.35
2009	-0.65	-1.98	3.23	-4.38	1.76	-2.01	10.67	4.21	328.80	8.13	487.33	1.71	133.43
2010	-0.67	-1.79	3.50	-4.39	2.01	-1.34	11.48	4.28	334.08	8.49	494.37	1.84	143.51
2011	-0.70	-3.74	0.73	-4.37	-0.45	-8.53	12.19	4.34	339.80	7.56	598.88	1.95	152.40
2012	-0.73	-1.51	1.96	-4.65	1.08	-3.85	9.88	4.42	345.53	9.10	517.21	1.58	123.55
2013	-0.76	-2.67	1.71	-4.51	0.51	-5.71	11.95	4.49	351.72	8.78	572.46	1.91	149.38
2014	-0.79	-2.85	1.64	-4.55	0.56	-5.99	12.43	4.57	357.92	9.10	588.12	1.98	155.33
2015	-0.82	-3.30	1.44	-4.54	0.25	-6.97	14.41	4.65	364.38	9.13	631.56	2.30	180.12
20 yr NPV	-4.14	-13.04	13.55	-2.96	5.53	-1.06	70.34	35.97	2639.62	55.54	3532.14	11.81	879.27

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Rel Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
2016	-0.85	-3.43	1.50	-4.72	0.26	-7.24	15.97	4.73	371.09	9.55	661.24	2.55	199.60
2017	-0.88	-3.57	1.56	-4.91	0.27	-7.53	17.61	4.82	378.07	10.01	692.42	2.81	220.19
2018	-0.92	-3.71	1.62	-5.11	0.28	-7.83	19.35	4.91	385.33	10.48	725.19	3.09	241.93
2019	-0.96	-3.86	1.69	-5.31	0.29	-8.15	21.19	5.01	392.88	10.98	759.63	3.38	264.90
2020	-1.00	-4.01	1.76	-5.52	0.30	-8.47	23.13	5.11	400.73	11.50	795.83	3.69	289.17
2021	-1.03	-4.17	1.83	-5.74	0.31	-8.81	25.18	5.22	408.90	12.05	833.87	4.02	314.81
2022	-1.08	-4.34	1.90	-5.97	0.32	-9.17	27.35	5.32	417.39	12.63	873.86	4.36	341.90
2023	-1.12	-4.51	1.97	-6.21	0.34	-9.53	29.64	5.44	426.22	13.23	915.90	4.73	370.52
2024	-1.16	-4.69	2.05	-6.46	0.35	-9.91	32.06	5.55	435.41	13.87	960.09	5.11	400.76
2025	-1.21	-4.88	2.14	-6.72	0.36	-10.31	34.62	5.68	444.96	14.54	1006.55	5.52	432.71
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30 yr NPV	-0.86	-3.46	1.51	-4.76	0.26	-7.31	19.90	4.42	346.73	9.93	686.89	3.17	248.79
50 yr NPV	-5.60	-16.50	15.07	-7.72	5.78	-8.37	90.25	40.40	2986.35	65.46	4219.02	14.98	1128.07
Levelized								4.53	334.89	7.34	473.13	1.68	126.50

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

OUTPUT REPORT – ECONOMIC ANALYSIS

Range: ECONREPT

Alternative	7 Basin	Node 1 – Demand	2 Med
Cost Mode	1	Node 2 – Fuel Price	2 Med
FCR Mode	1	Node 3 – Altern Cost	2 Med
Retirement	1	Node 4 – NS2 Cost	2 Med
Tax	1		

	Present Value (M$)			
	NS2 Alternative		System	Net
Fuel/Energy Cost	17.71	118.61	–15.24	85.67
Variable O&M Cost	23.49	0.00	--	–23.49
Fixed O&M/Capacity Cost	27.24	146.70	–5.00	114.46
Investment Cost	141.55	28.20	--	–113.36
Emissions / Tax Cost	28.92	24.66	2.07	–2.19
Total	238.91	318.17	–18.16	61.10

	Present Value (M$)
Alternative Resource Capital Cost	28.20
Alternative Resource Operating Cost	265.31
Neil Simpson #2 Capital Cost	141.55
Neil Simpson #2 Operating Cost	68.43
Net System Generation & Reliability Cost	–20.23
Net Emissions / Tax Cost	–2.19
Net Cost	61.10

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATION – SELECTION OF TREE VALUES AND PROJECT PARAMETERS

Range: SELECT

Selected Tree Values										Mode Selectors	
Branch	Node 1 – Demand Value	Prob	Node 2 – Fuel Price Value	Prob	Node 3 – Altern Cost Value	Prob	Node 4 – NS2 Cost Value	Prob	Branch Probability	Alternative	7 Basin
										Cost Mode	1
										FCR Mode	1
41	2	0.6	2	0.6	2	0.6	2	0.6	0.1296	Retirement	1
	Med		Med		Med		Med			Tax	1

	NS2									Selected
Cost Scen #	2					2				Project
0 Project Number	BASE	1	2	3	4	5	6	7	0	7
1 Name	NS2	NS2	CT	CC	Wind	PV	PPL	Basin	0	Basin
2 Capacity (MW)	80	80	80	80	80	80	80	80	0	80
3 Capacity Purchase Adjust Period	0	0	0	0	0	0	5	5	0	5
4 Capacity Equivalence Factor	0.95	0.95	0.95	0.97	0.15	1	1	1	0	1
5 Equivalent Availability	0.895	0.895	0.913	0.933	0.3	0.3	1	1	0	1
6 Installed Cost ($/kW)	1561	1561	532	1023	1115	3185	220	300	0	300
7 Real Escalation Rate	0.03846	0.03846	0	0	−0.04	0	0	0	0	0
8 Fixed Charge Rate Pattern No.	1	1	2	3	2	2	1	5	0	5
9 Average Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	1000	1000	0	1000
10 Capacity Price Trajectory No.	0	0	0	0	0	0	7	9	0	9
11 Fuel Price Trajectory No.	1	1	5	4	0	0	8	10	0	10
12 Fixed O&M Cost ($/kW−yr)	26.46	26.46	11.56	14.14	54.5289	19.1422	0	24	0	24
13 Real Escalation Rate	0	0	0	0	0	0	0	0	0	0
14 Var O&M Cost ($/kW−yr)	3.04	3.04	4.5	6.07	0	0	0	0	0	0
15 Real Escalation Rate	0	0	0	0	0	0	0	0	0	0
16 SO2 Emissions Rate (tons/MWh)	0.00106	0.00106	0.00000	0.00000	0	0	0.00275	0.00106	0	0.00106
17 CO2 Emissions Rate (tons/MWh)	1.34375	1.34375	0.70695	0.48756	0	0	1.1	1.34375	0	1.34375
18 Fuel Type	1	1	3	2	0	0	1	1	0	1
19 Tax Heat Rate (Btu/kWh)	12499	12499	12738	8785	0	0	11000	11000	0	11000
20 Renewable Tax Credit	0	0	0	0	1	1	0	0	0	0
21 Production Cost Selector	1	1	2	3	1	1	4	4	0	4
22 Start−up Year	1996	1996	1996	1996	1996	1996	1996	1996	0	1996
23 Life	50	50	25	35	25	25	30	30	0	30

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – SELECTION OF SCENARIOS AND ESCALATION

Scenario #	Demand 2	DSM 2	Net Demand	Oil Price 2
1996	1818.2	0.0	1818.2	4.48
1997	1864.2	0.0	1864.2	4.60
1998	1911.7	0.0	1911.7	4.72
1999	1959.7	0.0	1959.7	4.85
2000	2007.8	0.0	2007.8	4.98
2001	2056.2	0.0	2056.2	5.12
2002	2104.8	0.0	2104.8	5.15
2003	2153.3	0.0	2153.3	5.15
2004	2201.8	0.0	2201.8	5.18
2005	2251.4	0.0	2251.4	5.23
2006	2302.3	0.0	2302.3	5.28
2007	2354.3	0.0	2354.3	5.35
2008	2407.7	0.0	2407.7	5.40
2009	2462.3	0.0	2462.3	5.40
2010	2518.2	0.0	2518.2	5.54
2011	2575.5	0.0	2575.5	5.77
2012	2634.1	0.0	2634.1	6.00
2013	2694.2	0.0	2694.2	6.26
2014	2755.7	0.0	2755.7	6.51
2015	2818.6	0.0	2818.6	6.77

	Escalation Rate	Annual Escalation	Compound Escalation
1996	0.0400	1.0400	1.0000
1997	0.0400	1.0400	1.0400
1998	0.0400	1.0400	1.0816
1999	0.0400	1.0400	1.1249
2000	0.0400	1.0400	1.1699
2001	0.0400	1.0400	1.2167
2002	0.0400	1.0400	1.2653
2003	0.0400	1.0400	1.3159
2004	0.0400	1.0400	1.3686
2005	0.0400	1.0400	1.4233
2006	0.0400	1.0400	1.4802
2007	0.0400	1.0400	1.5395
2008	0.0400	1.0400	1.6010
2009	0.0400	1.0400	1.6651
2010	0.0400	1.0400	1.7317
2011	0.0400	1.0400	1.8009
2012	0.0400	1.0400	1.8730
2013	0.0400	1.0400	1.9479
2014	0.0400	1.0400	2.0258
2015			2.1068
Beyond	0.0400	1.0400	

(Escalation is zero, with real cost mode.)

CALCULATIONS – PROJECT FUEL AND PURCHASED POWER COSTS

Range: FUELCALC

	Cap Price	Fuel Price
Real esc after 2015	3E-17	0.00961
Incr for high scenario	0.3	--
Decr for low scenario	0.3	--
Correl with oil price	--	0.25
Cap price factor	1	

Mode Selectors		Scenario	
Alternative	7 Basin	Node 1 – Demand	2 Med
Cost Mode	1	Node 2 – Fuel Price	2 Med
PCR Mode	1	Node 3 – Altern Cost	2 Med
Retirement	1	Node 4 – NS2 Cost	2 Med
Tax	1		

	Change In Oil Price %	NS2 Coal Price	NS2 Var O&M	NS2 Disp Cost	NS2 Fixd O&M	Alternative Cap Price	Alternative Fuel Price	Alternative Var O&M	Alternative Disp Cost	Alternative Fixd O&M
1996	0.00%	0.60	3.04	10.59	26.46	108.00	16.00	0.00	16.00	24.00
1997	0.00%	0.65	3.16	11.25	27.52	113.40	16.64	0.00	16.64	24.96
1998	0.00%	0.54	3.29	9.98	28.62	119.07	17.31	0.00	17.31	25.96
1999	0.00%	0.52	3.42	9.88	29.76	125.02	18.00	0.00	18.00	27.00
2000	0.00%	0.38	3.56	8.24	30.95	131.27	18.72	0.00	18.72	28.08
2001	0.00%	0.34	3.70	7.92	32.19	137.84	19.47	0.00	19.47	29.20
2002	0.00%	0.23	3.85	6.76	33.48	144.73	20.25	0.00	20.25	30.37
2003	0.00%	0.23	4.00	6.90	34.82	151.97	21.05	0.00	21.05	31.58
2004	0.00%	0.17	4.16	6.33	36.21	159.57	21.90	0.00	21.90	32.85
2005	0.00%	0.00	4.33	4.33	37.66	167.54	22.77	0.00	22.77	34.16
2006	0.00%	0.00	4.50	4.50	39.17	175.92	23.68	0.00	23.68	35.53
2007	0.00%	0.00	4.68	4.68	40.73	184.72	24.63	0.00	24.63	36.95
2008	0.00%	0.00	4.87	4.87	42.36	193.95	25.62	0.00	25.62	38.42
2009	0.00%	0.00	5.06	5.06	44.06	203.65	26.64	0.00	26.64	39.96
2010	0.00%	0.00	5.26	5.26	45.82	213.83	27.71	0.00	27.71	41.56
2011	0.00%	0.00	5.47	5.47	47.65	224.52	28.82	0.00	28.82	43.22
2012	0.00%	0.00	5.69	5.69	49.56	235.75	29.97	0.00	29.97	44.95
2013	0.00%	0.00	5.92	5.92	51.54	247.54	31.17	0.00	31.17	46.75
2014	0.00%	0.00	6.16	6.16	53.60	259.91	32.41	0.00	32.41	48.62
2015	0.00%	0.00	6.40	6.40	55.75	272.91	33.71	0.00	33.71	50.56

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – RESPONSE SURFACE MODEL

Range: RSMCALC

Prod Cost Selector # 4

	Base	Demand	Oil Price	NS2 Cost	Alt Cost	D*D	D*OP	OP*OP
CF Coefs	Alt Cost	6.9	0	-3.6	-3.6	0	0	0
Ben Coefs		0.9	0.25	--	--	0	0	0
1996	16.84	0	0	0	-0.0498	0	0	0
1997	17.54	0	0	0	-0.0513	0	0	0
1998	18.28	0	0	0	-0.0533	0	0	0
1999	19.07	0	0	0	-0.0562	0	0	0
2000	19.90	0	0	0	-0.0594	0	0	0
2001	20.82	0	0	0	-0.0650	0	0	0
2002	21.84	0	0	0	-0.0730	0	0	0
2003	22.95	0	0	0	-0.0825	0	0	0
2004	24.12	0	0	0	-0.0921	0	0	0
2005	25.41	0	0	0	-0.1037	0	0	0
2006	26.82	0	0	0	-0.1169	0	0	0
2007	28.34	0	0	0	-0.1308	0	0	0
2008	30.00	0	0	0	-0.1461	0	0	0
2009	31.74	0	0	0	-0.1606	0	0	0
2010	33.59	0	0	0	-0.1751	0	0	0
2011	35.54	0	0	0	-0.1892	0	0	0
2012	37.60	0	0	0	-0.2029	0	0	0
2013	39.78	0	0	0	-0.2164	0	0	0
2014	42.08	0	0	0	-0.2297	0	0	0
2015	44.52	0	0	0	-0.2428	0	0	0

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Dispatch and Production Cost

Net Peak Gen Factor 1

	NS2 CF				Alt CF				Energy (GWh)			
	Linear Sum	Quadratic Sum	Exp(CF')	CF	Linear Sum	Quadratic Sum	Exp(CF')	CF	NS2	Alt	Net Peak	Net Base
1996	0	0	5.04627	75.0%	0.17957	0	1.83246	64.8%	525.6	454.4	-18.1	89.3
1997	0	0	7.90502	79.8%	0.18472	0	2.52363	71.8%	559.2	503.4	-20.6	76.4
1998	0	0	7.40809	79.2%	0.19189	0	2.56497	72.2%	555.0	505.8	-22.2	71.4
1999	0	0	10.9708	82.4%	0.20240	0	3.49501	78.0%	577.5	546.9	-28.3	58.9
2000	0	0	12.7978	83.4%	0.21387	0	3.64720	78.8%	584.5	552.0	-29.7	62.1
2001	0	0	19.3062	85.5%	0.23404	0	4.72767	82.9%	599.2	580.8	-32.8	51.3
2002	0	0	20.7735	85.8%	0.26289	0	4.51141	82.2%	601.3	575.9	-32.0	57.4
2003	0	0	28.6210	86.9%	0.29726	0	6.04187	86.2%	609.0	603.8	-33.8	39.0
2004	0	0	30.6982	87.1%	0.33177	0	5.60736	85.2%	610.4	597.2	-34.0	47.2
2005	0	0	43.0561	87.9%	0.37360	0	7.83290	89.1%	616.0	624.2	-37.9	29.7
2006	0	0	47.8137	88.1%	0.42095	0	7.31769	88.4%	617.4	619.2	-39.4	37.5
2007	0	0	77.4743	88.8%	0.47111	0	2.75870	73.6%	622.3	516.0	-27.8	134.1
2008	0	0	77.4743	88.8%	0.52601	0	2.92684	74.8%	622.3	524.1	-24.8	123.1
2009	0	0	105.105	89.1%	0.57831	0	3.82681	79.6%	624.4	557.7	-33.9	100.6
2010	0	0	105.105	89.1%	0.63052	0	3.70168	79.0%	624.4	553.8	-28.7	99.4
2011	0	0	137.652	89.3%	0.68119	0	17.7782	95.1%	625.8	666.6	-56.2	15.4
2012	0	0	137.652	89.3%	0.73075	0	3.81470	79.5%	625.8	557.3	-22.2	90.7
2013	0	0	199	89.5%	0.77936	0	6.25549	86.6%	627.2	606.8	-37.4	57.8
2014	0	0	199	89.5%	0.82715	0	6.36290	86.8%	627.2	608.2	-38.5	57.5
2015	0	0	199	89.5%	0.87413	0	8.86111	90.3%	627.2	632.6	-43.0	37.7

Production Cost and Capacity Surplus Calculations

	Base Gen Cost					Pk Cost
	Base Val $/MWh	Linear Sum	Quadratic Sum	Exp(Q)	Adj Val $/MWh	Adj Val $/MWh
1996	13.21	0	0	1	13.21	42.85
1997	13.89	0	0	1	13.89	48.72
1998	14.43	0	0	1	14.43	51.78
1999	15.21	0	0	1	15.21	50.90
2000	15.74	0	0	1	15.74	51.27
2001	16.62	0	0	1	16.62	50.97
2002	17.09	0	0	1	17.09	52.20
2003	18.17	0	0	1	18.17	52.55
2004	18.48	0	0	1	18.48	54.49
2005	19.26	0	0	1	19.26	55.01
2006	19.97	0	0	1	19.97	59.90
2007	16.91	0	0	1	16.91	56.44
2008	17.13	0	0	1	17.13	57.85
2009	18.04	0	0	1	18.04	58.34
2010	18.69	0	0	1	18.69	62.12
2011	15.03	0	0	1	15.03	66.57
2012	10.15	0	0	1	10.15	67.85
2013	11.95	0	0	1	11.95	71.35
2014	11.06	0	0	1	11.06	74.02
2015	12.37	0	0	1	12.37	76.61

	Capacity Surplus	Lagged Capacity Surplus
1996	0.00	0.00
1997	0.00	0.00
1998	0.00	0.00
1999	0.00	0.00
2000	0.00	0.00
2001	0.00	0.00
2002	0.00	0.00
2003	0.00	0.00
2004	0.00	0.00
2005	0.00	0.00
2006	0.00	0.00
2007	0.00	0.00
2008	0.00	0.00
2009	0.00	0.00
2010	0.00	0.00
2011	0.00	0.00
2012	0.00	0.00
2013	0.00	0.00
2014	0.00	0.00
2015	0.00	0.00

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

Emissions Calculations

	Emissions (tons)							
	NS2		Alternative		Net Peaking		Net Base	
	SO2	CO2	SO2	CO2	SO2	CO2	SO2	CO2
1996	558	706275	483	610632	−0	−13075	723	138636
1997	594	751477	535	676504	−0	−14872	619	118620
1998	590	745826	537	679634	−0	−15996	579	110894
1999	614	775961	581	734841	−0	−20421	477	91448
2000	621	785378	587	741771	−0	−21424	503	96481
2001	637	805154	617	780383	−0	−23692	415	79598
2002	639	807979	612	773866	−0	−23110	465	89138
2003	647	818337	642	811377	−0	−24387	316	60518
2004	649	820221	635	802494	−0	−24558	383	73323
2005	655	827754	663	838766	−0	−27361	241	46153
2006	656	829638	658	832096	−0	−28400	304	58271
2007	661	836230	548	693387	−0	−20092	1087	208265
2008	661	836230	557	704223	−0	−17914	997	191061
2009	663	839055	593	749388	−0	−24452	815	156212
2010	663	839055	588	744143	−0	−20737	805	154278
2011	665	840938	708	895801	−0	−40583	16	20720
2012	665	840938	592	748892	−0	−16053	96	121943
2013	666	842822	645	815354	−0	−26980	61	77717
2014	666	842822	646	817266	−0	−27783	61	77299
2015	666	842822	672	849995	−0	−31043	40	50643

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

CALCULATIONS – ECONOMIC ANALYSIS

Range: ECONCALC

Alternative	7 Basin
Cost Mode	1
FCR Mode	1
Retirement	1
Tax	1

Node 1 – Demand	2 Med
Node 2 – Fuel Price	2 Med
Node 3 – Altern Cost	2 Med
Node 4 – NS2 Cost	2 Med

INTERMEDIATE CALCULATIONS

INITIAL COSTS		ESCALATION RATES	
Neil Simpson 2			
Construction Cost (M$)	124.88	NS2 Fuel Cost	1.000
		Variable O&M Cost	1.000
Retirement Year	2026	Fixed O&M Cost	1.000
Alternative			
Construction Cost (M$)	24.00	Fuel Cost	1.010
		Variable O&M Cost	1.000
Retirement Year	2026	Fixed O&M / Capacity Price	1.000
Last Year of Renewable Credit	0		
System			
		Net Prod Cost Savings, after 2020	1.000
		Cost Discount	1.000
Net Reliability Cost (M$)	-0.388	Net Reliability Cost	1.000

Discount Rate	0.107
Annual Discount Factor	0.904
Discount From 2015 to 1996	0.145

Energy Tax Rates ($/MWh)	
Neil Simpson 2	3.21
Alternative	2.83
Net Peaking	7.79
Net Base	3.34

Neil Simpson values are scaled to the size of the alternative project.

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De-escal	NS2						Alternative					
	Factor	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total
1996	1.000	3.97	1.60	2.12	15.73	1.97	25.38	7.27	0.00	10.56	3.13	1.53	22.49
1997	1.000	4.52	1.77	2.20	15.73	2.18	26.39	8.38	0.00	11.07	3.13	1.76	24.34
1998	1.000	3.72	1.82	2.29	15.73	2.25	25.80	8.75	0.00	11.60	3.13	1.84	25.32
1999	1.000	3.73	1.97	2.38	15.73	2.43	26.24	9.84	0.00	12.16	3.13	2.07	27.20
2000	1.000	2.74	2.08	2.48	15.73	2.56	25.58	10.33	0.00	12.75	3.13	2.17	28.38
2001	1.000	2.53	2.22	2.58	15.73	2.73	25.78	11.31	0.00	13.36	3.13	2.37	30.17
2002	1.000	1.75	2.31	2.68	15.73	2.85	25.32	11.66	0.00	14.01	3.13	2.45	31.25
2003	1.000	1.76	2.44	2.79	15.73	3.00	25.71	12.71	0.00	14.68	3.13	2.67	33.20
2004	1.000	1.32	2.54	2.90	15.73	3.13	25.61	13.08	0.00	15.39	3.13	2.74	34.35
2005	1.000	0.00	2.67	3.01	15.73	3.28	24.69	14.21	0.00	16.14	3.13	2.98	36.47
2006	1.000	0.00	2.78	3.13	15.73	3.42	25.06	14.67	0.00	16.92	3.13	3.08	37.79
2007	1.000	0.00	2.91	3.26	15.73	3.59	25.48	12.71	0.00	17.73	3.13	2.67	36.24
2008	1.000	0.00	3.03	3.39	15.73	3.73	25.87	13.42	0.00	18.59	3.13	2.82	37.97
2009	1.000	0.00	3.16	3.52	15.73	3.89	26.30	14.86	0.00	19.49	3.13	3.12	40.60
2010	1.000	0.00	3.29	3.67	15.73	4.05	26.73	15.34	0.00	20.43	3.13	3.22	42.13
2011	1.000	0.00	3.43	3.81	15.73	4.22	27.18	19.21	0.00	21.42	3.13	4.03	47.79
2012	1.000	0.00	3.56	3.96	15.73	4.39	27.64	16.70	0.00	22.46	3.13	3.51	45.80
2013	1.000	0.00	3.71	4.12	15.73	4.57	28.14	18.91	0.00	23.54	3.13	3.97	49.56
2014	1.000	0.00	3.86	4.29	15.73	4.76	28.63	19.71	0.00	24.68	3.13	4.14	51.67
2015	1.000	0.00	4.02	4.46	15.73	4.95	29.15	21.32	0.00	25.88	3.13	4.48	54.81
20 yr NPV		17.71	19.27	22.56	127.90	23.73	211.17	95.14	0.00	119.54	25.48	19.97	260.13

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	De-escal	NS2						Alternative					
	Factor	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total	Fuel Cost	Var Cost	Fixed Cost	Invst Cost	Tax Cost	Total
2016	1.000	0.00	4.18	4.64	15.73	5.14	29.69	22.39	0.00	26.91	3.13	4.65	57.09
2017	1.000	0.00	4.35	4.82	15.73	5.35	30.25	23.51	0.00	27.99	3.13	4.84	59.47
2018	1.000	0.00	4.52	5.02	15.73	5.56	30.83	24.68	0.00	29.11	3.13	5.03	61.96
2019	1.000	0.00	4.70	5.22	15.73	5.79	31.43	25.92	0.00	30.27	3.13	5.24	64.56
2020	1.000	0.00	4.89	5.43	15.73	6.02	32.06	27.21	0.00	31.48	3.13	5.45	67.28
2021	1.000	0.00	5.08	5.64	15.73	6.26	32.71	28.58	0.00	32.74	3.13	5.66	70.11
2022	1.000	0.00	5.29	5.87	15.73	6.51	33.39	30.00	0.00	34.05	3.13	5.89	73.08
2023	1.000	0.00	5.50	6.10	15.73	6.77	34.10	31.50	0.00	35.42	3.13	6.13	76.18
2024	1.000	0.00	5.72	6.35	15.73	7.04	34.83	33.08	0.00	36.83	3.13	6.37	79.41
2025	1.000	0.00	5.95	6.60	15.73	7.32	35.60	34.73	0.00	38.31	3.13	6.62	82.80
2026	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	1.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30 yr NPV		0.00	4.22	4.68	13.65	5.19	27.74	23.48	0.00	27.15	2.72	4.70	58.05
50 yr NPV		17.71	23.49	27.24	41.55	28.92	238.91	118.61	0.00	146.70	26.20	24.66	318.17

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Rel Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
1996	-0.39	-0.78	1.18	1.25	0.52	1.79	-1.10	4.83	317.22	4.95	281.12	-0.21	-13.78
1997	-0.40	-1.00	1.06	1.34	0.42	1.42	-0.64	4.72	329.93	4.83	304.21	-0.11	-7.99
1998	-0.42	-1.15	1.03	1.36	0.38	1.21	0.73	4.65	322.55	5.01	316.56	0.13	9.12
1999	-0.44	-1.44	0.90	1.48	0.24	0.74	1.70	4.54	328.03	4.97	340.03	0.29	21.27
2000	-0.45	-1.52	0.98	1.04	0.27	0.31	3.11	4.38	319.76	5.14	354.77	0.53	38.89
2001	-0.47	-1.67	0.85	0.88	0.15	-0.26	4.13	4.30	322.24	5.20	377.17	0.69	51.67
2002	-0.49	-1.67	0.98	0.12	0.22	-0.84	5.09	4.21	316.48	5.43	390.58	0.85	63.59
2003	-0.51	-1.78	0.71	0.19	0.03	-1.36	6.13	4.22	321.41	5.50	414.98	1.01	76.58
2004	-0.53	-1.85	0.87	-0.15	0.11	-1.55	7.19	4.20	320.16	5.75	429.34	1.18	89.82
2005	-0.55	-2.09	0.57	-0.15	-0.11	-2.33	9.45	4.01	308.58	5.84	455.84	1.53	118.16
2006	-0.57	-2.36	0.75	-0.37	-0.04	-2.60	10.13	4.06	313.24	6.10	472.40	1.64	126.69
2007	-0.60	-1.57	2.27	-4.46	1.19	-3.17	7.59	4.10	318.55	7.02	453.04	1.22	94.85
2008	-0.62	-1.44	2.11	-4.42	1.15	-3.22	8.87	4.16	323.42	7.24	474.57	1.42	110.85
2009	-0.65	-1.98	1.81	-4.38	0.80	-4.39	9.91	4.21	328.80	7.28	507.47	1.59	123.85
2010	-0.67	-1.79	1.86	-4.39	0.88	-4.11	11.30	4.28	334.08	7.61	526.60	1.81	141.19
2011	-0.70	-3.74	0.23	-4.37	-0.68	-9.26	11.35	4.34	339.80	7.17	597.42	1.81	141.84
2012	-0.73	-1.51	0.92	-4.65	0.33	-5.63	12.52	4.42	345.53	8.22	572.45	2.00	156.48
2013	-0.76	-2.67	0.69	-4.51	-0.13	-7.37	14.05	4.49	351.72	8.17	619.45	2.24	175.57
2014	-0.79	-2.85	0.64	-4.55	-0.16	-7.71	15.32	4.57	357.92	8.50	645.83	2.44	191.53
2015	-0.82	-3.30	0.47	-4.54	-0.40	-8.59	17.07	4.65	364.38	8.66	685.12	2.72	213.42
20 yr NPV	-4.14	-13.04	8.50	-2.96	2.49	-9.15	39.80	35.97	2639.62	46.88	3251.57	6.44	497.53

NEIL SIMPSON UNIT NO. 2 ECONOMIC ANALYSIS

	Rest of System						Net	NS2		Alternative		Savings	
	Rel Cost	Peak Cost	Base Cost	Coal Cost	Tax Cost	Total	Savings	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr	cents/kWh	$/kW-yr
2016	-0.85	-3.43	0.49	-4.72	-0.41	-8.93	18.47	4.73	371.09	9.03	713.62	2.95	230.92
2017	-0.88	-3.57	0.50	-4.91	-0.43	-9.29	19.94	4.82	378.07	9.40	743.40	3.18	249.25
2018	-0.92	-3.71	0.52	-5.11	-0.45	-9.66	21.48	4.91	385.33	9.80	774.50	3.42	268.45
2019	-0.96	-3.86	0.55	-5.31	-0.47	-10.04	23.09	5.01	392.88	10.21	807.00	3.68	288.58
2020	-1.00	-4.01	0.57	-5.52	-0.48	-10.45	24.77	5.11	400.73	10.64	840.96	3.95	309.66
2021	-1.03	-4.17	0.59	-5.74	-0.50	-10.86	26.54	5.22	408.90	11.08	876.43	4.23	331.74
2022	-1.08	-4.34	0.61	-5.97	-0.52	-11.30	28.39	5.32	417.39	11.55	913.49	4.53	354.88
2023	-1.12	-4.51	0.64	-6.21	-0.55	-11.75	30.33	5.44	426.22	12.04	952.22	4.84	379.12
2024	-1.16	-4.69	0.66	-6.46	-0.57	-12.22	32.36	5.55	435.41	12.55	992.68	5.16	404.52
2025	-1.21	-4.88	0.69	-6.72	-0.59	-12.71	34.49	5.68	446.96	13.09	1034.95	5.50	431.13
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30 yr NPV	-0.86	-3.46	0.49	-4.76	-0.42	-9.01	21.30	4.42	346.73	9.18	725.60	3.40	266.25
50 yr NPV	-5.00	-16.50	6.99	-2.72	2.07	-18.16	61.10	40.40	2986.35	56.06	3977.17	9.84	763.78
Levelized								4.53	334.89	6.29	446.01	1.10	85.65

APPENDIX A3

Calculation of Production Cost Savings

APPENDIX A3
CALCULATION OF PRODUCTION COST SAVINGS

The net cost of an alternative resource relative to Neil Simpson #2 is calculated in the spreadsheet as the sum of the costs of the alternative less the costs of Neil Simpson #2, plus the net change in the operating costs of the rest of the system, as shown in Table A3-1.

Table A3-1
Components of Net Cost

	Component	Sign
1	Alternative Resource Capital Cost	+
2	Alternative Resource Operating Cost	+
3	Neil Simpson #2 Capital Cost	-
4	Neil Simpson #2 Operating Cost	-
5	Net System Generation & Reliability Cost	+
6	Net Emissions / Tax Cost	+
	Net Cost	Sum

Sign indicates whether the component is added (+) or subtracted (-) in taking the algebraic sum to calculate Net Cost.

The cost components in Table A3-1 are made up of the subcomponents listed in Table A3-2.

The Fuel / Energy Cost and Variable O&M Cost subcomponents represent the costs that depend on the level of energy generation from a resource in a particular year and are calculated on the basis of results from POWRPRO production simulation runs, as described below.

The Fixed O&M / Capacity Cost and Investment Cost subcomponents represent the costs that do not depend on the level of energy generation from a resource. Fixed O&M / Capacity Cost for the alternative resource includes any capacity demand charges or transmission demand costs.

Table A3-2 Subcomponents of Net Cost			
	Neil Simpson #2	Alternative	Rest of System
Fuel / Energy Cost	4,+	2,+	5,+
Variable O&M Cost	4,+	2,+	*
Fixed O&M / Capacity Cost	4,+	2,+	5,+
Investment Cost	3,+	1,+	**
Emissions / Tax Cost	6,-	6,+	6,+
The number indicates the component in Table A3-1 in which a particular subcomponent is included. The sign indicates whether the subcomponent is added (+) or subtracted (-) in making the component. * Variable O&M Cost for the rest of the system is included in Fuel / Energy Cost. ** Investment Cost for the rest of the system does not change between the cases with Neil Simpson #2 and the alternative resource.			

Fixed O&M / Capacity Cost for the rest of the system represents a reliability penalty based on the difference in forced outage rates between the alternative resource and Neil Simpson #2. The penalty is calculated on the basis of the annual cost of combustion turbine capacity that would be required to make up the difference between the reliability of Neil Simpson #2 and the alternative resource. In the case of the PPL or Basin purchases, which are modeled as system purchases with perfect reliability, this penalty is negative, which is equivalent to a credit, partially offsetting the cost of the alternative resource.

The Emissions / Tax Cost subcomponent includes: (a) the value of allowances required for SO_2 emissions from the resource; (b) the cost of a CO_2 emissions tax or federal energy tax imposed on the resource; and (c) the federal renewable energy tax credit, if applicable to the alternative resource, which is treated as a negative cost.

Production Costs from POWRPRO

The Fuel / Energy Cost and Variable O&M Cost subcomponents are calculated on the basis of production simulation results from the POWRPRO model. The difference between the sum of fuel and variable O&M costs calculated by POWRPRO for two cases, one with the alternative resource and the other with Neil Simpson #2, is the net value of these two subcomponents for the alternative resource and rest of the system less Neil Simpson #2.

Total Fuel and Variable O&M Cost with Alternative Resource

- Total Fuel and Variable O&M Cost with Neil Simpson #2

= *Fuel and Variable O&M Cost of Alternative Resource*

- Fuel and Variable O&M Cost of Neil Simpson #2

+ Change in Fuel and Variable O&M Cost of Rest of System

The change in fuel and variable O&M cost of the rest of the system is further broken down into the following components:

Change in Fuel and Variable O&M Cost of Rest of System

= *Change in Fuel and Variable O&M Cost of System Peaking Generation*

+ Change in Fuel and Variable O&M Cost of System Baseload Generation

+ Change in Coal Prices

The calculation of these components in the spreadsheet and their derivation from POWRPRO results are described below.

Fuel and Variable O&M Cost of the Alternative Resource

The fuel and variable O&M cost of the alternative resource is calculated as follows:

Fuel and Variable O&M Cost of Alternative Resource

= *[Fuel Price ($/MBtu) x Heat Rate (Btu/kWh) / 1000*

+ Variable O&M Rate ($/MWh)]

x Capacity (MW) x Equivalent Availability Factor x 8760 hours

x Dispatch Capacity Factor

The dispatch capacity factor depends on the incremental cost of the alternative resource relative to other generation and represents the capacity factor at which a resource with 100% availability would be dispatched.

Year-by-year base case values of capacity factor are taken directly from POWRPRO results for the cases listed in Table A3-3.

Table A3-3 POWRPRO Cases From Which Base Case Values Were Obtained	
Resource	POWRPRO Case
Neil Simpson #2	106
PPL Purchase	106A
Combined Cycle	106B
Combustion Turbine	106C

For a given resource and year, let:

EAF = equivalent availability factor of the resource;

CF = average capacity factor of the resource in the year;

COST = incremental dispatch cost of the resource in the year;

LOAD = annual total system energy demand in the year;

FUEL = general fuel (oil) price level in the year;

and let CF_0, $COST_0$, $LOAD_0$, and $FUEL_0$ be the base case values of the respective variables in that year. Then the capacity factor for scenarios other than the base case for these four resources is calculated using the following formula:

$$CF = \left[\frac{1}{B} \left(\frac{\exp(Q_{CF})}{1 + \exp(Q_{CF})} - \frac{1}{2} \right) + \frac{1}{2} \right] \cdot EAF \qquad (1)$$

where:

$$Q_{CF} = CF_0' + a_1 \cdot COST' + a_2 \cdot LOAD' + a_3 \cdot FUEL' + a_{22} \cdot LOAD'^2 + a_{23} \cdot LOAD' \cdot FUEL' + a_{33} \cdot FUEL'^2 \qquad (2)$$

$$COST' = \frac{COST - COST_0}{COST_0}$$
$$LOAD' = \frac{LOAD - LOAD_0}{LOAD_0} \qquad (3)$$
$$FUEL = \frac{FUEL - FUEL_0}{FUEL_0}$$

$$CF_0' = \ln\left[\frac{\frac{1}{2} + B\left(\frac{CF_0}{EAF} - \frac{1}{2}\right)}{\frac{1}{2} - B\left(\frac{CF_0}{EAF} - \frac{1}{2}\right)}\right] \qquad (4)$$

Table A3-4 shows the values used for the parameters.

Table A3-4
Parameters of the Capacity Factor Formula

Parameter	Value
B	0.99
a_1	-3.6
a_2	6.9
a_3	0
a_{22}, a_{23}, a_{33}	0

The values of the parameters were determined as follows:

- B, the end-point parameter, can take any value less than (but not equal to) 1.0 and greater than 0. The purpose of this parameter is to transform values of dispatch capacity factor that may range between 0 and 1.0, including the end-points, to a slightly narrower range in order to avoid taking the logarithm of 0 or ∞. B was set at 0.99.

- a_1 is the coefficient on the ratio of the incremental dispatch cost of a resource

in a scenario relative to the incremental dispatch cost of the resource underlying the estimate of base case capacity factor. It was derived as the average of the values a_1' calculated year-by-year for cases 106 and 106A using the following formula:

$$a_1' = \frac{CF_{NS2,106} - CF_{PPL,106A}}{\ln\left(\frac{COST_{NS2,106} - COST_{PPL,106A}}{COST_{PPL,106A}}\right)} \qquad (5)$$

- a_2 is the coefficient on changes in net demand from the base case. It was derived as the average of the values a_2' calculated year-by-year for cases 106, 201, and 203 using the following formula:

$$a_2' = \frac{CF_{PPL,c} - CF_{PPL,106A}}{\ln\left(\frac{LOAD_c - LOAD_{106}}{LOAD_{106}}\right)} \qquad (6)$$

where c is case 201A or 203A.

- a_3 is the coefficient on changes in general fuel prices from the base case. It was set at zero, because no consistent and significant patterns in the sensitivity of the capacity factor of a candidate resource to general fuel prices was observed in the POWRPRO results.

- All cross effects (a_{22}, a_{23}, a_{33}) were set at zero.

Fuel and Variable O&M Cost of Neil Simpson #2

The fuel and variable O&M cost of Neil Simpson #2 is calculated in a manner similar to that for the alternative resource described above, using the same formulas and parameter values.

Change in Fuel and Variable O&M Cost of System Peaking Generation

Between two POWRPRO runs, one with Neil Simpson #2 and the other with an alternative resource, there is a change in the energy output from system peaking generation if Neil Simpson #2 and the alternative have different outage rates. The term "system peaking generation" refers to the diesel units, the RCIA combustion turbines, RCIA support from PPL, the peak purchase from Tri-State, emergency generation, and new combustion turbines,

excluding the first two 40 MW combustion turbines added in the case in which combustion turbines are substituted for Neil Simpson #2. If Neil Simpson #2 and the alternative resource have the same outage rates, then there may still be some change in generation from peaking units owing to differences in ramp rates, minimum generation requirements, and other operating constraints; but this difference will be relatively small.

The change in energy output from system peaking generation, denoted $\Delta Peak_{PPL,0}$, in the base case between a case with Neil Simpson #2 and a case with the PPL purchase is simply the difference in energy output from system peaking generation in Cases 106 and 106A. The change in the cost of operating system peaking generation is simply the difference in fuel cost of peaking generation between Cases 106 and 106A. The change in fuel cost is divided by the change in energy output to convert it to an average incremental cost of peaking generation.

The change in energy output from system peaking generation, denoted $\Delta Peak_{r,0}$, in the base case between a case with Neil Simpson #2 and a case with another alternative resource r is calculated as proportional to the difference in capacity equivalence factors up to a limit:

$$\Delta Peak_{r,0} = \Delta Peak_{PPL,0} \cdot \frac{\max \{ CEF_r - CEF_{NS2}, ACF_{CT} \}}{CEF_{PPL} - CEF_{NS2}} \qquad (7)$$

where CEF_{NS2}, CEF_{PPL}, and CEF_r denote the capacity equivalence factors of Neil Simpson #2, the PPL purchase, and the candidate resource, and ACF_{CT} denotes the average annual capacity factor of the first new combustion turbines in Case 106B. The CEF of a resource is defined for purposes of this study as 1.0 minus the forced outage rate.

The limit is the annual average capacity factor of the two new combustion turbines with the largest capacity factors in Case 106B. This limit ensures that a resource with a very low CEF, such as wind, is not penalized for system peaking generation except in on-peak hours. The change in cost of operating existing peaking generation is calculated by applying the average incremental peaking cost determined from the difference between Cases 106 and 106A to the change in output.

The change in energy output from system peaking generation between a case with Neil Simpson #2 and a case with an alternative resource for scenarios other than the base case is calculated by adjusting the base case values using the following formula:

$$\Delta Peak_r = \Delta Peak_{r,0} \cdot \exp\ (b_1 \cdot LOAD') \qquad (8)$$

where the parameter b_1 has the value 3.4.

The value of the parameter b_1 was derived as the average of the year-by-year values b_1' calculated using the following formula for scenarios 106, 201, and 203:

$$b_1' = \frac{\ln\left(\frac{Peak_c - Peak_{cA}}{Peak_{108} - PEAK_{108A}}\right)}{\left(\frac{Load_c - LOAD_{108}}{LOAD_{108}}\right)} \qquad (9)$$

where c and cA denote a pair of cases, either 201 and 201A or 203 and 203A.

The average incremental peaking cost is assumed to vary in proportion to the general fuel price level FUEL, since peaking generation on the Black Hills system is entirely oil- or gas-fired.

Change in Fuel and Variable O&M Cost of System Baseload Generation

Between two cases, one with Neil Simpson #2 and the other with an alternative resource instead of Neil Simpson #2, energy output from system baseload generation will change to compensate for the net difference between energy output from Neil Simpson #2 and the alternative and the change in peaking generation. System baseload generation refers to all existing and new coal units owned by Black Hills other than Neil Simpson #2, and the existing PPL Colstrip purchase. For fossil-fueled alternative resources, energy output from the alternative will be lower than from Neil Simpson #2 because the incremental dispatch cost is higher, owing to the zero fuel cost assigned to Neil Simpson #2 through the coal pricing mechanism. Energy output will increase from units with an incremental dispatch intermediate between Neil Simpson #2 and the alternative resource.

The change in energy output from system baseload generation for any scenario between a case with Neil Simpson #2 and a case with the PPL purchase is calculated as the difference between the energy output from Neil Simpson #2 and the alternative resource less the net change in system peaking generation, all calculated as described above.

The change in the operating cost of system baseload generation for the base case between a case with Neil Simpson #2 and a case with either the PPL purchase, combustion turbines, or a combined cycle unit is obtained by multiplying the change in energy output by an average incremental baseload cost. The average incremental baseload cost $p_{r,0}$ for the change in system baseload generation resulting from the substitution of an alternative resource r, for the base case, is derived from POWRPRO results using the following formula:

$$P_{r,0} = \frac{BaseGen_{108A} - BaseGen_{108}}{BaseCost_{108A} - BaseCost_{108}} \qquad (10)$$

BaseGen and BaseCost denote the total energy output and fuel cost calculated by

POWRPRO for all system baseload generation as defined in this section. Case 106x denotes either Case 106B, 106C, or 106A, which corresponds to the alternative resource as shown in Table A3-3.

The base case value of average incremental baseload cost is adjusted by the following formula to obtain the value for other scenarios:

$$p_r = p_{r,0} \cdot \exp\,(Q_p) \tag{11}$$

where:

$$Q_p = d_1 \cdot LOAD' + d_2 \cdot FUEL' + d_{11} \cdot LOAD'^{\,2} + d_{12} \cdot LOAD' \cdot FUEL' + d_{22} \cdot FUEL'^{\,2} \tag{12}$$

and the parameters have the values shown in Table A3-5.

Table A3-5
Parameters of the Formula for
Average Incremental Baseload Cost

Parameter	Value
d_1	0.9
d_2	0.25
d_{11}, d_{12}, d_{13}	0

The values of the parameters were determined as follows:

d_1, the coefficient on changes in net demand from the base case was derived as the average of the values d_1' calculated year-by-year for cases 106, 201, and 203 using the following formula:

$$d_1' = \frac{\ln\left(\frac{P_{PPL,c}}{P_{PPL,106}}\right)}{\left(\frac{LOAD_c - LOAD_{106}}{LOAD_{106}}\right)} \tag{13}$$

where $p_{PPL,c}$ denotes the average incremental baseload cost derived from POWRPRO runs c and cA (for example, 201 and 201A), and c denotes case 201 or 203.

d_2, the coefficient on general fuel prices, was set at 0.25, to be consistent with the fact that all of the system baseload generation is coal-fired and with the construction of the fuel price scenarios in which coal prices change only 10% when the general fuel price level changes by 40%.

Change in Coal Prices

The total change in production cost between cases with Neil Simpson #2 and alternative resources includes this additional component, which results from the coal pricing mechanism for coal-fired generation owned by Black Hills. Between cases with and without Neil Simpson #2 the prices of coal burned by other units are reduced, because price discounts that are allocated primarily to Neil Simpson #2 are allocated instead to the other units, in the absence of Neil Simpson #2.

The component of the change in total production costs that results solely from the change in coal prices was calculated for the base case as the sum over all of Black Hills' coal units of the generation in Case 106A multiplied by the difference between the coal prices in Cases 106 and 106A. The value calculated in this way for the PPL purchase was applied as well to all other scenarios and to all other alternatives relative to Neil Simpson #2.

8-132-22-284

APPENDIX A4

Public Involvement Appendix

A-4.0 PUBLIC PARTICIPATION

The process which Black Hills Power and Light Company has used to evaluate the decision to construct 80 megawatts of coal-fired generation at the Wyodak Mine has allowed for significant public participation. Black Hills Power and Light Company, as early as its 1988 Form 10-K began indicating that the construction of coal-fired plants would again be needed in the mid to late 1990's. Subsequent Form 10-K's continued to indicate this with management indicating in the 1991 Form 10-K that "Management is of the opinion that it is in the best interest of the Company, the shareholders, and its electric customers to proceed at this time to construct and own electric generation at the site of the Wyodak Resource Mine." Black Hills Power and Light Company during those same years reported to the South Dakota and Wyoming Commissioners and Staff that it would be in need of additional baseload generation or resources in the mid 1990's. Beginning in the fall of 1991 Black Hills made a request for waiver of permit application to the Wyoming Industrial Siting Administration to site the Neil Simpson Unit #2. Public input meetings were noticed and held and the Wyoming Industrial Siting Council waived the permit application requirements and issued a permit in January 1992.

Black Hills also recognized early on that the load growth in its service territory would require the addition of significant baseload resources by 1996. As a result of the rate increases necessary to recover the costs associated with meeting customer requirements the Company proposed and promoted legislation to allow the Public Utilities Commission of South Dakota to review rate stability plan applications. The intent of the rate stability plan application is to bring major capital additions necessary for meeting customer requirements into a forum for discussion prior to significant commitments being made by utility companies and to allow for lower related rate increases. This legislation was overwhelmingly supported by both the House and Senate in South Dakota and became law on July 1, 1992. On October 30, 1992, Black Hills Corporation filed a Rate Stability Plan Application with the South Dakota Public Utilities Commission for its consideration.

Black Hills also filed an Application for a Certificate of Public Convenience and Necessity with the Wyoming Public Service Commission in August of 1992. This intent to acquire a Certificate has been noticed by the Wyoming Public Service Commission and initial hearings were held in the City of Gillette in January of 1993 to allow for both public input and for an admission of testimony by the parties to the proceeding.

Due to its plans to construct what is its least cost option, Neil Simpson Unit #2, Black Hills Power and Light Company has implemented a significant public awareness program. The Company upon applying for a rate stability plan in South Dakota held a news conference to discuss the need for the power plant, the options considered, and the proposed rate increases. At the same time the Company mailed letters discussing the project and rate increase proposal to 200 thought leaders in the communities served by Black Hills Power and Light Company. These thought leaders included city council

members, school board members, county commissioners, economic development boards, chamber of commerce officials, and others who were considered to be thought leaders in the communities Black Hills serves. The Company also made personal contacts with its 140 largest customers to discuss its plans. During the month of December 1992 the Company conducted Town Hall Meetings to discuss the project and rate increase plans in each of its South Dakota communities. These Town Hall Meetings were advertised both through radio and newspapers so that its customers could become aware of the Company's plans for meeting their increased energy requirements. During the months of November and December 1992 and January 1993 the Company made over 40 presentations to service clubs, news media representatives, government officials, economic development boards, and chamber of commerce officials.

In addition, the Company in its customer opinion survey conducted in the spring of 1991, included questions regarding the construction of power plants, reliability of service, and importance of price. The customers responded by showing acceptance of the construction of new generation by Black Hills Power and Light Company, by indicating the importance for reliable and uninterrupted service and the maintenance of reasonably priced rates.

Although the regulatory process would not require it to seek the input of the South Dakota customers or the approval of the South Dakota Public Utilities Commission, it is important that these decisions which significantly affect rates be discussed openly prior to the significant commitment of dollars to meet our customers requirements. Black Hills is receiving positive feedback at its presentations from customers that recognize the necessity for constructing the power plant and the importance of mitigating the rate impact associated with this construction.

EXHIBIT
BHPL
LFF-5

Black Hills Power & Light Company
Integrated Resource Plan

September 1992

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1.0 Introduction

1.1 Introduction

This report and the accompanying appendices present the results of the Integrated Resource Plan (IRP) prepared for Black Hills Power and Light (BHPL) by Black & Veatch. This IRP was based on BHPL's fiscal year which runs from January 1 through December 31. All references to year in this report refer to fiscal year unless stated otherwise. This IRP covers the study period from 1993 through 2015.

The plan provided long-range projections to enable proper evaluation of the long term effect of various alternatives. The long-range projections reflect long-range trends inherent in the underlying assumptions. The actual value of projected variables for any given year may be above or below the long-range trend line. The use of these projections is necessary to properly analyze the implications of individual power supply alternatives.

1.2 Objective

The objective of the IRP is to develop a power supply strategy for BHPL which would provide reliable electric service with the lowest practical revenue requirements; and thus the lowest electric rates. To accomplish this broad objective the following specific objectives were identified.

- Projection of Load Growth.
- Development of Reliability Criteria.
- Review of Clean Air Act Amendments.
- Development of Financial and Economic Projections.
- Development of Generation Capacity Addition Alternatives.
- Screen Capacity Alternatives.
- Development of Alternative Expansion Plans.
- Economic Evaluation of Alternative Expansion Plans.

1.3 Summary of Study

Section 2.0 of the IRP lists the conclusions and recommendations made by the study.

Section 3.0 describes BHPL's existing system. BHPL owns nine coal units in addition to 20 percent of the Wyodak unit. These units include Ben French, Neil

Simpson, Osage 1, 2 and 3, and Kirk 1 through 4 (Kirk 1 through 3 are in cold reserve starting January, 1993). BHPL also owns and operates five diesel generators and four combustion turbines. The four combustion turbines are presently leased to Pacific Power and Light in coordination with a Reserve Capacity Integration Agreement.

Section 4.0 presents the results of a recent system load forecast.

Section 5.0 presents the reliability criteria adopted by the Western Systems Coordinating Council. The criteria, as it applies to BHPL, requires a reserve capacity equal to the largest risk plus five percent of the load responsibility. The need for future capacity expansion is presented based on this criteria.

Section 6.0 reviews Title IV of the Clean Air Act Amendments of 1990 and its affect on new BHPL generating units.

Section 7.0 develops the criteria required to evaluate the available expansion alternatives. The criteria presented includes.

- Inflation and Escalation.
- Weighted Average Cost of Capital.
- Present Worth Rate.
- Fixed Charge Rates.
- Fuel Cost Projections.
- Purchase Power Cost Projections.

Section 8.0 develops power supply alternatives that will most likely be available to BHPL. The alternatives fall into the following categories.

- Neil Simpson 2.
- Combined Cycle Unit.
- Combustion Turbine.
- Purchased Power.

Section 9.0 provides a screening analysis of the capacity expansion alternatives. The screening analysis indicated that all of the alternatives should be evaluated in greater detail.

Section 10.0 provides the four basic strategies which were evaluated. Each strategy involved a different capacity addition identified in Section 8.0. Each strategy included several plans. Each plan contained different combinations of future unit additions. Section 11.0 presents the results of the economic evaluation of the available expansion plans. The plans were evaluated on a comparative cumulative present worth system cost basis. All production costs, purchase power costs and new

plant fixed charges were included in this evaluation. Costs which are common to all plans such as embedded transmission system costs were not included. Several favorable expansion plans were identified. Appendix A provides the detailed spreadsheets leading to the conclusions presented in Section 11.0.

2.0 Conclusions and Recommendations

BHPL has experienced load growth of approximately three percent over the last five years. The "Black Hills Power and Light Company System Load Forecast" was completed by Black & Veatch in April 1992. This load forecast projected growth to be approximately 2.6 percent per year over the next five years; and approximately 2.4 percent over the study period.

BHPL is a member of the Western Systems Coordinating Council (WSCC). WSCC reliability planning criteria recommends that BHPL have reserve capacity equal to the largest generating risk. This requirement is described in Section 5.0. BHPL's largest risk is its share of Wyodak which is 59 MW at 100 F. Based on WSCC's planning criteria, BHPL is presently short of capacity. By 1996 BHPL is expected to be short of capacity by 59 MW.

The capacity addition alternatives available to BHPL are coal fired capacity, combined cycle units, combustion turbines and purchased power. Coal unit and combined cycle unit additions were evaluated in a prefeasibility study. Unit characteristics from that study were used to perform a more detailed economic evaluation. In addition, a 40 MW combustion turbine and purchased power from Pacific Power and Light were evaluated.

A screening analysis in Section 9.0 indicated that combustion turbine and coal fired units are expected to be the most economical generation capacity additions. The detailed economic evaluation confirmed the screening curves. The economic evaluation indicated that coal fired units are more economical than combined cycle units or purchased power. The evaluation indicated that the Neil Simpson 2 unit should be constructed for commercial operation in January 1996. After that, combustion turbine units should be considered for the next capacity additions.

The present natural gas pipeline is not adequate to provide gas for the existing combustion turbine units in Rapid City much less the requirements of an additional combined cycle unit. A natural gas delivery expansion cost estimate was developed. An appropriate gas transmission delivery charge was assessed to the plans that were evaluated with combined cycle units.

In addition, the electrical high voltage transmission system is presently inadequate to import BHPL's requirements under certain conditions. The purchase of extra capacity would require a transmission upgrade. The cost of the required transmission upgrade was assessed to the purchase power plans that were evaluated.

As a result of the Integrated Resource Plan, Black and Veatch recommends that BHPL build Neil Simpson 2 for commercial operation by January 1996. Also, BHPL will most likely require combustion turbine capacity additions in 1997 and 1998. Since the construction time is shorter for combustion turbines, this decision may be delayed for several years. In the meantime, BHPL should reserve space at the Lange Substation for several combustion turbines. In addition, future transmission and substation upgrades should consider the possibility that these units may be added at a later date.

3.0 Description of Existing System

Black Hills Corporation was incorporated under the laws of South Dakota in 1941 under the name of Black Hills Power and Light Company (BHPL). In 1986 the Company changed its name to Black Hills Corporation and now operates its investor-owned electric utility under the assumed name of Black Hills Power and Light Company.

In addition, the Company has diversified operations in coal mining through Wyodak Resources Development Corp and oil and gas production through Western Production Company.

BHPL is engaged in the generation, purchase, transmission, distribution, and sale of electric energy in 11 countries and serves approximately 52,000 customers in a 9,300 square mile area of western South Dakota, northeastern Wyoming, and southeastern Montana.

The territory served by BHPL includes 20 incorporated communities and various unincorporated and rural areas. BHPL's service area is shown in Figure 3-1.

BHPL uses transmission and distribution systems to deliver power throughout the service area. The transmission voltages are 230 kV, 69 kV, and 47 kV. The distribution systems range from 4.16 kV, 12.47 kV, and 24.9 kV. BHPL and Basin Electric Cooperative are joint owners of the transmission system. BHPL is a member of and works in close coordination with Western System Coordinating Council (WSCC).

BHPL owns and operates four electric generating power plants which produce electricity. The power plants are Neil Simpson Station, Kirk Station, Osage Station, and Ben French Station. BHPL also owns five diesel engine generators. In addition, BHPL has a 20 percent ownership share of the Wyodak plant. Table 3-1 describes the generation owned by BHPL.

BHPL also has purchase power agreements as listed in Table 3-2.

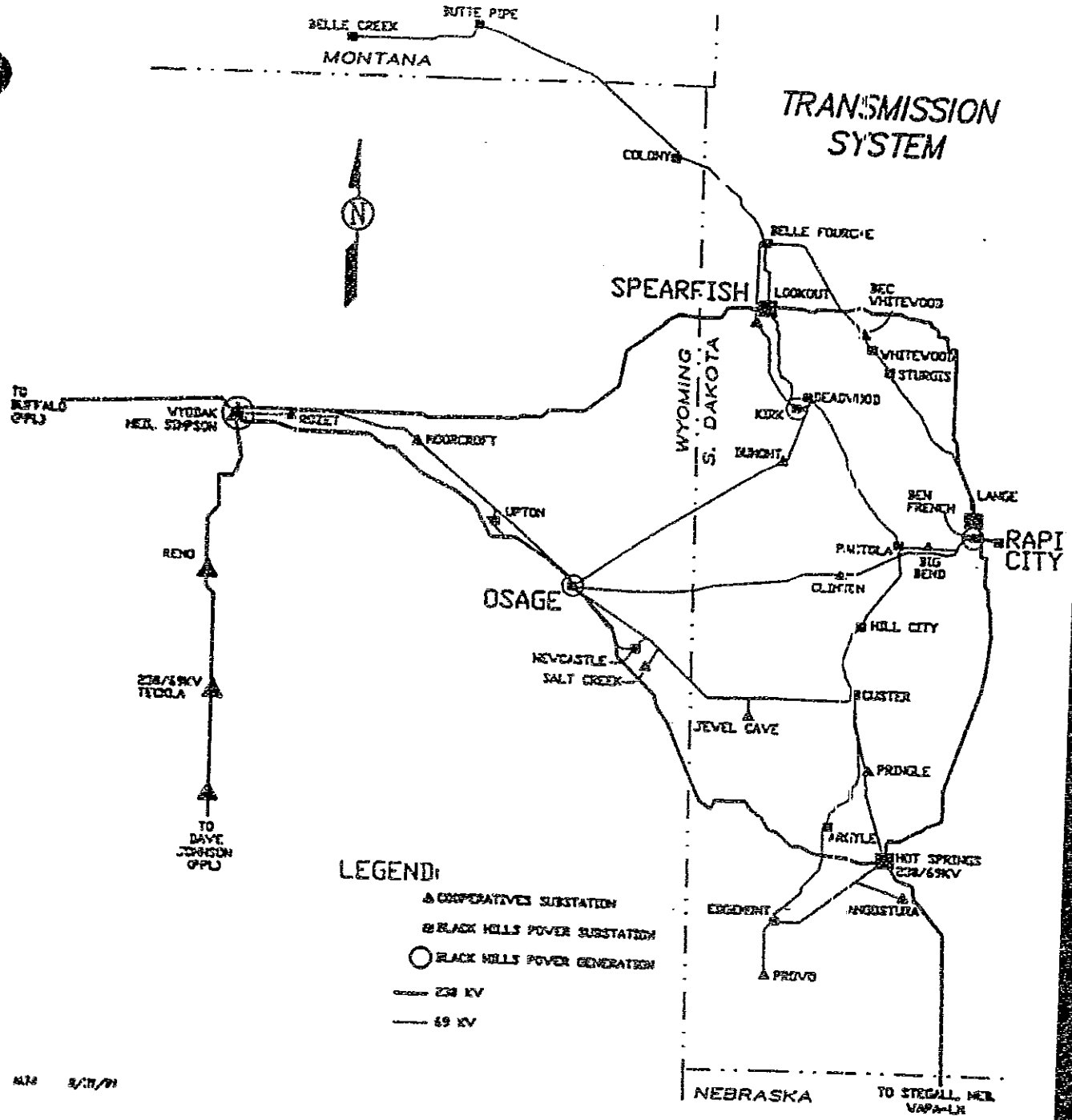


Figure 3-1
BHPL
Service Area

Table 3-1 Black Hills Power & Light Existing Generation

Units	Unit Type	Fuel Type	On-Line Date	Retirement Date	Maximum Capacity		Full Load Net Heat Rate 80°	Estimated Forced Outage Rate*	Maintenance
					Net Rating 80°	100 F Rating			
				(December 31st)	MW		(Btu/kWh)	(Percent)	(Weeks)
Wyodak	Pulverized Coal	Coal	1978	2025	64.0	59.0	11,500	6.0	4
Ben French	Cyclone	Coal	1960	2010	21.6	21.6	13,188	5.0	4
Neil Simpson	Pulverized Coal	Coal	1969	2012	18.1	14.6	13,970	4.0	4
Kirk 4**	Stoker	Coal	1956	2008	10.1	10.1	14,620	5.0	4
Osage 1	Stoker	Coal	1948	2010	10.1	10.1	16,025	5.0	4
Osage 2	Stoker	Coal	1950	2010	10.1	10.1	16,025	5.0	4
Osage 3	Stoker	Coal	1952	2010	10.1	10.1	16,025	5.0	4
Diesel 1	Diesel	No. 2 Oil	1963	N/A	2.0	2.0	9,700	5.0	4
Diesel 2	Diesel	No. 2 Oil	1963	N/A	2.0	2.0	9,700	5.0	4
Diesel 3	Diesel	No. 2 Oil	1963	N/A	2.0	2.0	9,700	5.0	4
Diesel 4	Diesel	No. 2 Oil	1963	N/A	2.0	2.0	9,700	5.0	4
Diesel 5	Diesel	No. 2 Oil	1963	N/A	2.0	2.0	9,700	5.0	4
CT1***	Combustion Turbine	No. 2 Oil	1977	2025	19.2	16.0	13,629	5.0	2
CT2***	Combustion Turbine	No. 2 Oil	1977	2025	19.2	16.0	13,629	5.0	2
CT3***	Combustion Turbine	No. 2 Oil/Gas	1978	2025	19.2	16.0	13,629	5.0	2
CT4***	Combustion Turbine	No. 2 Oil/Gas	1979	2025	19.2	16.0	13,629	5.0	2

*Estimated 1996 forced outage rates.
**Kirk units 1, 2 and 3 are in cold reserve starting January 1993.
***Combustion turbine capacity is available in conjunction with the Reserve Capacity Interchange Agreement with PPL. The RCIA terminates in 2012 at which time the combustion turbines revert back to BHPL.

Table 3-2 Black Hills Power & Light Purchase Power Agreements

Supplier	Capacity (MW)	Start Date	Termination Date
PPL-RCIA[1]	100	7/1/1987	6/30/2012
PPL-Colstrip	75	1/1/1989	12/31/2023
Montana Power Company	30	10/1/1992	9/30/1993
Tri-State G&T[2]	20	10/1/1993	12/31/1997
S D State Allocation[3]	6	5/1/1987	5/1/1999

[1]RCIA is available in conjunction with the 4 combustion turbines.

[2]May be terminated on 12/31/1995 or 1996.

[3]Allocation is based on an hourly schedule. The maximum of 6 MW occurs on the 16th or 17th hour of the day.

4.0 Load Forecast

4.1 General

This section presents the load forecast which was used to determine capacity and energy requirements for the IRP study period. BHPL engaged Black & Veatch to perform a "System Load Forecast" which was completed in April 1992. The "System Load Forecast" presented a short-term and a long-term forecast. The short-term forecast was developed using time series methodology while the long-term forecast used a regression-based model. The load forecast study period extended through 2014.

4.2 Demand-Side Management

Demand-side management programs at BHPL were established some fifty years ago. Competition with other energy alternatives led the way to end-use efficiency efforts. BHPL established construction standards for energy conservation more than 25 years ago.

Energy Conservation Standards have been upgraded as materials and construction technology have improved. Equipment efficiency recommendations are provided to assist customers in their selection of energy efficient electrical equipment and effective equipment installation to meet customer needs at the lowest feasible, long-term cost. Operating economics information is provided to customers who can minimize their costs of operation through energy management.

The goal of demand-side management is to maximize the efficient utilization of resources. This is accomplished through conservation, reducing energy demands and shifting energy requirements. Measurement of demand-side management effects is difficult to document. However, it is possible to estimate the effect using reasonable assumptions based on actual measurements and information provided by customers. BHPL estimates the effect of their demand-side management efforts as follows:

- Energy Conservation Standards are estimated to have reduced the on-peak load of total electric homes by 25 percent. Seven thousand total electric homes and apartments, with a five kilowatt average coincident on-peak load, provide an estimated nine MW reduction.

Conservation standards for more than 500 total electric commercial customers are estimated to have reduced the on-peak load by an additional one MW.

- Equipment Efficiency Recommendations for lighting, refrigeration, air conditioning, heating equipment, and motors are estimated to have reduced peak demand by 10 MW.
- Operating Economics Information is estimated to have reduced peak demand by five MW by showing the savings which can result from power factor savings and proper sizing of replacement equipment.
- Load shifting efforts over the past 10 years have resulted in more measurable reduction by shifting load from on-peak to off-peak periods. Estimates of peak demand reductions are:
  - Residential: two MW
  - Commercial: three MW
  - Industrial: five MW
  - Municipal: one-half MW

It is estimated that energy conservation has reduced peak demand by more than 25 MW and load shifting has reduced the peak by an additional 10 MW. These demand-side management programs are reflected in the historical data used to develop the load forecast. Therefore, the forecast presented in the "System Load Forecast" includes the efforts.

4.3 Load Forecast

The forecast provides monthly peak demands and monthly energy sales through 2004. Annual peak demand and energy sales are provided through 2014. The forecast also provides monthly and annual net energy for load. Net energy for load is sales plus losses, company use, and billing cycle effects. The peak demand forecast was calculated directly from the net energy for load forecast based on monthly (through 2004) and annual (2005 through 2014) load factors. A small declining annual trend is applied to the load factors used in future years to account for the decreased growth rate in the higher load factor industrial customer sector.

Annual peaks are forecasted to occur during the summer. Several factors contribute to the trend toward higher summer peaks.

- Winter and summer energy sales in South Dakota are approximately equal. However, the lower summer load factor provides a higher summer peak demand.
- General Service and Large General Service are strong summer peaking classes; and these classes are forecasted to grow faster than the residential class.
- The percentage of sales in Wyoming, which have a winter peak, is declining compared to total sales.
- The percentage of sales to Gillette, which have a winter peak, is declining compared to total sales.
- The higher winter peaks experienced in 1989 and 1990 are not considered "typical".

4.4 Load Forecast Results

The load forecast predicts an average annual net energy for load increase of 2.6 percent from 1993 through 2000; 2.3 percent from 2000 through 2005; and 2.3 percent from 2005 through 2014. The average annual peak demand forecast is expected to be 2.6 percent through 2000; 2.5 percent from 2000 through 2005; and 2.4 percent from 2005 through 2014.

Results of the net energy for load and peak demand forecasts are summarized in Table 4-1. The basic forecast did not consider the random influences (such as weather) that cause sales to vary from the forecasted values. Therefore, upper and lower bandwidths were calculated based on these unexplained influences. Tables 4-2 and 4-3 present the upper and lower bandwidths of the load forecast respectively.

Table 4-1 Black Hills Expected Energy and Peak Forecast

Year	Net Energy for Load (GWh)	Peak Demand (MW)
1993	1,680.5	297
1994	1,727.0	304
1995	1,773.3	312
1996	1,818.2	321
1997	1,864.2	329
1998	1,911.7	338
1999	1,959.7	347
2000	2,007.8	355
2001	2,056.2	364
2002	2,104.8	373
2003	2,153.3	382
2004	2,201.8	391
2005	2,251.4	401
2006	2,302.3	411
2007	2,354.3	421
2008	2,407.7	431
2009	2,462.3	441
2010	2,518.2	452
2011	2,575.5	463
2012	2,634.1	474
2013	2,694.2	485
2014	2,755.7	497

Table 4-2 Black Hills Energy and Peak Forecast Upper Bandwidth

Year	Net Energy for Load (GWh)	Peak Demand (MW)
1993	1,765.5	311
1994	1,814.9	320
1995	1,861.3	328
1996	1,911.0	337
1997	1,960.2	346
1998	2,010.5	355
1999	2,061.0	365
2000	2,111.8	375
2001	2,162.7	383
2002	2,213.6	393
2003	2,264.4	402
2004	2,316.0	412
2005	2,368.9	422
2006	2,423.0	432
2007	2,478.5	443
2008	2,535.3	453
2009	2,593.5	464
2010	2,653.2	476
2011	2,714.2	487
2012	2,776.8	499
2013	2,840.9	511
2014	2,906.5	523

Table 4-3 Black Hills Energy and Peak Forecast Lower Bandwidth

Year	Net Energy for Load (GWh)	Peak Demand (MW)
1993	1,595.9	282
1994	1,640.3	289
1995	1,682.9	297
1996	1,727.8	305
1997	1,768.7	312
1998	1,813.1	320
1999	1,858.3	329
2000	1,903.9	337
2001	1,949.7	345
2002	1,995.7	354
2003	2,041.9	362
2004	2,088.0	371
2005	2,135.3	380
2006	2,183.6	389
2007	2,233.2	399
2008	2,284.0	408
2009	2,335.9	418
2010	2,389.2	428
2011	2,443.7	438
2012	2,499.5	449
2013	2,556.7	460
2014	2,615.3	471

5.0 Reliability Criteria

5.1 Western Systems Coordinating Council

5.1.1 Reserve Margin

BHPL is a member of the Rocky Mountain Power Area (RMPA) subregion of the Western Systems Coordinating Council (WSCC). BHPL is also a subarea of the Western Area Power Administration - Lower Missouri control area.

The WSCC has recommended power supply design criteria. The recommendation is that the area or system defined for analysis should meet or exceed at least one of the criteria.

Criteria 1. Criteria 1 (as it applies to BHPL) indicates that the monthly reserve capacity should be (a) the greater of 15 percent of the monthly load responsibility, or (b) the largest risk plus 5 percent of the load responsibility (plus 6 MW auxiliary load from Wyodak which must be served when the plant is down). Load responsibility is the firm peak load demand plus firm sales minus firm purchases for which reserve capacity must be provided by the supplier.

In any month, BHPL's peak demand may be higher or lower than the expected peak demand. Therefore, BHPL must be prepared to serve not only the expected peak demand, but also any higher peaks caused by hotter or colder weather, or other random influences. For the purpose of determining reliability criteria, the upper bandwidth peak demand forecast in Table 4-2 was used.

BHPL's load responsibility is the peak demand minus the firm purchases. Firm purchases include the 75 MW Colstrip purchase, the 100 MW Reserve Capacity Integration Agreement, the 30 MW purchase from Montana Power Company in 1993, the 20 MW purchase from Tri-State Generation and Transmission Association and the Electric Power Service Agreement with the State of South Dakota.

The S D Allocation Agreement involves an hourly MW schedule from May 1 through October 31 and continues through the summer of 1999. The resource is provided by WAPA but is subject to renewal each summer. The schedule calls for 6 MW for the 16th and 17th hour of the day and 5 MW for hours 9 through 15 and 18, and 19. Since the peak may not fall on the 16th or 17th hour, 5 MW is used for the capacity at peak.

The Tri-State purchase commences October 1, 1993 and terminates December 31, 1997. However, BHPL may terminate the agreement on December 31, 1995 or 1996.

BHPL's load responsibility (peak demand minus firm purchases) is shown in Table 5-1. Table 5-1 also shows that the minimum reserve requirement defined by Criteria 1 is the loss of the largest unit plus 5 percent of the load responsibility. This value is shown in column (c) as 70 MW in 1993.

Criteria 2. To meet criteria 2 the reserve requirement should be equal to the two largest units. Table 5-2 shows the reserve requirements to satisfy Criteria 2. Table 5-2 indicates that 81 MW of reserve is required in 1993 to meet Criteria 2.

WSCC recommends that the system should meet or exceed at least one of the planning criteria. The least restrictive criteria for BHPL is Criteria 1 as indicated by Tables 5-1 and 5-2. BHPL's peak demand and reserve requirements are shown in Table 5-3 along with the existing capacity and capacity expansion requirements. Table 5-3 indicates that BHPL's capacity expansion requirement is 21 MW in 1993 and 59 MW in 1996.

5.1.2 Operating Reserve

Reliable operation of interconnected power systems require that adequate generating capacity be available at all times to provide regulation and to replace any generation lost due to forced outage. WSCC requires that the Western Area Power Administration - Lower Missouri control area carry adequate operating reserve. Operating reserve comprises spinning reserve and quick start capacity that can be started, synchronized, and loaded in 10 minutes.

WSCC requires that the Western Area Power Administration - Lower Missouri control area carry spinning reserve equal to the regulating margin plus the greater of (a) one half of the loss of generating capacity resulting from the most severe single contingency, or (b) 3 1/2 percent of the load carried on thermal generation.

BHPL is a sub-area of the Western Area Power Administration - Lower Missouri control area. BHPL has an agreement with WAPA for 5 MW of load regulation service. This load regulation service plus the Reserve Capacity Interchange Agreement with PPL fulfills BHPL's operating reserve requirement.

Table 5-1 WSCC Power Design Criteria 1

Year	Firm Peak Load Plus Firm Sale	Firm Purchases					Load Responsibility[2]	Reserve 16% L.R.	Largest Risk (Hyrdro at 100 F)	6% L.R.	5 MW Aux.	Largest Risk Plus 6% L.R. Plus 5 MW Aux.	Greater of a or b
		Colstrip	BCTA	Tri-State	MPC	SD State Association							
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
1993	311	75	100		30	5	101	15	59	5	6	70	70
1994	320	75	100	20		5	120	18	59	6	6	71	71
1995	328	75	100	20		5	128	19	59	6	6	71	71
1996	337	75	100	20		5	137	21	59	7	6	72	72
1997	346	75	100	20		5	146	22	59	7	6	72	72
1998	355	75	100			5	175	26	59	9	6	74	74
1999	365	75	100			5	185	28	59	9	6	74	74
2000	374	75	100				199	30	59	10	6	75	75
2001	383	75	100				208	31	59	10	6	75	75
2002	393	75	100				218	33	59	11	6	76	76
2003	402	75	100				227	34	59	11	6	76	76
2004	412	75	100				237	36	59	12	6	77	77
2005	422	75	100				247	37	59	12	6	77	77
2006	432	75	100				257	39	59	13	6	78	78
2007	443	75	100				268	40	59	13	6	78	78
2008	453	75	100				278	42	59	14	6	79	79
2009	464	75	100				289	43	59	14	6	79	79
2010	476	75	100				301	45	59	15	6	80	80
2011	487	75	100				313	47	59	16	6	81	81
2012	499	75					424	64	59	21	6	86	86
2013	511	75					436	65	59	22	6	87	87
2014	523	75					448	67	59	22	6	87	87

(a) 15 percent of the anxiety load responsibility.
(b) The largest risk plus 5 percent of the anxiety load responsibility plus a little anxiety load from Wyodak which must be picked up when the plant is down.
(c) The greater of (a) or (b).
[1] Montana Power Company
[2] Peak year load plus firm sales minus firm purchases
[3] Optional - May be processed by WSPP.

Table 5-2 WSCC Power Design Criteria 2 - Loss of Two Largest Risks

Year	Wyodak*	Ben French	Total
	MW	MW	MW
1993	59	22	81
1994	59	22	81
1995	59	22	81
1996	59	22	81
1997	59	22	81
1998	59	22	81
1999	59	22	81
2000	59	22	81
2001	59	22	81
2002	59	22	81
2003	59	22	81
2004	59	22	81
2005	59	22	81
2006	59	22	81
2007	59	22	81
2008	59	22	81
2009	59	22	81
2010	59	22	81
2011	59	22	81
2012	59	22	81
2013	59	22	81
2014	59	22	81

*At 100 F.

Table 5-3 Capacity Expansion Requirement

Year	Peak Demand	Reserve Requirement[2]	Capacity Requirement	Existing Capacity[3]	Capacity Expansion Requirement
	MW	MW	MW	MW	MW
1993	311	70	381	369	11
1994	329	71	381	350	41
1995	328	71	399	350	49
1996	337	72	409	350	59
1997	346	72	418	350	68
1998	355	74	429	350	79
1999	365	74	439	350	109
2000	374	75	449	325	124
2001	383	75	458	325	133
2002	393	76	469	325	144
2003	402	76	478	325	153
2004	412	77	489	325	164
2005	422	77	499	325	174
2006	432	78	510	325	185
2007	443	78	521	309	212
2008	453	79	532	309	223
2009	464	79	543	309	235
2010	476	80	556	309	247
2011	487	81	568	287	280
2012	499	81	580	287	293
2013	511	81	592	174	418
2014	523	81	604	174	430

Note: 1. Rows may not sum due to rounding.
2. Based on WSCC Criteria 1.
3. At 100 F; takes into account expected unit retirements.

5.2 Inland Power Pool

BHPL has the option of joining the Inland Power Pool. The Inland Power Pool requires members to comply with the Western Systems Coordinating Council's Power Supply Design Criteria. Therefore membership in the Pool would not reduce BHPL's capacity requirements.

6.0 Clean Air Amendments

6.1 General

BHPL will be affected by Title IV of the Clean Air Act Amendments of 1990 (CAAA). This Title restricts the amount of pollutants a given generating unit or plant may emit. A review of this Amendment and its effects on a new BHPL generating unit have been reviewed as part of the Neil Simpson 2 preinvestment survey. The conclusions of this survey are discussed in the following sections.

6.2 Title IV

Title IV of the CAAA reduces SO_2 emissions by 10 million tons per year from 1980 emission levels. Reductions in emissions will be achieved by allocating allowances based on the unit's emissions during the base period of 1985 through 1987. A pollution allowance permits an affected source to emit one ton of pollutant over an annual period.

Phase I affected units are listed in the CAAA and are considered the top sources of pollution emissions. Affected units must achieve SO_2 emission limits of 2.5 lb/MBtu times the average annual fuel consumption for 1985 through 1987 by January 1, 1995.

Phase II affected units meet the affected unit definition and are not included in the Phase I list. Affected units, as defined under Title IV, are all fossil generating units larger than 25 MW, except combustion turbines which are exempt. Diesel and combined cycle units are affected units if they are larger than 25 MW. A non-affected unit is any existing fossil generating unit of 25 MW or less or any existing combustion turbine. In general, affected units must achieve SO_2 emissions of 1.2 lb/MBtu times the average annual fuel consumption for 1985 through 1987 by January 1, 2000.

6.2.1 Allowances Received by Wyodak Unit

The number of allowances to be granted to each Phase II unit have been calculated by the EPA in accordance with provisions of Section 405 of Title IV. These allowances are summarized in a document entitled "The National Allowance Data Base, Version 2.1" (May 1992). According to the data base the Wyodak unit will receive 15,327 allowances per year from the year 2000 through 2009, then receive 1[illegible]17 allowances per year in the year 2010 and thereafter. The allowance allocation

from 2000 through 2009 is higher due to the receipt of "bonus" allowances for the "Clean States" provision of Section 405.

With 20 percent ownership of the Wyodak plant, BHPL will receive 20 percent of the total allowances allocated. This amounts to approximately 3,065 allowances per year from 2000 to 2009 and 2,963 allowances per year in 2010 and thereafter.

6.2.2 Allowances Used by Wyodak Unit

It is estimated that the existing Wyodak unit will use(i.e. emit SO_2 in the amount of) 7,600 allowances per year. Of that, 1,520 allowances (20 percent) are assigned to BHPL. These estimates are based on the following assumptions.

- Gross unit input of 340 MW.
- Plant heat rate of 10,500 Btu/kWh.
- Annual capacity factor of 97 percent.
- SO_2 emission rate of 0.5 lb/MBtu.

Subtracting the 1,520 BHPL allowance use rate from the 3,065 BHPL allowances receipt rate from 2000 to 2009 results in an estimated net positive balance of 1,545 BHPL allowances per year from 2000 through 2009. BHPL can use these allowances at other units or sell/trade them to other utilities or allowance holders.

6.2.3 New Unit Allowance Use

It is estimated that a new 80 MW unit would consume 862 allowances per year. This estimate is based on the following assumptions.

- Unit heat input of 1,014 MBtu/h.
- Annual capacity factor of 97 percent.
- SO_2 emission rate of 0.2 lb/MBtu.

Although the unit would initially be dispatched at an 80 percent capacity factor, it is conservatively assumed that the unit may be baseloaded in the future with a 3 percent forced outage rate. The 0.2 lb/MBtu SO_2 emission rate is the maximum allowed under Wyoming law. The BHPL positive allowance balance in the year 2000 and thereafter drops to 1,443 per year because BHPL will be receiving 2,963 allowances per year.

6.2.4 Allowance Balance

As previously estimated, BHPL will realize a net positive balance of 1,545 allowances from its portion of the Wyodak unit operation from 2000 through 2009 and 1,443 allowances per year thereafter. It was also estimated that a new 80 MW unit would consume 862 allowances per year. It is concluded that sufficient allowances will be available from the Wyodak unit for a new 80 MW unit. Furthermore, BHPL will have approximately 683 excess allowances per year from 2000 to 2009 and 581 excess allowances per year thereafter.

7.0 Evaluation Criteria

This section presents the estimates used as the basis for the economic evaluation of the Neil Simpson 2 generating unit as part of BHPL's power system. Evaluation criteria include both economic evaluation criteria as well as the fuel price forecast. The following paragraphs discuss these estimates based on data provided by BHPL.

7.1 Economic Parameters

7.1.1 Inflation Rate

This study will use 4 percent as the general inflation rate for capital costs and operation and maintenance costs.

7.1.2 Escalation Rate

This study will use 4 percent as the escalation rate for capital costs and operation and maintenance expense. The capital cost escalation rates are used to adjust capital costs for new capacity additions to their commercial operation date.

7.1.3 Weighted Average Cost of Capital

The weighted average cost of capital is the interest rate at which new capacity additions will be financed. The following cost of capital assumptions are for new capitalization and used for new generation capacity in this study.

	Capitalization (Percent)	Rate (Percent)
Common Stock	48	12.50
Preferred Stock	0	0
Debt	52	9.00
Weighted Average Cost of Capital	10.68	

7.1.4 Present Worth Discount Rate

The present worth discount rate is used to evaluate various alternatives on a present worth basis. The present worth discount rate used for this study is 10.68 which is the same as the weighted average cost of capital.

7.1.5 Fixed Charge Rate

The fixed charge rate is a factor used to convert a capital cost to a number of equal annual payments. The fixed charge rate depends on the term and rate of the financing arrangements as well as financing fees, taxes, depreciation, debt reserve fund, insurance, and any other costs directly related to a particular project. It is assumed that combustion turbines would have a book life of 25 years with a 15 year tax depreciation; that combined cycle would have a book life of 35 years with a 20 year tax depreciation; and that coal units would have a book life of 50 years and a tax life of 20 years. The 25 year levelized annual fixed charge rate for combustion turbines is 15.158 percent. The 35 year levelized annual fixed charge rate for combined cycle units is 14.702. The 50 year levelized annual fixed charge rate for coal units is 12.593 percent. It is assumed that coal units would be built in Wyoming and that combustion turbines or combined cycles would be built in South Dakota.

7.1.6 Income Tax Rates

The states of South Dakota and Wyoming do not tax BHPL's income. The Federal income tax rate is 34 percent.

7.1.7 Property Tax Rates

The property tax rate for combustion turbines and combined cycles in Rapid City, South Dakota would be 2.20 percent. The property tax rate for coal units in Wyoming would be 0.55 percent.

7.2 Fuel Price Forecast

7.2.1 Coal Price Forecast

The coal price forecast was developed by BHPL for the units on their system. The quantity of coal delivered, and thus the coal price, would depend on whether or not new coal units are constructed and the construction timing. Therefore one coal price forecast was developed assuming no new coal units. Table 7-1 presents BHPL's

Table 7-1 Delivered Coal Cost by Plant - Without Coal Unit Addition ($/MBtu)*

Year	Wyodak	Neil Simpson #1	Osage #1,2,3	Ben French	Kirk #4
1996	0.6631	0.7618	0.9866	1.2875	1.1941
1997	0.7230	0.8129	1.0460	1.3590	1.2615
1998	0.6757	0.7823	1.0251	1.3512	1.2496
1999	0.7089	0.8060	1.0581	1.3970	1.2914
2000	0.6551	0.7710	1.0331	1.3859	1.2757
2001	0.6826	0.7870	1.0604	1.4270	1.3130
2002	0.6451	0.7696	1.0539	1.4352	1.3166
2003	0.6878	0.8006	1.0963	1.4928	1.3695
2004	0.6377	0.7724	1.0799	1.4903	1.3640
2005	0.6857	0.8066	1.1264	1.5513	1.4219
2006	0.6504	0.7938	1.1264	1.5714	1.4337
2007	0.6936	0.8319	1.1678	1.6317	
2008	0.6629	0.8156	1.1753	1.6577	
2009	0.7196	0.8559	1.2301	1.7317	
2010	0.6883	0.8508	1.2399	1.7617	
2011	0.7489	0.8936			
2012	0.7168	0.8896			
2013	0.7816				
2014	0.7289				
2015	0.8014				

*Net of Statement R cost reductions passed through to rate payers. BHPL pays contract coal prices based upon fair market value contracts entered into in the 1970's. These prices are higher than reflected above.

delivered coal price forecast should no new coal unit be constructed. Appendix B presents fuel price forecasts for the various plans evaluated in Section 11.0. Each forecast is tailored to the timing and number of future coal unit additions. Delivered costs include coal cost, transportation, and handling.

7.2.2 Natural Gas Price Forecast

The 1992 commodity cost of natural gas is estimated to be $1.20/MBtu which is equivalent to the average spot price plus a 5 percent premium for firm purchases. The 1992 delivered commodity cost of natural gas is $1.33/MBtu. The natural gas commodity cost is assumed to escalate at 5 percent annually which is one percent above the expected inflation rate.

The present gas transportation pipeline is insufficient to supply gas to new generation in the Rapid City area. Black & Veatch performed a Natural Gas Transportation Evaluation for BHPL. That evaluation estimated the facility enhancements required to supply firm, uninterruptible gas to BHPL.

The Natural Gas Transportation Evaluation indicated a gas transportation demand cost ranging from $0.91/MCF to $1.10/MCF in 1992. To be conservative, the lower end of the range was used in this study. $0.86/MCF of the transportation cost is the demand while the remaining $0.05/MCF includes variable costs such as compression gas.

The demand cost is comprised of $0.447/MCF for existing transportation outside of the affected area, $0.215/MCF for additional facility cost, and $0.250 for storage for upstream flexibility. The gas transportation facilities costs were escalated from 1992 to 1996. The existing facility demand cost were escalated at 1.5 percent while the new facilities were escalated at the underlying inflation rate of 4 percent used in the study.

The study assumes that, if a combined cycle unit were installed, sufficient firm gas transportation would be purchased to operate that unit. For example, a daily requirement of 17,000 MCF would require a daily gas transportation demand cost of $14,620 and consequently a $5.3 million annual demand charge in 1992. Table 7-2 shows the delivered natural gas commodity cost and the transportation demand charge.

Table 7-2 Projected Natural Gas Cost ($/MBtu)

Year	Delivered Gas Commodity Cost	Transportation Demand Charge
1993	1.39	0.88
1994	1.46	0.91
1995	1.53	0.93
1996	1.61	0.96
1997	1.68	0.99
1998	1.76	1.02
1999	1.83	1.05
2000	1.92	1.08
2001	2.00	1.11
2002	2.09	1.14
2003	2.19	1.18
2004	2.29	1.21
2005	2.39	1.25
2006	2.50	1.28
2007	2.61	1.32
2008	2.73	1.36
2009	2.85	1.40
2010	2.98	1.45
2011	3.12	1.49
2012	3.26	1.54
2013	3.40	1.59
2014	3.56	1.64
2015	3.72	1.69

7.2.3 Oil Price Forecast

The oil forecast was based on 1991 cost data compiled by the Department of Energy (DOE) on the average price of fuel oil delivered to the Wyodak plant, and 1992 DOE Annual Energy Outlook fuel price projections through 2010. Forecasted oil prices through 2015 are listed in Table 7-3.

7.3 Purchase Power Price Forecasts

This section discusses the purchase power price forecasts associated with MPC, PPL, and Tri-State power and energy. The contract for these purchases are detailed in Section 3.3.

7.3.1 Montana Power Company

The Montana Power Company contract expires September 30, 1993. The projected rates for Montana Power Company power and energy as provided by Montana Power Company were adjusted by 7 percent to compensate for transmission losses. BHPL must also compensate Montana Power Company for transmission costs charged by PPL. The transmission charge as given by PPL was adjusted by 7 percent to account for losses. The projected 1993 demand charge is $3.21/kW-mo. The energy charge is $21.40/MWh, and transmission charges are $2.61/kW-mo.

7.3.2 Pacific Power & Light

BHPL purchases power from PPL under two separate contracts. The contracts are Colstrip and the Reserve Capacity Integration Agreement (RCIA). The purchase power price forecasts associated with these contracts are discussed in the following subsections.

7.3.2.1 Colstrip. The demand charge for the Colstrip purchase is equal to the sum of the initial levelized annual fixed cost, subsequent levelized annual fixed costs if any, and other fixed annual charges including property taxes, insurance, and taxes other than income tax divided by net Colstrip capacity. The 1992 demand charge for Colstrip power is $18.98/kW-month. The demand charge is a cost that will be incurred by BHPL regardless of other capacity additions. Since the Colstrip demand charge is common to all plans it will not affect the results of the evaluation and will not be included.

Table 7-3 No. 2 Oil Price Forecast

Year	No. 2 Oil ($/MBtu)
1993	4.55
1994	4.53
1995	4.46
1996	4.48
1997	4.60
1998	4.72
1999	4.85
2000	4.98
2001	5.12
2002	5.15
2003	5.15
2004	5.18
2005	5.23
2006	5.28
2007	5.35
2008	5.40
2009	5.40
2010	5.54
2011	5.77
2012	6.00
2013	6.26
2014	6.51
2015	6.77

The forecasted energy charge for the Colstrip purchase was estimated by BHPL from 1993 through 2001 and is presented in Table 7-4. The energy charges were escalated from 2002 through 2015 at the same escalation rate.

7.3.2.2 RCIA. The energy charge for the RCIA purchase is based on the incremental cost of generation. The incremental cost is based on the highest average annual production cost for any hour for any of PPL's owned or leased coal-fired plants. The production cost is determined from PPL's most recently filed FERC Form No. 1. The fuel cost component of the production cost is increased by 7 percent for system losses.

The 1991 FERC Form 1 indicates that Cholla #4 has the highest average annual production cost. Therefore, the production cost for this unit is used as the basis for the RCIA energy charge forecast. The fuel cost for Cholla #4 is $14.55/MWh and the total production cost is $17.39/MWh. The fuel cost is increased by 7 percent for system losses and escalates with coal prices. The coal price escalation rate is assumed to be 3 percent. The cost difference between the production cost and the fuel cost is assumed to escalate with the general inflation rate. Table 7-5 shows the forecasted energy charge for the RCIA purchase.

7.3.3 Tri-State

The capacity and energy charges associated with the Tri-State purchase are fixed over the term of the contract. The capacity charge is fixed at $8.40/kW-month. The energy charge is fixed at $16.00/MWh. Tri-State may increase these rates if its generation facilities costs are increased due to a transaction privilege tax or other tax that is imposed directly on electricity generation by a governmental authority after the effective date of the contract. For evaluation purposes, it is assumed that no new taxes will be imposed directly on electricity generation. Therefore, the rates given above are assumed through the term of the contract.

The Tri-State purchase agreement may be terminated on December 31, 1995, December 31, 1996, or may be continued until December 31, 1997.

Table 7-4 Colstrip Purchase Power Cost Forecast ($/MWh)

Year	Energy Charge
1993	12.85
1994	13.37
1995	13.90
1996	14.46
1997	15.04
1998	15.64
1999	16.26
2000	16.91
2001	17.59
2002	18.29
2003	19.03
2004	19.79
2005	20.58
2006	21.40
2007	22.26
2008	23.15
2009	24.07
2010	25.04
2011	26.04
2012	27.08
2013	28.16
2014	29.29
2015	30.46

Table 7-5 RCIA Purchase Power Cost Forecast

Year	Fuel	Losses	Losses Plus Fuel	Energy Adder	Total Delivered Energy Cost
	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
1991	16.50	1.16	17.66	3.70	21.36
1992	17.00	1.19	18.18	3.85	22.03
1993	17.50	1.23	18.73	4.00	22.73
1994	18.03	1.26	19.29	4.16	23.45
1995	18.57	1.30	19.87	4.33	24.20
1996	19.13	1.34	20.47	4.50	24.97
1997	19.70	1.38	21.08	4.68	25.76
1998	20.29	1.42	21.71	4.87	26.58
1999	20.90	1.46	22.36	5.06	27.43
2000	21.53	1.51	23.04	5.27	28.30
2001	22.17	1.55	23.73	5.48	29.20
2002	22.84	1.60	24.44	5.70	30.13
2003	23.53	1.65	25.17	5.92	31.10
2004	24.23	1.70	25.93	6.16	32.09
2005	24.96	1.75	26.70	6.41	33.11
2006	25.71	1.80	27.51	6.66	34.17
2007	26.48	1.85	28.33	6.93	35.26
2008	27.27	1.91	29.18	7.21	36.39
2009	28.09	1.97	30.06	7.50	37.55
2010	28.93	2.03	30.96	7.80	38.75
2011	29.80	2.09	31.89	8.11	39.99
2012	30.69	2.15	32.84	8.43	41.27

8.0 Capacity Addition Alternatives

8.1 General

The capacity expansion requirements discussed in Section 5.0 indicates that BHPL will need substantial capacity additions. Four capacity expansion options have been identified and are described below.

8.2 Coal Fired Unit

Neil Simpson 2 is the first coal fired generating unit evaluated for this study. Neil Simpson 2 is designed to burn Wyodak Mine coal and to optimize the use of Wyodak Plant facilities. The unit is 80 MW and is proposed to be located on the Wyodak Plant property. The unit utilizes air cooled condensers and existing Wyodak Plant ash sluicing, service water, demineralized water and fuel oil systems. The generation will be stepped up to 69 kV and fed into BHPL's system. The Neil Simpson 2 unit is a pulverized coal unit based on the expected lower fuel cost due to higher boiler efficiency than the fluidized bed alternative. Table 8-1 provides the estimated capital cost and performance data for the Neil Simpson 2 unit which was used in the evaluation process.

A significant window of opportunity exists for coal fired generation equipment in 1996 due to economic conditions and negotiations with vendors. Vendors have substantially reduced their bids on equipment compared to their original quotes. Delaying the plant would cause BHPL to forego these reduced prices. It is assumed that the cost of Neil Simpson 2 would have a real increase of four percent if delayed to 1997 with an additional four percent increase if delayed to 1998. Thereafter the cost of a coal unit similar to Neil Simpson 2 is assumed to increase at the underlying inflation rate.

Future coal units used to supply additional capacity units are similar to the Neil Simpson 2 unit.

8.3 Combined Cycle Unit

In a combustion turbine combined cycle facility, the hot exhaust gases from the combustion turbine pass through a heat recovery steam generator (HRSG). The steam generated by the HRSG is expanded through a steam turbine which, in turn, drives an additional generator. With a typical gas inlet temperature of 1,000 F into the HRSG, steam conditions of about 1,000 psi and 900 F can be produced by the

Table 8-1 Pulverized Coal Technology Unit Cost and Performance Data

Net Plant Output, MW*	80	
Total Cost, 1996 $/kW**	1,561	
Fixed O&M Cost, 1996 $/kW-yr	26.46	
Variable O&M, 1996 $/MWh	3.04	
Net Plant Heat Rate, Btu/kWh	20*	80*
Full load	12,310	12,499
75 percent load	12,250	12,350
50 percent load	12,789	12,775
25 percent load	16,022	15,721
Equivalent Availability, percent	89.5	
Forced Outage Rate, percent	3	
Planned Maintenance Outage, weeks/year	4	
Construction Period, months	24	

*Based on one boiler serving one steam turbine generator, VWO-OP.

**Includes escalation, indirect cost, and interest used during construction.

Table 8-2 Combined Cycle Technology Unit Cost and Performance Data

Net Plant Output, MW*	60	
Total Cost, 1996 $/kW**	1,023	
Fixed O&M Cost, 1996 $/kW-yr	14.14	
Variable O&M, 1996 $/MWh	6.07	
Net Plant Heat Rate, Btu/kWh	20°	80°
Full load	8,738	8,785
75 percent load	8,839	8,844
50 percent load	9,300	9,242
25 percent load	10,818	10,568
Equivalent Availability, percent	93.3	
Forced Outage Rate, percent	3	
Planned Maintenance Outage, weeks/year	3	
Construction Period, months	14	

*Based on one Westinghouse 251 combustion turbine, one unfired HRSG, and one steam turbine.

**Includes escalation, indirect cost, and interest used during construction.

HRSG. Combustion turbine combined cycle systems typically burn natural gas and/or No. 2 oil and are available in a wide variety of sizes and configurations. This section provides cost and performance estimates for the addition of a combustion turbine combined cycle unit on the BHPL system. The estimates are based on a Westinghouse 251 combustion turbine in combined cycle operation with single HRSG and steam turbine. This unit configuration can produce a net plant output of approximately 60 MW burning natural gas fuel. Estimated performance and cost data for the 60 MW combined cycle system are provided in Table 8-2. The cost estimate is based on the installation of the combined cycle at the BHPL Lange Substation.

8.4 Combustion Turbine Unit

Combustion turbine systems typically burn natural gas and/or No. 2 oil and are available in a wide variety of sizes and configurations. This section provides cost and performance estimates for a combustion turbine unit on the BHPL system. The estimates are based on a General Electric PG6541(B) combustion turbine (Frame 6) with an International Standards Organization (ISO) rating of approximately 40 MW on natural gas.

Combustion turbines are generally used for peaking and reserve purposes because of their relatively low capital cost, higher full load heat rate, and the higher cost of fuel when compared to conventional baseload capacity. Combustion turbines have the added benefit of providing quick-start capability in certain configurations. Estimated performance and cost data for the Frame 6 combustion turbine system are provided in Table 8-3. The cost estimate is based on the installation of the combustion turbine at the BHPL Lange Substation.

8.5 Purchase Power Opportunities

PPL has offered to provide long-term firm capacity and energy to BHPL. The contract terms would require BHPL to utilize the purchase at a minimum capacity factor of 50 percent. The prices for firm capacity and energy for the period 1993 through 2012 would be based on the weighted fully distributed fixed and variable costs of resources contained in an 800 MW resource pool plus system transmission and losses. The capacity component would be based on a levelized annual fixed charge for the resources in the pool. The energy component would be based on the production cost for the resource in the pool.

Table 8-3 Combustion Turbine Technology Unit Cost and Performance Data

Net Plant Output, MW*	40	
Total Cost, 1996 $/kW**	532	
Fixed O&M Cost, 1996 $/kW-yr	11.56	
Variable O&M, 1996 $/MWh	4.50	
Net Plant Heat Rate, Btu/kWh	20°	80°
Full load	12,168	12,738
75 percent load	12,766	13,371
50 percent load	14,549	15,257
25 percent load	-	-
Equivalent Availability, percent	91.3	
Forced Outage Rate, percent	5	
Planned Maintenance Outage, weeks/year	2	
Construction Period, months	10	

*Based on GE Frame 6 20 F ambient temperature and 14.9 psi.

**Includes escalation, indirect cost, and allowance for funds used during construction.

Table 8-4 provides PPL's estimate of capacity and energy from 1993 through 2012. The estimated prices (provided by PPL) are based on 1989 actual costs of existing PacifiCorp resources with capacity escalated at 0.5 percent per year and energy escalated by the percent change each year over the previous year in the estimated price of coal delivered to electric utilities as published by the Data Resources Inc. for the Mountain #1 region (Rocky Mountain area).
The PPL offer states

> Although PacifiCorp currently has no new resource additions planned, beginning in 1997, 100 MW of the existing resources in the resource pool could be replaced each year by different cost resources that PacifiCorp owns, leases or has under long-term contract during this period. For the purpose of this exhibit, no new resources have been rolled into the 800 MW resource pool.

Thus the capacity and energy prices could be higher than those provided by PPL in Table 8-4.

Table 8-4 Capacity and Energy Prices Provided by Pacific Power and Light

	Capacity Price	Energy Price
Year	$/kW-mo	$/MWh
1993	17.51	15.18
1994	17.59	15.62
1995	17.68	16.19
1996	17.77	16.84
1997	17.86	17.54
1998	17.95	18.28
1999	18.04	19.07
2000	18.13	19.90
2001	18.22	20.82
2002	18.31	21.84
2003	18.40	22.95
2004	18.49	24.12
2005	18.59	25.41
2006	18.68	26.82
2007	18.77	28.34
2008	18.87	30.00
2009	18.96	31.74
2010	19.05	33.59
2011	19.15	35.54
2012	19.25	37.60

9.0 Screening Analysis

9.1 General

Conventional generation and purchase power alternatives are screened based on 1996 through 2015 levelized total costs developed for each alternative. The purpose of this screening process is to eliminate alternatives with little economic merit from further evaluation and to assist in the optimization of the various plans. Levelized total costs for generation alternatives are based on the cost and operating characteristics contained in Section 8.3, the fuel cost price projections contained in Section 7.2, and the economic parameters contained in Section 7.1. Levelized total costs include capital costs, fixed and variable O&M, and fuel.

9.2 Generating Unit Alternatives

Screening curves were developed for combustion turbine, combined cycle, coal alternatives, in addition to purchase power options. Figure 9-1 contains the combined screening curves for a 80 MW pulverized coal unit, 62 MW combined cycle unit, 40 MW combustion turbine unit and the PPL purchase power option. The screening curve indicates that, in general, the pulverized coal unit is more economical at capacity factors above 25 percent while the combustion turbine unit is more economical at capacity factors below 25 percent.

Screening curves do not consider such dynamic operating effects as startup cost, maintenance and forced outage, and reserve requirements. Also, the curves do not include any changes in the dispatch of other existing units on the system. Therefore, they can only be used as a guide to unit addition. None of the options screened can be dropped from further evaluation based on the screening curve. Plans involving coal, combustion turbine and combined cycle unit additions will be developed. The optimum of these plans will be tested to determine if purchased power could displace any unit additions.

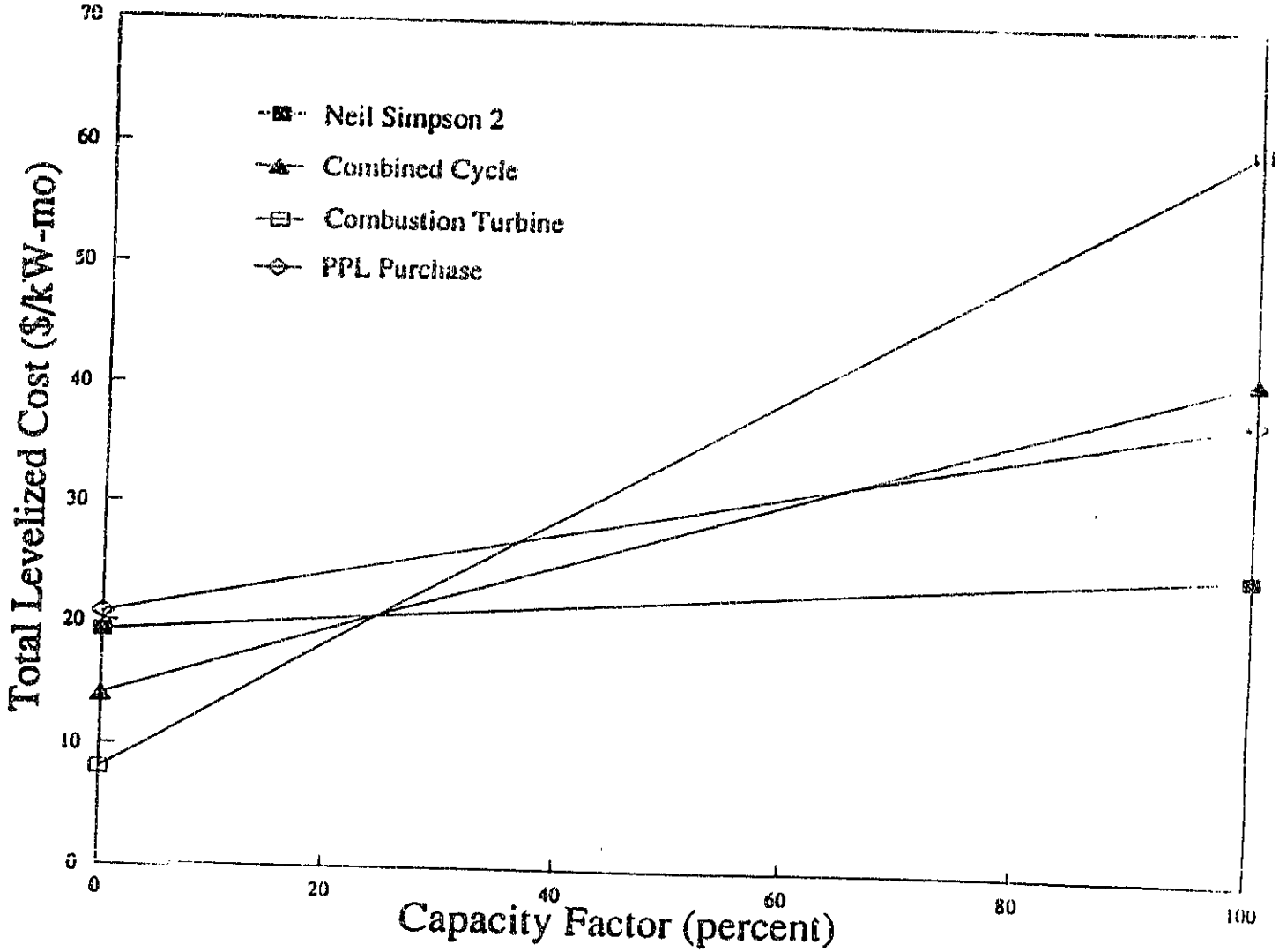


Figure 9-1
Capacity Alternatives
Screening Curve

10.0 Alternative Expansion Strategy Development

This section uses the results of the alternative screening curves in Section 9.0 to develop possible expansion plans to supply BHPL's future power requirements. The screening curves indicated that all capacity alternatives considered should be evaluated further. The detailed economic evaluation will be performed in Section 11.0. Each alternate expansion plan will be considered separately.

Section 5.0 indicated that BHPL is expected to require an additional 59 MW of capacity by 1996, and a total of 436 MW additional by 2014. This study is performed to determine the most economical type of capacity for the first addition in 1996. There are four strategies available for the first addition.

- Strategy A – Neil Simpson 2 coal unit.
- Strategy B – Gas fired combined cycle unit.
- Strategy C – Purchase power from PPL.
- Strategy D – Combustion turbine unit.

Each strategy could change the mix of capacity on the BHPL system; and thus changes the other future capacity addition requirements. Each strategy will be tested with several plans that contain different combinations of future units. The optimum plan for each strategy will be used in the final evaluation.

11.0 Economic Evaluation of Alternative Expansion Plans

11.1 Evaluation Method

The power supply strategies developed in Section 10.0 will be evaluated on a comparative cost basis. Comparative costs are useful for comparing alternatives but cannot be used to project actual total costs for other uses. The comparative costs contain the following components.

- Production Costs
- Purchase Power Costs
- Fixed Charges

The production costs are based on production costing simulation for the entire BHPL system. Production cost simulation is necessary to incorporate the effect of new unit additions on the operation of the existing units. Production costs include fuel and variable and fixed O&M, for all BHPL-owned units and purchased power costs. The purchase power component consists of purchased power demand and energy charges, wheeling charges and losses.

The fixed charge component consists of fixed charges found by applying the fixed charge rate developed in Section 7.0 to the capital cost of various alternatives. The capital cost includes escalation and allowance for funds used during construction. Fixed charges for the existing transmission and distribution system and generating units, and for transmission and distribution system expansion projects are not included since they are common to all plans.

Annual comparative and 1993 cumulative present worth comparative costs (at the 10.68 percent worth discount rate presented in Section 7.0) are presented in the tables in Appendix A.

11.2 Economic Evaluation of Expansion Plans

11.2.1 Strategy A -- Neil Simpson 2

Section 5.0 indicated that BHPL is expected to require 59 MW of capacity by 1996. The addition of the Neil Simpson 2 unit could supply this capacity requirement.

The Western Systems Coordinating Council recommends that its members maintain a reserve capacity equal to the largest generating unit risk plus 5 percent of the load responsibility (as described in Section 5.0). Presently the largest risk is

the Wyodak plant. Should the Neil Simpson 2 plant be built, it would become the largest risk. Reserve capacity would be required based on Neil Simpson 2's summer rating. Presently reserve capacity is based on BHPL's share of Wyodak which is 59 MW at 100 F. Neil Simpson 2's 100 F rating is 75 MW . Thus, an additional 16 MW of reserve capacity and ultimately, total capacity, would be required with the addition of Neil Simpson 2.

Several plans were developed to meet BHPL's future capacity requirements. All plans in this strategy assumed the Neil Simpson 2 unit would be installed in 1996. The various plans had different combinations of future units. The Appendix contains spreadsheets which compile costs associated with each plan. Table 11-1 summarizes the data contained in the spreadsheets in the Appendix. Table 11-1 shows what years future capacity additions were made, and the 1993 cumulative present worth cost of each plan.

Within Strategy A (Neil Simpson 2 in 1996) several plans were evaluated with different units in 1997 and thereafter. Plans were evaluated with a second coal unit in 1997, a combined cycle unit in 1997, and two combustion turbines in 1997. Table 11-1 indicates that plans with combustion turbines as the second units are substantially more economical than those plans with a coal unit or a combined cycle unit as the second addition.

Table 11-1 indicates that Plan BHPL 106 has the least cumulative present worth cost. Plan BHPL 106 includes the Neil Simpson 2 plant in 1996 with combustion turbine additions in 1997, 1998, 2001, and 2005. Plan BHPL 106 is slightly less than Plan BHPL 107 which has a coal unit in 2005 instead of a combustion turbine.

Comparison of plans BHPL 100 and BHPL 103 indicate that future coal unit additions are more economical than future combined cycle additions.

Plan BHPL 101 has coal unit additions in both 1996 and 1997. This plan is $38.3 million higher than the Base plan, indicating that after the Neil Simpson 2 unit is installed, peaking capacity will be required.

11.2.2 Strategy B–Combined Cycle Unit

Three plans were evaluated for Strategy B. Each plan in Strategy B assumed a combined cycle unit in 1996. Plan BHPL 110 has a mix of combined cycle and combustion turbine additions. The cumulative present worth cost of this plan is $77.8 million higher than the optimum Neil Simpson 2 Plan. This indicates that combined cycle units are not competitive with coal fired capacity on the BHPL system.

Table 11-1 Economic Comparison of Capacity Expansion Plans

PLAN	YEAR 1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	CUMULATIVE PRESENT WORTH COST $ MILLION	COMPARISON TO BASE PLAN $ MILLION
BHPL100	NS2	CT	CT				COAL					CT			CT	CT	COAL	CT			507.3	2.9
BHPL101	NS2	COAL					COAL					CT			CT	CT	COAL	CT			543.7	39.3
BHPL102	NS2	CC					COAL					CT			CT	CT	COAL	CT			535.1	30.7
BHPL103	NS2	CT	CT				CC					CT			CT	CT	CC	CT			516.4	12.0
BHPL104	NS2	CT		COAL						CT		COAL				CT	COAL	CT			526.2	21.8
BHPL105	NS2	CT		COAL						CT		CT			COAL		COAL	2-CT			520.9	16.5
BHPL106	NS2	CT	CT			CT				CT		COAL				CT	COAL	CT			504.4	BASE
BHPL107	NS2	CT	CT			CT				COAL					CT	CT	COAL	CT			505.0	0.6
BHPL110	CC	CT	CT			CC					CT		CT			CC	CC	CT	CT		582.2	77.8
BHPL111	CC	CT	CT			COAL						CT	CT			COAL	COAL			CT	544.7	40.3
BHPL112	CC	NS2			CT			CT				CT	CT			COAL	COAL			CT	535.7	31.3
BHPL120	FPL80MW		CT		CT				CC				CT			2-CT	CC	CT			560.8	56.4
BHPL121	FPL80MW		CT		CT				COAL				CT			2-CT	COAL	CT			543.5	39.1
BHPL122	FPL80MW		CC				CT				COAL					2-CT	COAL		CT		569.6	65.2
BHPL123	FPL40MW CT		COAL				CT				COAL					2-CT	COAL	CT			536.9	32.5
BHPL124	FPL80MW		COAL				CT				COAL					2-CT	COAL		CT		565.8	61.2
BHPL130	2-CT		CT	CT			COAL					CT		CT		CT	COAL			CT	538.1	34.7
BHPL131	2-CT		NS2				COAL					CT			CT		COAL	CT			512.7	8.3
BHPL132	2-CT		NS2			CT				COAL					CT	CT	COAL	CT			514.4	10.0

NS2 = NEIL SIMPSON 2
CT = COMBUSTION TURBINE
CC = COMBINED CYCLE UNIT

Plan BHPL 111 replaces future combined cycle units with coal units and reduces cumulative present worth cost by $37.5 million; once again indicating that coal unit additions are more competitive than combined cycle units on the BHPL system.

Plan BHPL 112 replaces the combustion turbine unit additions in 1997 with a coal unit. This plan has higher cumulative present worth cost than the previous plan which has combustion turbine additions in 1997. Plan BHPL 112 indicates that base load capacity is not required in 1997 after other base load capacity is added in 1996.

11.2.3 Strategy C--PPL Purchase Power

Strategy C evaluated plans which included purchase of capacity from PPL. The PPL purchase is high capacity cost with relatively low energy cost. It is expected that a PPL purchase would dispatch similarly to base load generation such as a coal unit. The transmission import capability into the BHPL system is not adequate to reliably handle this purchase. BHPL estimates that a $17.6 million transmission upgrade would be required. Table 11-1 indicates that all purchase plans were higher in cost than the Base plan with Neil Simpson 2 in 1996.

Plans BHPL 120 and BHPL 121 both have combustion turbines as the second and third units. Plan BHPL 120 has future combined cycle units while plan BHPL 121 has future coal units. The plan with combined cycle units is $18.3 million higher than the plan with coal units; once again indicating that combined cycles are not competitive with coal units on the BHPL system.

11.2.4 Strategy D--Combustion Turbine Unit

Plans in Strategy D assume combustion turbine unit additions in 1996 instead of Neil Simpson 2. The combustion turbine units evaluated were 40 MW, thus two combustion turbines were required to replace the coal unit. Plan 130 indicates that replacing Neil Simpson 2 with combustion turbines in 1996 is $34.7 million cumulative present worth higher than the Base plan.

Plan 131 is similar to Plan 100. Plan 100 has Neil Simpson in 1996, a combustion turbine in 1997, and a second combustion turbine in 1998. Plan 131 has two combustion turbines in 1996 with Neil Simpson 2 delayed until 1998. This plan indicates that it would cost BHPL $8.3 million to delay the construction of Neil Simpson 2 by two years.

Plan 132 is similar to Plan 131 except that the second coal unit is delayed by installing a combustion turbine instead of the coal unit in 2002. Delay in the second coal unit caused a higher cumulative present worth cost.

11.3 Summary

The economic evaluation indicates that the construction of the Neil Simpson 2 plant in 1996 is BHPL's least cost option. The evaluation also indicated that peaking capacity will be required after the Neil Simpson 2 plant is constructed.

Plan BHPL 131 assumes that two combustion turbines would be installed in 1996 with the Neil Simpson plant delayed until 1998. The delay of Neil Simpson 2 would cost BHPL rate payers $8.3 million.

The evaluation also showed that combined cycle units are not competitive with coal units on the BHPL system because of coal prices and the requirement to provide major gas pipeline upgrades in order to supply sufficient natural gas.

Appendix A

Economic Evaluation Spreadsheets

EMPL 100
NEIL SIMPSON 1996
CT-1997 CT-1998 COAL-2002 CT-2007 CT-2010 CT-2011 COAL-2012 CT-2013

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YEAR	PRODUCTION FUEL	TOTAL O&M	TOTAL PROD.	CAPITAL COSTS N.S. 2	COAL 2	COAL 3	C.T. 1	C.T. 2	C.T. 3	C.T. 4	C.T. 5	C.T. 6	PEAK DEMAND	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	12,593	13,108	32,701	15,726	0	0	0	0	0	0	0	0	2,160	50,587	33,711
1997	21,962	14,321	38,272	15,726	0	0	3,355	0	0	0	0	0	0	55,353	67,038
1998	22,423	15,481	37,894	15,726	0	0	3,355	3,489	0	0	0	0	0	60,454	99,924
1999	24,630	16,275	41,105	15,726	0	0	3,355	3,489	0	0	0	0	0	63,675	131,220
2000	25,450	17,031	42,481	15,726	0	0	3,355	3,489	0	0	0	0	0	65,051	160,108
2001	28,245	17,927	46,172	15,726	0	0	3,355	3,489	0	0	0	0	0	68,742	187,887
2002	20,852	21,739	41,791	15,726	21,761	0	3,355	3,489	0	0	0	0	0	86,122	218,906
2003	21,226	22,908	44,133	15,726	21,761	0	3,355	3,489	0	0	0	0	0	88,464	247,880
2004	21,513	23,886	45,399	15,726	21,761	0	3,355	3,489	0	0	0	0	0	89,730	274,433
2005	24,368	25,182	49,550	15,726	21,761	0	3,355	3,489	0	0	0	0	0	93,881	299,533
2006	25,208	26,249	51,457	15,726	21,761	0	3,355	3,489	0	0	0	0	0	95,788	322,672
2007	28,848	27,843	56,692	15,726	21,761	0	3,355	3,489	4,966	0	0	0	0	104,989	345,566
2008	29,418	28,220	57,638	15,726	21,761	0	3,355	3,489	4,966	0	0	0	0	106,935	368,673
2009	32,914	29,709	62,623	15,726	21,761	0	3,355	3,489	4,966	0	0	0	0	111,920	386,613
2010	33,579	31,797	65,376	15,726	21,761	0	3,355	3,489	4,966	5,586	0	0	0	120,259	405,972
2011	50,893	31,456	82,449	15,726	21,761	0	3,355	3,489	4,966	5,586	5,810	0	0	143,142	426,791
2012	32,589	37,242	69,831	15,726	21,761	32,212	3,355	3,489	4,966	5,586	5,810	0	0	162,736	448,175
2013	40,895	38,015	78,911	15,726	21,761	32,212	3,355	3,489	4,966	5,586	5,810	6,284	0	176,100	469,320
2014	42,878	39,686	82,564	15,726	21,761	32,212	3,355	3,489	4,966	5,586	5,810	6,284	0	181,753	488,817
2015	49,168	41,831	91,000	15,726	21,761	32,212	3,355	3,489	4,966	5,586	5,810	6,284	0	190,189	507,250
															507,250

RUPL 101
BASIL STEPSON 15016
COAL-97 COAL-2002 CT-2007 CT-2010 CT-2011 COAL-2012 CT-2013

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YEAR	PRODUCTION FUEL	TOTAL O&M	TOTAL PROD.	CAPITAL COSTS B.S. 2	COAL 2	COAL 3	COAL 4	C.T. 1	C.T. 2	C.T. 3	C.T. 4	PEAK DEMAND	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1986	10,553	13,108	33,781	15,726	0	0	0	0	0	0	0	2,140	50,587	33,781
1987	17,574	18,217	33,781	15,726	17,224	0	0	0	0	0	0	0	86,741	73,894
1988	17,678	16,928	34,597	15,726	17,224	0	0	0	0	0	0	0	67,547	110,639
1989	16,573	17,844	38,618	15,726	17,224	0	0	0	0	0	0	0	68,366	144,731
2000	18,823	18,862	37,434	15,726	17,224	0	0	0	0	0	0	0	70,434	176,569
2001	18,565	18,682	38,287	15,726	17,224	0	0	0	0	0	0	0	72,217	204,983
2002	18,356	23,281	41,618	15,726	17,224	21,761	0	0	0	0	0	0	96,327	239,902
2003	19,041	24,517	43,558	15,726	17,224	21,761	0	0	0	0	0	0	98,269	272,087
2004	19,039	25,581	44,591	15,726	17,224	21,761	0	0	0	0	0	0	99,592	301,472
2005	20,704	26,941	47,641	15,726	17,224	21,761	0	0	0	0	0	0	102,352	328,837
2006	21,205	28,108	48,316	15,726	17,224	21,761	0	0	0	0	0	0	104,025	353,968
2007	22,721	29,028	51,750	15,726	17,224	21,761	0	4,966	0	0	0	0	111,427	378,285
2008	23,493	30,356	53,778	15,726	17,224	21,761	0	4,966	0	0	0	0	113,156	400,858
2009	25,046	31,229	56,265	15,726	17,224	21,761	0	4,966	0	0	0	0	116,872	421,445
2010	25,700	32,297	58,007	15,726	17,224	21,761	0	4,966	5,586	0	0	0	123,070	441,578
2011	24,853	33,029	65,872	15,726	17,224	21,761	0	4,966	5,586	5,810	0	0	130,745	461,466
2012	26,926	30,585	65,513	15,726	17,224	21,761	32,212	4,966	5,586	5,810	0	0	140,736	483,648
2013	29,261	69,657	69,668	15,726	17,224	21,761	32,212	4,966	5,586	5,810	6,284	0	178,237	504,026
2014	30,669	63,268	72,559	15,726	17,224	21,761	32,212	4,966	5,586	5,810	6,284	0	182,698	524,504
2015	23,228	64,543	77,873	15,726	17,224	21,761	32,212	4,966	5,586	5,810	6,284	0	183,642	542,871

542,871

IMPL 102
NEIL SIMPSON 1996
CC-1997 COAL-2002 CT-2007 CT-2010 CT-2011 COAL-2012 CT-2013

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YEAR	PRODUCTION TOTAL	TOTAL O&M	TOTAL PROD.	CAPITAL COSTS N.S. 2	COAL 2	COAL 3	C.C. 1	C.T. 1	C.T. 2	C.T. 3	C.T. 4	PEAK DEMAND	GAS LINE	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	19,593	13,108	32,701	15,726	0	0	0	0	0	0	0	2,160	0	50,587	33,710
1997	19,650	15,031	34,681	15,726	0	0	9,698	0	0	0	0	0	4,523	64,628	72,622
1998	20,034	15,680	35,714	15,726	0	0	9,698	0	0	0	0	0	4,523	65,861	108,340
1999	21,581	16,594	38,176	15,726	0	0	9,698	0	0	0	0	0	4,523	68,123	141,822
2000	21,849	17,388	39,237	15,726	0	0	9,698	0	0	0	0	0	4,523	69,184	172,544
2001	23,746	18,387	42,133	15,726	0	0	9,698	0	0	0	0	0	4,523	72,080	201,464
2002	19,236	21,735	40,971	15,726	21,761	0	9,698	0	0	0	0	0	4,523	92,879	235,060
2003	20,231	22,940	43,171	15,726	21,761	0	9,698	0	0	0	0	0	4,523	94,879	268,135
2004	20,358	23,832	44,300	15,726	21,761	0	9,698	0	0	0	0	0	4,523	96,008	294,545
2005	22,873	25,282	48,235	15,726	21,761	0	9,698	0	0	0	0	0	4,523	99,943	321,266
2006	23,777	26,353	50,130	15,726	21,761	0	9,698	0	0	0	0	0	4,523	101,838	345,866
2007	25,834	27,342	53,176	15,726	21,761	0	9,698	4,966	0	0	0	0	4,523	109,850	369,841
2008	26,771	28,501	55,273	15,726	21,761	0	9,698	4,966	0	0	0	0	4,523	111,947	391,917
2009	29,287	30,167	59,454	15,726	21,761	0	9,698	4,966	0	0	0	0	4,523	116,128	412,807
2010	30,109	32,236	62,346	15,726	21,761	0	9,698	4,966	5,586	0	0	0	4,523	124,608	432,665
2011	41,141	32,790	73,930	15,726	21,761	0	9,698	4,966	5,586	5,810	0	0	4,523	142,000	453,318
2012	29,568	37,567	67,333	15,726	21,761	32,212	9,698	4,966	5,586	5,810	0	0	4,523	167,615	475,344
2013	35,371	38,735	74,107	15,726	21,761	32,212	9,698	4,966	5,586	5,810	6,284	0	4,523	180,673	498,794
2014	37,980	40,471	77,551	15,726	21,761	32,212	9,698	4,966	5,586	5,810	6,284	0	4,523	184,117	516,545
2015	41,589	42,866	84,435	15,726	21,761	32,212	9,698	4,966	5,586	5,810	6,284	0	4,523	191,001	535,056
															535,056

BNPS 103
NEIL SIMPSON 1996
CT-1997 CT-1998 CC-2002 CT-2007 CT-2010 CT-2011 CC-2012 CT-2013

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YEAR	PRODUCTION FUEL	TOTAL O&M	TOTAL PROD.	CAPITAL COSTS N.S. 2	C.C. 1	C.C. 2	C.T. 1	C.T. 2	C.T. 3	C.T. 4	C.T. 5	C.T. 6	PEAK DEMAND	GAS LINE	ANNUAL COST	1992 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	18,593	13,198	32,791	15,726	0	0	0	0	0	0	0	0	2,160	0	50,587	33,711
1997	21,952	14,221	36,272	15,726	0	0	3,355	0	0	0	0	0	0	0	55,353	67,038
1998	22,423	15,461	37,884	15,726	0	0	3,355	3,489	0	0	0	0	0	0	60,454	98,824
1999	24,830	16,275	41,105	15,726	0	0	3,355	3,489	0	0	0	0	0	0	63,676	131,220
2000	25,150	17,021	42,171	15,726	0	0	3,355	3,489	0	0	0	0	0	0	65,691	160,106
2001	26,345	17,827	44,172	15,726	0	0	3,355	3,489	0	0	0	0	0	0	68,742	187,887
2002	24,180	20,372	44,552	15,726	11,799	0	3,355	3,489	0	0	0	0	0	5,221	84,152	218,192
2003	28,671	21,822	48,193	15,726	11,799	0	3,355	3,489	0	0	0	0	0	5,221	87,763	246,943
2004	27,886	22,457	48,537	15,726	11,799	0	3,355	3,489	0	0	0	0	0	5,221	89,127	273,317
2005	28,978	23,743	52,720	15,726	11,799	0	3,355	3,489	0	0	0	0	0	5,221	92,309	297,995
2006	30,332	24,715	55,047	15,726	11,799	0	3,355	3,489	0	0	0	0	0	5,221	95,087	320,967
2007	36,529	25,814	62,343	15,726	11,799	0	3,355	3,489	4,568	0	0	0	0	5,221	106,899	344,238
2008	38,534	28,553	66,527	15,726	11,799	0	3,355	3,489	4,568	0	0	0	0	5,221	110,883	366,805
2009	43,345	28,543	71,888	15,726	11,799	0	3,355	3,489	4,822	0	0	0	0	5,221	116,464	386,755
2010	48,536	29,661	78,200	15,726	11,799	0	3,355	3,489	4,568	5,588	0	0	0	5,221	126,088	407,652
2011	54,846	31,134	85,979	15,726	11,799	0	3,355	3,489	4,568	5,588	5,810	0	0	5,221	141,931	429,169
2012	55,674	35,561	91,235	15,726	11,799	17,466	3,355	3,489	4,568	5,588	5,810	0	0	12,255	171,867	451,734
2013	68,111	37,256	105,367	15,726	11,799	17,466	3,355	3,489	4,568	5,588	5,810	4,284	0	12,255	182,703	474,513
2014	72,560	38,922	112,483	15,726	11,799	17,466	3,355	3,489	4,568	5,588	5,810	4,284	0	12,255	189,219	495,983
2015	82,945	41,154	124,139	15,726	11,799	17,466	3,355	3,489	4,568	5,588	5,810	4,284	0	12,255	210,875	516,421
																516,421

BNPL 104
BILL SIMPSON 1996
CT-1997 COAL-1999 CT-2005 COAL-2007 CT-2011 COAL-2012 CT-2013

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YEAR	PRODUCTION FUEL	TOTAL GEN	TOTAL PROD.	CAPITAL COSTS N.G. 2	COAL 2	COAL 3	COAL 4	C.T. 1	C.T. 2	C.T. 3	C.T. 4	PEAK DEMAND	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	18,595	13,168	32,701	15,726	0	0	0	0	0	0	0	2,160	50,587	33,711
1997	21,952	14,321	36,273	15,726	0	0	0	3,355	0	0	0	0	55,354	67,038
1998	22,412	14,957	37,369	15,726	0	0	0	3,355	0	0	0	0	56,436	97,735
1999	18,572	18,384	36,956	15,726	19,348	0	0	3,355	0	0	0	0	75,383	134,785
2000	16,846	19,226	36,070	15,726	19,348	0	0	3,355	0	0	0	0	76,497	168,754
2001	19,569	20,268	39,817	15,726	19,348	0	0	3,355	0	0	0	0	78,244	200,147
2002	20,053	21,129	41,183	15,726	19,348	0	0	3,355	0	0	0	0	79,610	229,006
2003	21,203	22,273	43,476	15,726	19,348	0	0	3,355	0	0	0	0	81,903	256,831
2004	21,522	23,227	44,748	15,726	19,348	0	0	3,355	0	0	0	0	83,175	283,444
2005	24,388	25,162	49,550	15,726	19,348	0	0	3,355	4,592	0	0	0	92,569	305,193
2006	25,208	26,249	51,457	15,726	19,348	0	0	3,355	4,592	0	0	0	94,476	328,015
2007	22,714	29,771	52,485	15,726	19,348	28,478	0	3,355	4,592	0	0	0	121,980	354,638
2008	23,513	31,059	54,572	15,726	19,348	28,478	0	3,355	4,592	0	0	0	124,067	379,103
2009	25,053	32,729	57,782	15,726	19,348	28,478	0	3,355	4,592	0	0	0	127,277	401,779
2010	25,700	34,107	59,807	15,726	19,348	28,478	0	3,355	4,592	0	0	0	129,302	422,594
2011	31,493	33,979	65,472	15,726	19,348	28,478	0	3,355	4,592	5,810	0	0	140,977	443,097
2012	26,008	39,505	65,513	15,726	19,348	28,478	32,212	3,355	4,592	5,810	0	0	175,030	465,835
2013	23,201	46,467	69,668	15,726	19,348	28,478	32,212	3,355	4,592	5,810	6,284	0	183,469	487,617
2014	36,689	42,240	78,930	15,726	19,348	28,478	32,212	3,355	4,592	5,810	6,284	0	186,731	507,648
2015	33,330	44,543	77,873	15,726	19,348	28,478	32,212	3,355	4,592	5,810	6,284	0	191,674	526,225
														526,225

ENPL 105
KEIL SIMPSON 1806
CT-1997 COAL-1998 CT-2005 CT-2007 COAL-2010 COAL-2012 CT-2013

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YEAR	PRODUCTION FUEL	TOTAL O&M	TOTAL PROD.	CAPITAL COSTS E.E. 2	COAL 2	COAL 3	COAL 4	C.T. 1	C.T. 2	C.T. 3	C.T. 4	C.T. 5	PEAK DEMAND	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1994	19,193	13,108	32,301	15,726	0	0	0	0	0	0	0	0	2,160	50,587	33,711
1997	21,662	14,521	36,222	15,726	0	0	0	3,355	0	0	0	0	0	55,353	67,038
1998	22,611	14,837	37,348	15,726	0	0	0	3,355	0	0	0	0	0	56,430	97,734
1999	18,512	18,324	36,836	15,726	19,348	0	0	3,355	0	0	0	0	0	75,383	134,784
2000	18,844	19,226	38,070	15,726	19,348	0	0	3,355	0	0	0	0	0	76,427	168,754
2001	19,549	20,268	39,817	15,726	19,348	0	0	3,355	0	0	0	0	0	78,244	200,187
2002	20,653	21,129	41,183	15,726	19,348	0	0	3,355	0	0	0	0	0	79,610	229,004
2003	21,203	22,379	43,478	15,726	19,348	0	0	3,355	0	0	0	0	0	81,903	255,839
2004	21,422	23,227	44,748	15,726	19,348	0	0	3,355	0	0	0	0	0	83,179	280,443
2005	24,558	25,182	49,539	15,726	19,348	0	0	3,355	4,592	0	0	0	0	92,549	305,193
2006	25,228	26,219	51,457	15,726	19,348	0	0	3,355	4,592	0	0	0	0	94,478	328,815
2007	26,849	27,843	54,692	15,726	19,348	0	0	3,355	4,592	4,966	0	0	0	103,677	350,843
2008	28,418	28,226	57,638	15,726	19,348	0	0	3,355	4,592	4,966	0	0	0	105,623	371,471
2009	22,814	25,789	48,603	15,726	19,348	0	0	3,355	4,592	4,966	0	0	0	120,608	391,177
2010	25,696	26,843	52,541	15,726	19,348	29,782	0	3,355	4,592	4,966	0	0	0	126,398	412,456
2011	27,259	28,979	56,238	15,726	19,348	29,782	0	3,355	4,592	4,966	0	0	0	143,438	434,218
2012	28,996	29,586	58,582	15,726	19,348	29,782	22,213	3,355	4,592	4,966	0	0	0	179,492	457,379
2013	29,211	41,402	70,613	15,726	19,348	29,782	22,213	3,355	4,592	4,966	6,284	6,284	0	193,160	480,312
2014	30,656	43,213	73,868	15,726	19,348	29,782	22,213	3,355	4,592	4,966	6,284	6,284	0	196,415	501,392
2015	33,225	45,566	78,791	15,726	19,348	29,782	22,213	3,355	4,592	4,966	6,284	6,284	0	201,436	520,904
															520,904

BHPL 106
NEIL SIMPSON 1996
CT-1997 CT-1998 CT-2001 CT-2005 COAL-2007 CT-2011 COAL-2012 CT-2013

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YEAR	PRODUCTION MWH	TOTAL O&M	TOTAL PROD.	CAPITAL COSTS N.S. 2	COAL 2	COAL 3	C.T. 1	C.T. 2	C.T. 3	C.T. 4	C.T. 5	C.T. 6	PEAK DEMAND	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	19,593	13,108	32,701	15,728	0	0	0	0	0	0	0	0	2,160	50,587	33,711
1997	21,852	14,021	36,272	15,728	0	0	3,365	0	0	0	0	0	0	55,353	67,038
1998	22,420	15,461	37,884	15,728	0	0	3,365	3,489	0	0	0	0	0	60,454	99,924
1999	24,830	16,275	41,105	15,728	0	0	3,365	3,489	0	0	0	0	0	63,675	131,220
2000	25,450	17,031	42,481	15,728	0	0	3,365	3,489	0	0	0	0	0	65,851	160,196
2001	28,253	18,519	46,772	15,728	0	0	3,365	3,489	3,925	0	0	0	0	73,267	189,502
2002	28,822	19,318	47,938	15,728	0	0	3,365	3,489	3,925	0	0	0	0	74,434	216,485
2003	32,244	20,330	52,574	15,728	0	0	3,365	3,489	3,925	0	0	0	0	79,069	242,381
2004	32,479	21,197	53,677	15,728	0	0	3,365	3,489	3,925	0	0	0	0	80,172	266,106
2005	35,738	22,899	58,735	15,728	0	0	3,365	3,489	3,925	4,592	0	0	0	89,822	290,121
2006	37,251	24,005	61,256	15,728	0	0	3,365	3,489	3,925	4,592	0	0	0	92,373	312,435
2007	28,648	27,788	56,434	15,728	28,476	0	3,365	3,489	3,925	4,592	0	0	0	113,997	337,315
2008	29,427	28,992	58,419	15,728	28,476	0	3,365	3,489	3,925	4,592	0	0	0	115,982	360,186
2009	32,897	30,516	63,414	15,728	28,476	0	3,365	3,489	3,925	4,592	0	0	0	120,977	381,740
2010	33,579	31,797	65,376	15,728	28,476	0	3,365	3,489	3,925	4,592	0	0	0	122,939	401,530
2011	36,993	31,458	68,449	15,728	28,476	0	3,365	3,489	3,925	4,592	5,810	0	0	145,822	422,738
2012	32,589	37,242	69,831	15,728	28,476	32,212	3,365	3,489	3,925	4,592	5,810	0	0	165,416	444,475
2013	40,095	38,015	78,911	15,728	28,476	32,212	3,365	3,489	3,925	4,592	5,810	8,284	0	180,780	465,938
2014	42,078	39,486	82,564	15,728	28,476	32,212	3,365	3,489	3,925	4,592	5,810	8,284	0	184,433	485,722
2015	49,168	41,831	91,000	15,728	28,476	32,212	3,365	3,489	3,925	4,592	5,810	8,284	0	192,869	504,415
															504,415

EMPL 197
NEIL SIMPSON 1996
CT-1997 CT-1998 CT-2001 COAL-2005 CT-2010 CT-2011 COAL-2012 CT-2013

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YEAR	PRODUCTION FUEL ($000)	TOTAL O&M ($000)	TOTAL PROD. ($000)	CAPITAL COSTS N.S. 1 ($000)	COAL 2 ($000)	COAL 3 ($000)	C.T. 1 ($000)	C.T. 2 ($000)	C.T. 3 ($000)	C.T. 4 ($000)	C.T. 5 ($000)	C.T. 6 ($000)	PEAK DEMAND ($000)	ANNUAL COST ($000)	1993 CUMULATIVE PRESENT WORTH COST ($000)
1996	19,593	13,185	32,781	15,720	0	0	0	0	0	0	0	0	2,160	50,587	33,711
1997	21,652	14,321	36,272	15,720	0	0	3,355	0	0	0	0	0	0	55,353	67,038
1998	22,423	15,481	37,824	15,720	0	0	3,355	3,489	0	0	0	0	0	60,454	99,924
1999	24,830	16,276	41,106	15,720	0	0	3,355	3,489	0	0	0	0	0	63,675	131,220
2000	25,650	17,091	42,741	15,720	0	0	3,355	3,489	0	0	0	0	0	65,051	160,166
2001	28,253	18,519	46,772	15,720	0	0	3,355	3,489	3,925	0	0	0	0	70,267	189,502
2002	26,822	19,318	47,939	15,720	0	0	3,355	3,489	3,925	0	0	0	0	74,434	218,485
2003	32,244	20,330	52,574	15,720	0	0	3,355	3,489	3,925	0	0	0	0	79,069	242,381
2004	32,479	21,197	53,677	15,720	0	0	3,355	3,489	3,925	0	0	0	0	80,172	266,106
2005	34,416	25,555	59,972	15,720	24,479	0	3,355	3,489	3,925	0	0	0	0	101,232	293,171
2006	35,247	26,362	61,609	15,720	24,479	0	3,355	3,489	3,925	0	0	0	0	103,183	318,056
2007	38,564	27,843	66,407	15,720	24,479	0	3,355	3,489	3,925	0	0	0	0	108,881	341,389
2008	39,433	28,220	67,653	15,720	24,479	0	3,355	3,489	3,925	0	0	0	0	108,627	362,806
2009	42,833	29,798	72,630	15,720	24,479	0	3,355	3,489	3,925	0	0	0	0	113,612	383,042
2010	43,564	31,287	74,851	15,720	24,479	0	3,355	3,489	3,925	5,566	0	0	0	121,951	402,873
2011	51,868	33,436	85,302	15,720	24,479	0	3,355	3,489	3,925	5,566	5,810	0	0	144,822	423,738
2012	52,803	37,242	90,045	15,720	24,479	22,212	3,355	3,489	3,925	5,566	5,810	0	0	150,427	445,249
2013	60,311	38,935	99,246	15,720	24,479	22,212	3,355	3,489	3,925	5,566	5,810	6,284	0	159,732	466,831
2014	62,851	38,806	101,657	15,720	24,479	22,212	3,355	3,489	3,925	5,566	5,810	6,284	0	163,443	486,263
2015	68,102	41,834	109,936	15,720	24,479	22,212	3,355	3,489	3,925	5,566	5,810	6,284	0	171,860	504,923

504,365

EXPL 110
COMBINED CYCLE 1998
CT-1997 CT-1998 CC-2001 CT-2006 CT-2008 CC-2011 CC-2012 CT-2013 CT-2014

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Year	PRODUCTION FUEL	TOTAL O&M	TOTAL PROD.	CAPITAL COSTS C.C. 1	C.C. 2	C.C. 3	C.C. 4	C.T. 1	C.T. 2	C.T. 3	C.T. 4	C.T. 5	C.T. 6	PEAK DEMAND	GAS LINE	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	25,972	12,383	38,338	9,325	0	0	0	0	0	0	0	0	0	2,160	4,397	54,218	36,130
1997	29,343	13,659	43,002	9,325	0	0	0	3,355	0	0	0	0	0	0	4,397	60,079	72,302
1998	30,128	14,689	44,818	9,325	0	0	0	3,355	3,489	0	0	0	0	0	4,397	65,384	107,870
1999	33,977	15,595	49,572	9,325	0	0	0	3,355	3,489	0	0	0	0	0	4,397	70,138	142,342
2000	35,257	16,315	51,572	9,325	0	0	0	3,355	3,489	0	0	0	0	0	4,397	72,138	174,376
2001	33,222	19,385	52,607	9,325	11,345	0	0	3,355	3,489	0	0	0	0	0	9,469	89,599	210,321
2002	34,220	19,857	54,077	9,325	11,345	0	0	3,355	3,489	0	0	0	0	0	9,469	91,080	243,330
2003	38,054	21,185	59,239	9,325	11,345	0	0	3,355	3,489	0	0	0	0	0	9,469	96,222	274,845
2004	36,571	21,982	58,553	9,325	11,345	0	0	3,355	3,489	0	0	0	0	0	9,469	97,516	303,791
2005	42,931	23,407	66,338	9,325	11,345	0	0	3,355	3,489	0	0	0	0	0	9,469	103,321	331,326
2006	44,061	25,125	69,186	9,325	11,345	0	0	3,355	3,489	4,775	0	0	0	0	9,469	110,944	358,128
2007	51,203	25,801	77,005	9,325	11,345	0	0	3,355	3,489	4,775	0	0	0	0	9,469	118,763	384,048
2008	53,400	27,679	81,079	9,325	11,345	0	0	3,355	3,489	4,775	5,165	0	0	0	9,469	128,002	409,287
2009	59,396	29,436	88,832	9,325	11,345	0	0	3,355	3,489	4,775	5,165	0	0	0	9,469	135,755	433,474
2010	61,628	30,518	92,146	9,325	11,345	0	0	3,355	3,489	4,775	5,165	0	0	0	9,469	139,069	455,860
2011	70,529	34,018	104,548	9,325	11,345	16,794	0	3,355	3,489	4,775	5,165	0	0	0	16,291	175,085	481,325
2012	65,466	38,328	103,794	9,325	11,345	16,794	17,466	3,355	3,489	4,775	5,165	0	0	0	23,325	198,833	507,453
2013	78,035	40,093	118,128	9,325	11,345	16,794	17,466	3,355	3,489	4,775	5,165	6,284	0	0	23,325	219,451	533,507
2014	81,972	42,899	124,871	9,325	11,345	16,794	17,466	3,355	3,489	4,775	5,165	6,284	6,535	0	23,325	232,729	558,472
2015	91,750	45,484	137,233	9,325	11,345	16,794	17,466	3,355	3,489	4,775	5,165	6,284	6,535	0	23,325	245,091	582,226
																	582,226

BNPL 111
COMBINED CYCLE 1999
CT-1997 CT-1998 COAL-1999 CT-2007 CT-2008 COAL-2011 COAL-2012 CT-2015

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YEAR	PRODUCTION COST	TOTAL O&M	TOTAL FIXED	CAPITAL COSTS C.C. 1	COAL 1	COAL 2	COAL 3	C.T. 1	C.T. 2	C.T. 3	C.T. 4	C.T. 5	PEAK DEMAND	G&S LINE	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	25,876	12,362	38,237	9,395	0	0	0	0	0	0	0	0	2,180	4,397	54,289	38,177
1997	29,343	13,660	42,982	9,395	0	0	0	3,355	0	0	0	0	0	4,397	60,149	72,392
1998	30,139	14,080	44,218	9,395	0	0	0	3,355	3,489	0	0	0	0	4,397	65,454	107,598
1999	33,877	15,696	49,572	9,395	0	0	0	3,355	3,489	0	0	0	0	4,397	70,208	142,504
2000	38,297	18,318	56,615	9,395	0	0	0	3,355	3,489	0	0	0	0	4,397	72,208	174,589
2001	23,694	18,963	42,657	9,395	28,824	0	0	3,355	3,489	0	0	0	0	4,397	84,817	208,599
2002	24,198	20,372	44,562	9,395	28,824	0	0	3,355	3,489	0	0	0	0	4,397	88,122	239,819
2003	26,871	21,822	48,193	9,395	28,824	0	0	3,355	3,489	0	0	0	0	4,397	89,753	269,215
2004	27,669	22,467	49,537	9,395	28,824	0	0	3,355	3,489	0	0	0	0	4,397	91,697	296,172
2005	28,978	25,741	52,718	9,395	28,824	0	0	3,355	3,489	0	0	0	0	4,397	94,270	321,376
2006	30,722	24,775	55,497	9,395	28,824	0	0	3,355	3,489	0	0	0	0	4,397	97,967	344,824
2007	36,525	26,816	63,343	9,395	28,824	0	0	3,355	3,489	4,966	0	0	0	4,397	108,869	368,585
2008	38,698	27,787	66,486	9,395	28,824	0	0	3,355	3,489	4,966	5,165	0	0	4,397	117,989	391,852
2009	43,258	28,948	72,206	9,395	28,824	0	0	3,355	3,489	4,966	5,165	0	0	4,397	124,290	414,814
2010	45,436	30,812	76,248	9,395	28,824	0	0	3,355	3,489	4,966	5,165	0	0	4,397	127,877	436,540
2011	49,161	33,815	82,976	9,395	28,824	30,873	0	3,355	3,489	4,966	5,165	0	0	4,397	137,424	457,158
2012	29,778	38,697	68,243	9,395	28,824	30,873	32,212	3,355	3,489	4,966	5,165	0	0	4,397	183,119	481,519
2013	35,771	36,736	74,187	9,395	28,824	30,873	32,212	3,355	3,489	4,966	5,165	0	0	4,397	188,383	503,958
2014	37,840	40,471	77,551	9,395	28,824	30,873	32,212	3,355	3,489	4,966	5,165	0	0	4,397	192,427	524,598
2015	41,558	43,880	85,438	9,395	28,824	30,873	32,212	3,355	3,489	4,966	5,165	6,737	0	4,397	207,111	544,671
																544,671

EMPL 112
COMBINED CYCLE 1996
COAL-1997 CT-2000 CT-2003 CT-2007 CT-2008 COAL-2011 COAL-2012 CT-2015

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YEAR	PRODUCTION FUEL	TOTAL GAS	TOTAL PROD.	CAPITAL COSTS C.C. 1	W.S. 2	COAL 2	COAL 3	C.T. 1	C.T. 2	C.T. 3	C.T. 4	C.T. 5	PASS DEMAND	GAS LINE	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	25,974	12,363	38,337	9,325	0	0	0	0	0	0	0	0	2,160	4,397	54,219	36,131
1997	19,383	15,532	34,715	9,325	16,984	0	0	0	0	0	0	0	0	4,397	65,421	75,520
1998	20,034	15,680	35,714	9,325	16,984	0	0	0	0	0	0	0	0	4,397	66,420	111,651
1999	21,581	16,594	38,176	9,325	16,984	0	0	0	0	0	0	0	0	4,397	68,882	145,506
2000	21,852	17,654	39,506	9,325	16,984	0	0	3,774	0	0	0	0	0	4,397	74,286	178,494
2001	23,673	18,974	42,647	9,325	16,984	0	0	3,774	0	0	0	0	0	4,397	77,127	209,438
2002	24,293	18,762	43,054	9,325	16,984	0	0	3,774	0	0	0	0	0	4,397	78,444	237,875
2003	26,871	21,522	48,193	9,325	16,984	0	0	3,774	4,245	0	0	0	0	4,397	86,918	266,342
2004	27,080	22,457	49,537	9,325	16,984	0	0	3,774	4,245	0	0	0	0	4,397	88,262	292,460
2005	28,970	23,741	52,710	9,325	16,984	0	0	3,774	4,245	0	0	0	0	4,397	91,435	316,907
2006	30,732	24,775	55,507	9,325	16,984	0	0	3,774	4,245	0	0	0	0	4,397	94,232	339,670
2007	36,529	25,814	62,343	9,325	16,984	0	0	3,774	4,245	4,966	0	0	0	4,397	106,034	362,612
2008	38,599	27,707	66,306	9,325	16,984	0	0	3,774	4,245	4,966	5,165	0	0	4,397	115,154	385,520
2009	43,359	29,349	72,859	9,325	16,984	0	0	3,774	4,245	4,966	5,165	0	0	4,397	121,555	407,177
2010	45,435	30,511	75,946	9,325	16,984	0	0	3,774	4,245	4,966	5,165	0	0	4,397	124,802	427,267
2011	41,184	33,656	74,780	9,325	16,984	30,973	0	3,774	4,245	4,966	5,165	0	0	4,397	154,589	449,750
2012	29,776	38,467	68,243	9,325	16,984	30,973	32,212	3,774	4,245	4,966	5,165	0	0	4,397	180,284	473,441
2013	35,371	38,735	74,107	9,325	16,984	30,973	32,212	3,774	4,245	4,966	5,165	0	0	4,397	186,148	495,541
2014	37,899	40,471	77,551	9,325	16,984	30,973	32,212	3,774	4,245	4,966	5,165	0	0	4,397	189,592	516,979
2015	41,558	43,880	85,438	9,325	16,984	30,973	32,212	3,774	4,245	4,966	5,165	6,797	0	4,397	204,276	535,677
																535,677

IMPL 120
90 MW PPL-1998
[illegible]-1998 CT-2005 CC-2006 CT-2008 2007-2011 CC-2012 CT-2013

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YEAR	PRODUCTION FUEL	TOTAL GAS	TOTAL PROD.	CAPITAL COSTS C.C. 1	C.C. 2	C.T. 1	C.T. 2	C.T. 3	C.T. 4	C.T. 5	C.T. 6	PPL DEMAND	TRI-STATE DEMAND	GAS LINE	TRANSM. COSTS	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1986	24,884	9,273	34,157	0	0	0	0	0	0	0	0	17,859	2,018	0	2,296	55,329	37,903
1987	27,455	9,672	37,127	0	0	0	0	0	0	0	0	17,146	2,018	0	2,296	58,584	72,378
1988	29,008	10,815	39,823	0	0	3,483	0	0	0	0	0	17,232	0	0	2,296	62,300	106,492
1989	32,260	11,338	43,607	0	0	3,483	0	0	0	0	0	17,318	0	0	2,296	65,711	139,280
1990	33,459	12,454	45,943	0	0	3,483	3,774	0	0	0	0	17,405	0	0	2,296	72,907	171,655
1991	37,316	13,009	50,326	0	0	3,483	3,774	0	0	0	0	17,491	0	0	2,296	77,446	202,728
1992	38,381	13,078	51,078	0	0	3,483	3,774	0	0	0	0	17,578	0	0	2,296	79,114	231,407
1993	42,945	14,383	57,328	0	0	3,483	3,774	0	0	0	0	17,664	0	0	2,296	84,562	259,103
1994	39,221	16,871	56,093	12,762	0	3,483	3,774	0	0	0	0	17,750	0	5,536	2,296	101,700	289,197
1995	43,395	17,882	61,277	12,762	0	3,483	3,774	0	0	0	0	17,848	0	5,536	2,296	104,980	317,860
1996	44,948	18,686	63,635	12,762	0	3,483	3,774	0	0	0	0	17,933	0	5,536	2,296	109,424	344,233
1997	51,229	18,806	69,035	12,762	0	3,483	3,774	0	0	0	0	18,019	0	5,536	2,296	115,811	369,509
1998	53,808	29,282	75,868	12,762	0	3,483	3,774	5,165	0	0	0	18,115	0	5,536	2,296	125,905	394,159
1999	58,732	21,647	81,379	12,762	0	3,483	3,774	5,165	0	0	0	18,202	0	5,536	2,296	132,602	417,785
2010	62,130	22,813	84,743	12,762	0	3,483	3,774	5,165	0	0	0	18,288	0	5,536	2,296	136,053	439,586
2011	62,634	23,435	186,469	12,762	0	3,483	3,774	5,165	5,810	5,810	0	18,384	0	5,536	2,296	169,475	464,334
2012	76,905	28,260	183,145	12,762	17,466	3,483	3,774	5,165	5,810	5,810	0	18,490	0	12,589	2,296	190,775	489,403
2013	85,837	29,212	118,838	12,762	17,466	3,483	3,774	5,165	5,810	5,810	6,284	18,595	0	12,589	2,296	213,858	514,809
2014	[illegible]	[illegible]	[illegible]	12,762	17,466	3,483	3,774	5,165	5,810	5,810	6,284	18,701	0	12,589	2,296	219,485	538,243
2015	105,941	32,559	138,499	12,762	17,466	3,483	3,774	5,165	5,810	5,810	6,284	18,806	0	12,589	2,296	[illegible]	[illegible]
																	562,799

ARPL 121
50 MW PPL-1996
CT-1996 CT-2000 COAL-2004 CT-2008 2CT-2011 COAL-2012 CT-2013

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YEAR	PRODUCTION FUEL	TOTAL O&M	TOTAL PROD.	CAPITAL COSTS COAL 1	COAL 2	C.T. 1	C.T. 2	C.T.3	C.T. 4	C.T. 5	C.T. 6	PPL DEMAND	TRI-STATE DEMAND	TRANSM. COSTS	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	24,834	9,273	34,157	0	0	0	0	0	0	0	0	17,059	2,016	2,296	55,528	37,803
1997	27,455	9,872	37,127	0	0	0	0	0	0	0	0	17,148	2,016	2,296	58,586	72,276
1998	29,098	10,815	39,883	0	0	3,489	0	0	0	0	0	17,232	0	2,296	62,900	106,492
1999	32,269	11,338	43,608	0	0	3,489	0	0	0	0	0	17,318	0	2,296	66,711	139,269
2000	33,489	12,454	45,944	0	0	3,489	3,774	0	0	0	0	17,405	0	2,296	72,907	171,648
2001	37,314	13,080	50,394	0	0	3,489	3,774	0	0	0	0	17,491	0	2,296	77,444	202,726
2002	38,301	13,676	51,978	0	0	3,489	3,774	0	0	0	0	17,578	0	2,296	79,134	231,407
2003	42,553	14,803	57,356	0	0	3,489	3,774	0	0	0	0	17,664	0	2,296	84,559	259,101
2004	29,664	18,178	48,843	23,537	0	3,489	3,774	0	0	0	0	17,750	0	2,296	99,889	288,601
2005	31,221	20,240	51,462	23,537	0	3,489	3,774	0	0	0	0	17,846	0	2,296	102,410	315,982
2006	33,394	21,034	54,428	23,537	0	3,489	3,774	0	0	0	0	17,933	0	2,296	105,457	341,456
2007	37,638	20,882	58,520	23,537	0	3,489	3,774	0	0	0	0	18,019	0	2,296	109,435	365,341
2008	39,856	22,372	62,228	23,537	0	3,489	3,774	5,165	0	0	0	18,115	0	2,296	118,404	388,729
2009	44,406	23,404	67,871	23,537	0	3,489	3,774	5,165	0	0	0	18,202	0	2,296	124,333	410,881
2010	46,772	24,496	71,268	23,537	0	3,489	3,774	5,165	0	0	0	18,288	0	2,296	127,837	431,458
2011	63,612	24,122	87,534	23,537	0	3,489	3,774	5,165	5,810	5,810	0	18,384	0	2,296	155,799	454,116
2012	47,552	30,330	77,882	23,537	32,212	3,489	3,774	5,165	5,810	5,810	0	18,490	0	2,296	178,484	477,567
2013	57,872	30,583	88,455	23,537	32,212	3,489	3,774	5,165	5,810	5,810	6,284	18,595	0	2,296	195,827	500,769
2014	60,573	31,866	92,539	23,537	32,212	3,489	3,774	5,165	5,810	5,810	6,284	18,701	0	2,296	199,817	522,182
2015	58,627	33,632	102,459	23,537	32,212	3,489	3,774	5,165	5,810	5,810	6,284	18,806	0	2,296	209,642	542,501
																542,501

BKPL 122
60 MW PPL-1996
'996 CT-2002 COAL-2008 2CT-2011 COAL-2012 CT-2014

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YEAR	PRODUCTION FUEL	TOTAL GAS	TOTAL PROD.	CAPITAL COSTS COAL 1	COAL 2	C.C. 1	C.T. 1	C.T. 2	C.T. 3	C.T. 4	PPL DEMAND	TRI-STATE DEMAND	GAS LINE	TRANSM. COSTS	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	24,884	9,273	34,157	0	0	0	0	0	0	0	17,059	2,016	0	2,296	55,528	37,065
1997	27,465	9,672	37,127	0	0	0	0	0	0	0	17,146	2,018	0	2,296	58,584	72,276
1998	27,960	11,494	39,581	0	0	10,086	0	0	0	0	17,232	0	4,653	2,296	72,828	111,892
1999	29,554	12,134	41,688	0	0	10,086	0	0	0	0	17,318	0	4,653	2,296	76,041	149,267
2000	30,568	12,717	43,285	0	0	10,086	0	0	0	0	17,405	0	4,653	2,296	77,745	183,790
2001	33,479	13,685	46,963	0	0	10,086	0	0	0	0	17,491	0	4,653	2,296	81,489	218,685
2002	34,583	14,643	49,226	0	0	10,086	4,082	0	0	0	17,578	0	4,653	2,296	87,812	268,354
2003	36,166	15,622	53,688	0	0	10,086	4,082	0	0	0	17,664	0	4,653	2,296	92,489	278,639
2004	39,184	16,211	55,695	0	0	10,086	4,082	0	0	0	17,750	0	4,653	2,296	94,272	306,536
2005	43,516	17,196	60,572	0	0	10,086	4,082	0	0	0	17,846	0	4,653	2,296	99,535	333,148
2006	37,185	21,819	53,924	25,458	0	10,086	4,082	0	0	0	17,933	0	4,653	2,296	118,432	361,757
2007	35,240	21,847	58,088	25,458	0	10,086	4,082	0	0	0	18,019	0	4,653	2,296	121,484	388,271
2008	37,521	23,832	60,153	25,458	0	10,086	4,082	0	0	0	18,115	0	4,653	2,296	124,843	412,683
2009	41,181	23,812	65,072	25,458	0	10,086	4,082	0	0	0	18,202	0	4,653	2,296	129,849	436,024
2010	43,885	24,962	68,847	25,458	0	10,086	4,082	0	0	0	18,288	0	4,653	2,296	133,510	457,516
2011	53,783	25,681	79,464	25,458	0	10,086	4,082	5,810	5,810	0	18,384	0	4,653	2,296	156,843	480,211
2012	44,878	26,658	75,528	25,458	22,212	10,086	4,082	5,810	5,810	0	18,490	0	4,653	2,296	184,426	504,445
2013	52,618	30,652	83,121	25,458	22,212	10,086	4,082	5,810	5,810	0	18,595	0	4,653	2,296	191,123	527,255
2014	54,758	33,073	87,830	25,458	22,212	10,086	4,082	5,810	5,810	8,535	18,701	0	4,653	2,296	203,475	549,082
2015	61,172	35,088	96,259	25,458	22,212	10,086	4,082	5,810	5,810	8,535	18,806	0	4,653	2,296	212,008	569,830
																569,830

BRPL 123
4Q96 PPL + CT 1996
COAL-1998 CT-2002 COAL-2006 2CT-2011 COAL-2012 CT-2013

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YEAR	PRODUCTION FUEL	TOTAL O&M	TOTAL FIXED	CAPITAL COSTS B.E. 2	COAL 2	COAL 3	C.T. 1	C.T. 2	C.T. 3	C.T. 4	C.T. 5	PPL DEMAND	TRI-STATE DEMAND	TRANSM. COSTS	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	26,215	10,041	36,256	0	0	0	3,226	0	0	0	0	8,530	2,016	2,296	52,323	34,887
1997	23,497	10,520	40,017	0	0	0	3,226	0	0	0	0	8,573	2,016	2,296	56,128	68,651
1998	21,681	14,421	36,102	18,343	0	0	3,226	0	0	0	0	8,616	0	2,296	68,583	105,969
1999	23,681	15,175	38,855	18,343	0	0	3,226	0	0	0	0	8,659	0	2,296	71,180	140,953
2000	23,928	15,874	39,802	18,343	0	0	3,226	0	0	0	0	8,702	0	2,296	72,369	173,989
2001	25,935	16,703	42,638	18,343	0	0	3,226	0	0	0	0	8,746	0	2,296	75,249	203,280
2002	28,597	18,834	46,832	18,343	0	0	3,226	4,082	0	0	0	8,789	0	2,296	81,367	232,776
2003	29,275	18,963	48,238	18,343	0	0	3,226	4,082	0	0	0	8,832	0	2,296	85,017	260,621
2004	29,753	19,779	49,532	18,343	0	0	3,226	4,082	0	0	0	8,875	0	2,296	86,354	286,175
2005	31,961	20,784	52,745	18,343	0	0	3,226	4,082	0	0	0	8,923	0	2,296	89,616	310,135
2006	27,879	25,338	52,418	18,343	25,458	0	3,226	4,082	0	0	0	8,966	0	2,296	114,788	337,663
2007	29,572	25,316	54,888	18,343	25,458	0	3,226	4,082	0	0	0	9,010	0	2,296	117,303	363,485
2008	30,673	26,599	57,272	18,343	25,458	0	3,226	4,082	0	0	0	9,058	0	2,296	119,734	387,076
2009	33,618	27,834	61,450	18,343	25,458	0	3,226	4,082	0	0	0	9,101	0	2,296	123,956	409,160
2010	35,094	28,998	64,092	18,343	25,458	0	3,226	4,082	0	0	0	9,144	0	2,296	126,641	429,546
2011	45,692	29,362	75,054	18,343	25,458	0	3,226	4,082	5,810	5,810	0	9,192	0	2,296	149,271	451,256
2012	34,643	35,178	69,821	18,343	25,458	32,212	3,226	4,082	5,810	5,810	0	9,245	0	2,296	178,303	474,424
2013	40,361	35,841	76,202	18,343	25,458	32,212	3,226	4,082	5,810	5,810	6,284	9,298	0	2,296	189,021	496,866
2014	42,336	37,421	79,757	18,343	25,458	32,212	3,226	4,082	5,810	5,810	6,284	9,350	0	2,296	192,629	517,529
2015	47,256	39,434	86,689	18,343	25,458	32,212	3,226	4,082	5,810	5,810	6,284	9,403	0	2,296	199,614	536,875

536,875

EHPL 124
BASIC EFF. 1994
COAL-19 2002 COAL-2008 2C7-2011 COAL-2012 CT-2014

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YEAR	PRODUCTION FUEL	TOTAL O&M	TOTAL PROD.	CAPITAL COSTS B.S. 2	COAL 2	COAL 3	C.T. 1	C.T. 2	C.T. 3	C.T. 4	FPL DEMAND	TRI-STATE DEMAND	TRANSM. COSTS	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	24,084	9,273	34,157	0	0	0	0	0	0	0	17,050	2,016	2,296	55,523	37,003
1997	23,655	9,872	37,127	0	0	0	0	0	0	0	17,146	2,016	2,296	58,584	72,276
1998	22,671	13,483	36,154	18,343	0	0	0	0	0	0	17,232	0	2,296	74,025	112,544
1999	24,044	14,150	38,194	18,343	0	0	0	0	0	0	17,318	0	2,296	76,181	148,988
2000	24,637	14,828	39,465	18,343	0	0	0	0	0	0	17,405	0	2,296	77,508	184,405
2001	26,132	15,602	41,734	18,343	0	0	0	0	0	0	17,491	0	2,296	79,864	218,458
2002	28,896	16,508	45,392	18,343	0	0	4,082	0	0	0	17,578	0	2,296	88,090	247,864
2003	29,051	17,765	46,805	18,343	0	0	4,082	0	0	0	17,664	0	2,296	89,190	276,836
2004	29,632	18,517	48,149	18,343	0	0	4,082	0	0	0	17,750	0	2,296	90,629	303,632
2005	31,323	19,458	50,781	18,343	0	0	4,082	0	0	0	17,846	0	2,296	93,349	328,850
2006	30,250	23,752	54,002	18,343	25,458	0	4,082	0	0	0	17,933	0	2,296	122,113	358,148
2007	32,448	23,631	56,080	18,343	25,458	0	4,082	0	0	0	18,019	0	2,296	124,278	385,272
2008	34,128	24,878	58,006	18,343	25,458	0	4,082	0	0	0	18,115	0	2,296	127,100	410,335
2009	36,733	25,303	62,716	18,343	25,458	0	4,082	0	0	0	18,202	0	2,296	131,096	433,692
2010	38,838	27,088	65,927	18,343	25,458	0	4,082	0	0	0	18,288	0	2,296	134,394	455,326
2011	44,024	27,342	71,966	18,343	25,458	0	4,082	5,819	5,819	0	18,384	0	2,296	152,169	477,455
2012	45,779	28,258	74,037	18,343	25,458	32,212	4,082	5,819	5,819	0	18,490	0	2,296	165,268	501,792
2013	47,461	30,648	78,110	18,343	25,458	32,212	4,082	5,819	5,819	0	18,585	0	2,296	168,718	524,156
2014	49,541	35,897	85,439	18,343	25,458	32,212	4,082	5,819	5,819	6,535	18,701	0	2,296	199,885	545,640
2015	49,804	37,853	87,657	18,343	25,458	32,212	4,082	5,819	5,819	6,535	18,806	0	2,296	205,949	565,604
															565,604

SMPL 130
2CT'S 1996
CT-1998 CT-1999 COAL-2002 CT-2007 CT-2009 CT-2011 COAL-2012 CT-2015

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YEAR	PRODUCTION ECYS	TOTAL O&M	TOTAL PROD.	CAPITAL COSTS COAL 1	COAL 2	C.T. 1	C.T. 2	C.T. 3	C.T. 4	C.T. 5	C.T. 6	C.T. 7	C.T. 8	TRI-STATE DEMAND	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	30,189	11,029	41,189	0	0	3,226	3,226	0	0	0	0	0	0	2,016	49,857	33,091
1997	34,550	11,638	46,185	0	0	3,226	3,226	0	0	0	0	0	0	2,016	54,653	65,997
1998	39,539	13,114	52,653	0	0	3,226	3,226	3,489	0	0	0	0	0	0	62,594	109,047
1999	45,517	14,406	59,922	0	0	3,226	3,226	3,489	3,629	0	0	0	0	0	73,492	136,168
2000	47,208	15,064	62,290	0	0	3,226	3,226	3,489	3,629	0	0	0	0	0	75,860	169,854
2001	53,149	15,936	69,085	0	0	3,226	3,226	3,489	3,629	0	0	0	0	0	82,655	203,017
2002	28,844	19,932	48,576	21,761	0	3,226	3,226	3,489	3,629	0	0	0	0	0	83,907	233,433
2003	32,255	20,964	53,220	21,761	0	3,226	3,226	3,489	3,629	0	0	0	0	0	86,551	262,435
2004	32,540	21,869	54,409	21,761	0	3,226	3,226	3,489	3,629	0	0	0	0	0	89,740	288,991
2005	35,738	22,999	58,735	21,761	0	3,226	3,226	3,489	3,629	0	0	0	0	0	94,066	314,140
2006	37,281	24,005	61,286	21,761	0	3,226	3,226	3,489	3,629	0	0	0	0	0	96,617	337,460
2007	46,570	24,602	71,172	21,761	0	3,226	3,226	3,489	3,629	4,966	0	0	0	0	111,469	361,808
2008	48,575	25,670	74,245	21,761	0	3,226	3,226	3,489	3,629	4,966	0	0	0	0	114,542	384,395
2009	54,678	27,820	82,498	21,761	0	3,226	3,226	3,489	3,629	4,966	5,372	0	0	0	126,167	407,230
2010	56,430	28,986	85,416	21,761	0	3,226	3,226	3,489	3,629	4,966	5,372	0	0	0	131,085	428,331
2011	83,349	28,623	111,972	21,761	0	3,226	3,226	3,489	3,629	4,966	5,372	5,810	0	0	193,451	452,104
2012	54,731	34,621	89,352	21,761	32,212	3,226	3,226	3,489	3,629	4,966	5,372	5,810	0	0	173,043	474,843
2013	71,565	34,198	105,763	21,761	32,212	3,226	3,226	3,489	3,629	4,966	5,372	5,810	0	0	189,454	497,336
2014	76,923	35,709	110,632	21,761	32,212	3,226	3,226	3,489	3,629	4,966	5,372	5,810	0	0	194,323	518,181
2015	86,522	38,617	125,138	21,761	32,212	3,226	3,226	3,489	3,629	4,966	5,372	5,810	6,797	0	215,626	539,079
																539,079

BHPL 131
2CY'S 1998
O . COAL-2002 CT-2007 CT-2010 COAL-2012 CT-2013

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YEAR	PRODUCTION FUEL	TOTAL O&M	TOTAL PROD.	CAPITAL COSTS B.S. 2	COAL 2	COAL 3	C.T. 1	C.T. 2	C.T.3	C.T. 4	C.T. 5	TRI-STATE DEMAND	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	30,169	11,026	41,189	0	0	0	3,226	3,226	0	0	0	2,916	49,557	33,991
1997	31,550	11,634	46,185	0	0	0	3,226	3,226	0	0	0	2,918	54,853	65,997
1998	23,429	15,461	37,890	18,343	0	0	3,226	3,226	0	0	0	0	62,885	100,096
1999	24,659	16,276	41,165	18,343	0	0	3,226	3,226	0	0	0	0	65,960	132,185
2000	25,650	17,031	42,481	18,343	0	0	3,226	3,226	0	0	0	0	67,276	162,368
2001	28,265	17,927	46,172	18,343	0	0	3,226	3,226	0	0	0	0	70,967	190,833
2002	29,052	21,738	41,791	18,343	21,761	0	3,226	3,226	0	0	0	0	88,347	222,859
2003	21,226	22,908	44,133	18,343	21,761	0	3,226	3,226	0	0	0	0	90,689	252,582
2004	21,513	23,686	45,199	18,343	21,761	0	3,226	3,226	0	0	0	0	91,755	279,773
2005	24,388	25,162	49,550	18,343	21,761	0	3,226	3,226	0	0	0	0	96,106	305,468
2006	25,208	26,249	51,457	18,343	21,761	0	3,226	3,226	0	0	0	0	98,013	329,144
2007	28,649	27,643	55,862	18,343	21,761	0	3,226	3,226	4,966	0	0	0	107,214	352,544
2008	29,418	28,220	57,639	18,343	21,761	0	3,226	3,226	4,966	0	0	0	108,161	374,070
2009	32,814	29,709	62,523	18,343	21,761	0	3,226	3,226	4,966	0	0	0	114,145	394,687
2010	33,478	31,787	65,316	18,343	21,761	0	3,226	3,226	4,966	5,536	0	0	122,456	414,124
2011	68,975	69,646	81,505	18,343	21,761	0	3,226	3,226	4,966	5,536	0	0	138,673	434,292
2012	32,507	36,343	68,849	18,343	21,761	32,212	3,226	3,226	4,966	5,536	0	0	156,269	455,985
2013	40,884	37,077	77,962	18,343	21,761	32,212	3,226	3,226	4,966	5,536	6,284	0	173,586	475,836
2014	42,682	38,711	81,603	18,343	21,761	32,212	3,226	3,226	4,966	5,536	6,284	0	177,287	494,765
2015	45,186	40,813	85,993	18,343	21,761	32,212	3,226	3,226	4,966	5,536	6,284	0	185,537	512,693

512,693

BEPL 132
ICT'S 1996
COAL-98 CT-2001 COAL-2005 CT-2010 CT-2011 COAL-2012 CT-2013

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YEAR	PRODUCTION FUEL	TOTAL O&M	TOTAL PROD.	CAPITAL COSTS S.S. 2	COAL 2	COAL 3	C.T. 1	C.T. 2	C.T.3	C.T. 4	C.T. 5	C.T. 6	TRI-STATE DEMAND	ANNUAL COST	1993 CUMULATIVE PRESENT WORTH COST
	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
1996	30,189	11,020	41,189	0	0	0	3,226	3,226	0	0	0	0	2,016	49,657	33,091
1997	34,550	11,636	46,185	0	0	0	3,226	3,226	0	0	0	0	2,016	54,653	65,997
1998	22,426	15,461	37,886	18,343	0	0	3,226	3,226	0	0	0	0	0	62,685	100,896
1999	24,830	16,275	41,105	18,343	0	0	3,226	3,226	0	0	0	0	0	65,900	132,485
2000	25,450	17,031	42,481	18,343	0	0	3,226	3,226	0	0	0	0	0	67,276	162,368
2001	28,253	16,519	45,772	18,343	0	0	3,226	3,226	3,925	0	0	0	0	75,492	192,649
2002	28,622	19,318	47,939	18,343	0	0	3,226	3,226	3,925	0	0	0	0	76,659	220,438
2003	32,244	20,330	52,574	18,343	0	0	3,226	3,226	3,925	0	0	0	0	81,294	247,063
2004	32,479	21,197	53,677	18,343	0	0	3,226	3,226	3,925	0	0	0	0	82,397	271,446
2005	24,395	25,848	50,243	18,343	26,479	0	3,226	3,226	3,925	0	0	0	0	103,442	299,102
2006	25,232	26,962	52,194	18,343	26,479	0	3,226	3,226	3,925	0	0	0	0	105,393	324,561
2007	28,649	27,043	55,692	18,343	26,479	0	3,226	3,226	3,925	0	0	0	0	108,891	348,327
2008	29,418	28,220	57,638	18,343	24,479	0	3,226	3,226	3,925	0	0	0	0	110,837	370,184
2009	32,914	29,709	62,623	18,343	24,479	0	3,226	3,226	3,925	0	0	0	0	115,822	390,819
2010	33,579	31,797	65,376	18,343	24,479	0	3,226	3,226	3,925	5,586	0	0	0	124,181	410,806
2011	50,993	31,656	82,649	18,343	24,479	0	3,226	3,226	3,925	5,586	5,810	0	0	147,044	432,192
2012	32,589	37,242	69,831	18,343	24,479	32,212	3,226	3,226	3,925	5,586	5,810	0	0	166,638	454,090
2013	40,895	38,015	78,911	18,343	24,479	32,212	3,226	3,226	3,925	5,586	5,810	6,284	0	182,002	475,698
2014	42,878	39,686	82,564	18,343	24,479	32,212	3,226	3,226	3,925	5,586	5,810	6,284	0	186,655	495,613
2015	49,168	41,831	91,000	18,343	24,479	32,212	3,226	3,226	3,925	5,586	5,810	6,284	0	194,091	514,424
															514,424

Appendix B

Coal Price Forecasts

BV-FUEL3

FUEL COST PROJECTIONS BY PLANT WITHOUT THE ADDITION OF NSS #2
(in thousands)
SEPTEMBER 1, 1992

TOTAL FUEL COST PER M-BTU	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
BEN FRENCH	1.0355	1.0585	1.1272	1.1677	1.2875	1.3590	1.3512	1.3970	1.3859	1.4270	1.4352	1.4928
NEIL SIMPSON	0.5866	0.6863	0.7306	0.7525	0.7618	0.8129	0.7823	0.8060	0.7710	0.7870	0.7696	0.8006
KIRK	0.9839	1.0895	1.1304	1.1725	1.1941	1.2618	1.2498	1.2914	1.2757	1.3130	1.3166	1.3695
OSAGE	0.8029	0.8562	0.9361	0.9729	0.9866	1.0460	1.0251	1.0581	1.0331	1.0604	1.0539	1.0963
WYODAK I	0.5952	0.6096	0.6390	0.6741	0.6631	0.7230	0.6757	0.7089	0.6551	0.6826	0.6451	0.6878

TOTAL FUEL COST PER M-BTU	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.4923	1.5663	1.6724	1.6317	1.6877	1.7317	1.7617	1.8409	1.8750	1.9589	1.9788	2.0728
NEIL SIMPSON	0.7724	0.8068	0.7938	0.8219	0.8156	0.8559	0.8509	0.8936	0.8898	0.9353	0.9132	0.9546
KIRK	1.3640	1.4219	1.4337	1.4874	1.5077	1.5757	1.5984	1.6722	1.6995	1.7774	1.7889	1.8754
OSAGE	1.0796	1.1264	1.1264	1.1678	1.1753	1.2301	1.2399	1.2983	1.3107	1.3730	1.3084	1.4381
WYODAK I	0.6377	0.6657	0.6504	0.6936	0.6829	0.7196	0.6883	0.7489	0.7158	0.7816	0.7269	0.8014

TOTAL FUEL COST PER M-BTU	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
BEN FRENCH	2.1215	2.2238	2.2771	2.3872	2.4455	2.5639	2.6278	2.7552	2.8249	2.9622
NEIL SIMPSON	0.9690	1.0252	1.0305	1.0907	1.0972	1.1617	1.1694	1.2385	1.2476	1.3217
KIRK	1.9162	2.0103	2.0551	2.1562	2.2053	2.3141	2.3680	2.4850	2.5439	2.6699
OSAGE	1.4613	1.5372	1.5531	1.6446	1.6782	1.7607	1.7924	1.8864	1.9214	2.0225
WYODAK I	0.7728	0.8518	0.8217	0.9065	0.8748	0.9661	0.9325	1.0308	0.9953	1.1011

BHPL-100

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	0.9012	0.9456	0.9842	1.0365	1.0830	1.1357	1.1901	1.2374	1.2858	1.2775
NEIL SIMPSON #1	0.7368	0.7835	0.7912	0.8200	0.8499	0.8811	0.9135	0.9468	0.9967	1.0116
KIRK #4	0.7956	0.8211	0.8466	0.8910	0.9253	0.9643	1.0057	1.0523	1.0924	1.1095
OSAGE #1	0.7819	0.8220	0.8538	0.8966	0.9353	0.9798	1.0199	1.0461	1.1068	1.1048
OSAGE #2	0.7803	0.8213	0.8523	0.8981	0.9346	0.9791	1.0187	1.0654	1.1076	1.1072
OSAGE #3	0.7824	0.8077	0.8396	0.8847	0.9228	0.9661	1.0061	1.0519	1.0943	1.0909
WYODAK I	0.6556	0.6790	0.7034	0.7287	0.7549	0.7823	0.8108	0.8397	0.7856	0.8971
NEIL SIMPSON #2 - 1996	0.6042	0.6466	0.6356	0.5186	0.3751	0.3391	0.2332	0.2316	0.1734	0.0000
NEIL SIMPSON #3 - 2002							0.3700	0.3855	0.3829	0.8317
NEIL SIMPSON #4 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3278	1.3824	1.4472	1.5196	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1064	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0966									
OSAGE #1	1.1763	1.2363	1.2766	1.3558	1.3701					
OSAGE #2	1.1654	1.2343	1.2715	1.3560	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK I	0.9241	0.9518	0.9803	1.0098	1.0400	1.0712	1.1034	1.1364	1.1706	1.2057
NEIL SIMPSON #2 - 1996	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 2002	0.8691	0.7201	0.8184	0.8520	0.8218	1.0018	0.7810	0.8092	0.8586	0.9179
NEIL SIMPSON #4 - 2012							0.7810	0.8092	0.8586	0.9179

EMPL-101

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	0.9012	0.9469	0.9842	1.0368	1.0800	1.1357	1.1801	1.2374	1.2858	1.2775
NEIL SIMPSON #1	0.7368	0.7635	0.7912	0.8200	0.8499	0.8811	0.9135	0.9468	0.9957	1.0116
KIRK #4	0.7858	0.8211	0.8496	0.8910	0.9253	0.9663	1.0097	1.0523	1.0924	1.1095
OSAGE #1	0.7819	0.8220	0.8538	0.8956	0.9353	0.9796	1.0199	1.0661	1.1066	1.1048
OSAGE #2	0.7822	0.8213	0.8523	0.8961	0.9346	0.9791	1.0187	1.0654	1.1078	1.1072
OSAGE #3	0.7824	0.8077	0.8398	0.8847	0.9226	0.9661	1.0061	1.0519	1.0943	1.0909
WYODAK I	0.6555	0.6790	0.7054	0.7287	0.7649	0.7823	0.8108	0.8397	0.7855	0.8971
NEIL SIMPSON #2 - 1998	0.6042	0.6468	0.6356	0.6166	0.3751	0.3381	0.2332	0.2318	0.1734	0.0000
NEIL SIMPSON #3 - 1997		0.3664	0.3643	0.3650	0.3751	0.3774	0.3693	0.3754	0.3732	0.6493
NEIL SIMPSON #4 - 2002							0.3693	0.3754	0.3732	0.6493
NEIL SIMPSON #5 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3278	1.3924	1.4472	1.5196	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1388	1.1727	1.2079	1.2441			
KIRK #4	1.0869									
OSAGE #1	1.1763	1.2383	1.2768	1.3558	1.3701					
OSAGE #2	1.1654	1.2343	1.2715	1.3540	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK I	0.9241	0.9518	0.9803	1.0098	1.0400	1.0713	1.1034	1.1364	1.1706	1.2057
NEIL SIMPSON #2 - 1998	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 1997	0.5643	0.6049	0.5371	0.5734	0.4831	0.6303	0.6867	0.8163	0.7764	0.8306
NEIL SIMPSON #4 - 2002	0.5643	0.6049	0.5371	0.5734	0.4831	0.6303	0.6867	0.8163	0.7764	0.8306
NEIL SIMPSON #5 - 2012							0.6867	0.8163	0.7764	0.8306

SHPL-102

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	0.9012	0.9458	0.9842	1.0266	1.0600	1.1357	1.1801	1.2374	1.2956	1.2775
NEIL SIMPSON #1	0.7388	0.7835	0.7812	0.8200	0.8499	0.8811	0.9135	0.9468	0.9957	1.0116
KIRK #4	0.7858	0.8211	0.8485	0.8810	0.9252	0.9883	1.0057	1.0523	1.0924	1.1095
OSAGE #1	0.7819	0.8220	0.8536	0.8866	0.9353	0.9796	1.0199	1.0681	1.1086	1.1048
OSAGE #2	0.7803	0.8213	0.8523	0.8851	0.9346	0.9791	1.0187	1.0654	1.1079	1.1072
OSAGE #3	0.7824	0.8077	0.8398	0.8647	0.9228	0.9661	1.0091	1.0618	1.0943	1.0809
WYODAK I	0.6556	0.6790	0.7034	0.7387	0.7649	0.7823	0.8108	0.8397	0.7858	0.8971
NEIL SIMPSON #2 - 1996	0.6042	0.6468	0.6356	0.6168	0.3761	0.3381	0.2332	0.2318	0.1734	0.0000
NEIL SIMPSON #3 - 2002							0.3790	0.3955	0.3823	0.8317
NEIL SIMPSON #4 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3278	1.3924	1.4472	1.5195	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0969									
OSAGE #1	1.1763	1.2383	1.2766	1.3558	1.3701					
OSAGE #2	1.1654	1.2343	1.2715	1.3500	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK I	0.9241	0.9518	0.9803	1.0096	1.0400	1.0713	1.1034	1.1364	1.1706	1.2057
NEIL SIMPSON #2 - 1996	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 2002	0.6991	0.7301	0.8184	0.8620	0.8215	1.0315	0.7610	0.8092	0.8596	0.9179
NEIL SIMPSON #4 - 2012							0.7610	0.8092	0.8596	0.9179

BHPL-103

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	0.9013	0.9456	0.9842	1.0366	1.0800	1.1357	1.1801	1.2374	1.2859	1.2775
NEIL SIMPSON #1	0.7366	0.7635	0.7912	0.8200	0.8499	0.8811	0.9136	0.9466	0.9867	1.0116
KIRK #4	0.7856	0.8211	0.8406	0.8810	0.9253	0.9683	1.0057	1.0523	1.0924	1.1095
OSAGE #1	0.7819	0.8220	0.8535	0.8958	0.9352	0.9796	1.0199	1.0581	1.1026	1.1046
OSAGE #2	0.7803	0.8213	0.8523	0.8981	0.9346	0.9791	1.0187	1.0654	1.1078	1.1072
OSAGE #3	0.7824	0.8077	0.8396	0.8847	0.9228	0.9661	1.0061	1.0519	1.0943	1.0909
WYODAK I	0.6558	0.6790	0.7034	0.7287	0.7549	0.7823	0.8108	0.8397	0.7958	0.8971
NEIL SIMPSON #2 - 1996	0.6042	0.6468	0.5356	0.5166	0.5751	0.3381	0.2332	0.2316	0.1734	0.0000

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3276	1.3924	1.4472	1.5196	1.6771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0969									
OSAGE #1	1.1763	1.2383	1.2766	1.3558	1.3701					
OSAGE #2	1.1654	1.2343	1.2715	1.3550	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK I	0.9241	0.9516	0.9803	1.0098	1.0400	1.0713	1.1034	1.1364	1.1708	1.2057
NEIL SIMPSON #2 - 1996	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

BHPL-104

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN [illegible] JH	0.9012	0.9464	0.9842	1.0366	1.0800	1.1357	1.1801	1.2374	1.2868	1.2775
NEIL SIMPSON #1	0.7358	0.7835	0.7912	0.8200	0.8499	0.8811	0.9135	0.9486	0.9847	1.0118
KIRK #4	0.7856	0.8211	0.8498	0.8910	0.9253	0.9683	1.0057	1.0523	1.0924	1.1098
OSAGE #1	0.7819	0.8220	0.8538	0.8966	0.9363	0.9798	1.0189	1.0661	1.1086	1.1048
OSAGE #2	0.7803	0.8213	0.8523	0.8961	0.9346	0.9791	1.0187	1.0654	1.1078	1.1072
OSAGE #3	0.7824	0.8077	0.8368	0.8847	0.9228	0.9661	1.0061	1.0519	1.0943	1.0609
WYODAK I	0.6556	0.6790	0.7034	0.7287	0.7549	0.7823	0.8106	0.8397	0.7856	0.8971
NEIL SIMPSON #2 - 1998	0.6042	0.6468	0.6358	0.5166	0.3751	0.3381	0.2332	0.2318	0.1734	0.0000
NEIL SIMPSON #3 - 1999				0.3650	0.3781	0.3774	0.3790	0.3856	0.3823	0.8317
NEIL SIMPSON #4 - 2007										
NEIL SIMPSON #5 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3278	1.3824	1.4472	1.5196	1.5771					
NEIL SIMPSON #1	1.0418	1.0732	1.1054	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0966									
OSAGE #1	1.1753	1.2383	1.2755	1.3568	1.3701					
OSAGE #2	1.1854	1.2343	1.2715	1.3589	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK I	0.9241	0.9518	0.9803	1.0098	1.0400	1.0713	1.1034	1.1364	1.1706	1.2057
NEIL SIMPSON #2 - 1998	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 1999	0.6691	0.6049	0.5371	0.5734	0.4831	0.6303	0.6667	0.6163	0.7764	0.6306
NEIL SIMPSON #4 - 2007		0.6049	0.5371	0.5734	0.4831	0.6303	0.6667	0.6163	0.7764	0.6306
NEIL SIMPSON #5 - 2012							0.6667	0.6163	0.7764	0.6306

SHPL-106

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	0.9012	0.9458	0.9842	1.0366	1.0800	1.1357	1.1801	1.2374	1.2858	1.2775
NEIL SIMPSON #1	0.7368	0.7635	0.7912	0.8200	0.8499	0.8811	0.9135	0.9466	0.9967	1.0116
KIRK #4	0.7856	0.8211	0.8496	0.8910	0.9263	0.9683	1.0057	1.0523	1.0924	1.1095
OSAGE #1	0.7819	0.8220	0.8536	0.8966	0.9353	0.9796	1.0199	1.0661	1.1065	1.1048
OSAGE #2	0.7803	0.8213	0.8523	0.8951	0.9346	0.9791	1.0187	1.0654	1.1076	1.1072
OSAGE #3	0.7624	0.8077	0.8396	0.8847	0.9228	0.9681	1.0061	1.0519	1.0943	1.0909
WYODAK I	0.6556	0.6780	0.7034	0.7287	0.7549	0.7823	0.8108	0.8387	0.7856	0.8971
NEIL SIMPSON #2 - 1996	0.5042	0.5469	0.5356	0.5166	0.3751	0.3381	0.2332	0.2318	0.1734	0.0000
NEIL SIMPSON #3 - 1999				0.3650	0.3791	0.3774	0.3790	0.3855	0.3823	0.8317
NEIL SIMPSON #4 - 2010										
NEIL SIMPSON #5 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3278	1.3624	1.4472	1.5196	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1388	1.1727	1.2079	1.2441			
KIRK #4	1.0989									
OSAGE #1	1.1763	1.2383	1.2766	1.3558	1.3701					
OSAGE #2	1.1654	1.2343	1.2715	1.3560	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK I	0.9241	0.9518	0.9803	1.0098	1.0400	1.0713	1.1034	1.1364	1.1706	1.2057
NEIL SIMPSON #2 - 1996	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 1999	0.6891	0.7301	0.6184	0.6620	0.4831	0.6303	0.6867	0.8163	0.7784	0.8306
NEIL SIMPSON #4 - 2010					0.4831	0.6303	0.6867	0.8163	0.7784	0.8306
NEIL SIMPSON #5 - 2012							0.6867	0.8163	0.7784	0.8306

BHPL-106

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BE[illegible]ENCH	0.9012	0.9458	0.9842	1.0366	1.0800	1.1357	1.1801	1.2374	1.2858	1.3776
NEIL SIMPSON #1	0.7566	0.7835	0.7912	0.8200	0.8499	0.8811	0.9135	0.9466	0.8967	1.0116
KIRK #4	0.7856	0.8211	0.8496	0.8910	0.9253	0.9663	1.0057	1.0523	1.0924	1.1098
OSAGE #1	0.7819	0.8220	0.8538	0.8936	0.9353	0.9795	1.0199	1.0661	1.1068	1.1048
OSAGE #2	0.7803	0.8213	0.8523	0.8981	0.9346	0.9791	1.0187	1.0654	1.1078	1.1072
OSAGE #3	0.7924	0.8077	0.8396	0.8847	0.9228	0.9661	1.0061	1.0519	1.0943	1.0809
WYODAK I	0.6558	0.6790	0.7034	0.7287	0.7549	0.7823	0.8108	0.8397	0.7858	0.8971
NEIL SIMPSON #2 - 1998	0.5042	0.5468	0.5356	0.5166	0.3751	0.3381	0.2332	0.2316	0.1734	0.0000
NEIL SIMPSON #3 - 2007										
NEIL SIMPSON #4 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3278	1.3924	1.4472	1.5198	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0580									
OSAGE #1	1.1753	1.2383	1.2766	1.3558	1.3701					
OSAGE #2	1.1864	1.2243	1.2716	1.3560	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK I	0.8241	0.8518	0.8803	1.0098	1.0400	1.0713	1.1034	1.1364	1.1706	1.2057
NEIL SIMPSON #2 - 1998	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 2007		0.7361	0.8184	0.8629	0.8218	1.0018	0.7810	0.8062	0.8598	0.9179
NEIL SIMPSON #4 - 2012							0.7810	0.8062	0.8598	0.9179

SHPL-107

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	0.9012	0.9456	0.9842	1.0366	1.0800	1.1367	1.1801	1.2374	1.2858	1.2775
NEIL SIMPSON #1	0.7368	0.7635	0.7912	0.8200	0.8499	0.8811	0.9135	0.9466	0.9967	1.0116
KIRK #4	0.7868	0.8311	0.8496	0.8910	0.9253	0.9583	1.0057	1.0523	1.0924	1.1095
OSAGE #1	0.7918	0.8220	0.8538	0.8985	0.9353	0.9796	1.0199	1.0661	1.1086	1.1045
OSAGE #2	0.7903	0.8213	0.8523	0.8991	0.9348	0.9791	1.0187	1.0654	1.1078	1.1072
OSAGE #3	0.7824	0.8077	0.8398	0.8947	0.9228	0.9661	1.0061	1.0519	1.0943	1.0809
WYODAK I	0.6556	0.6790	0.7034	0.7287	0.7549	0.7823	0.8108	0.8397	0.7656	0.8971
NEIL SIMPSON #2 - 1996	0.6042	0.6466	0.6356	0.6166	0.3761	0.3381	0.2332	0.2316	0.1734	0.0000
NEIL SIMPSON #3 - 2005										0.9344
NEIL SIMPSON #4 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3278	1.3824	1.4472	1.5196	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0969									
OSAGE #1	1.1763	1.2393	1.2766	1.3358	1.3701					
OSAGE #2	1.1654	1.2343	1.2715	1.3560	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK I	0.9241	0.9518	0.9803	1.0096	1.0400	1.0713	1.1034	1.1364	1.1706	1.2057
NEIL SIMPSON #2 - 1996	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 2005	0.8919	0.7325	0.6208	0.6543	0.6241	1.0036	0.7622	0.9103	0.8606	0.9189
NEIL SIMPSON #4 - 2012							0.7622	0.9103	0.8606	0.9189

BKPL-111

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	1.2575	1.3580	1.3512	1.3970	1.3859	1.1357	1.1601	1.2374	1.2850	1.2775
NEIL SIMPSON #1	0.7518	0.8129	0.7923	0.8060	0.7710	0.8611	0.9135	0.9466	0.8967	1.0116
KIRK #4	1.1941	1.2818	1.2498	1.2914	1.2767	0.9683	1.0057	1.0523	1.0924	1.1095
OSAGE #1	0.9868	1.0460	1.0251	1.0581	1.0331	0.9796	1.0199	1.0661	1.1066	1.1048
OSAGE #2	0.9868	1.0460	1.0251	1.0581	1.0331	0.9791	1.0187	1.0654	1.1078	1.1072
OSAGE #3	0.9868	1.0460	1.0251	1.0581	1.0331	0.9881	1.0081	1.0518	1.0943	1.0809
WYODAK1	0.6631	0.7230	0.6757	0.7060	0.6551	0.7823	0.8108	0.8397	0.7856	0.8971
NEIL SIMPSON #2 - 2001						0.3381	0.2332	0.2318	0.1734	0.0000
NEIL SIMPSON #3 - 2011										
NEIL SIMPSON #4 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3278	1.3924	1.4472	1.5196	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0969									
OSAGE #1	1.1763	1.2363	1.2766	1.3556	1.3701					
OSAGE #2	1.1654	1.2343	1.2715	1.3560	1.3715					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK1	0.9241	0.9518	0.9803	1.0098	1.0400	1.0713	1.1034	1.1364	1.1705	1.2057
NEIL SIMPSON #2 - 2001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 2011						1.0018	0.7810	0.9092	0.8598	0.9179
NEIL SIMPSON #4 - 2012							0.7810	0.9092	0.8598	0.9179

BHPL-112

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	1.2875	0.9458	0.9842	1.0368	1.0800	1.1357	1.1801	1.2374	1.2858	1.2775
NEIL SIMPSON #1	0.7516	0.7635	0.7912	0.8200	0.8499	0.8811	0.9135	0.9466	0.9957	1.0118
KIRK #4	1.1941	0.9211	0.9496	0.9810	0.9253	0.9583	1.0057	1.0523	1.0924	1.1095
OSAGE #1	0.9666	0.8220	0.8539	0.8988	0.9353	0.9798	1.0199	1.0661	1.1066	1.1046
OSAGE #2	0.9666	0.8213	0.8523	0.8981	0.9346	0.9791	1.0187	1.0654	1.1078	1.1072
OSAGE #3	0.9666	0.9077	0.9396	0.9847	0.9229	0.9661	1.0081	1.0519	1.0943	1.0909
WYODAK I	0.6631	0.6790	0.7034	0.7287	0.7549	0.7823	0.8108	0.8397	0.7856	0.8971
NEIL SIMPSON #2 - 1997		0.6468	0.5356	0.5166	0.3751	0.3381	0.2332	0.2316	0.1734	0.0000
NEIL SIMPSON #3 - 2011										
NEIL SIMPSON #4 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3276	1.3924	1.4472	1.5196	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0969									
OSAGE #1	1.1753	1.2383	1.2766	1.3558	1.3701					
OSAGE #2	1.1654	1.2343	1.2715	1.3560	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK I	0.9241	0.9519	0.9803	1.0098	1.0400	1.0713	1.1034	1.1364	1.1705	1.2057
NEIL SIMPSON #2 - 1997	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 2011						1.0018	0.7610	0.8092	0.8598	0.9179
NEIL SIMPSON #4 - 2012							0.7610	0.8092	0.8598	0.9179

BHPL-121

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	1.2875	1.3560	1.3512	1.3970	1.3859	1.4270	1.4352	1.4926	1.2864	1.2775
NEIL SIMPSON #1	0.7616	0.8129	0.7923	0.8060	0.7710	0.7870	0.7896	0.8005	0.8907	1.0116
KIRK #4	1.1941	1.2618	1.2485	1.2914	1.2757	1.3130	1.3166	1.3656	1.0824	1.1085
OSAGE #1	0.9666	1.0460	1.0251	1.0581	1.0331	1.0504	1.0539	1.0963	1.1068	1.1048
OSAGE #2	0.9666	1.0460	1.0251	1.0581	1.0331	1.0804	1.0539	1.0963	1.1078	1.1072
OSAGE #3	0.9666	1.0460	1.0251	1.0581	1.0331	1.0604	1.0539	1.0963	1.0943	1.0809
WYODAK 1	0.6831	0.7230	0.6757	0.7089	0.6551	0.6826	0.6451	0.6978	0.7856	0.8971
NEIL SIMPSON #2 - 2004									0.1754	0.0000
NEIL SIMPSON #3 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3278	1.3824	1.4472	1.5196	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0988									
OSAGE #1	1.1783	1.2383	1.2766	1.3566	1.3701					
OSAGE #2	1.1654	1.2343	1.2715	1.3560	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK 1	0.9241	0.9518	0.9803	1.0096	1.0400	1.0713	1.1034	1.1364	1.1705	1.2057
NEIL SIMPSON #2 - 2004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 2012							1.0843	1.3196	1.2248	1.3258

BHPL-122

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	1.2875	1.3590	1.3612	1.3970	1.3859	1.4270	1.4352	1.4928	1.4923	1.5553
NEIL SIMPSON #1	0.7818	0.8129	0.7823	0.8060	0.7710	0.7870	0.7696	0.8006	0.7724	0.8066
KIRK #4	1.1941	1.2518	1.2488	1.2914	1.2757	1.3130	1.3166	1.3696	1.3840	1.4219
OSAGE #1	0.9856	1.0460	1.0251	1.0581	1.0331	1.0604	1.0539	1.0963	1.0799	1.1264
OSAGE #2	0.9856	1.0460	1.0251	1.0581	1.0331	1.0604	1.0539	1.0963	1.0799	1.1264
OSAGE #3	0.9856	1.0460	1.0251	1.0581	1.0331	1.0604	1.0539	1.0963	1.0799	1.1264
WYODAK I	0.6831	0.7230	0.6757	0.7089	0.6551	0.6828	0.6451	0.6878	0.6377	0.6857
NEIL SIMPSON #2 - 2006										
NEIL SIMPSON #3 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3278	1.3924	1.4472	1.5196	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0969									
OSAGE #1	1.1763	1.2383	1.2756	1.3558	1.3701					
OSAGE #2	1.1654	1.2343	1.2715	1.3560	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK I	0.9241	0.9518	0.9803	1.0098	1.0400	1.0713	1.1034	1.1364	1.1706	1.2057
NEIL SIMPSON #2 - 2006	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 2012							1.0643	1.3185	1.2249	1.3255

BHPL-123

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	1.2875	1.3560	0.9842	1.0368	1.0200	1.1357	1.1501	1.2374	1.2858	1.2775
NEIL SIMPSON #1	0.7818	0.8129	0.7912	0.8200	0.8490	0.8811	0.9136	0.8468	0.8967	1.0116
KIRK #4	1.1941	1.2616	0.8496	0.8910	0.9263	0.9583	1.0057	1.0523	1.0924	1.1095
OSAGE #1	0.9866	1.0460	0.8536	0.8986	0.9353	0.9796	1.0199	1.0581	1.1058	1.1048
OSAGE #2	0.9866	1.0460	0.8523	0.8981	0.9348	0.9791	1.0187	1.0654	1.1078	1.1072
OSAGE #3	0.9868	1.0460	0.8396	0.8847	0.9228	0.9651	1.0051	1.0519	1.0943	1.0909
WYODAK I	0.6831	0.7230	0.7034	0.7287	0.7549	0.7823	0.8108	0.8397	0.7856	0.8971
NEIL SIMPSON #2 - 1998			0.5356	0.5166	0.3781	0.3361	0.2332	0.2318	0.1734	0.0000
NEIL SIMPSON #3 - 2006										
NEIL SIMPSON #4 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3276	1.3924	1.4472	1.5196	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0969									
OSAGE #1	1.1753	1.2383	1.2706	1.3558	1.3701					
OSAGE #2	1.1554	1.2343	1.2715	1.3560	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3450					
WYODAK I	0.9241	0.9518	0.9803	1.0098	1.0400	1.0713	1.1034	1.1364	1.1705	1.2057
NEIL SIMPSON #2 - 1998	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 2006	0.6891	0.7301	0.6154	0.6620	0.6218	1.0016	0.7610	0.8092	0.8596	0.9179
NEIL SIMPSON #4 - 2012							0.7610	0.8092	0.8596	0.9179

BHPL-124

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	1.2875	1.3580	0.9642	1.0366	1.0800	1.1357	1.1801	1.2374	1.2858	1.2775
NEIL SIMPSON #1	0.7618	0.8128	0.7912	0.8200	0.8498	0.8811	0.9135	0.9466	0.8987	1.0116
KIRK #4	1.1941	1.2618	0.8498	0.8910	0.9253	0.9683	1.0057	1.0523	1.0924	1.1095
OSAGE #1	0.9666	1.0460	0.8536	0.8956	0.9353	0.9795	1.0199	1.0681	1.1095	1.1046
OSAGE #2	0.9666	1.0460	0.8523	0.8981	0.9346	0.9791	1.0187	1.0664	1.1078	1.1072
OSAGE #3	0.9666	1.0460	0.8396	0.8647	0.9226	0.9661	1.0061	1.0519	1.0943	1.0909
WYODAK I	0.6631	0.7230	0.7034	0.7267	0.7649	0.7823	0.8108	0.8397	0.7856	0.8971
NEIL SIMPSON #2 - 1998			0.5358	0.5168	0.3751	0.3381	0.2332	0.2316	0.1734	0.0000
NEIL SIMPSON #3 - 2006										
NEIL SIMPSON #4 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3278	1.3824	1.4472	1.5193	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0989									
OSAGE #1	1.1753	1.2383	1.2766	1.3558	1.3701					
OSAGE #2	1.1654	1.2343	1.2715	1.3560	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK I	0.9241	0.9518	0.9803	1.0098	1.0400	1.0713	1.1034	1.1364	1.1706	1.2057
NEIL SIMPSON #2 - 1998	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 2006	0.6891	0.7301	0.6184	0.6820	0.5218	1.0018	0.7610	0.8092	0.8598	0.9179
NEIL SIMPSON #4 - 2012							0.7610	0.8092	0.8598	0.9179

BHPL-130

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	1.2875	1.3580	1.3512	1.3970	1.3859	1.4270	1.1801	1.2374	1.2858	1.2775
NEIL SIMPSON #1	0.7516	0.8129	0.7823	0.8060	0.7710	0.7970	0.9135	0.9466	0.8367	1.0116
KIRK #4	1.1941	1.2318	1.2486	1.2914	1.2757	1.3130	1.0057	1.0523	1.0924	1.1095
OSAGE #1	0.9555	1.0450	1.0251	1.0581	1.0331	1.0604	1.0199	1.0581	1.1048	1.1045
OSAGE #2	0.9555	1.0450	1.0251	1.0581	1.0331	1.0604	1.0167	1.0554	1.1078	1.1072
OSAGE #3	0.9555	1.0450	1.0251	1.0581	1.0331	1.0604	1.0051	1.0519	1.0943	1.0909
WYODAK I	0.6631	0.7230	0.6767	0.7089	0.6551	0.6828	0.8108	0.8397	0.7856	0.8971
NEIL SIMPSON #2 - 2002							0.2332	0.2318	0.1734	0.0000
NEIL SIMPSON #3 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3278	1.3924	1.4472	1.5196	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0969									
OSAGE #1	1.1783	1.2383	1.2706	1.3558	1.3701					
OSAGE #2	1.1654	1.2343	1.2715	1.3560	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3450					
WYODAK I	0.9241	0.9518	0.9803	1.0098	1.0400	1.0713	1.1034	1.1364	1.1705	1.2057
NEIL SIMPSON #2 - 2002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 2012							1.0343	1.0655	1.2249	1.3255

BHPC-131

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BEN FRENCH	1.2976	1.3590	0.9842	1.0366	1.0800	1.1357	1.1801	1.2374	1.2856	1.2775
NEIL SIMPSON #1	0.7618	0.8129	0.7912	0.8200	0.8499	0.8811	0.9135	0.9466	0.8967	1.0116
KIRK #4	1.1941	1.2618	0.8496	0.8910	0.9253	0.9683	1.0057	1.0523	1.0924	1.1095
OSAGE #1	0.9368	1.0460	0.8538	0.8966	0.9353	0.9796	1.0199	1.0661	1.1086	1.1048
OSAGE #2	0.9368	1.0460	0.8523	0.8961	0.9346	0.9791	1.0187	1.0654	1.1078	1.1072
OSAGE #3	0.9368	1.0460	0.8526	0.8947	0.9226	0.9661	1.0061	1.0519	1.0943	1.0509
WYODAK I	0.6831	0.7230	0.7034	0.7287	0.7549	0.7823	0.8108	0.8397	0.7856	0.8971
NEIL SIMPSON #2 - 1998			0.5356	0.5165	0.3761	0.3361	0.2932	0.2318	0.1734	0.0000
NEIL SIMPSON #3 - 2002							0.3790	0.3358	0.3523	0.8317
NEIL SIMPSON #4 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3276	1.3924	1.4472	1.5196	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1388	1.1727	1.2079	1.2441			
KIRK #4	1.0999									
OSAGE #1	1.1753	1.2383	1.2766	1.3556	1.3701					
OSAGE #2	1.1654	1.2343	1.2715	1.3560	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK I	0.9241	0.9518	0.9803	1.0098	1.0400	1.0713	1.1034	1.1364	1.1706	1.2057
NEIL SIMPSON #2 - 1998	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 2002	0.5891	0.7301	0.6184	0.6520	0.5218	1.0016	0.7610	0.9092	0.8596	0.9179
NEIL SIMPSON #4 - 2012							0.7610	0.9092	0.8596	0.9179

BHPL-132

TOTAL FUEL COST PER M-BTU	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
[illegible] FRENCH	1.2375	1.3590	0.9842	1.0356	1.0900	1.1357	1.1801	1.2374	1.2858	1.2775
NEIL SIMPSON #1	0.7618	0.8129	0.7912	0.8200	0.8499	0.8811	0.9135	0.9466	0.8967	1.0116
KIRK #4	1.1941	1.2818	0.9498	0.9910	0.9253	0.9883	1.0057	1.0523	1.0924	1.1095
OSAGE #1	0.9868	1.0460	0.8538	0.8866	0.9183	0.9798	1.0199	1.0681	1.1088	1.1048
OSAGE #2	0.9868	1.0460	0.8523	0.8981	0.9346	0.9791	1.0187	1.0654	1.1078	1.1072
OSAGE #3	0.9868	1.0460	0.8396	0.8847	0.9226	0.9661	1.0061	1.0519	1.0943	1.0909
WYODAK I	0.6031	0.7230	0.7034	0.7287	0.7549	0.7823	0.8108	0.8397	0.7856	0.8971
NEIL SIMPSON #2 - 1998			0.5358	0.5166	0.3761	0.3391	0.2332	0.2319	0.1734	0.0000
NEIL SIMPSON #3 - 2005										0.6317
NEIL SIMPSON #4 - 2012										

TOTAL FUEL COST PER M-BTU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BEN FRENCH	1.3279	1.3924	1.4472	1.5196	1.5771					
NEIL SIMPSON #1	1.0419	1.0732	1.1054	1.1386	1.1727	1.2079	1.2441			
KIRK #4	1.0989									
OSAGE #1	1.1753	1.2383	1.2766	1.3558	1.3701					
OSAGE #2	1.1854	1.2343	1.2715	1.3360	1.3713					
OSAGE #3	1.1422	1.2149	1.2575	1.3300	1.3430					
WYODAK I	0.9241	0.9518	0.9803	1.0096	1.0400	1.0713	1.1034	1.1364	1.1706	1.2057
NEIL SIMPSON #2 - 1998	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NEIL SIMPSON #3 - 2005	0.8891	0.7221	0.8154	0.8520	0.8218	1.0018	0.7610	0.8082	0.8596	0.9179
NEIL SIMPSON #4 - 2012							0.7610	0.8082	0.8596	0.9179

Exhibit DMH-2 submitted with

DIRECT TESTIMONY OF DONALD M. HARDY
WYOMING PUBLIC SERVICE COMMISSION
BLACK HILLS POWER AND LIGHT COMPANY
DOCKET NO. 20003-HA-92-27

Desirable Wind Resource Data

Various types of meteorological data are needed in planning a wind facility.

The distribution of wind energy varies markedly in space and in time. Of necessity, continental scale analyses have relied on a large number of wind observations conducted to support the agricultural, aviation, and marine industries. Observations are often available at airports which are generally not located in the more wind areas. Traditional wind data are also very difficult to interpret in mountainous or hilly regions.

High wind areas with mean wind speeds around 8 to 10 meters per second within about 70m of the surface are of primary interest for large-scale wind energy conversion systems. A neutral boundary layer and power law vertical profile can therefore be assumed in most cases. However, the possibility of directional wind shear with increasing height above ground level cannot be overlooked in siting studies

because of the resulting equipment stresses, and areas of highly turbulent flow are to be avoided.

Several meteorological and environmental properties of any region are of interest in wind energy collection. These include:

1) Areas of smoothly accelerated or enhanced winds;
2) Mean hourly wind velocity distributions;
3) Characteristics of local turbulence and gusts;
4) Occurrences of extreme winds and calms;
5) Vertical profiles of the wind velocity; and
6) Frequency of severe thunderstorms, lightning, hail, icing, or tornadoes.

The spatial and temporal scales of interest to three aspects of wind energy development -- initial evaluations, site selection and assessment, and machine design and performance -- vary significantly. Initial evaluations are based largely on National Weather Service (NWS) data that can be usefully interpolated down to horizontal scales of approximately 100 km over uniform terrain and to periods as short as a week. Data for site selection and assessment are more difficult to obtain from the NWS data because the density of measurements at scales less than 100 km is relatively poor, especially in mountainous areas. Thus, mathematical models, wind tunnel models, and on-site meteorological measurements become increasingly important. Local measurements are quite

important in planning specific wind power projects. Generic data are used for many machine design and performance needs. Modern wind turbines are designed to operate successfully under various climatic conditions. Site-specific data can be used to optimize designs, and on-site data will be required for wind turbine performance evaluations at any location.

The collection of wind power at levels from 20 to 100 megawatts represents a very significant undertaking. Large arrays of turbines are required. The overall system size must be planned, turbines sited, and the array output over months and years estimated. Existing weather stations cannot provide all data that are necessary, and project specific data are needed.

State-wide maps of expected wind power potential are available from the Battelle National Laboratory. These maps were developed from the traditionally available meteorological records and a considerable amount of screening, analysis, and interpretation of the primary data records. Such results show the areas within a state which have the greatest promise. Although these maps are very helpful in general planning studies, local wind measurements are needed in planning specific wind projects.

Wind speed and direction data should be taken at the anticipated project sites. Wind data should be collected at two or three vertical levels above ground because significant

variations usually occur. Data should be collected for at least a one-year period to examine the month-to-month wind variations. Site data can be compared to multi-year airport data to estimate year-to-year variations.

Wind speed data are usually reduced to mean monthly wind speeds and to the number of hours of wind speed in uniform increments of speed, such as 1 meter per second increments. Additional important site data include:

average air density, corrected for site evaluation above sea level and mean temperature,

wind speed data adjusted vertically from 10m data level to hub-height of the wind turbine, and

wind direction information and statistics giving relative fraction of time the wind comes from different directions.

Wind turbine power output varies directly with local air density which itself can vary somewhat seasonally. Wind speeds measured at several vertical levels above ground document the variation in wind speed above ground level. Under normal conditions, wind speeds increase above ground level resulting in greater turbine power output. In some cases speeds may decrease beyond a certain level above ground, resulting in a less productive resource site. Wind direction is used to plan the deployment of multiple wind turbines. When almost all strong winds come from a well-defined direction, "rows" of wind turbines can be used generally perpendicular to the prevailing wind direction. If there is

no prevailing wind direction, the wind turbines need to be dispersed uniformly at greater distances apart.

For multi-turbine projects, several wind measurement stations are recommended within the area of the project. Wind conditions vary much more in rugged complex mountainous terrain. Very complex terrain can require much more measurement to map the variation in the wind flow over the site area. If the local terrain is only moderately variable, one wind station for every four or five wind turbines is recommended. Fewer wind measurements are possible if little variation of wind across the extremes of the project area appear to exist.

For initial project planning, a 3 to 6 month period of wind measurements at relatively few stations within the project boundaries is recommended. For more detailed project evaluation, more wind stations are needed. Wind speeds at some locations should be measured at the heights of the wind turbine lower blade tip, hub height and upper blade tip. Wind data should be collected for at least a twelve-month period. Long-term airport data can be correlated with on-site wind data to estimate the likely year-to-year wind variations at the project site.

Additional specialized data may be needed to optimize the deployment of multiple turbines in an array. Data such as the standard deviation of wind direction can be used in models to

estimate how quickly wind turbine wakes recover energy from the general air flow, and therefore how close the downwind turbine can be placed to the turbines located upwind.

Key Wind Project Planning Steps

In addition to economic assessment, designing and implementing a multi-turbine wind facility involves a number of key planning issues. The preferred wind resource areas must be identified, based upon expected energy potential and avoidance of environmentally sensitive areas (such as national parks). Transmission access must be considered as well as available transmission capacity to move wind generated electricity from the resource areas to the load centers. When sufficient land is available, all megawatts desired could be deployed in one geographic area. Several smaller wind projects aggregating to the same total number of megawatts can be equally viable. Geographically dispersed wind projects normally will reduce variability in total energy output, resulting in a more steady and consistent delivery of wind generated electricity.

Land use rights must be obtained either by purchase or lease. Wind turbines are compatible with most forms of agriculture and directly use land mainly for machine foundations and service roads. The land between widely spaced wind turbines is still available for other uses.

Permitting for wind turbine installations must be secured. Permitting requirements may vary among states and even from county to county within a single state. If clear and reasonable permitting guidelines are lacking, project development activities will be delayed.

Commercial wind turbine products are available from 10 KW to 500 KW in size. The more cost-effective products for utility applications are the larger products which range from 250 KW to 500 KW in maximum rated power. The primary technical specifications for all wind turbines include the power output versus wind speed at hub height, rotor hub height, rotor diameter, number of blades, blade pitch control, maximum rated power, start-up and shut-down wind speeds, survival wind speed, and type of generator (synchronous or induction). Expected KWH output needs to be calculated from site wind speeds and air density to compare the expected performance of one product to another.

An on-site wind measurement program needs to be planned and completed. In a few cases, land may be owned by a utility where adequate wind data were taken for other reasons. In most cases, wind data specifically designed for wind project planning will be required.

General wind facility lay-out(s) must be done. Wind data, local terrain, transmission access, and construction transportation routes are all useful or necessary for the site

plan. Civil engineering must be done for turbine foundations, service roads, and on-site maintenance buildings. Electrical engineering is needed for the high-voltage collection system which carries electricity from the individual turbines to the substation, and for the central substation itself. The normal high voltage electrical safety devices and power meters are always part of the overall wind-facility.

The utility should evaluate competitive turbine purchase terms and prices, including manufacturer warranties and performance guarantees. A budget must be developed for construction and turbine installation costs. Requirements for turbine performance acceptance testing should be established. An O&M service and training program should be planned. Finally, the preferred construction schedule must be chosen (season of the year may affect construction), appropriate construction bids must be solicited, and regulatory approval for the wind project(s) must be obtained.

Available Wind Resource Data

The Black Hills service territory includes parts of western South Dakota, eastern Wyoming, and southeastern Montana. Due to the importance of siting in wind facility economics, potential development areas both internal to and external to the Black Hills service territory were considered. Available wind resource information was reviewed for the

states of Wyoming, South Dakota, and Montana. The amount and type of wind information that exists for these states varies as described below.

The Energy Office of each state also was contacted for wind information. State-sponsored reports were obtained for South Dakota and Montana. No such report apparently exists for Wyoming.

In 1989 the Western Area Power Administration reported the results of a wind prospecting program in which data were collected at 205 sites located throughout thirteen western states. Over 140 sites recorded over one year of useful data. Nearly one hundred utility customers of WAPA participated by monitoring these selected sites.

The results of this effort illustrate both the strengths and weaknesses of such prospecting studies. Wind measurements over a very broad geographical area were examined, relative wind quality was determined, and monthly variations at each location were documented. One site in Wyoming reasonably near the Black Hills service territory was shown to have excellent wind power potential. Thirty-five sites had annual average wind speeds over 12 mph but only six sites had annual average speeds over 14 mph indicating significant wind energy potential. However, because of the particular locations of these wind measurement sites, the extensive wind resource area at Medicine Bow, Wyoming was not identified in this

prospecting study. Other studies, covering a more limited geographic area, have evaluated in detail the Medicine Bow resource as discussed below.

Two WAPA study sites in the vicinity of the Black Hills service territory illustrate the variations which occur in wind resource quality. The Mission, South Dakota site in Todd county has an annual average wind speed of 12.6 mph. This site is in South Central South Dakota. Wind speeds and available wind power at this location are much lower in the months of June through October than in the remainder of the year. Available wind power peaks during the daylight hours between 6:00 a.m. and 6:00 p.m. in all seasons, with the strongest peaks in the Spring season between 9:00 a.m. and 3:00 p.m.

The WAPA study also identified the Wheatland, Wyoming site in Platte County, which has an excellent annual average wind speed of 18.2 mph. The Wheatland site is in southeast Wyoming. Wind speeds and available wind power at this location are much greater in the Winter months. However, the wind resource is still very good during the May through October months. Available wind power peaks during the 6:00 a.m. to 6:00 p.m. period in all seasons of the year. The annual available wind power density in watts per square meter at Wheatland, Wyoming is about five times greater than that at Mission, South Dakota. Overall, the wind resource at

Wheatland, Wyoming should provide economical wind generated electricity in all months of the year, with approximately two-thirds of the annual energy produced during the six coldest months of the year. The general patterns and quality of this resource area are quite similar to those of the Medicine Bow area.

Medicine Bow

The primary wind resource area in Wyoming is in the Medicine Bow region, approximately 180 miles south of Gillette. More than ten years ago this area was chosen for study because various economic and technical considerations indicated this region to be the most suitable for large-scale wind facility development. Among these considerations are land availability, proximity to electrical transmission lines, and the distance to established railroad lines and highways which can support construction and maintenance requirements. The region is an area of relatively smooth terrain bordered at a distance by mountain ranges which funnel the air flow and enhance wind speeds. The potential developable area is very large, spanning at least 16 miles north-south and 32 miles east-west. In total, 500 to 600 square miles experience persistent strong winds. This exceptional number of square miles of quality wind resource makes the total wind power potential of Medicine Bow very large indeed.

Wind measurements were conducted in the Medicine Bow region at five primary sites during the 1980 time period. Unlike many other studies, wind data were collected from a tall tower to a height of approximately 60 meters above ground level. Such data are especially useful when considering modern commercial wind turbines which have maximum blade-tip heights of up to 60 meters. Wind data were collected at three vertical levels appropriate for the performance evaluation of large wind turbines. Wind data also were collected at five locations spanning the region. These measurements showed a very consistent pattern of wind speed variation by month, indicating a systematic resource across the area. Monthly wind speeds are lowest and are approximately the same during June, July, August, September and October. Monthly speeds are approximately 50 percent greater in February, March, April and May. Maximum monthly speeds occur in November, December and January, with December winds speeds being approximately twice as great as the lowest "summer season" winds.

Wind speed variations with height above ground level also were documented. Available data indicate a normal and favorable increase in wind speed and power density at increasing heights. Modern commercial turbines can reach to 60 meters (200 feet) AGL and benefit from the stronger winds

at higher levels above ground. Vertical variations of wind speed and power density at Medicine Bow are as follows:

Height AGL (feet)	Average Wind Speed (miles per hour)		Average Power Density (watts per square meter)	
	East Site	Central Site	East Site	Central Site
33	15.0	14.8	373	361
150	18.8	19.5	687	683
200	19.5	20.4	761	772

The East and Central sites are separated by a distance of 16 miles. These results also show that the Medicine Bow wind resource is of consistent high quality over large spatial distances.

Annual average wind speed at the 43m height AGL is 8.30 meters per second, which is excellent. This height is the typical hub height of commercial 500 KW wind turbines. Under standard conditions for air density, nominal statistical wind variations about the mean speed and no losses, a 500 KW turbine could yield at least 1,800,000 KWH per year at a site with this average wind speed. This represents a capacity factor of 41 percent. The elevation of the Medicine Bow area is approximately 6,600 feet above sea level (ASL) which reduces air density significantly. Local temperature also affects air density, and reduced air density reduces turbine output. On an annual average basis, the Medicine Bow combined elevation and temperature correction factor is 0.83. However, greater turbine output due to higher wind speeds will occur in

the winter months when the temperature density correction factor increases air density (and output) by 8 percent. Therefore the actual annual KWH may be approximately 90 percent of that which would occur under nominal sea level and air temperature conditions. Miscellaneous other energy losses may reduce annual yield by an additional 8 percent. Estimated annual production after these corrections would be at least 1,500,000 KWH per year for a 500 KW turbine which represents a net capacity factor of 34 percent. Actual performance might be better as a result of local wind statistics and optimization of the turbines to the specific local wind conditions.

Wind directions at Medicine Bow during the strong winter winds are essentially 100 percent from within plus or minus 30 degrees of due West. This significantly simplifies planning for a multi-turbine facility, and allows multiple rows of turbines to be placed perpendicular to the prevailing winds.

Hourly wind variations are determined from the primary twelve-month data record. The diurnal wind speed variations show peak winds during the middle part of the day and lowest winds in early morning. The 43m minimum wind speed was 6.6 m/s at 6:00 a.m. and the maximum wind speed ranged from 9.3 m/s to 9.9 m/s between 11:00 a.m. and 4:00 p.m.

Year-to-year variations in wind speed are estimated from the long-term data at Casper, Wyoming. Casper is about 80

miles north of Medicine Bow and is exposed to the same general conditions affecting the Medicine Bow region. Wind speed data over 28 consecutive years show an annual average of about 6.1 m/s (10m AGL) with most years averaging within plus or minus 0.5 m/s of the long-term mean. This indicates a consistent long-term pattern with relatively little variation in the resource from year-to-year.

As long ago as 1980 the federal Bureau of Reclamation (BOR) estimated the monthly output of a 100 megawatt wind facility at Medicine Bow. At that time, the power characteristics of experimental turbines larger than current commercial products were combined with wind measurements to calculate the expected monthly KWH output. The BOR defined onpeak and offpeak periods for the six-month "Winter" and

"Summer" seasons noted below and derived the following results:

Medicine Bow Region

Period	Winter	Summer
Onpeak	7 a.m. to 11 p.m.	11 a.m. to 10 p.m.
Offpeak	11 p.m. to 7 a.m.	10 p.m. to 11 a.m.

Month	Wind turbine generation (million kilowatt-hours) Monthly Total	Onpeak Total	Offpeak Total
Winter			
October	23	20	4
November	35	26	9
December	40	27	14
January	40	30	10
February	33	24	9
March	35	26	10
Subtotal	207	151	56
Summer			
April	33	18	16
May	34	20	14
June	19	13	6
July	18	13	6
August	18	14	5
September	21	13	8
Subtotal	144	90	55
Total	351	241	111

As shown in the table above, the total average annual generation is estimated at 351 million KWH per year from 100

megawatts of installed capacity. Of particular significance to the BOR was the fact that most of this wind energy output would occur during the winter onpeak periods as BOR defined these periods. The BOR concluded that this pattern of output was ideal for integration with its then-current hydropower operations. The available wind power is higher in the winter than the summer, while more water is available for hydropower in the summer than the winter. Wind speeds also reach a maximum during the middle of the day at Medicine Bow, which corresponds to the BOR's period of daily peak power demand.

The BOR also concluded that the Colorado River Storage Project (CRSP) hydrosystem can provide convenient and economical storage for the integration of wind energy from the Medicine Bow region. Advantages of the hydrosystem units are the ability to start up quickly, make rapid adjustments in power output, and operate efficiently whether used for short or long periods. The hydrosystem capability was seen as an ideal system into which the power from wind turbines can be integrated.

<u>Interaction of Wind Power with Black Hills</u>

In this section the qualitative interaction of wind power with the Black Hills utility system is discussed.

Wind power is an inherently variable resource. However, the wind resource is subject to systematic trends which can be

compared to the most likely load variations which any specific utility experiences. Wind variations follow seasonal patterns which result in month-to-month changes in available wind power. Typical daily patterns of wind power also result in a most likely profile during each 24-hour cycle. Year-to-year variations in annual wind energy are considerably less than the comparable deviations experienced in hydropower resources. Wind power, even with its natural variations, is successfully integrated into utility operations on a large scale. Its use is expected to increase greatly, not as a replacement for conventional generation, but as a useful complement within a diverse system of conventional and renewable generating resources.

Regional wind power can correlate with general utility load requirements. In California, more wind power occurs during the warmer periods of the year which also are the times of greater system loads. In the Pacific Northwest, wind power and loads are both greater during the colder periods of the year. The match between wind power and utility loads is never perfect but the favorable correspondences which can occur are valuable.

Geographic diversity of wind plants produces a more constant aggregate output. A diversity of wind plans spread over significant distances function more like a base load resource. The probability of experiencing a wind calm over

many distributed locations at the same time is lower than the probability of a calm at any one wind site. Utilities with either large service territories or access to transmission over a wide area could sponsor multiple wind facilities for these advantages.

The California experience has shown that wind power output can effectively contribute to system capacity. Annual capacity factors at good wind sites average 20 percent to 30 percent in California. Monthly capacity factors sometimes reach 40 percent to 50 percent. In addition, well designed and maintained wind facilities regularly have availabilities in excess of 95 percent. In general broad planning, roughly 30 percent of the installed wind capacity may be treated as being comparable to conventional generating capacity. This, for example, is done in current planning by PacifiCorp.

The ability of a utility to get assistance from the federal hydro system can greatly affect the manner in which the utility uses wind power. The federal hydro system can in effect "bank" wind generated electricity and deliver power when the utility needs it. The costs and specific amounts of power to be so used would be up to the utility and the federal hydro system to decide jointly.

For a "stand alone" wind project it is useful to qualitatively compare wind energy variations with the typical local curves which Black Hills experiences. In general, there

is limited wind resource data within the Black Hills service territory. Some information on wind power variations can be gained from the broad studies such as the Battelle Laboratory wind atlas and the similar South Dakota state report.

The South Dakota state report summarizes seasonal wind power as follows. Winter (December, January, February) is the season of maximum wind power on well exposed ridge crests in the Black Hills mountains. Estimated winter winds at these locations could reach Class 6 which is 300 to 400 watts per square meter (10 meter height AGL). A broad area east and north of the Black Hills mountains is estimated at Class 5 which is 250 to 300 watts per square meter. Otherwise, Spring (March, April, May) is the season of greater wind power in South Dakota. Winds of Class 5 and a limited area of Class 6 near the Black Hills are estimated in Spring. In Summer (June, July, August), wind power declines to Class 2 which is 100 to 150 watts per square meter or Class 3 (which is 150 to 200 watts per square meter) in northeastern South Dakota. In Autumn (September, October, November), estimated wind power is Class 4 (which is 200 to 250 watts per square meter) in the BHPL service territory with some Class 5 winds expected in the Black Hills mountains.

It should be noted that these wind power Class estimates for South Dakota are based on inferences made from very sparse data. These estimates of mean available wind power apply to

terrain features that are favorably exposed to the wind, such as ridge crests, hilltops, and uplands. The best documented wind resource sites are external to the BHPL service territory.

The prevailing and strongest winds are from the northwest during the winter and spring seasons of greater wind power.

Diurnal wind speed patterns, at least in the stations used for the broad area estimates, consistently show maximum wind speeds in the afternoon from noon to 5:00 p.m. Higher wind speeds occur earlier in the day during the winter season.

Typical BHPL Load Variations

Winter

The Black Hills load variations on an average day in winter show a generally sustained maximum load between the hours of 8:00 a.m. through 10:00 p.m. Loads during other hours of the day are approximately 80 percent of the maximum loads.

Winter winds in western South Dakota show a general pattern of maximum wind speeds between approximately 10:00 a.m. through 5:00 p.m. These wind variations are therefore similar to the Black Hills winter load pattern, but maximum wind speeds do not occur as early in the day or extend as late into the night hours as does the utility load.

Winds in the Medicine Bow region show a general pattern of maximum wind speeds from 11:00 a.m. through 4:00 p.m. Relatively strong winds continue at Medicine Bow until 11:00 p.m. The maximum wind speeds in this region begin later than the 8:00 a.m. high load and decrease from maximum winds speeds earlier than the 10:00 p.m. end of the maximum load. However, the Medicine Bow winds are quite strong and wind speeds from 5:00 p.m. through 11:00 p.m. exceed 8 meters per second at 40 meters AGL, which will result in very good turbine production.

Winter is the season of maximum wind speeds in South Dakota and Wyoming.

Summer

The Black Hills load variations on an average day in summer show maximum load between the hours of 11:00 a.m. through 10:00 p.m. Summer maximum load is approximately as great as winter maximum load. Wind Speed data by hour in the summer season are more difficult to obtain. However, the summer season is the period of minimum wind speeds in South Dakota and Wyoming, which makes the diurnal pattern less significant.

Overall, winds speeds by hour of the day track reasonably well with the winter load pattern of Black Hills. Available wind power in the three states of interest to Black Hills is strongly winter peaking. This seasonal pattern does not correspond to the summer peak load of the utility. Wind power

output in the winter months will correspond very well to the winter seasonal period of maximum monthly loads.

BHPL Generation Mix

The BHPL system uses a substantial amount of purchased power, generation from four coal plants, one gas turbine unit and one diesel internal combustion plant. The gas turbine and diesel units should be the most expensive sources of electricity and normally would be reduced in operations by the addition of a wind power facility. However, the 1991 operations data show that BHPL generated very little electricity from the gas turbine and diesel units, which together produced only about 6,900 megawatt-hours in 1991 according to system operational data. This compares to a system total of 1,150,000 megawatt-hours produced (or purchased). It appears that the gas turbine and diesel units are being used to a very minimal extent for the purpose of system regulation. Wind power, if added to the BHPL system, therefore likely would not change or reduce very much the KWH generated from the gas turbine and diesel units. Rather, the introduction of wind power would apparently change the amount of purchased power or coal-fired generation by BHPL.

Costs of Utility Wind Generation

The following analysis provides an estimate of the cost to Black Hills of installing and operating a wind power facility. Possible project alternatives could range from a small demonstration wind facility of a few megawatts to the combination of several wind facilities at different locations each of about 5 to 10 megawatts in size. For simplicity, it is assumed that a commercial wind facility is located in one contiguous geographic area and has a total size of 20 megawatts.

Recommended turbines for utility applications range from 250 to 500 KW in maximum rated power. Smaller turbines generally are less cost effective based upon manufacturers' price quotes. Project cost elements include the wind turbine and its tower, turbine foundations, on-site installation, shipping or transportation to the site, and on-site support facilities. Support facilities include electrical interconnection among the turbines, roads, fences, monitoring and controls, maintenance facilities, initial spare parts, and substation for grid connection. It should be noted that non-turbine costs are site-specific and will vary based upon local requirements. These estimates represent reasonable costs based upon typical conditions, but are not based on a particular wind project because no specific site is identified or proposed at this time.

Wind turbine cost is the largest component of total project cost. Several efforts are in progress to develop advanced lower-cost wind turbine systems. These turbine development programs are projected to reduce installed total project cost to approximately $800 per KW. Representative current costs for the major wind project items are as follows:

Wind Project 1993 Cost

	Per MW	20 MW
Turbine & Tower	$ 851,000	$17,020,000
Foundations	$ 68,000	$ 1,360,000
Installation	$ 17,000	$ 340,000
Transportation/Shipping	$ 26,000	$ 520,000
Support Facilities	$ 153,000	$ 3,060,000
Total	$1,115,000	$22,300,000

Operating costs can be estimated from fixed costs per KW installed and variable costs per KWH produced. Representative costs used by the Utility Wind Interest Group are $8 per KW for fixed O&M costs and 0.7 cents per KWH for the variable O&M cost. The combined O&M cost also can be reasonably estimated as 1.0 cents per KWH. This simpler method is often used for planning or screening estimates of this type. These O&M cost factors are levelized over a twenty-year period.

When considering both conventional generation as well as renewable resources such as wind, the cost of electricity (COE) using utility economic assumptions is evaluated by the National Renewable Energy Laboratory (NREL) using formulas

which incorporate data from the Electric Power Research Institute (EPRI). The basis for this COE method is described below.

In the non-utility industrial sector, an investor will look at the net present value of wind project cashflows, discounted at some required rate of return, to judge whether the project is financially viable. In the utility sector, the utility investor would examine the project's cashflows to determine what level of revenue would be required from the investment to recoup its expenses. Utilities often express this required revenue in terms of a levelized busbar cost of electricity over the project's life. The EPRI Technical Assistance Guide (TAG) outlines a standard approach to performing these calculations, and NREL used such EPRI data to determine factors used in its COE formula.

In each year, any project will cost the utility a certain amount to pay for its capital investment (debt, equity, depreciation, taxes,etc.) and to pay for operation (fuel and O&M). In determining the cost associated with the capital investment, the sum of the various percentages of initial capital investment is often called the "fixed charge rate." O&M and fuel costs, which are not a function of the initial investment cost, can escalate over the project's life but also can be levelized. The sum of the fixed carrying charges and the variable expenses determine the utilities' required

revenues. The cost of electricity (COE) is the annual levelized required revenues divided by the energy output of the wind project (or conventional generating plant).

NREL has found this simplified approach to be useful in comparing a broad range of renewable and non-renewable technologies. In the case of wind, additional assumed costs can be included. These are intended to model the cost to replace mechanical and/or electrical components of some of the wind turbines in future years. It is assumed that these replacements are in addition to cost associated with regular year-to-year O&M cost. Opinions vary as to the amount for such replacement costs, but example amounts are 5 to 10 percent of the original turbine cost, to be incurred in years 10 and 20. These amounts are reduced to a levelized cost by a Present Value Factor (PVF) and a Capital Recovery Factor (CRF) taken from the EPRI results. The NREL formula used for the wind project Levelized Replacement Cost (LRC) is the following:

LRC = PVF x (Cost in Year Incurred) x CRF

Where

Year 10 PVF = 0.558
Year 20 PVF = 0.238
CRF = 0.073

If 10 percent of the original turbine cost of $851,000 per megawatt is assumed to be spent on replacements in years 10 and 20, the LRC per megawatt becomes:

LRC = (0.558 + 0.238) x (0.073) x $85,100

LRC = $4,895 per megawatt

The NREL formula for the COE is as follows:

COE = (FCR x ICC + LRC)/Annual Energy
+ O&M Expenses

Where

FCR = 0.102

ICC = Initial Capital Cost

If the wind facility capacity factor is 30 percent, and the initial (total) capital cost is $1,115,000 per megawatt, and the O&M expenses are 1.0 cents per KWH, then the COE becomes:

COE = ($113,730 + $4,895)/2,628,000 KWH + O&M Expenses
= (11,862,500 cents)/2,628,000 KWH + O&M Expenses
COE = 5.51 cents per KWH

At a 20 percent capacity factor, the COE becomes 7.77 cents per KWH, illustrating the importance of wind site resource quality.

In summary, these COE amounts indicate the (levelized) revenues the utility needs to recover from the investment to recover all of its expenses associated with the wind facility. This NREL COE method is intended to compare the cost to a utility of various technologies when using reasonable and consistent utility economic factors. This method is not intended to calculate the value to a utility of wind generated

electricity, e.g., when measured in savings due to reduced usage of expensive marginal cost generating units. Similarly, the COE method is not intended to and does not attempt to include the value of the new federal production tax credit of 1.5 cents per KWH for wind generated electricity.

Potential for Wind Utilization

The factors favoring the utilization of wind power by Black Hills are several. The 1600 megawatts installed and three billion KWH delivered annually in America demonstrate that wind power can be successfully integrated into utility operations. Capital costs for wind power plants have fallen from $3,000 per kilowatt to just over $1,000 per kilowatt. Current trends point to a continuing decline in capital costs which will make more regions economically viable. Wind plants have low operating costs and zero fuel cost. The wind resource is non-polluting and uses no water resources. A wind plant developed by Black Hills would provide a "hedge" against the effects of a future carbon tax. Broad area wind resource screening studies indicate that wind resources in western South Dakota would be classified as good but not outstanding.

Several practical considerations argue against the utilization of wind power by Black Hills, at least in the very near term on a commercial scale. Very little wind resource data, of the type required for project planning, exist within

the Black Hills service territory. In addition, much of the Black Hills service territory consists of national parks and national grasslands. These areas are not suitable for energy projects, including multi-megawatt wind power plants. The broad-area wind resource screening studies indicate that the most exposed hilltops, ridge lines, etc. in western South Dakota have annual wind resources of Class 4 (200 to 250 watts per square meter at 10 meters AGL). Class 4 wind resources are considered good but more energetic sites are commercially used in California today.

More wind measurements will be important to actual project development. Wind speed variations above ground need to be documented. Wind speeds normally increase with height above ground level and this is very important for the energy production of modern wind turbines which reach heights of 300 feet. However, in North Dakota unusually strong night winds occur above ground level which could require special planning to avoid stresses on the wind turbines. Upper level wind measurements therefore can be important for several reasons.

The best wind sites with documentation are outside the Black Hills service territory. These sites are in Wheatland, and Medicine Bow, Wyoming and in Livingston, Montana. These are at least Class 6, ranging from 300 to 400 watts per square meter (10 meters AGL), and the Wheatland site is apparently in the top Class 7 (400 to 1,000 watts per square meter at 10

meters AGL). Wind power is much more economical with these wind resources. Black Hills also serves a small part of southeast Montana. The broad-area studies show southeast Montana has only Class 3 wind resources (150 to 200 watts per square meter at 10 meters AGL). This wind resource is not desirable for development. A very high quality Class 6 wind resource exists at Livingston, Montana. A large land area of relatively gentle terrain is quite suitable for wind project development at Livingston. However, the Livingston area is about 250 miles from the Black Hills service territory.

In summary, the potential for wind utilization by Black Hills in the near future is limited by: (1) the lack of detailed wind resource data within its service territory; (2) the large fraction of its service territory which is designated as some form of national park land; and (3) insufficient current information about the ability of Black Hills to use wind resource areas external to its service territory.

Examples of Wind Utilization

The importance of the wind resource in the economics and utilization of wind power points to the need for additional assessment of potential wind sites. Site-specific studies produce more information than just the average annual wind speed. The utility may be interested in the correspondence of

wind speeds at different locations with the utility's seasonal and daily load curves. Possible site problems could include potentially damaging turbulence, wind shear, or high winds. The effect of combining several wind resource locations may provide a pattern of energy output more useful than any one site alone, or may minimize any transmission capacity issues.

A joint wind measurement program with state or county agencies may be possible. Such programs involving government and utilities have occurred in California and New York. Such wind assessment programs, focused on the more practical areas for actual project installation, might also occur in Wyoming, South Dakota, and Montana.

Another activity which a number of utilities find worthwhile is the sponsorship of a relatively small wind demonstration facility. The scope of this activity could range from a few wind turbines or be as large as five or six megawatts using two or three competing turbine products. Demonstration facilities give the utility hands-on experience with the field performance of commercial turbines. Performance of the demonstration facility also provides data on the actual variations of wind power, which the utility can use in its operational planning.

In addition to consideration of the wind resource areas which might be used, there is a need for adequate planning to implement a wind power plant. The key planning issues are

discussed elsewhere in this testimony. Given the constraints which affect Black Hills, the utility needs to consider several actions to determine how it can most beneficially use wind power. Black Hills could: (1) evaluate priority wind areas external to its service territory which could be developed and used in its operations; (2) conduct wind measurements at promising sites within its service territory; (3) seek the assistance of the federal hydropower system in utilization and delivery of wind generated electricity; and (4) perform the key planning steps needed for wind facility development. These activities will take some time to complete but they are important to success.

Description of Cases
(Millions of $)

Case Number	NSR2	CT	CC	Coal	PP	Wind	DSM	Gas Pipe	Trans Cost	REC	QF	Total Cost M$	Comparison to Base M$	Levelized cents/kWh[1]
106	1996	1997, 1998, 2001, 2005, 2011, 2013		2007, 2012								504.4	BASE	3.83
107	1996	1997, 1998, 2001, 2010, 2011, 2013		2008, 2012								505.0	0.6	3.84
100	1996	1997, 1998, 2007, 2010, 2011, 2013		2002, 2012								507.3	2.9	3.86
133	1998	2-1996, 1997, 2001, 2005, 2011, 2013		2007, 2012								513.9	9.5	3.90
132	1998	2-1996, 2001, 2010, 2011, 2013		2005, 2012								514.4	10.0	3.91
103	1996	1997, 1998, 2007, 2010, 2011, 2013	2002, 2012					Yes				516.4	12.0	3.91
131	1998	2-1996, 2007, 2010, 2013		2002, 2012								516.7	12.3	3.93
Basin		1997, 1998, 2001, 2005, 2013		2007, 2012	80 MW 1996 Basin				Yes			521.6	17.2	3.95
105	1996	1997, 2005, 2007, 2-2013		1999, 2010, 2012								520.9	16.5	3.96
104	1996	1997, 2005, 2011, 2013		1999, 2007, 2012								526.2	21.8	4.00
102	1996	2007, 2010, 2011, 2013	1997	2002, 2012				Yes				535.1	30.7	4.08
112	1997	2000, 2003, 2007, 2008, 2015	1996	2011, 2012				Yes				535.7	31.3	4.08
123		1996, 2002, 2-2011, 2013		1998, 2006, 2012	40 MW 1996 PPL				Yes			536.9	32.5	4.08
130		2-1996, 1998, 1999, 2007, 2009, 2011, 2015		2002, 2012								539.1	34.7	4.09
121		1998, 2000, 2008, 2-2011, 2013		2004, 2012	80 MW 1996 PPL				Yes			542.5	38.1	4.12
101	1996	2007, 2010, 2011, 2013		1997, 2002, 2012								542.7	38.3	4.14

Descriptions of Cases (cont.)
(Millions of $)

Case Number	NS#2	CT	CC	Coal	PP	Wind	DSM	Gas Pipe	Trans Cost	REC	QF	Total Cost M$	Comparison to Base M$	Levelized cents/kWh[1]
111		1997, 1998, 2007, 2008, 2015	1996	2001, 2011 2012				Yes				544.7	40.3	4.14
121A		1998, 2000, 2010, 2011, 2013, 2015		2012	280 MW 1996, 2004				Yes			547.1	42.7	4.15
120		1998, 2000, 2008, 2-2011, 2013	2004, 2012		80 MW 1996 PPL			Yes	Yes			560.8	56.4	4.24
124		2002, 2-2011, 2014		1998, 2006, 2012	80 MW 1996 PPL				Yes			565.6	61.2	4.31
122		2002, 2-2011, 2014	1998	2006, 2012	80 MW 1996 PPL			Yes	Yes			569.6	65.2	4.36
110		1997, 1998, 2006, 2008, 2013, 2014	1996, 2001, 2011, 2012					Yes				582.2	77.8	4.40

Costs are expressed as present values discounted to 1995 dollars and are over the 20-year period 1996-2015

Key: NS#2 - Neil Simpson #2, CT - Combustion Turbine, CC - Combined Cycle, Coal - Coal-fired unit, REC - Renewable Energy Production Credit, QF - Qualifying Facility, PP - Power Purchase, DSM - Demand-Side Management, Gas Pipe - Gas Pipeline, Trans Cost - Transmission Line Cost, Basin - Basin Electric, PPL - PacifiCorp

[1] Costs derived by dividing annual revenue requirements by annual generation, taking the present value of the results and levelizing them

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Net Cost of Alternative Resources
Relative to Neil Simpson #2
(Millions of $)

	PPL Purchase	Combustion Turbine	Combined Cycle	Wind	Photo-voltaics	Basin Purchase
Life of Alternative (years)	30	25	35	25	25	30
Alternative Resource Capital Cost	19.95	55.96	110.67	117.29	335.05	28.20
Alternative Resource Operating Cost	289.41	119.70	183.17	52.07	18.28	265.31
Neil Simpson #2 Capital Cost	141.55	136.42	144.64	136.42	136.42	141.55
Neil Simpson #2 Operating Cost	68.43	64.67	71.19	64.67	64.67	68.43
Net System Generation Cost	-14.15	154.33	14.29	140.60	-25.38	-20.23
Net Emissions/Tax Cost	5.02	21.41	-2.85	-15.97	-19.24	-2.19
Net Cost	90.25	150.31	89.45	92.89	107.61	61.10

Costs are expressed as present values, over the operating life of the alternative resource discounted to 1996.

Description of Sensitivity Cases (Millions of $)			
Case Pair	Description	Alternative to Neil Simpson #2	Customer Savings from Installation of Neil Simpson #2
106-106A	Base case	PPL purchase and transmission costs	52.3
106-106B	Base case	CC and gas pipeline	56.1
106-106C	Base case	CT	92.1
106W-106WA	Wind and renewable energy production credit	PPL purchase and transmission costs	77.3
201-201A	Low demand	PPL purchase and transmission costs	49.0
202-202A	Low demand, low fuel prices	PPL purchase and transmission costs	45.9
203-203A	High demand	PPL purchase and transmission costs	44.6
203-203AB	High demand	PPL purchase and install additional CC, gas pipeline and transmission costs	116.9
204-204A	High demand, high fuel prices	PPL purchase and transmission costs	57.1
205-205A	Low fuel prices	PPL purchase and transmission costs	49.1
206-206A	High fuel prices	PPL purchase and transmission costs	62.1
300-300A	Wind and DSM, renewable energy production credit	PPL purchase and transmission costs	37.1
300-300G	Wind and DSM, renewable energy production credit	Delay NS#2 to 1997	4.0
300-300P	Wind and DSM, renewable energy production credit	NS#2 in 1997, CT + 20 MW photovoltaics in 1996	74.8
300-300W	Wind and DSM, renewable energy production credit	CT + 20 MW wind 1996, coal in 1999, CT-1998, 2006, 2011, 2014, coal-2008, 2012	18.2

* Costs are expressed as present values of production and incremental capital costs over 1996-2015, discounted to 1993.

Probabilistic Analysis Results
Net Present Value of Savings from Neil Simpson #2
Relative to Alternative Resource Options
(Millions of $)

	PPL Purchase	Combustion Turbine	Combined Cycle	Wind	Photo-Voltaics	Basin Purchase
Base Case	90.25	150.31	89.45	92.89	107.61	61.10
10% Fractile	13.06	96.94	41.11	49.03	52.74	10.55
50% Fractile	88.33	148.93	87.79	91.90	106.66	56.32
90% Fractile	141.02	184.77	121.99	137.01	160.57	103.87
Expected Value	81.15	143.25	85.01	94.21	107.57	52.00
Probability of Negative Net Present Value	0.8%	0.0%	0.2%	0.2%	0.0%	8.8%

Base case and fractile numbers are net present values, over the operating life of the alternative resource in millions of 1996 dollars.

ENPRO vs. POWRPRO Comparison
Production Cost Savings
(Millions of Dollars)

	Savings		Savings as a Percent of Total Production Costs	
	POWRPRO	ENPRO	POWRPRO	ENPRO
106, 106A	36.9	41.9	9.2%	11.2%
201, 201A	32.3	38.0	9.0%	11.1%
203, 203A	39.9	45.6	8.8%	10.9%
205, 205A	32.6	36.0	9.1%	10.4%

Differences are expressed in net present value of revenue requirements in 1996 dollars. Values are for production costs only.
Percentage difference calculated relative to specified Neil Simpson #2 case as base.

Black Hills Power & Light
Forecast Comparison
Energy Projections (GWh)

Year	From 1993 IRP			October 1994 Forecast		
	Low	Medium	High	Lower Bandwidth	Expected	Upper Bandwidth
1996	1,636.4	1,818.2	2,000.0	1,693.9	1,738.5	1,839.8
1997	1,682.4	1,864.2	2,046.0	1,730.0	1,773.8	1,874.9
1998	1,729.9	1,911.7	2,093.5	1,761.8	1,803.3	1,906.4
1999	1,777.9	1,959.7	2,141.5	1,790.5	1,831.6	1,934.3
2000	1,826.0	2,007.8	2,189.6	1,802.1	1,842.5	1,945.0
2001	1,874.4	2,056.2	2,238.0	1,848 .4	1,886.8	1,992.4
2002	1,923.0	2,104.8	2,286.6	1,887.1	1,924.9	2,032.1
2003	1,971.5	2,153.3	2,335.1	1,934.0	1,970.5	2,079.0
2004	2,020.0	2,201.8	2,383.6	1,981.4	2,017.3	2,127.3
2005	2,069.6	2,251.4	2,433.2	2,028.9	2,064.6	2,176.2
2006	2,120.5	2,302.3	2,484.1	2,075.9	2,200.4	2,225.3
2007	2,172.5	2,354.3	2,536.1	2,124.1	2,251.6	2,372.0
2008	2,225.9	2,407.7	2,589.5	2,173.5	2,304.0	2,426.0
2009	2,280.5	2,462.3	2,644.1	2,224.1	2,357.7	2,481.3
2010	2,336.4	2,518.2	2,700.0	2,275.9	2,412.6	2,537.8
2011	2,393.7	2,575.5	2,757.3	2,329.1	2,468.9	2,595.7
2012	2,452.3	2,634.1	2,815.9	2,383.5	2,526.5	2,654.9
2013	2,512.4	2,694.2	2,876.0	2,439.3	2,585.5	2,715.6
2014	2,573.9	2,755.7	2,937.5	2,496.5	2,645.9	2,777.6
2015	2,636.8	2,818.6	3,000.4	2,555.1	2,707.8	2,841.1

Probabilistic Results
Updated Forecast and Construction Cost

	NPV Savings ($ millions)		
	1993 Results	Updated Demand	Updated Demand and Construction Cost
Base Case	90.25	60.39	60.39
10% Fractile	13.06	7.53	16.37
50% Fractile	88.33	60.07	60.07
90% Fractile	141.02	103.77	103.77
Expected Value	81.15	59.29	59.35
Prob. of Neg. NPV	0.8%	4.0%	0.0%

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APPLICATION TO

SOUTH DAKOTA
PUBLIC UTILITIES COMMISSION

FOR AN INCREASE IN ELECTRIC RATES
DOCKET NO. EL95-003

APPLICANT'S TESTIMONY AND EXHIBITS

VOLUME 3

BLACK HILLS CORPORATION

DIRECT TESTIMONY OF LEE SMITH
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
BLACK HILLS POWER AND LIGHT COMPANY
APPLICATION FOR AN INCREASE IN ELECTRIC RATES
DOCKET NO. EL95-003

Q: Please state your name and business address.

A: My name is Lee Smith. My business address is La Capra Associates, 64 Broad Street, Boston, Massachusetts.

Q: On whose behalf do you appear in this proceeding?

A: My testimony is filed on behalf of the Black Hills Power and Light Company ("Black Hills" or "Company"), of Rapid City, South Dakota.

Q: Ms. Smith, by whom and in what capacity are you employed?

A: I am employed by La Capra Associates as Chief Economist.

Q: Please state your education, training and employment which you believe qualifies you to present this testimony.

A: I have a B.A. from Brown University and an ABD from Tufts University in Economics. Prior to my employment at LaCapra Associates, I was Director of Rates and Research at the Massachusetts Department of Public Utilities. My complete resume is attached as BHPL Exhibit LS-1.

Q: Have you testified previously, Ms. Smith?

A: Yes, I have testified on behalf of numerous gas and electric utilities and regulatory bodies in Massachusetts, Vermont, Maine, and New Hampshire.

Q: What is the purpose of your testimony in this proceeding?

A: My testimony shall describe the analysis underlying the rate designs being sponsored in this proceeding by Mr. Kyle White.

Q: Are you familiar with rate analyses and rate design?

A: Yes, I have performed rate analyses and testified in rate design in more than 20 cases in several states. La Capra Associates has developed a number of models which are used extensively in rate analyses throughout the United States.

Q: Is this case somewhat unusual, based on your experience?

A: This case is unusual in that the Company is bringing on line a major generation plant addition with a rate increase that is not inordinately high, given the number of years between rate cases. At the same time, this is a very difficult period, in terms of growing competition, for a utility to raise its rates.

Q: What are the reasons why the Company is filing a rate case at this time?

A: There are two primary reasons for this rate case. First is the completion of Neil Simpson Unit #2. This unit is discussed in detail by Tom Ohlmacher. The secondary reason is the multitude of other cost increases that have occurred since 1982 when the Company last received a base rate increase. During those 12 years, the Consumer Price Index has risen by more than 50%. The Company's rate base, except for Neil Simpson Unit #2, has nearly doubled since the last rate case.

Q: What are the standard steps performed when designing rates?

A: Before beginning particular analyses, the Company needs to identify its rate design goals. The first analytical step is determining the jurisdictional cost of service, which establishes the revenues needed from South Dakota retail customers to recover the Company's costs. Next, it is customary to perform an allocated cost of service study, which allocates the full embedded costs across rate classes. Also, a marginal cost of service study determines the marginal costs which should provide price signals to customers.

(In some jurisdictions the marginal cost of service study is also used as the basis for interclass revenue allocations.) Finally revenue targets and rate elements calculated by theoretical analyses will be modified where necessary to meet the Company's various rate design objectives.

Q: What are the Company's rate objectives?

A: The Company's main objectives in this case are to collect the revenues necessary for the continued successful operation of the Company, to maintain a reasonable degree of rate continuity, to remain a competitive energy supplier, and to have rates which encourage economic efficiency.

Q: Was an allocated cost of service study performed by you or under your direction for Black Hills?

A: Yes. Costs were first allocated among the various jurisdictions, South Dakota, Montana, Wyoming and FERC regulated customers, and then to the various rate classes in South Dakota.

Q: What are the steps entailed in allocating embedded costs?

A: Preparation of an allocated cost of service study begins with separating expenses by function (generation, transmission, distribution, and

general), and then further classifying expenses as demand, energy, or customer-related. These processes facilitate the determination of cost causation and, therefore, of appropriate cost allocators. Costs which are customer-related are allocated on the basis of the number of customers in each class, weighted appropriately. For instance, the weights for meter plant reflect the fact that larger, more complex meters used by large general service customers are many times more expensive than residential meters. Energy costs are allocated on the basis of the sales of energy, adjusted for line losses incurred at different voltage levels. Distribution costs are allocated on the basis of the measure of peak load which best describes how the Company plans its distribution plant. Generation costs will be addressed separately below. Other more general costs are allocated on the basis of "internal" allocators which reflect the more directly identified allocations.

Q: What class load information is necessary to properly allocate embedded costs?

A: First, basic customer and energy information, derived from the Company's billing determinants.

Second, information on relative line losses.

Third, actual data or estimates on customer peak loads, on class peak loads, and on class peaks at the time of the monthly system peaks.

Q: How does the analyst estimate the characteristics of class use that cannot be measured directly, such as use at the time of system peak?

A: For customers with time-of-use metering, this information is known. For all customers with demand meters, we know the maximum customer demands although we do not know what the level of their usage was at the time of the system or the class peak. We do not have actual data on the demands of most residential and some small general service customers. These information gaps are filled by the use of load research, in which time-of-use information is collected from a significant number of sample customers in each class. Load research programs are not cost effective for small companies, so Black Hills does not have its own. As a substitute we have borrowed data from the Public Service Company of Colorado. For instance, the Colorado monthly residential load factors were applied to Black Hills' regular residential sales

to estimate what that class was doing at the time of Black Hills' peak loads.

Q: Is it normal to use data from one company to estimate load characteristics of another company?

A: Yes. The basic characteristics of particular customer classes are quite similar, especially in similar climates. Borrowed load data can work quite well if the known characteristics of the ratepayers in the borrowing utility are matched to the characteristics of the borrowed data. This was confirmed when we tested the results of the borrowed load data. When all classes were summed up, we had successfully estimated Black Hills' actual monthly peak loads.

Q: Why is the allocation of generation capacity of particular interest?

A: Because so much of the Company's rate base is in generation plant, this allocation is one of the most important. Cost causation of generation capacity is also complex because this plant is not built only to meet the system's peak loads. The planner achieves the lowest total system power cost by building baseload, intermediate, and peaking plant in combination. The planner's goals are twofold: meet the system peak (in the face of

probable system outages and maintenance schedules and produce the lowest total cost of plant and energy. The challenge in allocating generation plant is to recognize the two goals of the system planner. Thus the allocator for generation capacity must reflect both peak use and total energy use.

Q: Did you consider different allocation methods for generation capacity?

A: Yes, we considered a number of allocators which reflect both peak demand and energy use. In fact, we compared results of the study using different allocators and found that class rates of return were not very sensitive to the choice of allocator. The table below compares class revenue deficiencies based upon the average and excess and the FERC-approved 12 coincident peaks allocators. We finally elected to utilize the average and excess method, which has been used in previous cases in South Dakota and for Black Hills. Utilization of the traditional allocator provides continuity with previous results.

Class	Average & Excess	12 Coin. Peaks
Residential	24%	18%
Small Gen. Serv.	7%	8%
Large Gen. Serv.	19%	25%
Industrial Contract	12%	14%
Lighting	16%	-7%

Q: What information is provided by an embedded cost of service study?

A: An embedded cost of service study sums up the allocation of costs at a particular moment in time on the basis of the characteristics that caused the Company to incur those costs. By its nature, this is an imperfect process. It does not represent the costs of serving the incremental needs of each customer class or an estimate of what a market-based price would be.

Q: What are the specific results of this embedded cost of service study?

A: First, the total Company deficiency was 15.58%. Across customer classes, both the residential and the large general service customers had higher than average deficiencies. This basic relationship among classes was observed whichever generation capacity allocator was utilized.

Q: Please briefly describe the marginal cost study which you performed for the Company.

A: We estimated the additional cost per peak load of generation and distribution capacity cost, and also the cost per unit of additional generation.

Q: Did you advise the Company to design its rates on the basis of these results, without modification?

A: No, this would be inconsistent with other rate design objectives, such as rate continuity. One reason is the addition of Neil Simpson Unit #2 to rates. The introduction of a new unit, based on standard rate base treatment, always creates a disruption in rates. Generating plant additions tend to be "lumpy." Due to imperfections in the planning process and to economies of scale, generation plant is not added in continuous small increments, but in larger chunks. The addition of a unit creates the need for what is usually a substantial increase in rates. This occurs even though over time the new plant will have a much smaller impact and may even decrease rates. Aiming at this particular rate target is likely to be inconsistent with the longer-term cost of service.

Q: What about other rate design objectives?

A: Again, a 15.58% overall increase, with larger increases to the residential and large general

service classes, will be inconsistent with the Company's goal of remaining a competitive energy service provider. This is an increasing concern in a world in which many customers have or are exploring other power options.

Q: What are the solutions to the rate design dilemmas posed by this case?

A: The first problem is the overall level of the increase. While the Company can justify this level of increase, actually implementing this increase at one time is inconsistent with the rate continuity goal and with remaining a competitive supplier. While rates have not increased with inflation, the Company believes that customers will still perceive a 15.58% increase as unreasonable. One solution would be to phase in this increase over several years. The difficulties with phase-ins are that rates must be increased several times and that the final rate will be higher because of carrying costs on the deferred costs. Another solution is for Black Hills to give up some revenues to which it is entitled in order to hold the increase to a more reasonable level. Although the Company will not collect every dollar to which it is entitled,

there may be longer-term gains as the Company remains more competitive and retains customer satisfaction.

Q: Which solution is put forward in this case?

A: The Company is offering to reduce its revenue request if other parties will settle the case and if it is allowed to make no further adjustment for future revenues anticipated from a sale of power to MDU. This provides benefits to the Company, to its ratepayers, and to all parties in the case. Customers are likely to better understand and adjust to a single increase than to three or more years of increases, and I believe that this increase is within the bounds of reasonableness. The Company and the other parties are spared the expense of a full litigated rate case.

Q: What have you advised the Company in terms of interclass revenue increases?

A: I have advised the Company to increase the revenue targets of each customer class by the same percentage. Within the different rate schedules there will be some rate increases which will vary as the Company relies upon some general rate design principles.

Q: Why is each customer class receiving the same increase when the cost of service study finds that different levels of increase could be justified?

A: There are several reasons. First, as noted above, the cost of service study results are unlikely to hold for as long a period as these rates will be in effect, since the Company historically has gone long periods in between rate cases. During the time that these rates will be in effect, the class deficiencies may change markedly. For instance, a class which currently has a 14% deficiency may only have a 12% deficiency once the new plant has been somewhat depreciated and fuel costs have changed. Second, the level of increase needed is such that imposing even larger increases on some classes is inconsistent with rate continuity. The Company hopes that the average increase will be palatable to most customers, who realize that their rates have been stable for many years. However, if rates of increase to some rate groups are out of line, those groups are likely to understand why their increases are greater than the general publicized settlement increase. Third, and most important, the Company must be cognizant of its competitive position. Strict

adherence to embedded cost rates is in conflict with a more competitive world. If the Company ignores the increasingly competitive nature of its market, both the Company and its most captive ratepayers will suffer as the less captive customers find alternative sources of energy.

Q: Why is seeking alternate sources of energy a problem in South Dakota in which the Company exclusively serves franchised territories?

A: In today's changing environment, the Company cannot reasonably file what it expects to be its only rate case in five or more years under the assumption that the world will remain the same over that period. Either the state government or perhaps even the federal government can modify the law to allow retail wheeling. Moreover, to the extent that utilities allow their rates to become noncompetitive with other power sources, there will be pressure on governments to modify the current law. Over the past decade we have seen competition change the structure of the airline, telecommunications, and gas industries. There is every reason to believe that the trend toward more competition in the electric industry has just begun. If this Commission believes that it is in

the best interest of the public that utilities such as Black Hills survive in a more competitive environment, this proposed settlement should be approved. Black Hills has developed this complete approach, which even reduces rate levels below those which could be justified, to place itself in a competitive position.

Q: Are there any other rate objectives in this case?

A: Yes. The only rate case in many years should be an opportunity to rationalize rates in a number of ways. Secondary objectives include rate simplicity, logical consistency between rate schedules, and placing more customers on long-term contracts.

Q: Why are long-term contracts a rate design goal?

A: Black Hills Power and Light Company has always stood ready to serve all demands for power in its service territory. This obligation to provide service to all who request it is a major source of risk to the Company. Black Hills must build or purchase generating units to meet expected future demands. The necessity to plan and build in an uncertain world creates some risks to the Company and in fact to its continuing ratepayers. If projected load does not materialize, the Company's

demands and earnings will be less than projected. If the earnings deficiency is significant, other ratepayers will have to pay more.

This is becoming an increasing concern in a world in which many large customers have or are exploring other power options. Black Hills believes that its ratepayers will be best protected by longer-term contracts between itself and its largest customers. Large customers are likely to have more power supply choices (in the future, if not at the present), and in addition the departure of a very few customers can leave the Company with excess capacity and stranded investment. A load loss when the alternative seller does not actually face lower costs will not be economic to society and is certainly not economic for the Company and its remaining ratepayers. Reducing the risk of significant load variation has positive benefits to the Company and its more captive ratepayers.

Q: Why are long-term contracts with industrial users especially important in this case?

A: First, the customers who will be eligible for these contracts are a very significant portion of the Company's total load. Second, the customers

who will most likely qualify for these contracts are very high load factor customers. If the Company were to lose all of its largest general service customers its energy sales could decrease by 40% and its load factor would deteriorate significantly. Remaining customers would be left paying higher rates to recover the cost of a system that was designed to include these large high load factor customers.

Q: In practice, will the Company attempt to sign long-term contracts with all of its customers?

A: No. First, movement in and out of the system of small customers is normal and it is not disruptive to the Company's planning process. However, loss of a few very large customers can create serious revenue losses and stranded investment. Also, large customers with high load factors are the customers most able to consider and perhaps find alternatives to purchasing their energy needs from the Company. Both of these characteristics make this load economical to serve and worth competing for (through offering cogeneration, searching for alternative delivery paths, supporting retail wheeling).

Q: Are utilities elsewhere attempting to acquire longer-run customer commitments?

A: Yes. Long-term contracts are consistent with sound utility planning. They mirror the contracts which are being signed between buyers and sellers in the more competitive wholesale power markets. In Massachusetts, one large electric utility offers 5% discounts to any large customer who signs a five-year or longer contract. The Federal Energy Regulatory Commission is currently considering a definition of stranded investment in which utilities will be held liable in the future for load loss when the utilities did not take positive steps to mitigate losses. Although this is not yet federal or state policy, Black Hills is establishing policy and a rate design that will guide it into the future, in which this may become policy.

Q: What other rate recommendations have you made to the Company?

A: First and foremost, I advised the Company to move their tailblock rates (which are usually the rates paid by incremental users) closer to marginal costs. This entails raising demand charges and lowering energy charges (for three-part rates).

Secondly, I advised the Company to increase most energy charges within broad rate classes by the same amount per KWH. This does not increase existing differentials between similar rate schedules. In addition, it tends to give slightly higher increases to the lower cost rate schedules (who have higher embedded deficiencies) within classes. I also advised the Company to consider closing or opening rate schedules where needed, rolling in power costs, and any other steps which will improve the overall rate design.

Q: Did you have discussions with the Company regarding the rate issues related to the sale of power to Montana-Dakota Utilities Co. ("MDU"), beginning in 1997?

A: Yes. If the Company were requesting in this case the full 15.58% increase in rates that are justified by the cost of service study, it would also expect to reflect the impact of the MDU sale upon its revenue requirements at the time the sale begins. This would require a rate treatment and also an allocation to customers of these revenues.

Q: How would the MDU sale affect the Company's base rates?

A: First, if the Company were requesting the 15.58% increase, it would be doing so on a phased-in basis. This would mean that tariffs would change several times over the next three to four years. The second year of the phase-in would be almost synonymous with the beginning of the MDU sale. Therefore, the second year base increase percentage could be larger but be partially offset by the introduction of the MDU credit.

Q: What would be entailed in reflecting these revenues in base rates?

A: Basically the revenues would have to be normalized over either the entire period of the sale or over the period in which these rates are expected to be in effect. This would require estimating both gross revenues and costs associated with the contract.

Q: Since the terms of the contract are known, wouldn't it be a relatively simple matter to estimate the future net revenues?

A: The contract revenues cannot be estimated with a high degree of accuracy, because they will be dependent upon a number of different variables. The biggest unknown is the actual amount purchased in each year and each month, which will vary with

weather and economic conditions. We also do not know the cost of future capacity purchases or energy. The net revenue impact of the MDU contract will depend upon all of these elements.

Q: If this future contract were to be reflected in base rates, how would you recommend that it be done?

A: Revenue crediting is a normal way of accounting for off-system utility sales. The MDU sale will produce revenue from plant that would otherwise be unutilized or underutilized. The contract will produce both energy and capacity revenue. The net revenue contribution to the Company includes the capacity charge plus a portion of the energy charge, since the energy rate in the contract is higher than the actual energy costs will be. With the revenue credit approach, all costs are allocated to firm customers; then the contract revenues are allocated to firm customers to reduce the Company revenue requirements.

Q: What approach would you recommend to use in allocating these revenues?

A: The contract will be possible because of the existence of Neil Simpson Unit #2 capacity. This unit was built in order to provide benefits to

firm, retail customers. That full capacity is being allocated to jurisdictional customers. The earnings from that capacity (the contract net revenues) should be allocated back to jurisdictional customers on the same basis that the plant costs were allocated to them. This could be accomplished through preparation of a 1997 cost of service study or through simply allocating normalized net MDU revenues on the basis of the average and excess allocator and revising class revenue targets by this amount.

Q: Why is the revenue credit approach normally used, as opposed to treating the off-system customer as a separate class and allocating both costs and revenues to this class?

A: Crucial to this decision are the facts that the plant which serves the customer (MDU) was not built to serve this customer, and Black Hills does not have an obligation to serve this customer beyond the length of the contract.

Q: If Neil Simpson Unit #2 was not built to serve this customer, how does the Company have enough capacity to serve the customer?

A: Utilities cannot size their generation plant exactly to meet load at all times, for several

reasons. Generation plant investment is normally "lumpy," or built in relatively large increments. For instance, even though 73 MW of capacity might be needed, it may be necessary to build 80 MW. Generation plant is built for the future, so the utility may build more than is needed this year because that quantity is needed in a few years' time. Finally, forecasting is not an exact science, so the utility may have had expectations of faster load growth than materializes. For some combination of those reasons, if system loads grow as projected, the Company has some capacity available from its resources for a few years.

Q: What will happen when the MDU load cannot be fully met from this capacity?

A: The Company will purchase inexpensive peaking power as needed to meet the MDU load. As explained below, firm retail customers will not have to pay for this power.

Q: Are you in fact recommending that the Company propose that treatment in this proceeding?

A: No. Due to the unknown nature of future net revenues, I would not recommend that the Company attempt to include them in base rates. Moreover, the Company's total strategy is essentially to use

the MDU revenues to avoid a more complex phasing in, which enables the Company to increase base rates by only 9.96% in this proceeding. Only if the Company's proposed settlement is rejected would it become necessary to consider methods of reflecting the MDU sale specifically in future rates.

Q: In the treatment proposed in this case, how will the Company ensure that firm retail ratepayers will not pay for this incremental capacity or for the incremental energy costs associated with serving MDU?

A: The Company will calculate the amount of incremental energy and capacity costs caused by serving MDU and will credit the FPPA with revenues equal to these costs. Thus firm ratepayers' rates will not be affected by the sale.

Q: How can the Company determine these incremental costs?

A: First, for marginal energy costs, the Company can simulate the dispatch of its system with and without this sale, based on actual current running conditions and costs. The difference between the two dispatch runs is the incremental energy cost resulting from the MDU load. Second, the Company

will separately determine any capacity purchases made necessary because of the sale and will book as incremental capacity revenues an amount equal to the total cost of those purchases.

Q: Does this conclude your testimony?

A: Yes, it does.

EXHIBIT
BHPL
LS-1

LEE SMITH

EDUCATION

TUFTS UNIVERSITY, Registration Ph.D., Economics
BOSTON COLLEGE, Study of Statistics
BROWN UNIVERSITY, Bachelor of Arts with Honors, International Relations and Economics

Experience

1984- LA CAPRA ASSOCIATES
Senior Economist Ms. Smith's work has encompassed all costing issues, forecasting, rate design, demand and supply planning regarding electric and gas utilities. Ms. Smith has extensive experience in testifying and negotiating.

1982-84 Department of Public Utilities; Director of Rates and Research

1981-82 Department of Public Utilities; Economist, Long-Run Planning

1978-79 REGIS COLLEGE, Lecturer in Economics

1974-77 MERRIMACK COLLEGE, Lecturer in Economics

1973-74 UNIVERSITY OF MARYLAND, Faculty Research Associate

1972-73 TUFTS UNIVERSITY, Lecturer in Economics

1967 FEDERAL RESERVE BANK of Boston, Administrative Assistant, Research Department

1965-66 FEDERAL RESERVE BANK, Research Assistant, Banking and Regional Policy

Publications:

Non-price Issues in Gas Supply Planning, NATIONAL REGULATORY RESEARCH INSTITUTE, Biennial Regulatory Research Conference, 1994

The Economic Impact of Hurricane Agnes on the Chesapeake Bay in Maryland, JOHN HOPKINS PRESS

Honors:

Bunting Institute Fellowship, 1970-71
Tufts University Economics Department Fellowship, 1967-68
Brown University International Relations Prize, 1965

Description of Selected Projects

1994 Division of Energy Resources

Advised DOER on position on changes in Integrated Resource Management, including proposal to open Transmission and Distribution access to meet resource needs.

1994 Black Hills Power and Light Company (South Dakota)

Advised Company on rate treatment and phase-in of major new generating unit, development of transmission rate, and response to retail wheeling.

1994 New Hampshire Office of the Consumer Advocate

Advised Office on retail wheeling concerns; prepared testimony on cost of service, cost allocation and marginal cost presented by an electric utility.

1994 Massachusetts Municipal Wholesale Electric Company

Testified for MMWEC on appropriate allocation of gas transition costs; assisted MMWEC in formulating response to generic docket on interruptible gas transportation; prepared comments.

1994 Town of Fort Fairfield

Prepared response of town to CMP's threat to shut down a renewable energy facility following state-financed buyout of a high-priced unit contract, resulting in settlement.

1994 Blackstone Gas Company

Formulated plan for settlement of long-term debt with Tennessee Gas Pipeline Company; gained Massachusetts DPU approval for long-term debt financing.

1993 North Attleborough Gas Company

Revised long-run econometric forecast of load, assisted Company in preparation of supply/demand forecast for DPU.

1994 Constellation Energy

Projected market price of power, advised developer on potential market.

1994 Stow Electric Energy Study Committee

Advised committee on setting up new municipal utility, based upon results of response to RFP for provision of power and operations services, negotiated with bidders.

1993 Massachusetts Department of Energy Resources;

Assisted with analysis of economic impact of retiring older generating plants to meet Clear Air Act Targets.

1993 Eastern Energy Associates

Directed analysis and computation of avoided costs of a major electric utility.

1993 Blackstone Gas Company

Issued RFP, planned gas supply, negotiated supply contracts for small gas LDC.

1993 Maine Public Utility Commission Staff

Directed Staff's case in opposition to Central Maine Power Comp.'s request that it be allow to market power at below marginal cost rates; presented testimony on impact of CMP's proposal.

1993 Essex County Gas

Advised Company on long-run planning issues; developed innovative approach to reliability planning standards; directed full Demand and Supply Forecast which has been submitted to the Massachusetts Energy Facilities Siting Board.

1993 North Attleborough Gas Company

Directed development of long-run econometric forecast of load by type of customer.

1993 Office of the People's Counsel, Washington D.C.

Advised Office, presented testimony on appropriate recovery of deferred and present costs of ongoing Least Cost Planning program, including $10 million in expenses of conservation programs.

1993	Plattsburgh Municipal Lighting Department
	Advised utility on selection of least-cost power contracts.
1993	Wakefield Municipal Light Department
	Presented testimony on gas distribution systems, transportation pricing issues in Boston Gas Company rate case.
1993	Nantucket Electric Company
	Directed development of long-run end-use load forecast for tourism-based economy.
1992	Massachusetts Municipal Wholesale Electric Company
	Analysis of and testimony on economic inefficiencies created by Bay State pricing of interruptible gas to Stony Brook generating unit.
1992	Woodsville Water and Light Department
	Advised Department on least-cost power supply and led negotiations with potential suppliers, resulting in significant long-run savings.
1992	Stow Electric Energy Study Committee
	Advised Committee on advisability of separating from municipal electric system currently serving the town; analyzed costs and benefits of different sources of supply.
1992	Boston Edison Electric Company
	Assisted in analysis of customer's demand for experimental color-corrected streetlighting, resulting in settlement of long-standing dispute.
1992	Plattsburgh Municipal Light Department
	Prepared rate case, including revenue needs, allocation of costs, and rate design; directed Company in reorganization of billing data.
1992	Colonial Gas Company
	Directed analysis of company's new pipeline transportation contract with ANE (Iroquois); tested cost-effectiveness, analyzed non-pricing contract attributes.

1992	North Attleborough Gas Company
	Presented Company rate filing, including reconciliation of actual year experience with predictions of previous settlement.
1992	Altresco
	Advised on siting, fuel costs, and bidding of potential new intermediate power project.
1992	Middleton Electric Light Department
	Renegotiation of contract for transmission of all power to the utility.
1992	Nantucket Electric Company
	Directed revision of load research sampling (determining appropriate sample size and selection)
1991	Colonial Gas Company
	Assisted in development of Conservation and Load Management Plan, including development of avoided gas supply and distribution costs.
1991	Essex County Gas
	Prepared rate designs, testified in rate case on Company's marginal costs and rates; developed long-run avoided costs, including externalities, for use in screening Demand Side Measures.
1991	Massachusetts Electric Company
	Prepared testimony for fuel switching case which analyzed marginal cost of Boston Gas Company, comparability of marginal cost estimation of electric and gas utilities.
1991	North Attleborough Gas Company
	Assisted Company in all phases of filing rate case, including testimony and settlement negotiations, development of three new rate classes, and in developing strategy for phasing in very large (over 100%) increase in rate base.
1991	Nantucket Electric Company

Applied load research data to develop detailed (daily) demand and revenue projections.

1991 Nantucket Electric Company

Assisted in rate case, including allocating costs between customer classes, developing marginal costs, designing rates.

1991 Essex County Gas Company

Assisted Company in filing rate case, including development of labor allocator and other allocations, marginal cost analysis, rate design; prepared avoided cost for use in DSM program screening.

1991 Nantucket Electric Company

Presented testimony on externalities created by emissions from electric generation on Nantucket Island, and potential impact of inclusion of externalities on ratepayers.

1991 Blackstone Gas Company

Prepared full rate case (first filed by the Company in 9 years); presented testimony, assisted in a settlement of the case with intervenors.

1990 Wakefield Municipal Light Department

Assisted gas division of WMLD with avoiding hundreds of thousands of rate increase from Boston Gas Company; presented testimony on errors in Boston Gas filing; analyzed distribution system of both utilities.

1990 Illinois Office of Public Counsel

Provided expert advice to consumer advocate group on developing state least-cost planning guidelines for gas utilities.

1990 Berkshire Gas Company

Assisted company with development of a pilot DSM program, including directing the development of the screening tools, estimating long-run avoided costs based on daily dispatch of Company proposed supply portfolio, then in screening cost-effective measures.

1990 Plattsburgh Municipal Light Department

Developed new rate for large, 46 KV service customers, directed development of value of plant serving the proposed class.

1990 Colonial Gas Company

Assisted Company in developing various analyses for rate case, including converting class sales data (which includes a billing lag) to weather-adjusted, calendar data for use in revenue normalization and rate purposes. Refined La Capra Associates cost allocation model and trained company personnel in use of model.

1990 Blackstone Gas Company

Resolved long-run undercollection of gas costs; assisted company in negotiations with its major lender, developed long-run plan to resolve inappropriate debt.

1990 Mobile Gas Service Corporation

Assisted Company in development of strategy with regard to marketing plan in which electric company made payments to customers and appliance dealers to cause customers to switch to electric heat; directed detailed analysis of marginal costs and benefits of the electric marketing program.

1989 Middleton Electric Light Department

Developed innovative cost-based rate for very large interruptible customer and negotiated with both NEPOOL and customer.

1989 Berkshire Gas Company

Assisted Company in EFSC case, performing both innovative demand and supply analyses. We demonstrated that although the Company's original filing had deficiencies, improved methodologies showed that new pipeline contract was beneficial to ratepayers.

1989 Littleton Water and Light Department

Updated Company's revenue allocation and rates to reflect new marginal-cost based wholesale power tariff.

1989	Wakefield Municipal Light Department
	Advised company regarding gas supply planning; assisted in renegotiation of contract with Boston Gas Company.
1989	Essex County Gas Company
	Assisted with all aspects of rate case filing, including revenue estimation, cost allocation, and rate design, introducing subsidized rates for low-income customers.
1989	Colonial Gas Company
	Designed rates in rate case filing; reorganized commercial and industrial rate classes.
1989	Boston Edison Company
	Assisted Company in analysis of jurisdictional cost allocations in major court dispute; developed company response to FERC order on allocation of distribution/transmission plant.
1988	Reading Municipal Light Department
	Analyzed power supply options, determined least-cost options.
1987	Essex County Gas Company
	Assisted with all aspects of rate case filing, including revenue estimation, cost allocation, and rate design. This case moved rates closer to seasonal marginal costs, and class revenues closer to allocated costs. Modified Company's existing dispatch model to produce additional results for rate case and planning purposes, developed model to estimate marginal distribution costs.
1987	Wellesley Municipal Light Plant
	Redesigned rates for municipal utility, including allocating costs, estimating marginal costs, and designing rates, including a time-of-use rate for largest customers.

1986 Colonial Gas Company

Redesigned Company rates according to allocated cost of service study, marginal cost principles.

1985 Colonial Gas Company

Developed daily gas dispatch model to simulate actual daily dispatch, calculate marginal gas costs by season, and allocate gas costs between users.

LA CAPRA ASSOCIATES

DIRECT TESTIMONY OF KYLE D. WHITE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
BLACK HILLS POWER AND LIGHT COMPANY
APPLICATION FOR AN INCREASE IN ELECTRIC RATES
DOCKET NO. EL95-003

Q: Please state your name and business address.

A: Kyle White, 625 Ninth Street, P. O. Box 2400, Rapid City, South Dakota.

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

A: I am Director, Rates and Demand-Side Management for Black Hills Power and Light Company (Black Hills).

Q: Please describe your educational and business background.

A: I graduated with honors from the University of South Dakota in May of 1982, with a Bachelor of Science degree in Business Administration, majoring in management. In August of 1989 I graduated with a Masters degree in Business Administration, also from the University of South Dakota. I have been employed by Black Hills in rate-related work since July of 1982 and have been in my present position since May of 1993. I have been responsible for the preparation of the utility's rate studies and filings for eight years. In addition to on-the-job training in utility rate making, I have attended numerous seminars, trade association meetings and

regulatory conferences covering subjects including utility rate making principles.

Q: Have you previously testified before this Commission or other Commissions?

A: Yes, before the South Dakota Public Utilities Commission and the Wyoming Public Service Commission.

Integrated Resource Planning

Q: What is your understanding of Integrated Least-Cost Planning?

A: Integrated Least-Cost Planning is the process of considering how the Company can manage both its supply portfolio and its demand to minimize the cost of providing service to its customers.

Q: How are your responsibilities related to Integrated Resource Planning?

A: I supervise the Company's Demand Side Management activities.

Q. What is Demand Side Management?

A. Demand Side Management, which I will refer to as DSM, is the planning and implementation of utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape. These changes are in the time pattern and magnitude of

the utility's load. Utility programs falling under the umbrella of DSM include: Load management, new uses, strategic conservation, electrification, customer generation, and adjustments in market share. Any DSM activity must benefit both the utility and its customers to be appropriate for implementation.

Q: In what way are these activities a part of an Integrated Resource Planning approach?

A: Demand side management can contribute through lowering the Company's average costs either through reducing the use of energy, particularly when energy costs are high, or through improving the system load factor. By improving the system load factor, the Company essentially expands sales with little or no need to expand capacity.

Q. Have their been opportunities for DSM to reduce average costs at Black Hills?

A. Yes, although Black Hills maintains a relatively high system load factor for its operations, it does believe that there can still be improvements to its system load factor through continued implementation of DSM activities.

Q. You stated that Black Hills has a relatively high system load factor. What was the system load factor for 12 months ending September 1994?

A. Black Hills' system load factor for those 12 months was 69.4%. Peak day load factors were 80.8% for the 1994 summer peak and 88.7% for the 1993-94 winter peak.

Q. Are these load factors typical for Black Hills' system?

A. Yes. Apparently due to the lack of extreme weather, it is at the high end. Black Hills' annual system load factor is regularly in the low to mid 60's on a percentage basis. The highest system peak occurred during a recent winter and is 293 MW. For the test period, the average daily load factor was 86.8% with a maximum daily load factor of 92.6% (Christmas Day, 162 MW peak) and a minimum daily load factor of 78.0% (July 18, 278 MW peak). Black Hills is fortunate that it experiences summer and winter peaks of similar magnitude. The primary variable between the two seasons is the existence of extreme weather, particularly in the winter.

Q. What would be an optimal annual system load factor for Black Hills?

A. Black Hills would not want an annual system load factor of much more than 70% due to the requirements of providing for annual maintenance on our generating plants. I have attached as BHPL Exhibit KDW-1 which includes a table of Black Hills' monthly peaks for the 12 months ending September 1994. BHPL Exhibit KDW-1 also includes daily load profile information for the twelve months ended September 1994. A review of the graphs reveals the flat and consistent shape of our system load whether its a monthly peak, typical weekday or typical weekend day.

Q. Why is Black Hills' annual system load factor near the optimal system load factor?

A. Black Hills' system load factor is high due to several factors. First, our service territory is located where there is some balance in climate between the summer and winter seasons. Second, our industrial customers typically maintain good load factors. Third, the diversity between our commercial and residential customers also contributes to the high load factor. Finally, Black Hills' efforts throughout the years have

been to encourage uses of electricity that would improve system load factor. The primary focus has been to generate awareness and understanding with our customers regarding energy efficiency in their electricity consumption. A primary influence used by Black Hills has been our rate offerings and their design. Our existing rate schedules offer a sufficient number of options to allow for appropriate price signals to be given to improve their load characteristics. We have encouraged residential total electric living which improves our system load factor, which continues to be important since our summer peak is increasing at a faster rate than our winter peak. We have also utilized general service rates which include both demand and power factor pricing to encourage customers to control their demand and improve their power factor. Black Hills large commercial and industrial rates have included since the mid 1970's an off-peak demand forgiveness provision to encourage these customers to shift usage to off-peak periods. We estimate that three to five MW of customer demand has been shifted off-peak due to this provision. The Industrial Contract Service schedule also

encourages high load factor through the design of the energy blocks by using a Wright-Hopkinson methodology.

A package of optional DSM rates was approved by the South Dakota Commission in 1982 and in Wyoming in 1983. The package included tariffs for residential demand service, utility controlled service, energy storage service, interruptible service and curtailable service.

Q. Have the DSM rate designs been well received by Black Hills' customers?

A. Yes and no. Over 1,750 larger use residential customers have opted for the Residential Demand Service and installed a demand controller. This number of customers includes both existing customers who have switched over from Regular Residential Service or Total Electric Residential Service and newly constructed residences. We are beginning to find more of our customers using the General Service Utility Controlled rate schedule. The Interruptible and Curtailable Service tariffs were not well received by our industrial customers. In South Dakota in 1992 we discontinued our Interruptible and Curtailable

Service tariffs in favor of the Large Demand Curtailable Service (LDC) tariff. So far, four customers have contracted for this service and are providing approximately 1.7 MW of curtailable load.

Q. What have been the results of the utility controlled rate offered by Black Hills?

A. I have prepared and am submitting BHPL Exhibit KDW-2 which is a listing of the residential and commercial connected loads currently served under the utility-controlled rate. Black Hills' current practice is to set these accounts up with a time and temperature control device. During the summer months the control settings are between 12:00 A.M. and 6:00 P.M. daily whenever the outside temperature at the location exceeds 90° Fahrenheit. During the winter months the control settings are between 5:00 P.M. and 9:00 P.M. daily whenever the outside temperature at the location is below 0° Fahrenheit.

Q. What support does Black Hills provide its customers regarding their use of electricity and the effect of rate design on their cost for electricity?

A. Black Hills strives to contact at least annually each of its General Service - Large and Industrial Contract Service customers to discuss their cost of electricity, their historical power factor and load factor, and their future electricity requirements. When appropriate we offer to provide power factor correction analysis to determine the payback for the customer of investing in capacitors. The rate design is also discussed so that the customer may identify load management opportunities. Rebate programs promoting the purchase of energy efficient motors and lighting conversions to more efficient lighting are also promoted where appropriate.

Black Hills also supports its Residential Demand Service customers by explaining the installation of demand controllers, usually to electricians, and the operation of the demand controller to maximize savings through load factor improvement. In 1994, in addition to printed material, we began including a video tape explaining the operation of the demand controller with all new demand controllers purchased by the Company. We have also certified, through free Black Hills sponsored

training, over 60 electricians to install and explain the operation of new demand controllers.

Black Hills also assists customers, usually through a high-bill complaint, with evaluating the consumers' use of electricity in their home or business and explaining the cost of each consumption point.

Q. Other than through rate design has the Company encouraged the improved use of electricity through DSM type activities?

A. Yes. Black Hills in the early 1960's began promoting total electric living. An important consideration for making the total electric package competitive with alternative sources for heating was that the homes be well insulated. Black Hills has and continues to encourage insulation standards for total electric homes within its service territory. Black Hills also offered residential conservation audits during the 1980's under federal and state programs and continues to provide walk-through audits for our total electric residential customers. In addition, in 1987 Black Hills implemented a program (DSM) which includes rebates for customers

who purchase certain energy efficient electric equipment.

Q. Please describe for me what the program has been and is.

A. The mission statement which was used to develop our initial program in 1987 was this, "1. To balance five year electric supply and demand projections through selected programs of load building, load management, and conservation. 2. To retain existing electric loads when our product is competitive and represents a good value for our customers. 3. To analyze, anticipate, and meet customer needs and wants through surveys, market research, and load research. 4. To take advantage of opportunities (other than the sale of energy) in the energy market place."

Although the marketing activities are broad the primary emphasis of the initial program was to provide rebates and incentives for appliances and electrical equipment that would improve system load factor and overall efficiency. As we worked with these programs we have modified the rebate schedules and the equipment which qualify for rebates from Black Hills Power and Light Company.

The program (DSM) for Black Hills for 1995 includes the following activities:

1. The Energy Efficiency Electric Appliance Rebate Program is intended to encourage customers to consider higher efficiency equipment at the point of purchase. The Dealer Incentive Program pays quarterly incentives to individual sales people at appliance dealerships and contractors based upon reported results.
2. The Dealer Aid Program is available to all trade allies in our service area and reimburses 50% of qualified advertising costs up to a maximum of $500 per dealer annually. Advertising must feature "high efficiency" or "energy conserving" equipment and/or use the tag line "Electricity ... for all the comforts of home."
3. The Builder Program provides incentives for new single family total electric homes which meet or exceed energy efficiency construction standards. Owners of new total electric homes are eligible for additional appliance rebates.

4. The Heat Pump Maintenance Program was developed to address customer concerns on equipment reliability. This program provides preventive maintenance, and educational contact with heat pump customers and improved operating efficiencies due to regularly scheduled maintenance.

5. The Employee Grant Program is designed to allow evaluation of potential new or innovative energy saving or load management systems. Qualification requires an energy audit which may result in additional requirements to meet the goal of achieving the lowest practical monthly electric bill through innovative equipment design and construction standards.

Black Hills Power and Light Company no longer provides rebates for refrigerators, or freezers, and has restricted rebates to electric heat installed in conjunction with a demand controller. We also have limited air conditioning rebates to central systems with Seasonal Energy Efficiency Ratings (SEER) of 12 or more. Our Builder Program encourages the construction of energy efficient

total electric homes. We believe that the promotion of total electric homes is an important consideration in maintaining Black Hills' current balance between summer and winter peaks which contributes significantly to the Company's high system load factor. In fact Black Hills' load forecast indicates that in the future the summer peak will exceed the winter peak. New total electric homes, preferably with a demand controller installed, will help balance the summer air conditioning loads of buildings heated with other fuels.

Q. Has the free installation for residential demand controllers been effective in encouraging customers to elect the Residential Demand Service rate?

A. Yes. The Residential Demand Service rates were first approved for service in the early 1980's. During the first four and one-half years Black Hills, through targeted direct mailings and mass-media advertising, established 418 customers under the optional rate. We implemented our DSM programs mid-way through 1987, including the $150 ($200 for 1992 and 1993) rebate for installed residential demand controllers. By the end of

1987, and 1993 we had 517, 1,572 customers respectively electing this rate. As of September 1994 we had 1,732 customers on the rate. This customer group is a mix of new residences and customers switching existing residences from another rate in order to achieve savings on their electric bill.

Q. With the programs offered by Black Hills are customers inclined to construct residences with the Residential Demand Service rate in mind?

A. Some customers are. Between December of 1987 and December of 1993 Black Hills experienced the following customer growth in South Dakota customers:

	Customers 1987	Customers 1993	Change	%
Regular Residential Service	33,051	35,374	2,323	7.0
Total Electric Residential Service	6,063	5,843	(220)	(3.6)
Residential Demand Service	503	1,554	1,051	208.9

While many of the 1,051 new Residential Demand Service customers are actually converts from the other two rate schedules, there is somewhat modest movement toward the Residential Demand Service rate as an option for newly constructed residences.

Q. Does Black Hills offer a heat pump maintenance program for its customers?

A. Yes. Black Hills has had in the past and has today a heat pump maintenance program. It has been through Black Hills' efforts and support over the years that heat pump technology has developed in the Black Hills area. Heat pumps are beneficial because of their high efficiency when compared to other heating and cooling options. In addition to cooling, the heating load also provides the Company year-round energy sales, improving the utilization of our facilities and lowering the cost to serve all of our customers.

The Heat Pump Maintenance program has approximately 430 heat pumps under contract. Each of these heat pumps is serviced annually by trained heat pump technicians employed by Black Hills. If a unit needs repair our technicians trouble shoot the heat pump and either repair it or in some cases hire local contractors to make the repairs. Black Hills also has approximately 60 heat pumps on its facilities that are serviced by the technicians. In addition these technicians

trouble shoot problems that customers experience with their demand controllers.

Q. Is customer education included as part of Black Hills' DSM efforts?

A. Yes. The primary focus of Black Hills' DSM efforts is to generate awareness and understanding with our customers regarding energy efficiency in their electricity consumption. We accomplish this through several means. Our employees participate in area home shows to discuss electricity issues with our customers, including demand controllers, the rebate program, and energy efficient appliance purchases. Black Hills offers a variety of information regarding conservation and rates in all of its offices through energy information pamphlet racks. The pamphlets for these racks are acquired from sources like the Department of Energy, the South Dakota State Energy Office, the Edison Electric Institute, or developed internally. We also developed and have made available to appliance dealers a pamphlet entitled "Energy Guide, Appliance Comparison Labelling" to assist customers in determining the annual operating costs of the appliance options prior to purchase. Black Hills also uses direct and mass-

media advertising to promote DSM. We also invite representatives from area architectural and engineering firms to join us in attending the bi-annual Rocky Mountain Electrical League Seminar for Architects and Engineers where they can be exposed to electric conservation and efficiency design opportunities.

During 1994 we also increased our efforts to ensure that electricians who install the demand controllers for our customers are both knowledgeable about their installation and proper operation. Through Black Hills' sponsored free training over 60 area electricians have become certified demand controller installers. This, combined with the switch from a $200 rebate for a demand controller purchase to Black Hills' contracted free installation, ensures better demand controller installations and more knowledgeable customers. The certified electrician is now also responsible for assisting the customer with their understanding of the program, instead of just the electrical installation. This focus will result in lower demand settings and higher customer savings.

During 1994 Black Hills continued to focus on bringing geothermal systems into the mainstream for home heating, cooling and water heating applications in the Black Hills. These systems are the same system that was used in the E-2000 home constructed last year in Vermillion, that was co-sponsored by the South Dakota Public Utilities Commission. In January 1994 we offered, in Rapid City, free geothermal system installation training and certification for over 30 trade ally representatives working in the Black Hills. We also offer tuition scholarships for trade ally representatives to attend geothermal systems training and certification at South Dakota State University or manufacturers' training centers. For this super efficient technology to gain wide spread acceptance, our customers will need to find experienced, knowledgeable and certified contractors, as well as an enhanced competition between them. Even with these factors addressed, proper installation and customer satisfaction with the first systems installed in the Black Hills will set the pace for the general acceptance of geothermal systems in the Black Hills. Our efforts are intended to enhance customer

satisfaction with this energy conserving, peak balancing system.

Another factor in developing energy efficiency minded consumers is through early education regarding electricity issues. Black Hills provides school presentations regarding electricity to various age groups each year. We are also promoting safety and education regarding other electricity issues through the Louie the Lightning Bug television ads developed by Alabama Power Company.

Q. Does Black Hills believe that its efforts in Demand Side Management can and will be improved in the future?

A. Yes, in 1993 Black Hills implemented a high efficiency motor program and a lighting efficiency program. Through our efforts, these programs are now gaining acceptance with our customers and local distributors for these products. In addition we are having positive results with energy and demand efficient ground source heat pumps (geothermal systems) in residential applications and water coupled heat pumps in commercial applications. We expect to see

improvements in these three areas in upcoming years.

In addition, Black Hills Power and Light Company is increasing its focus and efforts related to DSM activities. Currently our Demand Side Management efforts are directed through each of our district offices primarily through the District Mangers. Black Hills provides regular training to employees responsible for DSM efforts to assist them in implementing and working with our customers. Black Hills is continuing to increase the support and assistance provided these employees for implementing DSM activities and to look for opportunities to improve or expand its programs.

Q. Does this complete your discussion of Black Hills Power and Light Company's Demand Side Management efforts?

A. Yes.

Economic Development

Q: Has Black Hills Power and Light Company included economic development dollars in its proposed revenue requirement?

A: Yes. We have included in our revenue requirement $50,000 each year for economic development

activities. Since Sioux Falls and Rapid City compete for new and expanded business within the State, we see this as both a growth and fairness issue. Black Hills Corporation shareholders will match these dollars as has been the practice approved by the Commission for Northern States Power Company's South Dakota economic development activities.

Q: Since you are requesting a revenue increase that is substantially less than what your testimony indicates Black Hills is entitled to, will you consider that the $50,000 for economic development is included?

A: We would like the Commission's order to specifically designate $50,000 for economic development.

Cost of Service

Q: Are your cost of service analyses presented at Statement N in compliance with the traditional rate making theories of this Commission, for example, the determination of a rate base for the purpose of determining revenue requirements? Please explain.

A: Yes. In determining our base cost of service analysis for this filing, we have applied the

traditional ratemaking principles this Commission has used in the past. The rate base is the adjusted 13-month average plant balances for electric utility plant that is used and useful for the benefit of our customers. The expenses represent those costs incurred on behalf of our electric customers during the test year adjusted for known and measurable future changes.

Q: What methodology has the Company used to allocate the capacity related costs included in the Company's cost of service analysis provided at Statement N?

A: The Company has elected to continue the use of the average and excess capacity allocation method for this filing. The average and excess capacity allocation method has been used by the Company and approved by the Commission in all of its previous rate case proceedings in South Dakota.

Q: Please describe for us the average and excess capacity allocation methodology?

A: The average and excess capacity allocation has two distinct components to its calculations of responsibility for the system peak demand of 279 MW. The system peak demand for the test period occurred August 22, 1994. First, each customer

class is allocated its average kW demand during the test year. Average kW demand is determined by taking the total kilowatt hour sales for the class, plus associated energy losses, divided by the number of hours within the test period. In this case, the number of hours used was 8,760, which is 365 days x 24 hours. The second component of the average and excess capacity allocation, allocates the remaining system peak demand (excess demand) not allocated by the sum of the individual class average demands. The excess demand is allocated based upon the relationship of the individual class non-coincident peak demands determined for the test period. The result of this approach is that customer classes with lower load factors are responsible for a greater percentage of the excess demand, whereas the customers with the higher load factors are responsible for a greater percentage of the average demand. The approach has the tendency to recognize that systems are made up of both base load resources and peaking resources, and that the load factors associated with each class of customer inspires system planners to acquire different mixes of resources.

Q: Why was the average and excess capacity allocation method selected for this rate case?

A: Since the Company has not made application to this Commission through a rate case for a formal rate increase since the Fall of 1981, we chose to review the allocation methodologies previously used, and compare them with alternative methodologies. Each of the prior rate cases used this methodology, and therefore, the results of the method were consistent with past cost allocation and the rate design provided for in the Company's rate schedules. We also recognized that this Commission has tended to be precedential in its decision making, and we felt that the average and excess methodology would be more acceptable to the Commission and our customers as a result of this precedent. Finally, we recognize that a system which has similar summer and winter peaks, and a high system load factor, should use a methodology that recognizes both the need to plan for base load resources and the need to acquire peaking resources. The average and excess methodology fits this need.

Q: Have you made adjustments to the test year figures?

A: Yes.

In accordance with past Commission practice we adjusted both the rate base and expenses for known and measurable changes to our costs. The most significant adjustment is the additional rate base and expenses related to Neil Simpson Unit #2 and its commercial operation on behalf of our customers.

Cash Working Capital

Q: Did you conduct a lead/lag study to measure the cash working capital requirements of the Company for this rate case? Please explain.

A: Yes. I directed the preparation of Schedule F-3 in Volume 1, which is the Company's lead/lag study. The lead/lag study measures the time lapse between: (1) the provision of electric service and the receipt of revenues from customers for the service provided (revenue lead days) and (2) Black Hills' expenditures for labor, materials, services and all other costs used to provide electric service (expense lag days). The difference between revenue lead days and expense lag days, when applied to the average daily expenses,

produces the cash working capital required for, or available from, those expenses. When the revenue lead days exceed the specific lag days of an expense, a positive cash working capital requirement results. Conversely, when the expense lag days are greater than the revenue lead days, a negative cash working capital requirement occurs.

Q: How have the revenue lead days for electric utility operations in South Dakota been determined?

A: The revenue lead days for South Dakota have been derived by reflecting a 20-day lag from billing to collection, which is consistent with prior Commission orders for other utilities. Adding to this one half of the average billing period (365 days ÷ 12 ÷ 2) plus the typical bill processing lag results in a total of 37.50 revenue lead days.

Q: How have the expense lag days been calculated?

A: The expense lag days result from analyzing the operating expenses by type of cost. Each of the expense categories shown on Schedule F-3 (for example, coal expense, gas expense, purchased power, labor, so forth) has been individually analyzed to determine the amount of time, in days, from when these items are used in the provision of

service until the expenses are actually paid. Interest has been included and common equity has been excluded, which is consistent with Commission precedent.

Q: What is the conclusion from your lead/lag study?

A: Black Hills has a positive cash working capital requirement of $939,823 for the 12 months ended September 30, 1994.

Tariff Revisions

Q: Did you prepare tariff schedules to reflect the new rates described in Section 2 of Volume 1 of the Application?

A: Yes.

Both the existing tariff schedules and the revised tariff schedules and newly proposed tariffs are in Section 2 of Volume 1 of the Application.

Q: Are you proposing modifications to the Company's fuel and purchased power adjustment tariff?

A: The Fuel and Purchased Power Adjustment tariff is proposed to be revised in three ways. The first revision reestablishes the Company's base cost for fuel and purchased power to be included in the rate schedules.

In 1988 under Dockets F-3647-4 and F-3735, the Company added 1.45¢ per kilowatt hour to all of the energy charges of its South Dakota retail rates to roll into base rates our increased cost for fuel and purchased power. Historically, the Commission precedent when addressing purchased capacity costs has been to allocate these costs to customer class based upon the appropriate capacity based allocation, as has been done in the adjusted cost of service presented at Statement N of this application. The result of the Company's increased reliance on purchased power during the 1980's, and the 1988 changes to our base rates was to allocate purchased capacity costs to class using an energy based allocation. In August of 1993, the Commission authorized under Docket EL93-022 certain revisions to Black Hills Power and Light Company's Fuel and Purchased Power Adjustment tariff to address this difference. Since the difference was being addressed without the benefit of changes to the base rate schedules and their related charges, the approach was to reallocate purchased capacity costs within the confines of the Fuel and Purchased Power Adjustment tariff.

Now that we are revising the base rate schedules and their related charges, we propose to include a separate base cost for energy related costs and purchased capacity related costs. The purchased capacity allocation requires that a separate base cost be established for each of the five customer classes, Residential Service, Small General Service, Large General Service, Industrial Contract Service, and Lighting Service. The revisions to the Fuel and Purchased Power Adjustment tariff appropriately include all fuel and purchased power related costs in the proposed rate schedule charges.

Q. You said that there were three revisions to the Fuel and Purchased Power Adjustment tariff? Please describe the second revision for us.

A: Later in my testimony, I will address proposals that will provide incentives to large customers that sign long-term contracts and a general service tariff for the contracts with deviations section of rate book that would provide flexible contracting alternatives. These techniques allow the Company to meet specific, unique, customer requirements for electric service. These tariff changes are designed to avoid load loss, thus

benefitting all customers. Since these revenue changes are not known and measurable, the company has not made an adjustment to the cost of service to reflect them. Accordingly, we propose to collect them through the fuel and purchased power adjustment, which can track these revenue losses exactly.

BHPL Exhibit KDW-3 is an example of page 1 the monthly calculation of the Fuel and Purchased Power Adjustment for Residential Service that Black Hills will provide once this tariff and the associated proposed rate schedules have been approved by the Commission. Page 2 will remain in the same format that we submit today. The sample calculation uses the adjusted cost of service data for the entire twelve month period. When implemented, the calculations that we provide will be for each calendar month for each of the five customer classes.

Q: What is the third revision that you are proposing be made to the Fuel and Purchased Power Adjustment tariff?

A: The third revision readies the Fuel and Purchased Power Adjustment for the effects of the

opportunity sale to Montana-Dakota Utilities Company (MDU) beginning in 1997. It also allows the Company to benefit from the second half of our rate phase-in settlement offer described in Mr. Hoyt's testimony. Initially, Black Hills will use its system resources, combined with the purchase of inexpensive peaking capacity, to fulfill its obligations to sell power to MDU. These costs will be included in our monthly cost for fuel and purchased power. Our proposal is to credit monthly MDU revenue, through the Fuel and Purchased Power Adjustment, equal to the incremental energy cost and incremental seasonal peaking capacity purchased as a result of the MDU sale. The determination of these revenue amounts is defined within the tariff. The result of the revisions is that the MDU sale has no effect on the Fuel and Purchased Power charges paid by our South Dakota customers. It also allows the Company to settle for rate levels below what would be a reasonable return because the MDU sale is expected to improve the level of earnings beginning in 1997.

Q: Other than the rate changes presented in Section 2 of Volume I of the Application, are there other

proposed material changes to the Company's rate schedules.

A: Yes, a few rate schedules have been modified to provide for more appropriate terms and conditions. The changes to the terms and conditions have been noted along the right hand margin of the tariff sheets located in Volume 1, Section 2.

The Company is proposing that the availability of off-peak service with a reduced capacity charge be available for all General Service Large customers that have billing capacities of 250 kVA or greater. The existing threshold is 500 kVA. In addition this schedule now requires a minimum three-year initial term for the Electric Service Agreement with a 2 year written notice of termination. The existing tariff provides for a minimum one-year initial term and a 30-day written notice of termination of service under the rate schedule. The Company believes that the existing provisions are not sufficient for customers of this size. This issue is discussed in the testimony of Lee Smith.

The Company is modifying its Industrial Contract Service rate schedule to again state that the Character of Service will be, "Alternating current, 60 hertz, three-phase at the Company's transmission voltage (69,000 volts and above) stated in the Industrial Contract Service Agreement." The Company is also changing the initial contract period from an initial minimum contract term of five years to nine years. The minimum notice of service termination period is currently 30 days written notice for termination. The new notice period will be six years written notice of termination of service under the Industrial Contract Service rate schedule.

Under separate application to this Commission the Company will request that Utility Controlled General Service be closed to any future customers interested in this type of service. In its place the Company will request approval of a rate schedule which is titled Small Interruptible Service. We found that customers who were requesting service under the Utility Controlled General Service were not providing the load control opportunities we desire from this type of

rate. Since no customers are receiving service under the Small Interruptible Service rate schedule it was designed at an appropriate pricing level and should not be subject to an increase as part of this application, assuming of course that the Commission does subsequently approve the rate schedule as proposed.

Also under separate application to this Commission the Company will request revisions to its Energy Storage Service rate schedule. Under the revised rate schedule residential customers will not be eligible for Energy Storage Service. We believe that the Utility Controlled Residential Service and the Residential Demand Service rate schedules can adequately and more appropriately respond to residential energy storage applications than can this rate. At this time we have no customers taking Energy Storage Service. The proposed revisions will make Energy Storage Service more feasible for commercial applications, including the cooling system renovation at the Pennington County Court House which will be our first partial ice storage cooling system. The expected on-peak capacity savings due to this energy storage

service installation is 70 kW. Again, no increase in charges is being proposed for this rate schedule.

We also made application to the Commission for a change to our Residential Demand Service rate that will allow customers with demand controllers which are capable and ready to receive communication signals from a time-of-use meter the option of being billed only for the maximum kW demand recorded during on-peak periods. This Application has assumed that this change will be approved by the Commission separate from this docket. This Application does, however, request that the charges for Residential Demand Service be increased.

We are also proposing that the Large Demand Curtailable Service schedule be available for customers that have curtailable loads of at least 200 kVA. The existing threshold is 500 kVA.

Q: Is the Company proposing tariffs to address the higher costs resulting to residual customers in the event large load customers are able to obtain lower cost power from others?

A: Yes.

Black Hills Power and Light Company has 8 customers within South Dakota that have kW or kVA loads in excess of 2000. These customers provide system benefits by the nature of their size and their individual load factors. If these customers were to find alternative sources of energy through self generation or purchases from other suppliers, the potential exists for the shifting of significant costs to our smaller customers. The three customers that make up the Industrial Contract Service schedule alone provided 18.1% of the total South Dakota billable revenue during the test year. These customers combined are responsible for 22.0% of the Company's energy sales and 16.8 % of the system demand. We are proposing that the Commission approve what we have described as the Large Load Stability Incentive. This proposed tariff can be found at Volume I, Section 2 in the proposed tariffs as Section No. 4, Original Sheet No. 2. This incentive would provide discounts for customers having electric service requirements of 2,000 kilowatts/kVA or more that have signed all requirements, General Service Large, or Industrial Contract Service

agreements with a minimum initial of term of 7 years. The discount is provided in two stages. The first stage is for those customers that have service agreements which will continue in effect for 72 months or more, the monthly billing shall be reduced by 75¢ for each kVA of Billing Capacity, and by .05¢ for each kilowatt hour purchased. The second stage is for those customers that have service agreements that will continue to be in effect for only 36-71 months. For these customers, the monthly billing shall be reduced by .05¢ for each kilowatt hour purchased. No discounts will apply when the service agreement is subject to termination in less than 36 months.

Q: What is the significance of the seven year contract period?

A: A seven year contract period was selected because seven years has historically been the resource planning period for electric utilities. The goal is to match resources with expected sales. By having an initial term of at least seven years and a six year notice of termination, we will be better able to adjust our resource mix in the event a customer chooses to acquire their energy needs elsewhere. The incentive is greater for

longer term commitments to reinforce the value of continuing to purchase electricity from the Company.

Q: Other than these incentives, is the Company proposing tariff provisions that will allow the ability to meet unique customer situations requiring flexibility in providing service and pricing?

A: Yes.

The Company is proposing that the Commission approve what we are describing as the Business Development Service rate schedule. This rate schedule would reside within the Contracts With Deviations Section of our rate book (Section 4, Sheets 3-5) and would provide the Company with the flexibility to respond to specific customer needs related to both existing load and new loads. The tariff can be best described as a combination load retention and economic development rate schedule. The Company under this tariff would be authorized to enter into individual contracts with customers having loads of 200 kVA or more, that have demonstrated to the Company's satisfaction that they in fact have either unique service

requirements or economic alternatives not addressed by the Company's standard tariffs and rate schedules.

Q: Do other customers benefit from this pricing flexibility?

A: Yes. Since any rates offered under the Business Development Service will be above our marginal cost of providing the service, a contribution toward the Company's fixed costs will result. This helps boost the Company's earnings and defers future rate increases. Customers will also see a direct benefit on their monthly bills when sales increase, because the purchased capacity costs included in the Fuel and Purchased Power Adjustment calculation will be spread across more sales. The result will be a lower monthly charge related to fuel and purchased power.

Separate from the electric billings benefits are the community benefits related to economic development. Examples include new employment, broader tax base and a more robust economy.

Q: How is the Company proposing that the incentives provided through the Large Load Stability

Incentive and the Business Development Service tariffs be recovered from customers?

A: We believe that all of our customers will benefit if we are able to maintain the stability of our largest customers, and to attract new load to our service area. We, therefore, are including language in our Fuel and Purchased Power Adjustment tariff that would allow the Company to recover the incentives provided to customers under these two rate schedules. By having all customers, including those receiving incentives, participate in the recovery of these incentives, we recognize the fact that these incentives are truly bringing a system benefit.

Q: Have you calculated what the potential incentives might be if customers eligible for the Large Load Stability Incentive were to sign the appropriate agreements?

A: Yes.

BHPL Exhibit KDW-4 shows the customers that fit this size category and the associated incentive they could receive. I have only indicated the summary information for these customers, since some of them may have found that their electric usage patterns were proprietary information

related to their business operation. We have not determined what incentives might be offered through the Business Development Service, since we have no customers which have demonstrated that it would be appropriate to negotiate specific contracts with them.

Q: Are you familiar with the long-term agreement effective with Homestake Mining Company beginning September 1, 1993?

A: Yes.

Q: Would Homestake Mining Company be eligible for the Large Load Stability incentive?

A: Yes. I believe they should be. As our largest customer, our customers can take comfort in the fact that Homestake Mining Company has committed to purchase all of its electric requirements, with the exception of some existing hydro-generation, most of which dates back to the early 1900's, from Black Hills Power and Light Company for at least another 7-1/2 years.

Q: As written the Large Load Stability Incentive specifies that customers must have signed an all requirements service agreement.

A: We believe an exception for the Homestake Contract and its related hydro-generation is appropriate and necessary for our largest customer.

Q: Are there any other customers that would be automatically be eligible for the incentive?

A: No.

To automatically be eligible for the incentive a customer must have had an initial contract term of seven years or more and a minimum written notice of cancellation that has not been exercised. Had they not exercised their seven year notice, our second largest retail customers the State-owned Dacotah Cement, would have been eligible. Our contract with them will terminate May 1, 1999. This incentive is intended to deter customers, like Dacotah Cement from terminating their electric service agreements with the Company.

Q: Are there any other customers that would be eligible for discounts at this time?

A: No. However, if the Commission approves these discounts, we will be contacting our largest customers and encouraging them to sign long-term all requirements contracts.

Q: Have you increased any other charges for customer services?

A: Yes. I am proposing that the Customer Service Charge be increased from $7.50 to $10.00 for service connections during normal business hours. The charge is the same for initial service connections and reconnections due to the customer having their service disconnected. This charge has not been increased since the 1970's and at $10.00 still remains below our actual cost. The adjusted cost of service analysis reflects an additional $47,850 of expected revenue related to this change.

I am also proposing that the charge imposed for a non-sufficient funds payment by a customer be increased from $5.00 to $15.00. At $15.00 the charge is below the most common charge of $20.00 plus collections costs levied by most local businesses, and is only half of the $30.00 charge customers might pay at some local businesses. The adjusted cost of service analysis reflects an additional $7,030 of expected revenue related to this change.

Q. Have you proposed a change to the way in which your customers' initial and final billings will be calculated?

A. Yes. We have a fairly transient population here in the Black Hills. As a result we issue many initial service and final service billings. Our Commission approved rules provide that the monthly Customer Charge provided for in our rate schedules is not to be prorated for initial and final service billings. This fact often leads to a customer inquiry regarding the amount of the initial or final billing when service is for only a few days or a low kilo-watt hour consumption. In addition, by offering customers the option of establishing new service by telephone, the customer may also find on their first bill the Customer Service Charge ($7.50/$10.00) and a billing for the Customer Deposit.

The rates that we propose assume that the monthly Customer Charge provided for in the rate schedules will be prorated for initial and final service bills. We have adjusted the billing units used for designing rates to allow for this change. The details can be found at Schedule I-1.

Q. I see that you have reduced the Special Installation charge provided for in the lighting schedules. Why are you recommending this change?

A. We are recommending the additional charge be lowered to 1% of the special installation cost from its current level of 2%. The change responds to two areas of customer concern. The first is that street lighting and to a slightly lesser extent private area lighting will remain in continuous service well beyond the initial 10 year contract term required for special installations. The 2% per month additional charge is a close proxy to what the result would be if a 10 year levelized fixed charge were applied to the Company's additional investment related to the customer requested special installation. The poles, conductor and transformers that make up the special installation have useful service lives that are 30 years or more. The 1% monthly additional charge is more in line with this fact and will be better received by our local governments. The reduced charge is proposed to be effective for both current and future customers with special lighting installations.

Q: Are there other significant changes being proposed by Black Hills?

A: No, the other changes noted on the tariff sheets are primarily cleanup items and in my opinion are not significant.

Q: Mr. White, in view of your cost allocation methodology applied to the rate classes, how do you justify applying the requested rate increases equally to all classes?

A: You know, I have lost quite a little sleep over that question. Rate theory and my training would indicate that our proposal for rate increases and rate design within the customer classes is incorrect. However, electric utilities face a different environment than existed in our monopolistic past. This environment demands more pricing and customer sensitivity.

We at Black Hills Power and Light Company expect to continue to provide the electric service for our South Dakota customers well past our careers, as evidenced by the construction of NS Unit #2. Management within customer expectations and needs is the best way for us to assure the continuation of this relationship.

As Lee Smith discusses in her testimony, we had several objectives related to rate design that weighed in favor of our proposal and against requesting that rates be set at each class' adjusted cost of service. Initial customer reaction to the rate increase was considered. We know from experience the importance of first impressions and customers tolerance for "rate shock". We also were concerned about our competitive position throughout the rate classes. Both existing competition and potential future competition were weighed in our decision. We also recognize that these differences between the classes didn't happen overnight and would be better addressed when the overall increase needed is not so large.

I believe that our proposal is fair to each of the customer classes and their respective rate schedules. It is a very practical approach to a theoretically difficult situation.

Q: Does that complete your testimony?

A: Yes.

Black Hills Power and Light Company

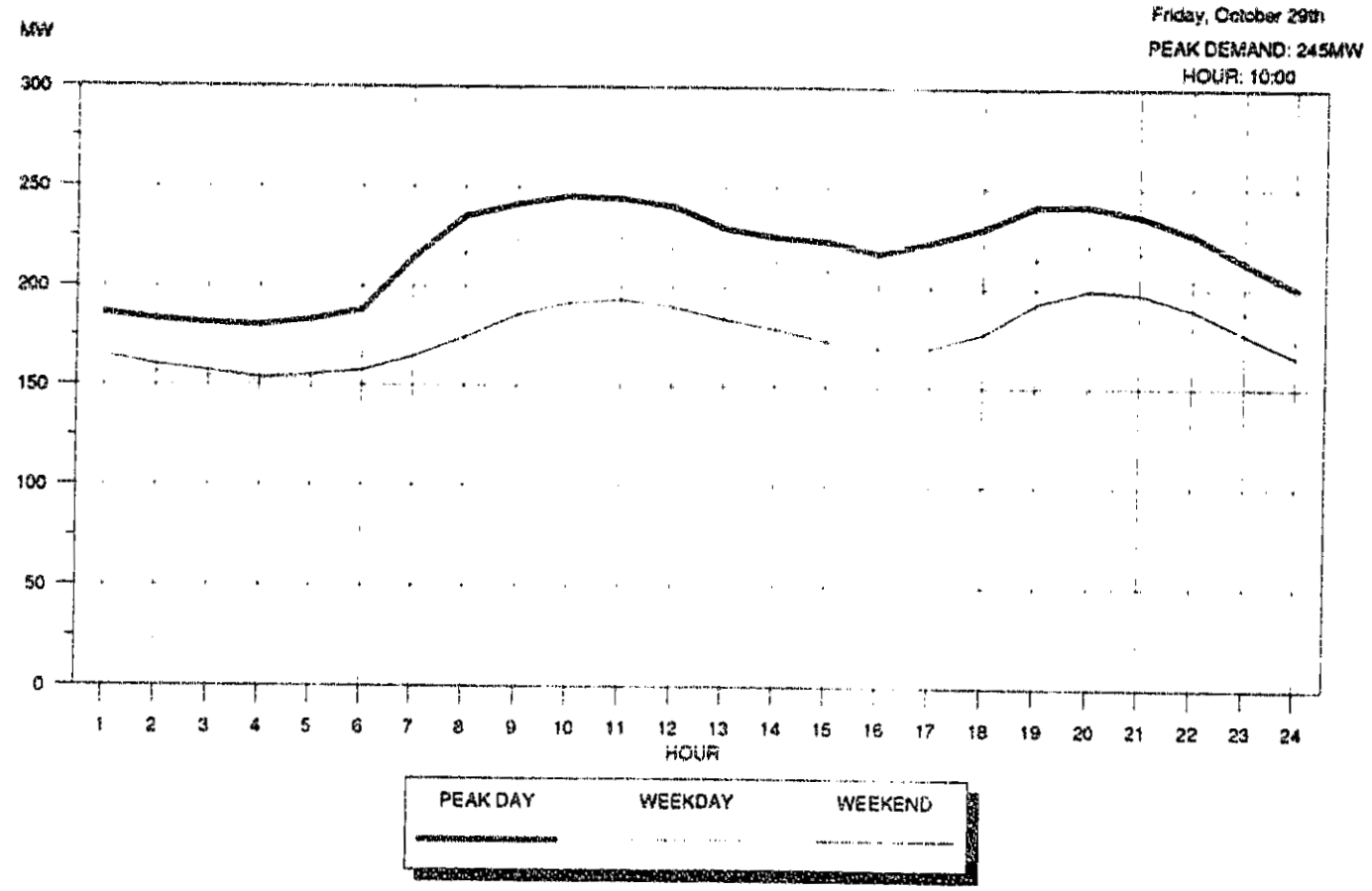
Monthly System Peak Days
For the Twelve Months Ended September 1994

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	Hour	Day	MW Load	Weather	Temperature high	Temperature low	MWH	Load Factor
October 29, 1993	10:00 AM	Friday	245	Overcast	26	20	5,225	88.86%
November 24, 1993	10:00 AM	Wednesday	277	Thin Clouds	8	-2	6,055	91.08%
December 15, 1993	07:00 PM	Wednesday	255	Fog	32	18	5,362	87.61%
January 17, 1994	12:00 PM	Monday	276	Rain/Snow	5	0	5,918	88.70%
February 7, 1994	10:00 AM	Monday	271	Rain/Snow	0	-5	5,755	88.48%
March 23, 1994	08:00 PM	Wednesday	238	Rain/Snow	36	20	4,894	85.68%
April 27, 1994	09:00 PM	Wednesday	233	Rain/Snow	33	20	4,912	87.84%
May 17, 1994	03:00 PM	Tuesday	231	Thin Clouds	85	62	4,614	83.23%
June 30, 1994	05:00 PM	Thursday	256	Clear	84	59	5,191	84.49%
July 18, 1994	02:00 PM	Monday	278	Thin Clouds	90	63	5,205	78.01%
August 22, 1994	03:00 PM	Monday	279	Thin Clouds	94	66	5,412	80.82%
September 9, 1994	03:00 PM	Friday	260	Clear	100	56	5,047	80.88%
		Maximum	279				6055	91.08%
		Minimum	231				4614	78.01%
		Average	258				5299	85.47%

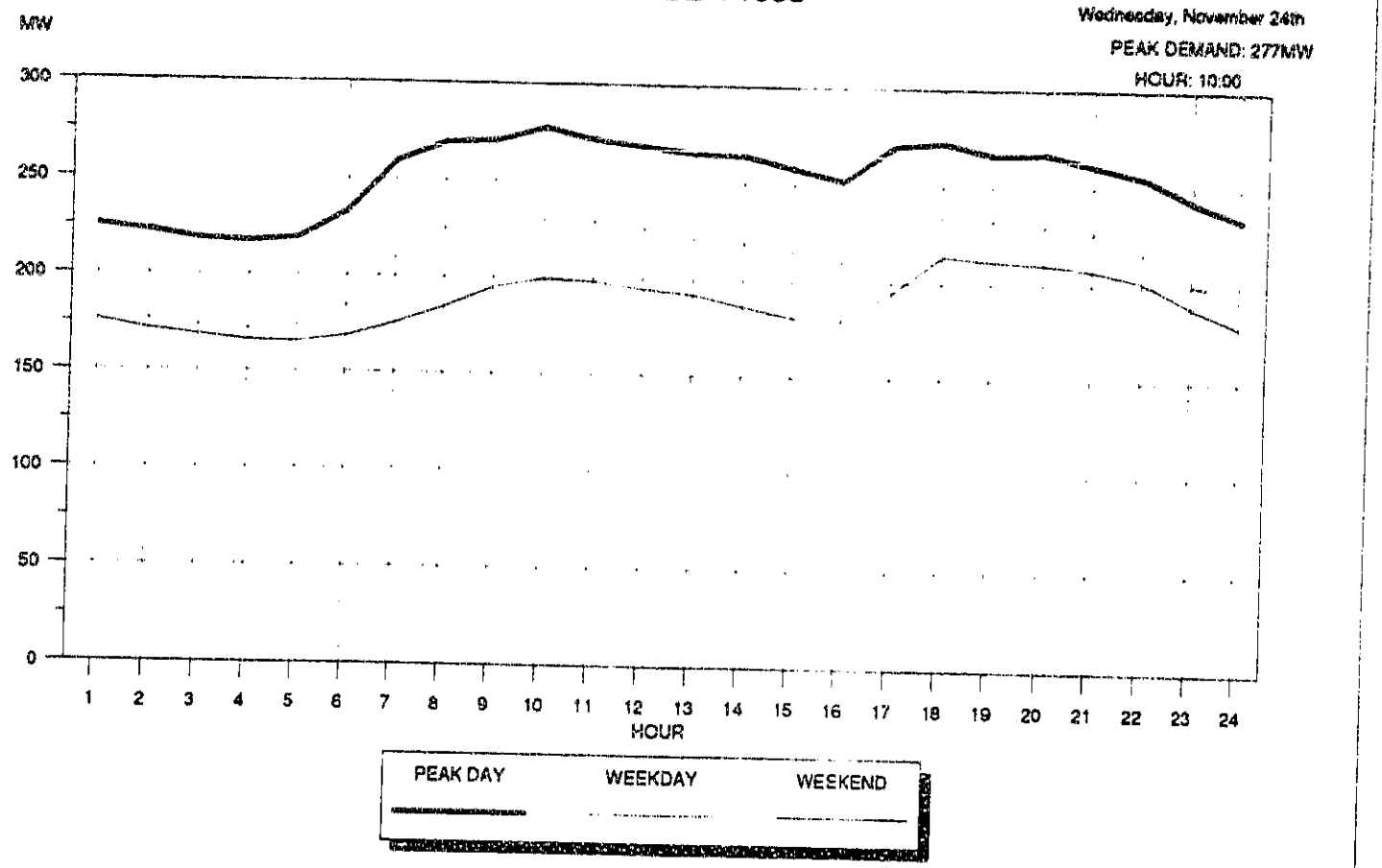
BLACK HILLS POWER AND LIGHT COMPANY

OCTOBER 1993



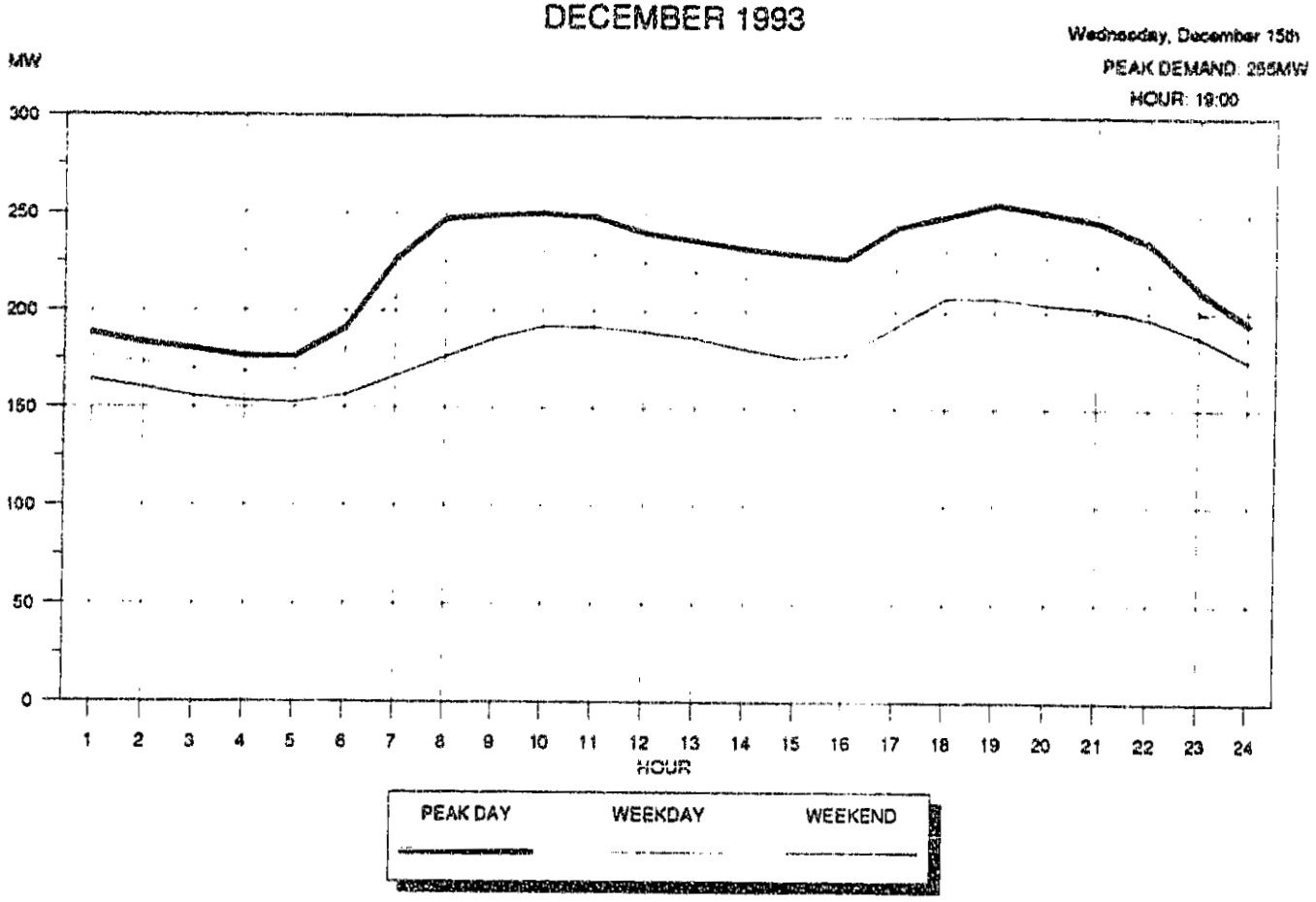
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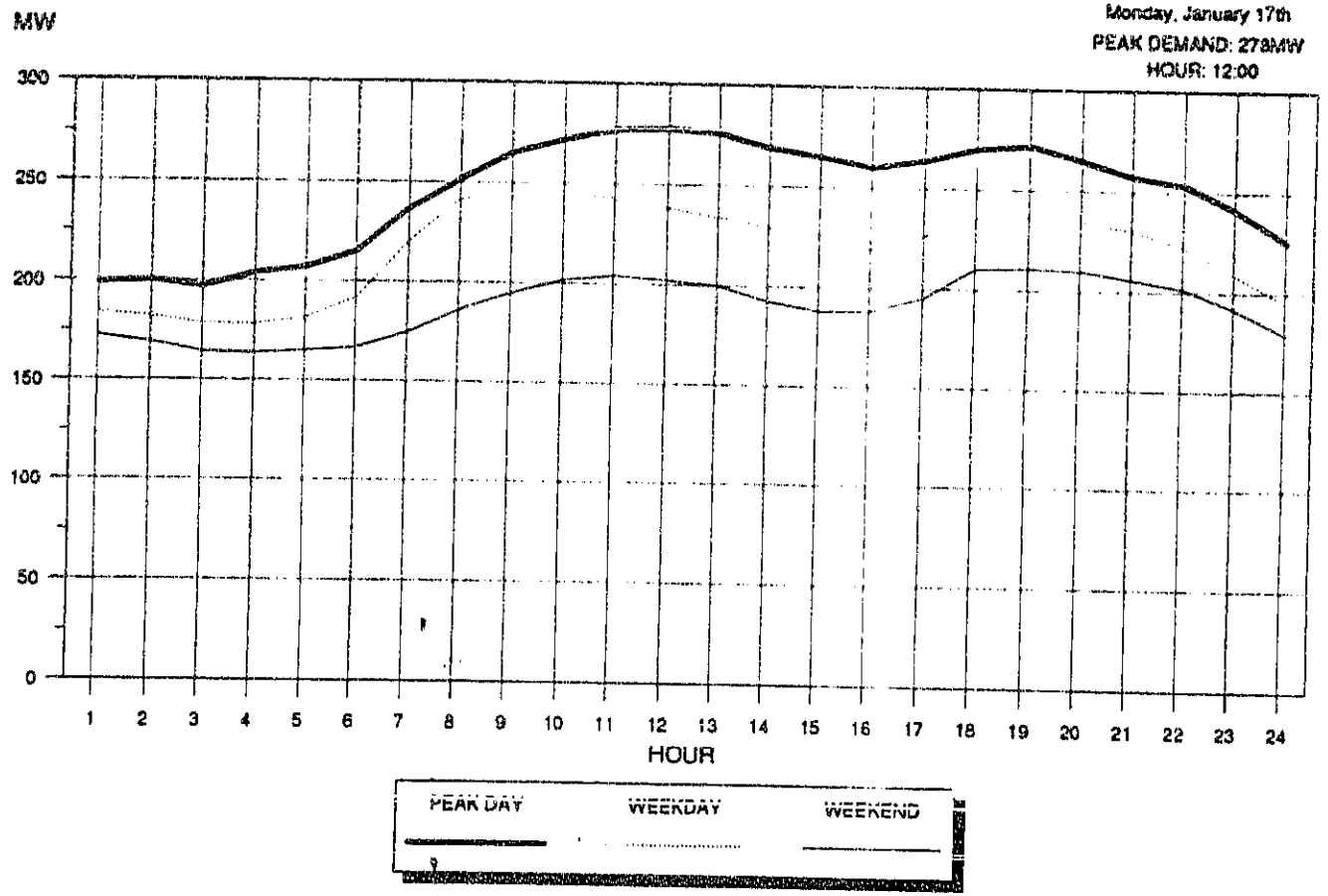
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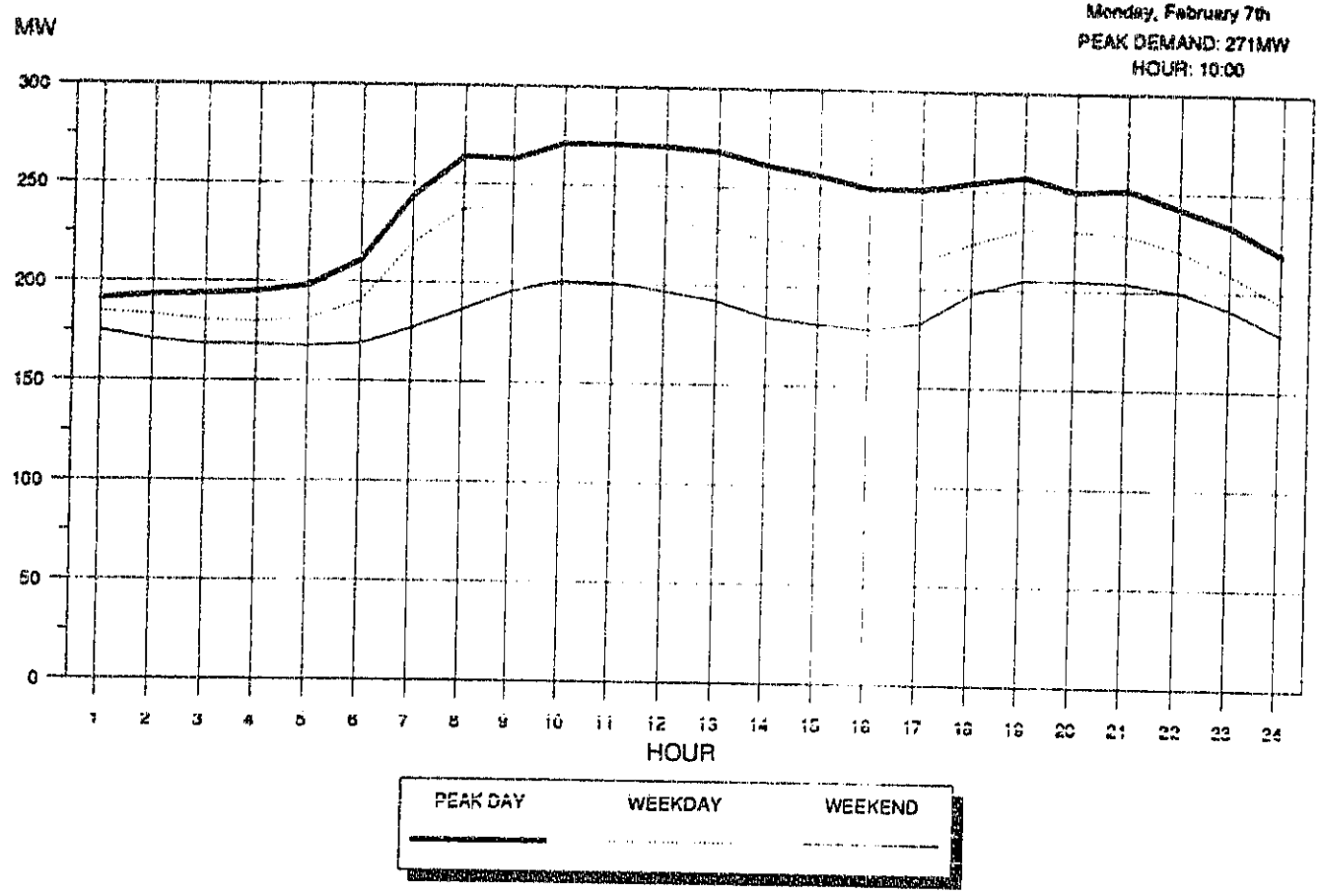
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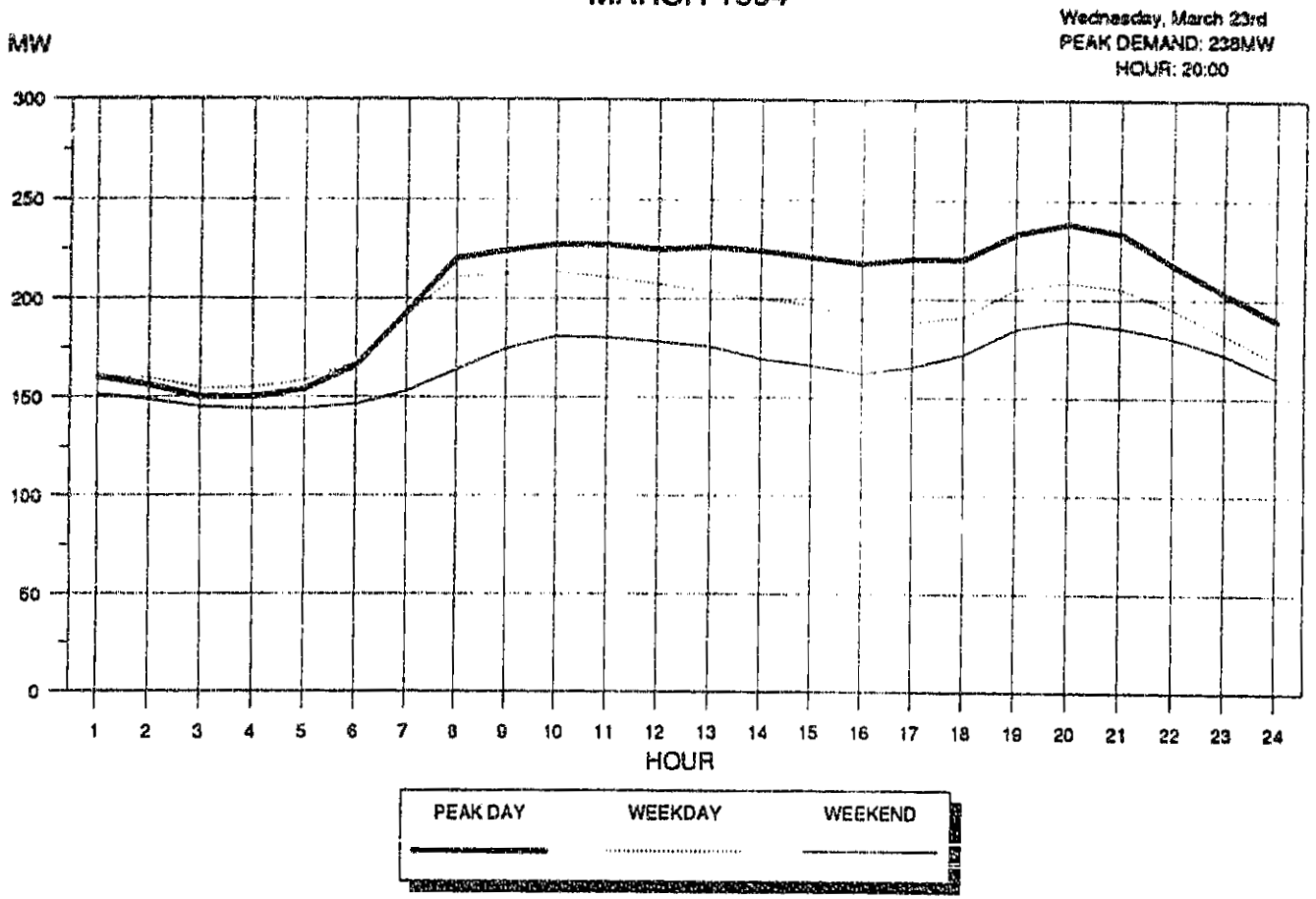
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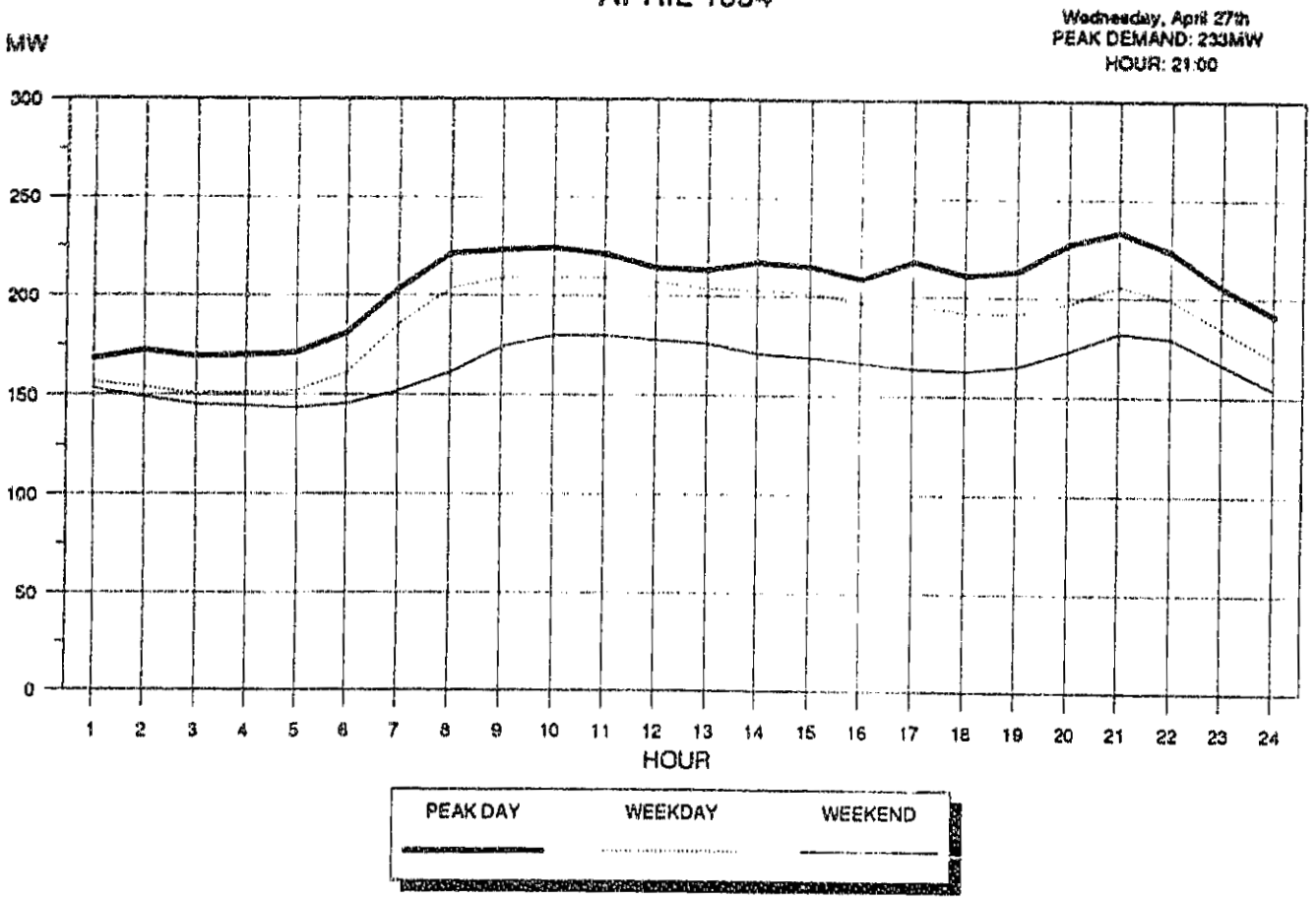
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MARCH 1994



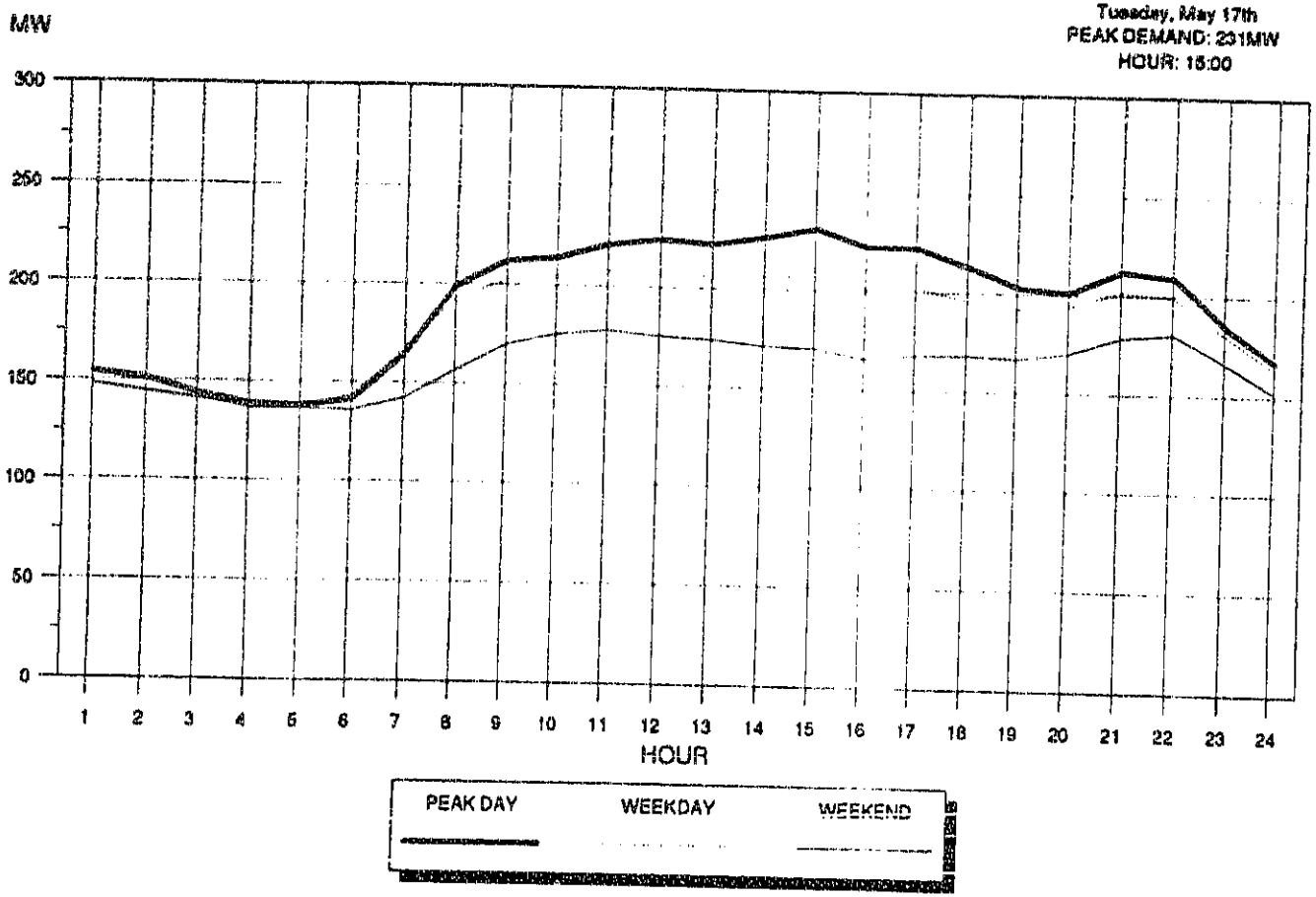
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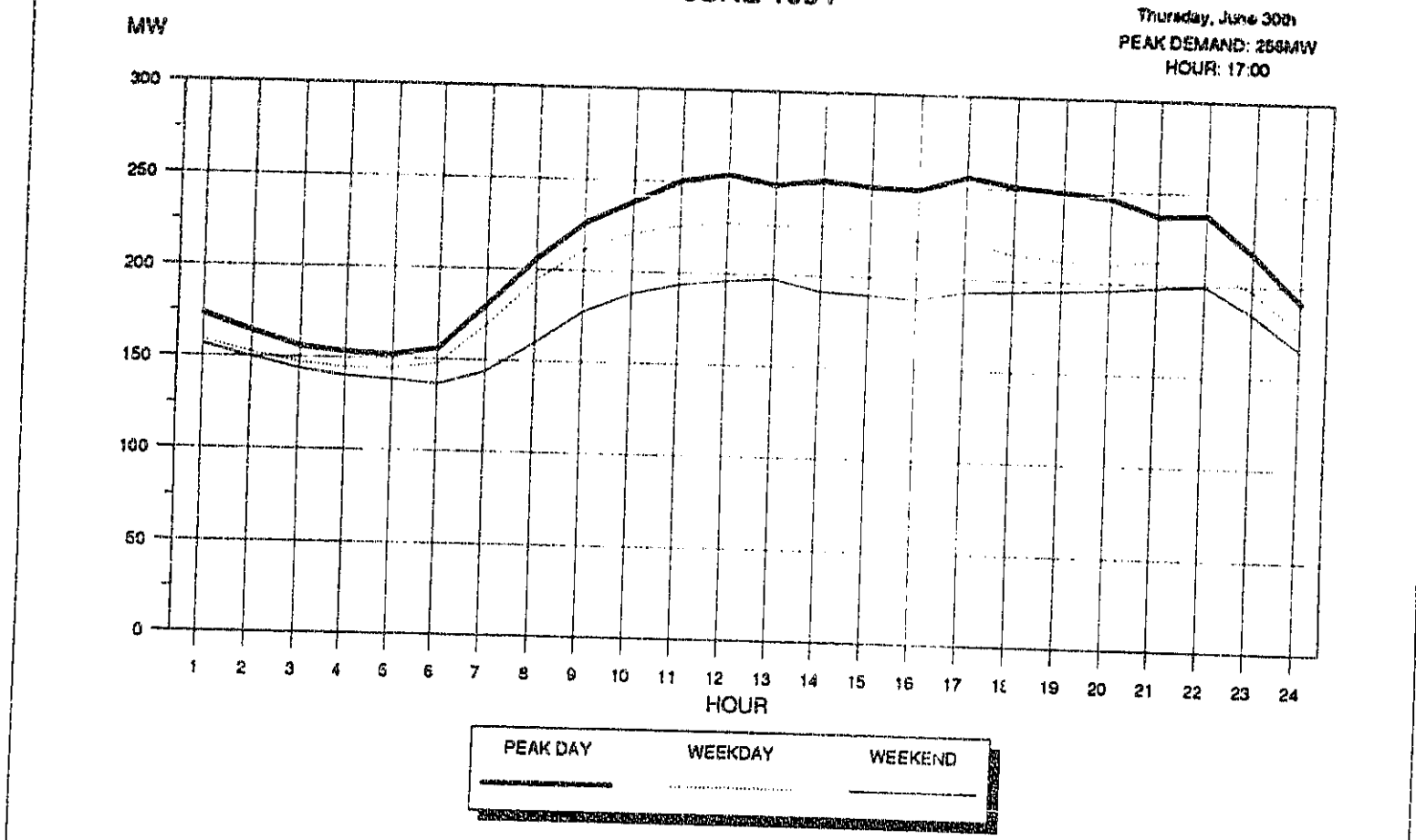
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MAY 1994



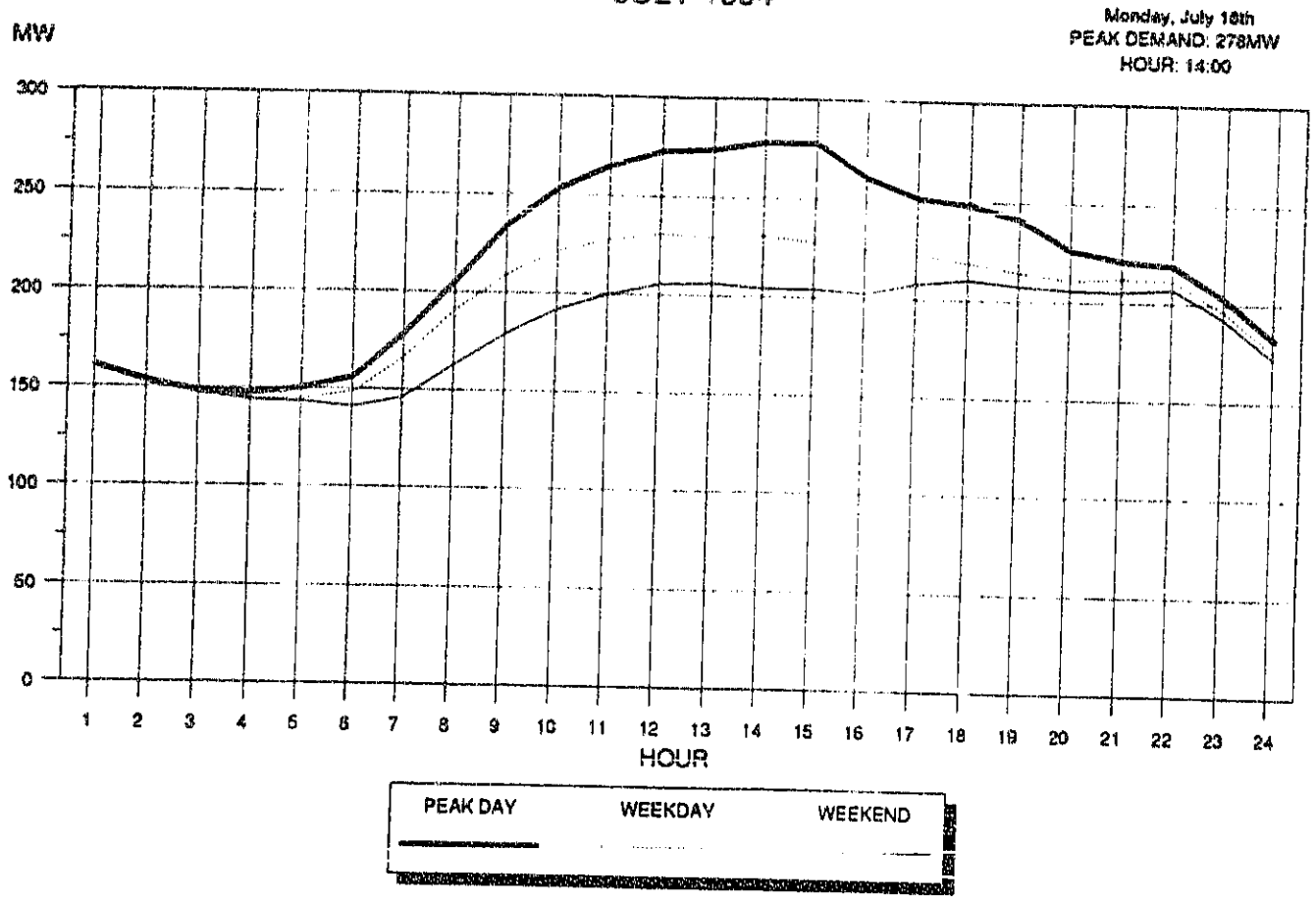
BLACK HILLS POWER AND LIGHT COMPANY

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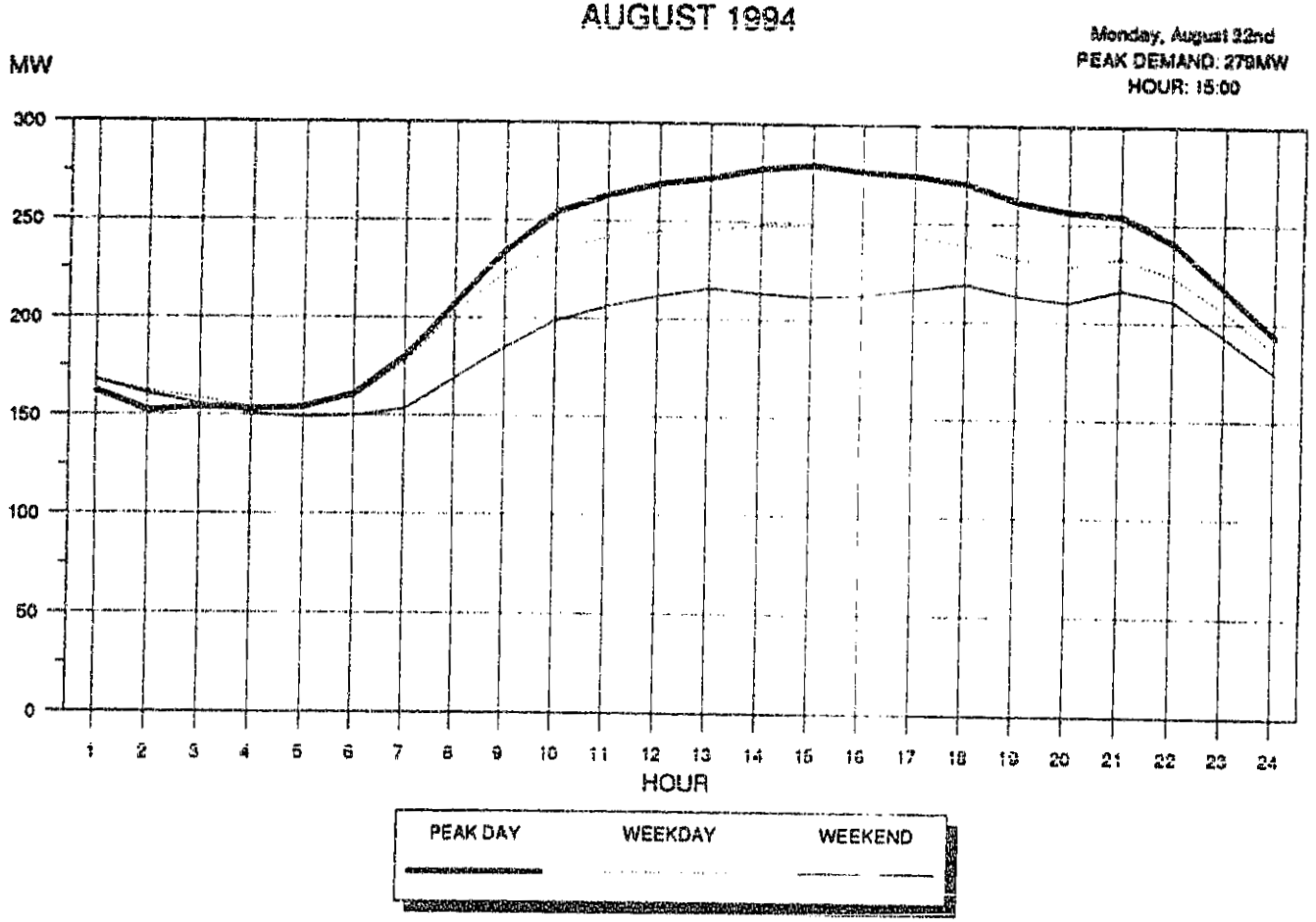
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BLACK HILLS POWER AND LIGHT COMPANY

AUGUST 1994

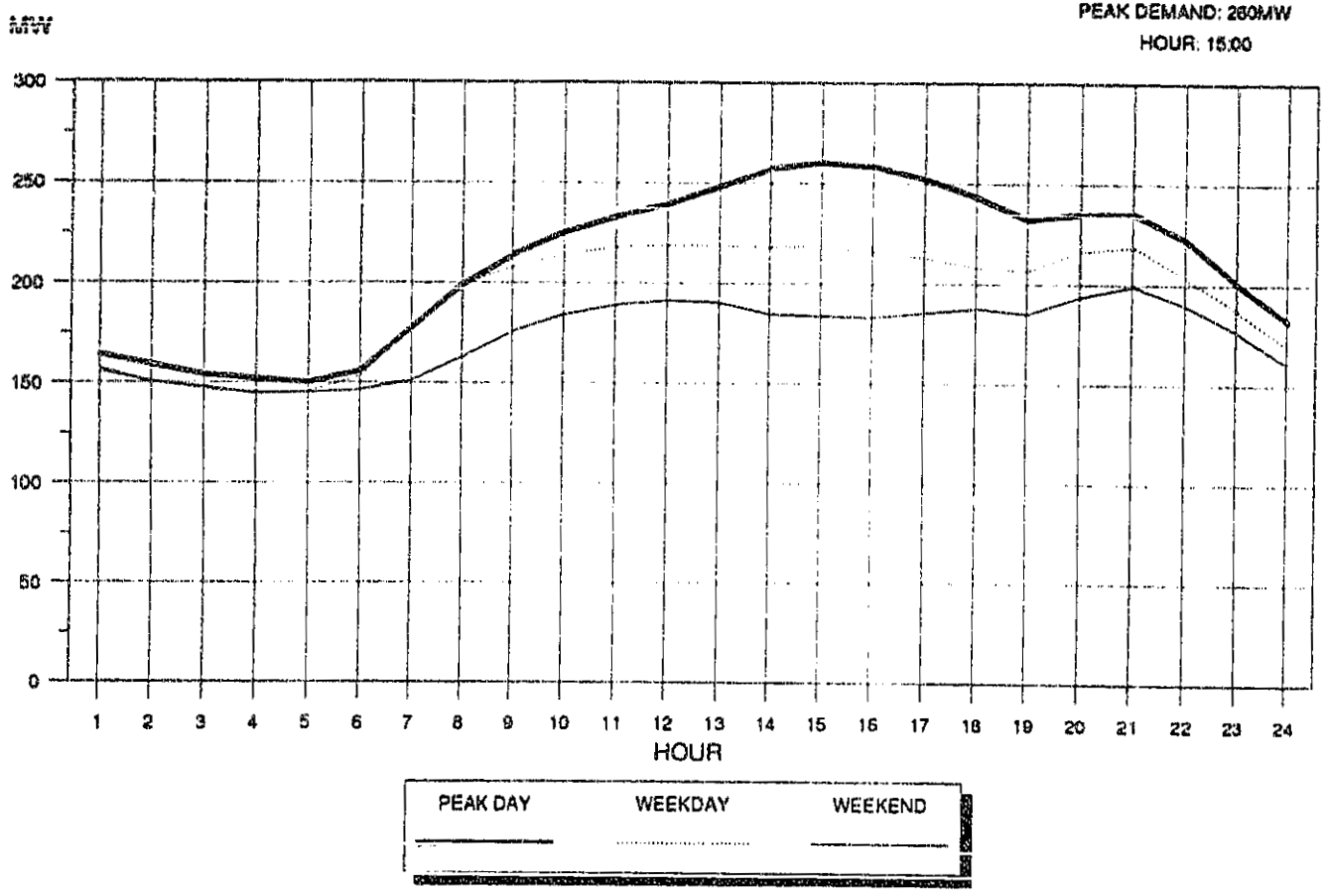


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BLACK HILLS POWER AND LIGHT COMPANY

SEPTEMBER 1994

Friday, September 9th
PEAK DEMAND: 260MW
HOUR: 15:00



BHPL Exhibit
KDW-2

BLACK HILLS POWER & LIGHT COMPANY
Utility Controlled Rates

Commercial Customers
South Dakota Rate 7 & Rate 27

	Description	Load (kW)
1	Hot Water Heating	75
2	Well Pumping	530
3	Snow Making	1,540
4	Well Pumping	30
5	Sewage Plant	233
6	Hot Water Heating	240
7	Air Conditioning	24
8	Space Heating	14
9	Water Pumping	30
10	Kiln	13
11	Hot Water Heating	171
12	Kiln	11
13	Air Conditioning	320
14	Space Heating	15
15	Air Conditioning	32
16	Hot Water Heating	36
17	Hot Water Heating	108
18	Hot Water Heating	84
19	Message Sign	10
20	Well Pumping	5
21	Irrigation Pump	300
22	Well Pumping	112
23	Floodlights	35
24	Parking Lot Lighting	10
25	Space Heating	30
26	Hot Tub/Swimming Pool Water Heating	35
27	Air Conditioning	210
28	Hot Water Heating	18
29	Swimming Pool Water Heating	24
30	Recycle Plant	130
	TOTAL:	4,425

Residential Customers
South Dakota Rate 17

	Description	Load (kW)
1	Swimming Pool Pump & Hot Tub	8
2	Hot Tub & Space Heating	22
3	Space and Hot Water Heating	20
4	Swimming Pool Water Heating	25
5	Hot Water & Space Heating	25
6	Hot Water & Space Heating	15
7	Space Heating	20
8	Hot Tub	6
	TOTAL	141

BHPL EXHIBIT
KDW-3

BLACK HILLS POWER AND LIGHT COMPANY
SOUTH DAKOTA FUEL AND PURCHASED POWER ADJUSTMENT
TWELVE MONTHS ENDED SEPTEMBER 1994 ENERGY ADJUSTMENT CALCULATION
RESIDENTIAL SERVICE

Line No.	Cost of Fuel and Purchased Power	
1	Total Fuel Expense	$11,867,177
2	Less: Other Fuel Costs	757,095
3	Less: Incremental Cost of Intersystem Sales	0
	Plus: Load stability Incentives	0
4	Plus: Purchased Energy Expense	4,329,987
5	Total Fuel and Purchased Power Cost	$15,440,069
	kWh Sales	
6	Total kWh Sold	1,543,765,510
7	Less: Intersystem Sales	0
8	Total Firm kWh Sales	1,543,765,510
	Energy Adjustment	
9	Energy Cost Per kWh (line 5/line 8)	$0.00939
10	Less: Base Energy Cost (Fb/Sb)	0.00939
11	Energy Adjustment Factor ($/kWh)	$0.00000
12	Purchased Capacity Adjustment Factor ($/kWh [1]	$0.00000
13	Residential Service Adjustment Factor ($/kWh)	$0.00000
14	SD Residential kWh Sales	356,610,144
15	Energy Adjustment Applicable For Month	$0

[1] Purchased Capacity Costs for Month		$16,209,000
Residential Class Capacity Resposibility	x	26.14%
Residential Class Capacity Cost Allocation		$4,237,033
SD Residential kWh Sales	÷	356,610,144
Purchased Capacity Cost Per kWh For The Month		$0.01188
Purchased Capacity Base Cost Per kWh	-	$0.01188
Purchased Capacity Adjustment Factor ($/kWh)		$0.00000

BHPL EXHIBIT
KDW-4

BLACK HILLS POWER AND LIGHT COMPANY

Large Load Stability Incentive
Customers > 2,000 kW/kVA

	kW/kVA	Energy Incentives	Demand Incentives	Total Incentives	Percent Savings
Customer #1	30,586	$93,600.80	$256,729.80	$350,330.60	4.37%
Customer #2	17,779	$59,211.15	$153,795.90	$213,007.05	4.20%
Customer #3	8,938	$27,141.56	$77,929.95	$105,071.51	4.47%
Customer #4	4,805	$10,715.40	$42,234.15	$52,949.55	4.70%
Customer #5	2,977	$6,562.80	$24,758.40	$31,321.20	4.60%
Customer #6	2,669	$3,986.70	$23,535.30	$27,522.00	5.87%
Customer #7	2,354	$5,305.20	$17,776.58	$23,081.78	4.25%
Customer #8	2,026	$5,067.20	$17,385.60	$22,452.80	4.26%
TOTAL	72,334	$211,590.81	$614,145.68	$825,736.49	

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DIRECT TESTIMONY OF DALE E. CLEMENT
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
BLACK HILLS POWER AND LIGHT COMPANY
APPLICATION FOR AN INCREASE IN ELECTRIC RATES
DOCKET NO. EL95-003

Q: State your name and residence.

A: Dale E. Clement, 625 Ninth Street, Rapid City, South Dakota 57701.

Q: What is your occupation?

A: I currently serve as Senior Vice President-Finance and Chief Financial Office of Black Hills Corporation, the applicant.

Q: What is your formal training and business experience?

A: I received a Bachelor of Arts in Economics from Tarkio College (Missouri) in 1954. After teaching in high school for one year and serving in the military for two years, I entered the University of Nebraska in the fall of 1957. I served as a teaching assistant in 1957 to 1958 and received a Master of Arts degree in Finance in 1959. From 1958-1961, I was an assistant professor of business at Midland Lutheran College in Fremont, Nebraska. I returned to the University of Nebraska in 1961 and held a teaching assistantship through 1963. I received a Doctor of Philosophy (Ph.D) in Finance in 1965. My doctoral dissertation involved an in-depth analysis of

nonoperating assets of Central Western Region Railroads. This included an analysis of oil, coal, and other mineral properties held by railroads in that region. The region included Wyoming, Colorado, and other western states.

In 1963 I joined the faculty at the University of South Dakota as an Assistant Professor of Finance, was promoted to Assistant Dean in 1966, and was appointed Dean and Professor of Finance in 1968, a position I held until August of 1989. I served on commercial bank boards from 1969 through 1989. As a board member, I held the positions of Chairman of the Audit and Investment Committees. I also served as President of the Freeman Investments, Inc., a Yankton, South Dakota, manufacturing company specializing in aircraft components from 1980 until July of 1989, at which time it was sold. This transaction resulted in over $4 million of funds being contributed to charitable institutions in southeastern South Dakota.

I was elected to the Board of the South Dakota Investment Council. I served as chairman of this board for three years, which is responsible for managing over $2.5 billion of

investments for the State of South Dakota. This position allowed me to be in daily contact with the bond and stock markets. My term was completed in June of 1994.

In 1979 I was elected to the Board of Directors of Black Hills Corporation. Since September 1, 1989, I have held the position of Senior Vice President-Finance of Black Hills Corporation.

Q: Describe your position as Senior Vice President-Finance of Black Hills Corporation.

A: In this position, the Controller and the Secretary and Treasurer of Black Hills Corporation report directly to me. In addition, I am responsible for the computer operations, internal auditing, the pension and defined benefits programs, Wyodak Resources Development Corp. and Western Production Company, and serve as the major liaison between the Corporation and the financial community.

In the latter function, I have direct contact and am responsible for all bond rating activities, preparation of funding plans for both short- and long-term capital needs, whether it be stock or bond financing, and primary responsibility for investor relations and answering questions of the

investing public. These positions, plus my relationship with the South Dakota Investment Council, allow for daily contact with the money and capital markets.

Q: What is the purpose of your testimony?

A: As the Senior Vice President - Finance and with my education and background in the financial and business area, I have been asked to give testimony supporting the cost of capital and the capital structure of the utility.

Q: Have you studied the capital structure of the investor owned electric utility industry?

A: Yes, I have reviewed carefully the capital structure of the 100 investor owned electric utilities that are in the 1993 EEI Financial Review.* The composite structure of the 100 companies is as follows:

Debt	49.4%
Common Stock	43.9%
Preferred Stock	6.7%

*Source: Edison Electric Institute, 1993 Financial Review, p. 13.

Q: Would you please describe the preferred stock section of the capital structure?

A: Preferred stock is listed on the balance sheet as an equity component; however, it has many of the characteristics of debt; indeed, many text books

describe preferred stock as a junior debt. Preferred stock, for example, normally has a set dividend, sometimes has a sinking fund, and has preference to common dividends and to liquidation over common stock, but yet is junior to all debt. The dividends are paid from after-tax earnings. In practice, many analysts look at preferred stock as subordinated debt of a company.

Q: Why would a company issue preferred stock?

A: There is no reason to issue preferred stock unless one can do it cheaper than debt or in the case of a company with marginal credit, sometimes preferred stock is the only access available to the capital market. In the latter case, the preferred dividends rate could be quite high.

Q: Does Black Hills Corporation have or plan to issue any preferred stock?

A: No, we do not have any preferred stock outstanding at the present time nor do we have any plans to issue a preferred stock in the immediate future. We have looked at preferred stock but have not found any economic advantages to either customers or stockholders.

Q: What is Black Hills Corporation's utility capital structure in this case?

A: We expect to have a utility capital structure with debt equaling 55% and common stock equaling 45% of total capitalization at the time NS #2 becomes commercial.

Q: Have there been events in the electric utility industry which have prompted you to review what is an appropriate level for stock versus debt?

A: Yes, the industry is in the midst of many studies which could well lead to changes in the traditional way that the industry has done business.

Examples of the changes include: competition for industrial customers; open access of transmission lines; and, in general, competition for all classes of customers. This is a radical change from the traditional franchised territories that the industry is accustomed to. It is a movement that is taking place throughout the world.

In the United States, we are studying what happened to the gas pipeline business and the telephone business in the opening of competition of those industries. Needless to say, these studies, particularly with the announcement of the California Public Utility Commission agenda to

mandate wheeling and competition at the retail level plus the rapid rise in long-term interest rates, have created havoc in the stock market.

From October of 1993 to January of 1995, for example, the stock market value of the electric utilities has fallen over 25 percent. At the same time, long-term interest rates have increased approximately 24%. In addition to the rise in interest rates, there are many other uncertainties as noted above facing the equity market.

These potential changes prompted the rating agencies to take a second look at how the debt securities of utilities are rated. In late October 1993, Standard & Poor's issued a new set of ratios for electric utility industries which, in essence, made it more difficult for companies to maintain their bond ratings. This was followed on July 4, 1994, with a second paper by Standard & Poor's which analyzed the business position of each of the utilities. Many questions were posed, including does a company have potential for stranded investment with the loss of industrial customers? What is the economic condition of their market and service area economy? What is the regulatory climate? All of these issues also

enter into the rating of our bond securities. It is fair to say that these items were considered in the past; however, given the changes that are taking place in the industry, the analysis has now become quite formal.

Q: Have you reviewed Black Hills Corporation bond ratings and the ongoing construction of Neil Simpson Unit #2 with the bond rating agencies?

A: Yes, we are reviewed by three bond rating agencies, Moody's, Standard & Poor's, and Duff & Phelps. Moody's reviewed our plans and we maintained our A1 rating, which is the highest A rating by Moody's. Duff & Phelps reviewed our plans and awarded an A+. Standard & Poor's, upon review, lowered our ratings from an A+ to an A and placed the Company on a negative watch. Standard & Poor's has indicated that once the rate case is settled satisfactorily, the negative will be removed. Both Moody's and Duff & Phelps indicated that if the rate case is not resolved satisfactorily, our ratings would immediately be reviewed for possible downgrading.

Q: Why are bond ratings important?

A: Electric utilities are capital intensive and issue new debt securities on a frequent basis. Bond

ratings are important in that they provide an independent opinion as to the creditworthiness of the Company's debt. It is imperative that the Company maintain investment grade ratings in order to sell securities at competitive interest rates. The lower interest rates translate into more competitive rates for our customers.

Obviously the Company's position would be enhanced if its debt securities were rated AA or AAA. Unfortunately, due to our small size, the higher ratings are not possible. Therefore, our strategy is to maintain A-rated investment grade ratings.

In addition to rating bonds, the three rating agencies publish thorough financial reviews of our Company which are widely disseminated throughout the debt and equity investment community. This gives our small corporation in-depth market exposure that we would otherwise not have.

Q: If the capital structure is not adjusted by this Commission in determining the revenue requirements, does this assure Black Hills Corporation of maintaining bond ratings?

A: No. The capital structure is only a part of the overall equation. A second major part, which will

be addressed in another section of this testimony, involves the allowable rate of return. The two components provide the basic measure from which the various coverages which must be met in order to maintain economic viability are calculated. One thing that is extremely important is that the relationships between the Corporation and its various regulatory bodies must be perceived by the investing public and rating agencies as being fair and reasonable to both customers and investors.

Q: Do the rating agencies and financial analysts recommend a capital structure different from what you are achieving?

A: Yes, they strongly recommend a 50% debt and 50% equity capital structure.

Q: Why have you not issued sufficient common stock to achieve 50% equity in this case?

A: We have reviewed, in depth, what we considered to be a reasonable ratio of debt and equity for both customers and stockholders. We want to stay competitive. Because of the Company's investments and material earnings from nonutility businesses, we are of the opinion that in Black Hills' case, an equity ratio of 45% for the utility will not degrade bond ratings. The rating agencies and the

financial analysts incorporate the nonutility financial statements as a consolidated corporation. Since the subsidiaries carry very little debt, their equity ratios and the upstreaming of cash for dividends becomes extremely important in the manner in which our company is viewed by the outside world. The utility, by itself, would not be strong enough to maintain the high visibility and the better-than-average debt ratings as an independent company. The success of the nonutility subsidiaries of Black Hills Corporation contributes substantially to the lower cost of capital and the other benefits that are enjoyed by our utility customers. In my opinion, if the Company were not engaged in its nonutility businesses, at least 50% equity would be required to maintain investment grade bond ratings.

Q: Please describe chronologically the actions that Black Hills Corporation has taken to raise capital for Neil Simpson Unit #2.

A: Before we finalized the plan to build Neil Simpson Unit #2, investment bankers were interviewed and questions were posed concerning the feasibility of raising the necessary capital to finance this

project. After interviewing several investment bankers, Merrill Lynch and PaineWebber were chosen as co-managers for the debt issuance, and Merrill Lynch was chosen to manage the stock sale.

After a thorough review, the Board of Directors authorized the Company to issue equity first. It was determined that since equity carries the highest risk and that the stock, at the time, was selling at a reasonably high market-to-book multiple that it would be prudent to issue the equity first. On October 18, 1993, 525,000 shares were sold at the price of $25.375, before expenses. Since that time our stock has traded between a high of 26.50 to a low of 17.875 and on January 13, 1995, the stock closed at $21.00 per share.

In addition, from January 1, 1993 to December 31, 1994, 20,597 additional shares of stock were exercised in the Employee Stock Purchase Plan.

The dividend reinvestment program was changed so that, beginning in 1993, new stock could be issued. From December 1993 through December 31, 1994, 137,777 shares of stock have been issued

through this program which has increased equity by $2,945,753.

In addition to the equity raised through the issuance of common stock, additional equity will be upstreamed from the Company's subsidiaries in the form of dividends.

On June 1, 1994, the Company sold $3 million of City of Gillette, Campbell County, Wyoming Environmental Improvement Revenue Bonds. These bonds were issued for 30 years and are priced at a variable rate of interest. The interest rate since issuance has been set weekly with the interest ranging between 2.45% to 5.95%. The transaction was handled by the investment firm of First Chicago.

On July 13, 1994, the Company filed a $100 million first mortgage shelf registration. On September 1, 1994, $45 million of bonds were issued under the shelf, carrying a coupon rate of 8.30% price to yield 8.32%. The Company still has an additional bond issue to sell, in order to complete the financing of Neil Simpson Unit #2. There still remains $55 million of first mortgage bonds which could be issued under the shelf registration. The Company does not intend to use

the full amount but will issue only what is appropriate to finance the project.

Q: How did you handle the financing during construction?

A: The Company arranged a $65 million line of credit with commercial banks, of which $50 million is at the LIBOR (London Inter-Banking Borrowing Rate). The interest, based on the LIBOR rate, has ranged from 3.875% to 7.0%, to date, and has provided low cost capital during construction. Prime rate, generally charged to a bank's less risky corporate investors, is currently at 8.5%.

Q: What cost of debt assumption is embedded in this rate case for the issuance of the balance of the bonds required?

A: To complete the financing of NS #2, approximately $30 million of additional bonds will be issued. We have estimated the cost to be 8.10%.

Q: When do you expect to issue the balance of debt and is the assumed cost of debt realizable?

A: We are in daily contact with the market. Our investment bankers, Merrill Lynch and PaineWebber, are fully informed of our interest rate parameters and are shopping the market. We would like to sell the securities and finish the financing as

soon as possible. We anticipate the bonds will have a maturity of 15 years or less.

The bond market is very unsettled and wide swings in interest rates within a short time period are not unusual. The shelf registration allows the Company to act quickly if interest rates approach our 8.10% goal. Whether or not the Company can sell bonds at 8.10% is dependent upon future interest rates, which are impossible to predict.

Q: Turning now to equity, did you calculate the cost of equity using the discounted cash flow model, referred to as DCF Model?

A: Yes.

Q: Please explain the model.

A: The Discounted Cash Flow Model is one of the methods used to estimate the cost of equity. The model attempts to find the investor required return on equity by determining how much the investor expects to receive in dividends and how much due to an increase in stock price. The theory assumes a constant interest rate environment so that price appreciation is assumed to be in direct proportion to future growth. As a result, the required return is said to be the

dividend yield and anticipated future growth rate of dividends. Investors buying the securities discount the cash flow so that it equates with the amount of risk that they are willing to take when investing their savings. The discount rate then becomes the cost of capital to the company.

The discount rate, or the cost of equity capital, therefore, is (1) the expected dividend in the first period, D_1, divided by the current market price, P_o, plus (2) the expected compounded growth rate in dividends, g. The growth rate is expected to be both constant and perpetual. The growth rate, K, is as shown below.

$$K = \frac{D_1}{P_o} + g$$

The DCF model includes five basic assumptions with which I do not entirely agree.

Assumption 1 - Investors discount dividends and not earnings. In actual practice, many investors use dividends, but others also use earnings or a combination thereof. Therefore, the absolute pricing of equity using strictly dividends as a basis of discount is flawed. This is particularly true for the electric utility industry during the past five years through October 1993, during which time the equity market

had price appreciation. Much of the increase, of course, was because of the decline of short-term interest rates and the switch of funds from money market CD type of instruments to utility securities where investors are searching for a higher yield. Since October 1993, the market has reversed with equity prices falling due to an increase in interest rates and investor switching out of electric utility stocks to government bonds and money market type of investments.

Assumption 2 - Investors are assuming a constant dividend rate for all years. In actual practice, the utility industry, in general, has had in many cases decreased their dividend rates. Therefore, it is difficult to assume that there will be a constant dividend growth into the future. The investment analysts are forecasting a dividend growth rate beginning in 1996 of 3%. This projected dividend growth rate is substantially below the historical growth rate of dividends over the past decade.

Assumption 3 - Investors assume a constant discount rate for the future. In actual practice, interest rates change through time; and as these

interest rates change, so do the risk premiums among investments. Therefore, the discount rate is not constant. Again, during the past four years we have seen visible evidence of this in our capital markets.

Assumption 4 - Investors follow the present value theory of investment. Some investors do not use the present value theory of investment. There are any number of different approaches that are used by investors in determining whether to buy stocks. For example, technical analysts review supply and demand for a stock. To them, recurring patterns of price movement are significant and reflect likely outcome patterns which are used for investment decisions. They use bottoms and tops and breakouts followed by lags and leads. All of these assumptions, of course, are not consistent with the DCF model.

Assumption 5 - The markets are efficient. This is a very bad assumption. Theoretically, markets should be efficient in adjusting to new information in evaluating common stocks. However, while they might be efficient in the short-run, there is a problem with the DCF model in that it assumes a time frame of perpetuity and a linear

relationship between dividends and price. The growth and discount rates must be constant. This, we know, is not the real world--no factors remain constant. For example, in the real world, many institutional investors are graded on the basis of quarterly performance and, therefore, focus on short-term results. As opposed to this approach, many investors of Black Hills Corporation stock have a longer-term outlook that is preconditioned by past experiences and, to some extent, by broker and investment services evaluations and recommendations. Therefore, there is an inconsistency between the results of the DCF model, which assumes constant conditions and perpetuity and the actual prices created in the market place. Short-term and long-term investor decisions are not consistent and create unusual market movements.

Due to the shorter term focus by many investors, the stock market cycle generally corresponds with the economic cycle. This cycle causes an ebb and flow of investor optimism and pessimism. Moreover, given the current structure of interest rates, there is a very strong defensive demand in yield bias through the

steepness of the yield curve which is not recognized by the DCF model.

While the DCF model can be of substantial assistance during periods when the market is constant and the growth of dividends is constant, it is flawed during periods of aberration in interest rates, heavy capital expenditures by utilities, a decline in dividend growth rate, and when stock prices are abnormally high. Since the DCF model does not meet the basic underlying assumptions as stated above and, as such, understates the actual market returns by material amounts, we do not think that it provides a good basis for developing a cost basis of common equity.

Q: Please explain your analysis of Black Hills Corporation using the DCF Model.

A: On January 16, 1995, Black Hills Corporation's stock closed at $21.00. The dividend paid is $1.32. Black Hills Corporation does not publicly forecast earnings or dividends. Financial analysts estimate dividends in 1995 to increase either $0.02 or $0.04 per share, with future increases beyond 1996 to be 3%. These estimates are considered reasonable by the Company.

The projected yields using the two scenarios are:

	1995 Estimated Yield		Yearly Increase 1996		Cost of Equity
$\frac{\$1.32 + \$0.02}{\$21.00}$	= 6.38%	+	3%	=	9.38%
$\frac{\$1.32 + \$0.04}{\$21.00}$	= 6.48%	+	3%	=	9.48%

The analysts' expectations for 1995 plus the 3% increase for 1996 forward give an anticipated cost of equity capital between 9.38% and 9.48%.

Q: The cost of equity capital of 9.38% to 9.48% seems extremely low. What are the shortcomings of this analysis?

A: The 9.38%-9.48% is totally unrealistic. The reason for the distortion is that the rate of return allowed for by public utility commissions is based on book value. The book value of Black Hills Corporation at the end of November was approximately $12.17. However, Black Hills Corporation stock which closed at 21.00 represented a market-to-book relationship of 173%. The difference between market and book creates a distortion of expectations between the investing public and the regulatory bodies that regulate the rate of return. If the market price and the book

price were approximately the same, the Discounted Cash Flow analysis would have merit in that both regulatory bodies and investors are analyzing the stock on the same basis. Unfortunately, the market value and the book value are seldom equal.

If, for example, one would substitute book value in the above formula for market value and using the forecasted dividend increases, the results would be:

		1995 Yield on Book		Increase From 1996		Cost of Equity
$\frac{\$1.32 + \$0.02}{\$12.17}$	=	11.0%	+	3%	=	14.0%
$\frac{\$1.32 + \$0.04}{\$12.17}$	=	11.18%	+	3%	=	14.18%

If the price of stock equaled book value, this would be a realistic measure.

The basic reason the analysis is flawed is because of the significant difference between book value and market value. Discounted Cash Flow value of 9.38%-9.48% is only slightly higher than what long-term single A-rated utility bonds currently yield. It obviously makes no logic whatever to have common stock, which is the risk portion of your investment, giving an anticipated

yield equal to or slightly above the first mortgage bonds which are senior securities.

Q: What then is your ultimate conclusion about the discounted cash flow model?

A: I do not believe it is an accurate model at this time to determine the cost of equity for Black Hills Corporation or any electric utility with a high market-to-book ratio. In addition, I do not believe the model is accurate for any utility at any time because the assumptions are not accurate as I have previously stated.

Q: Are there other theories to apply to develop the cost of equity?

A: Yes. One would be to look at the historical spread between an electric utility's long bond interest costs and its equity cost. Historically, we know that there is substantially more risk to the holding of equities than the holding of bonds. Prudency and historical precedence indicate that there should be at least a 3.00%-3.20% spread between the cost of bonds of a utility and the cost of its equity. This spread was reaffirmed in the average allowed rate of returns on common equity for utilities with rate cases that settled from 1984 to 1993 where the 10-year average risk

spread was 3.00%. Attached as BHPL Exhibit DEC-1 is my analysis.

In marketing debt issues of the Company, I have learned that the current interest rate cost to Black Hills Corporation is based on the August 2023 Government Bond. On November 11, 1994 this bond was priced to yield 8.20%. A-rated long-term utility bonds on that date were priced by the market at approximately 84 basis points above the comparable government maturity, thereby placing the approximate cost of our long-term debt on November 11, 1994 at 9.04%. This spread does change. For example, on October 19, 1992, as shown in the rate stability filing, the bond pricing for long-term utility bonds showed an approximate 110 basis point spread. The same spread on January 1, 1995 was approximately 98 basis points. Therefore, using the traditional 3.0%-3.2% spread, the current government bond pricing as adjusted for A-rated 30-year no-call-10 utility bonds would indicate a cost of equity between 12.04% and 12.32%. As competition becomes a reality and risk increases, one would assume that the risk spread will increase in the future.

Q: Did you consider the Equity Risks Premium model?

A: Yes. The formula is:

Required Return = Lowest Risk, Long-term Capital Costs + Equity Risk Premium

In the equity risk premium model, the required return is the sum of the lowest risk long-term capital, which in this case is long-term U. S. Government bonds. The equity risk premium is defined as the difference in risk between long-term U. S. Government bonds and the return earned by equity holders.

Q: Please explain the market equity risk premium.

A: This test is based on actual annual returns realized by investors in the electric utility companies as represented by the 90 electric utility companies in the Duff & Phelps, Inc. data bank. Total return is determined by the year-to-year price changes for all companies plus the dividend. The sum of the price and dividend represents total returns realized by investors in the utility stocks. The stock returns were then compared with long-term U. S. Government bond returns as calculated by Ibbotson & Associates. The difference between the stock and bond returns show the higher return (risk premium) required by investor when investing in the common stock. The

bond price was determined by the yield to maturity at year-end for long-term U. S. Government bonds which is the change in price from one year-end to the next plus the interest rate that was received by investors during that period. The premium or discount on the bond was amortized to maturity which, when added to the interest cost, gave a comparative yield to maturity.

Q: What are the assumptions of the equity risk premium model?

A: The underlying assumptions are:

1. Investors consider bonds as an alternative investment to common stock on a risk-adjusted basis.
2. There is more risk in common stocks than in bonds.
3. The equity risk premium is relative constant over time.
4. The markets are efficient. The market test shown in this analysis fulfilled the assumptions except that equity risk premiums are not constant over time, i.e., there are variations from one year to the next.

Q: Why do you find the equity risk premium is not constant over time?

A: The equity risk premium varies over an economic cycle. If investors are confident about the economy and the prospects for common stocks, stocks can be bid up in price relative to bonds. This would increase the total return for common stock versus bonds by more than a normal amount and would increase the apparent equity risk premium. When an economy enters a recession, the reverse could be true. Investors would become more pessimistic, common stock versus bonds, and the apparent equity risk premium would decline. Another major factor in looking at the equity risk premium involves the level of interest rates. As interest rates have declined, as indicated previously, particularly at the short end, there is a movement away from interest rates into common stocks. This would create an upward movement to stocks and a decrease in the return on bonds.

Q: What time period did you select to measure the equity risk premium?

A: I used the 15-year period from 1979-1993 to eliminate the possibility of manipulating the time period. As indicated, the equity risk premium does vary over an economic cycle. It is felt that this 15-year period would be sufficiently long so

as to reduce the impact of short-term market movements.

Q: What yield did you use for long-term U. S. Government bonds?

A: I used the average yield to maturity by year as prepared by the firm of Ibbotson & Company and published in Stocks, Bonds, Bills and Inflation 1994 Yearbook.

Q: What yield did you use for electric utility stocks?

A: The annual return on electric utility stocks was derived from the Duff & Phelps, Inc. data base consisting of 90 companies. Attached as DUFL Exhibit DEC-2 is my analysis and sources.

Q: What were the results of these analyses?

A: Tracing the differences in yield between the electric utility annual return and the long-term government bond over this 15-year period shows that on the average, investors were willing to pay a risk premium of approximately 4.38%. This risk premium added to the price of the August 2023 treasury bond 8.20% gives a suggested rate of return using the risk premium model of 12.58%.

Q: Would you summarize the various approaches?

A: As can be shown below, the suggested cost of capital varies widely depending upon the methodology used in determining cost of capital.

1. The DCF model for Black Hills Corporation shows: cost on market value 9.38% - 9.48%, cost on book value 14.0 - 14.18%.
2. The historical utility debt/equity margins show: 12.04%.
3. The equity risk premium shows: 12.58%.

Q: Would you summarize these models and give your conclusions?

A: In reviewing the various cost of capital models, we recognize that other models could have been used, such as a capital asset model and other technical approaches that might give indications as to how our common stock should be priced. I would suspect in the future that there will be risk comparisons between companies such as Black Hills and other corporations in similar risk positions, whether they be electric utilities or industrial corporations. The amount of potential possibilities for comparison is unlimited. Even though there is a wide variance between the DCF model, the historical averages, and the equity risk premium model, the suggested rate based on

our analysis falls within the general parameters. Therefore, in my opinion the appropriate cost of equity capital is 12.25%.

Q: I note that when applying your proposed return on equity that the Company is entitled to an overall rate increase of 17%, and yet you are only requesting a 10% increase. What is the resulting return on equity implicit in the 10% increase?

A: We have estimated the rate of return on Black Hills Power and Light based on a 10% increase in rates.

1995	1996	1997
11.5%	11.7%	12.2%

Whereas my testimony justified a 12.25% return on equity, the reduction in rate increase to 10% results in an estimated 11.5% return on equity. As noted, the MDU Sheridan sale starting in 1997 improves the return on equity to approximately 12.2%, which is the amount requested in testimony.

The program results in a phase-in of rates. During 1995 and 1996 the Company absorbs the lower return and the associated risks. The MDU Sheridan sale raises the return to a more appropriate

level. It is a reasonable plan for both customers and shareholders.

Q: I note that the Company's expected return on equity commencing with the rate increase and even in 1997 is below what you testify to as required to maintain bond ratings. Therefore, if this commission allows the rate increase you are requesting, aren't the bond ratings likely to be reduced? Please explain your answer.

A: The bond rating issue is a difficult one for the Company. For example, using the estimated numbers for a 10% rate increase plus the MDU Sheridan sale in 1997, the pretax interest coverage with purchase power adjustment is as follows:

	1993 Actual	1994 Actual	1995 Est.	1996 Est.	1997 Est.
Pretax interest coverage with purchase power adjustment	3.4 times	2.7 times	2.8 times	3.0 times	3.2 times
Standard & Poor's "A" rating criteria					2.5 - 4.0 times.

As noted above, the coverage declined from a strong 3.4 times to a low of 2.7 times. Again the MDU Sheridan sale in 1997 allows for some recovery. The other measures used by the rating agencies show similar trends.

It is my opinion that we can make a strong case to retain our bond ratings. The ratios in 1995 and 1996 are marginal. However, the 1997 MDU Sheridan sales allow us to present a plan for recovery to more adequate levels.

There are other positive aspects to highlight, such as the value of having NS #2 in rate base, the reduction of 50 megawatts of purchased power in 1995, and most importantly, having the consolidated financial strength of the unregulated companies which have very little debt to support the electric utility's debt ratios. While the debt is issued on the utility, we attempt to convince the rating agencies that we do not plan to spin off the subsidiaries, that they are an important part of our corporate goals and that their financial strength enhances the utility. While not totally accepted, they do strengthen our story. There is no guarantee we can maintain an "A" rating, but our goals and story has strength.

BHPL EXHIBIT DEC-1

AVERAGE EQUITY RETURN ON RATE CASES
COMPARED TO THE INTEREST RATE OF SINGLE A ELECTRIC
UTILITY FIRST MORTGAGE BONDS 1984-1993

Year	No. of Cases	Average Return on Equity*	Single A** Electric Utility First Mortgage Bonds	Spread
1984	82	15.37%	14.03%	1.34%
1985	59	15.16	12.47	2.69
1986	45	14.09	9.58	4.51
1987	29	12.99	10.10	2.89
1988	24	12.86	10.49	2.37
1989	27	12.83	9.77	3.06
1990	41	12.56	9.86	2.70
1991	44	12.58	9.36	3.22
1992	48	12.06	8.69	3.37
1993	30	11.40	7.59	3.81
Average Spread - 10 years 29.96 ÷ 10 years =				3.00%

Black Hills Corporation Single A First Mortgage Bond
11/11/94 9.04% + 3.00 = 12.04%

* Utility Industry Quarterly Regulatory Report, January 25, 1994, p. 61.

** Moody's

BHPL EXHIBIT DEC-2

EQUITY RISK PREMIUM
1977-1991

Year	Duff and Phelps, Inc. Actual Return %[1]	Long-Term Government Yield to Maturity[2]	Equity Risk Premium %
1979	1.10	-1.23	2.33
1980	5.88	-3.95	9.83
1981	20.55	1.86	18.69
1982	36.81	40.36	-3.55
1983	14.51	0.65	13.86
1984	21.49	15.48	6.01
1985	35.79	30.97	4.82
1986	32.57	24.53	8.04
1987	-9.27	-2.71	-6.56
1988	18.51	9.67	8.84
1989	26.62	18.11	8.51
1990	0.87	6.18	-7.05
1991	28.96	19.30	9.66
1992	8.56	8.05	.51
1993	10.01	18.24	-8.23

1979-1993 Average Risk Premium	4.38%
November 2021 Treasury Bond	8.20%
Return on Equity	12.58%

Source: [1]Duff & Phelps Inc. Electric Utility Data Base, p. 9 (90 companies)

[2]Ibbotson Associates 1994 yearbook, p. 175

DIRECT TESTIMONY OF ROXANN R. BASHAM
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
BLACK HILLS POWER AND LIGHT COMPANY
APPLICATION FOR A RATE STABILITY PLAN
DOCKET NO. EL95-003

Q: Please state your name and business address.

A: Roxann R. Basham, 625 Ninth Street, Rapid City, South Dakota.

Q: What positions do you hold with Black Hills Corporation, and what are your primary responsibilities?

A: I am the Secretary/Treasurer for Black Hills Corporation and its subsidiaries. I perform corporate responsibilities pursuant to the Bylaws and the statutory requirements of the companies, including the management of corporate treasury and shareholder activities. I am also responsible for all the financial forecasting and external financial reporting for Black Hills. Specific responsibilities include the Annual Report to Shareholders, Quarterly Letters to Shareholders, Form 10-K and 10-Q's filed with the Securities and Exchange Commission, forecasts for internal planning, and forecasts for the Bond Rating Agencies.

Q: What is your education and training which you believe qualifies you to give this testimony?

A: I graduated from the University of South Dakota's School of Business with a Bachelor of Science degree and a major in accounting. I have passed the Certified Public Accountant examination. I have ten years of experience doing the financial forecasting and reporting for Black Hills Power. I also regularly attend various seminars and training sessions pertaining to SEC filing requirements, accounting standards, and computer programs relative to my employment duties.

Q: From where will the fuel come to supply coal for Neil Simpson Unit #2?

A: Neil Simpson Unit #2 is being constructed at the site of the Wyodak coal mine, which is owned and operated by Wyodak Resources Development Corp., a wholly-owned subsidiary of Black Hills Corporation. Coal for Neil Simpson Unit #2 will be supplied from the Wyodak mine by Wyodak Resources which also supplies Black Hills' other plants.

Q: Does Wyodak Resources operate as a corporation separate from Black Hills Corporation?

A: Yes. Wyodak Resources is engaged only in the coal mining business and has no utility operations. It has its own employees and operating management and keeps books of accounting separate from Black Hills' books.

Q: Please describe the operations of Wyodak Resources.

A: Wyodak Resources was formed by Black Hills in 1956 for the purpose of engaging in the coal mining business and for that purpose acquired the coal mine in Campbell County, Wyoming, six miles east of Gillette. Prior to the acquisition, the mine was operated by Wyodak Coal Company, a subsidiary of Homestake Mining Company. Homestake did not have any federal coal under lease but did own some coal reserves which were leased to Black Hills for a royalty payment. Since that time, Wyodak Resources has greatly expanded its operation and has acquired federal coal leases. Most of the original Homestake coal has been mined and what is left has been purchased by Wyodak Resources from Homestake. Wyodak Resources has been the sole supplier of coal to its parent corporation, Black Hills, for all of its coal-fired power plants. Wyodak Resources' major contract is the

35-year all-requirements contract where Wyodak Resources took on the responsibility of supplying coal for the 330 MW Wyodak Plant, commencing with commercial operation in 1978. Twenty percent of those sales are in effect to Black Hills and 80 percent to PacifiCorp. Because shipping coal by rail to Black Hills' plants located away from the mine site became economically impractical, Wyodak Resources constructed a truck load-out facility so that coal hauling trucks can be efficiently loaded and dispatched to the various plants. Wyodak Resources has also had some other additional sales to various industrial users in our area.

Q: Does Wyodak Resources have storage facilities and rail load-out facilities capable of loading unit trains?

A: No.

Q: Why not?

A: Wyodak Resources in the past has had the capability of loading rail cars and did ship coal by rail to Black Hills' plants as well as coal to the power plants at Hastings, Nebraska, and Grand Island, Nebraska. However, these were not unit train load-outs capable of loading 110 cars

with 100 tons of coal each in a two- to four-hour time frame. Wyodak Resources could only load a few cars at a time over several hours. Wyodak Resources never constructed the long sidetrack and storage and loading facilities you would need to efficiently load unit trains. The reason Wyodak Resources never constructed those load-out facilities is its strategic decision to concentrate its business on furnishing coal for mine-mouth power plants, or later perhaps other types of coal-burning facilities, to be constructed on site and to furnish coal by truck delivery to users of the smaller quantities of coal away from the mine site. The best location, based on economic efficiencies and reliability of service for Black Hills to build power plants, is at the coal mine near Gillette. If during the oil embargo of the 1970s, Wyodak Resources had made the decision to build for unit train coal sales, the result would have been to commit its reserves to power plants away from the mine, and Wyodak Resources would have lost the opportunity to attract future power plants to the Wyodak site.

Q: What is the total annual production of Wyodak Resources at this time?

A: Approximately 2.7 million to 3 million tons depending on plant maintenance schedules.

Q: Who are the major customers of Wyodak Resources?

A: During 1994, PacifiCorp purchased approximately 1,600,000 tons of coal for its 80 percent interest in the Wyodak Plant, or approximately 56 percent of Wyodak Resources' total annual production and Black Hills purchased over 900,000 tons of coal for its 20 percent interest in the Wyodak Plant and for its other generating plants. Sales to industrial customers account for approximately 300,000 tons per year. It is expected that approximately 500,000 tons of coal per year will be required by Black Hills for operation of Neil Simpson Unit #2.

Q: Have the issues of coal supply and coal pricings for Neil Simpson Unit #2 and other Black Hills' power plants been presented previously for review by the South Dakota Public Utilities Commission and the Wyoming Public Service Commission?

A: Yes. These issues were discussed at length in testimony by Dan Landguth, Black Hills Corporation's Chief Executive Officer, in the

earlier Neil Simpson Unit #2 proceedings before the Wyoming Public Service Commission (Docket No. 20002-EA-92-27) and the South Dakota Public Utilities Commission (Docket No. EL92-026). The South Dakota Public Utilities Commission has for many years regulated the pricing of coal supplied to Black Hills by Wyodak Resources on the basis that the sale is a transaction between affiliated companies.

Q: Explain your familiarity with what we refer to as the Statement R calculation.

A: Part of my responsibilities is to make what we refer to as a Statement R calculation each year as it affects the Black Hills' Fuel and Purchased Power Adjustment tariff as applied to retail sales in South Dakota. The label of Statement R came from FERC accounting in presenting rate cases and is applied in most state jurisdictions. Statement R is the schedule in a rate case which relates to the sales from affiliates to the utility. In determining what Black Hills can pass through to customers under its current fuel adjustment tariff, the South Dakota commission limits any pass-on for all coal

sales from Wyodak Resources to Black Hills to the lower of the actual price provided for in the coal supply agreements or the amount that would yield Wyodak Resources a return on an earned investment base for sales to Black Hills equal to the interest rate for new long-term A-rated utility bonds being issued during the calendar year for which the calculation is being made plus four percentage points.

Q: Through what proceedings did the South Dakota Commission determine the methodology to limit the pass-through of coal costs?

A: In the Commission's Dockets F-3647-4 and F-3735, the Commission was investigating the effects of the 1986 Tax Reform Act (F-3647-4) and Black Hills' relationship with its trucking subsidiary, Universal Transport Inc. (F-3735). The Docket F-3735 also led to an investigation into coal purchased by Black Hills from Wyodak Resources, its coal subsidiary. This investigation led to a stipulation between Black Hills and the Commission's Staff dated August 1, 1988. I submit BHPL Exhibit RRB-1, as a copy of that

stipulation, and BHPL Exhibit RRB-2, as a copy of the Commission's order dated August 4, 1988 approving that settlement and closing the investigation.

Q: Has the Company complied with the Fuel and Purchased Power Adjustment rate schedule since this stipulation?

A: Yes. I am personally responsible for the preparation of the Statement R calculations of Wyodak Resources' return on coal sales to Black Hills to determine the necessity of any refund. Statement R calculations have been filed prior to April 1 of 1989, 1990, 1991, 1992, 1993 and 1994 as required by the stipulation and order.

Q: Were these calculations in compliance with the stipulation and order and the Fuel and Purchased Power Adjustment rate schedule in effect?

A: Yes

Q: Were refunds calculated and made?

A: Yes. The following refunds were calculated:

April 1, 1989	$475,825
April 1, 1990	$516,635
April 1, 1991	$1,011,231

April 1, 1992	$934,096
April 1, 1993	$1,537,606
April 1, 1994	$1,060,542

Refund credits on the Fuel and Purchased Power Adjustment were made in compliance with the stipulation and order.

Q: Have you prepared a Statement R calculation for the test year?

A: Yes. I have prepared a Statement R calculation for the twelve months ended September 30, 1994. The calculation is filed as Statement R in Volume 1 of this application.

Q: What was the amount of the coal adjustment calculated in Statement R?

A: The coal adjustment calculated for the test period, the twelve months ended September 30, 1994, was $948,066.

Q: Was the calculation for the test period in compliance with the stipulation and order and the Fuel and Purchased Power Adjustment rate schedule in effect?

A: Yes. However, any refunds due will be determined based upon calendar year 1994. This calculation is for illustration purposes only.

Q: Did you prepare the adjusted fuel and purchased power costs on Statement H filed in Volume I of this application?

A: Yes.

Q: What was the basis for this adjustment?

A: Fuel and purchased power costs were reduced to reflect the savings on fuel and purchased power costs associated with the operation of Neil Simpson Unit #2. When Neil Simpson Unit #2 becomes commercially operational, it will be replacing energy and capacity that is currently being purchased to support system sales. Fuel costs are forecasted to decrease slightly even with the additional coal purchased for Neil Simpson Unit #2 because of the pricing methodology used in the Neil Simpson Unit #2 coal contract and because of decreased transportation expenses.

Q: Ms. Basham, please explain the decrease in transportation expenses.

A: Neil Simpson Unit #2 is a mine mouth power plant, has no transportation charges associated with the coal it uses, and it will have the lowest production costs of all our power plants. Because of its low production costs it will be dispatched

at a high load factor. The power plants that require coal transportation have higher production costs and will be dispatched at lower load factors. These plants will have less coal transported and therefore savings in transportation costs.

Q: Please explain the pricing methodology used in the Neil Simpson Unit #2 Coal Contract.

A: The coal price for Neil Simpson Unit #2 during a calendar year is equal to the Affiliate Price Limitation (Statement R) less the amount paid by Black Hills to Wyodak Resources for coal consumption at the existing plants under the 1977 Coal Agreement and for Black Hills 20 percent interest in the Wyodak Plant under the PacifiCorp Coal Agreement for the calendar year for which the purchase price is being determined and further reduced by a dispatch discount. Wyodak Resources Development Corp. and Black Hills Corporation entered into the Restated and Amended Coal Supply Agreement for Neil Simpson Unit #2 as of February 12, 1993. A copy of that Coal Agreement is filed as BHPL Exhibit RRB-3. The dispatch discount is the amount Wyodak Resources will reduce the coal price for coal delivered to any of

the existing plants if necessary to make the existing plant economically dispatchable over the estimated variable costs of the Colstrip Agreement. Economically dispatchable for these purposes means that under Prudent Utility Practice, Black Hills would not have generated power from one or more of the existing plants unless the coal price to be paid under the September 1, 1977 Coal Agreement (attached as Exhibit A to Exhibit RRB-3) was reduced.

Q: What will be the typical coal price under this formula for Neil Simpson Unit #2?

A: I am submitting what is marked BHPL Exhibit RRB-4. This exhibit shows the calculation of the coal price using the Affiliate Coal Adjustment for years 1996-1999. Page 1 of this exhibit shows the incremental cost of coal per ton for Neil Simpson Unit #2 and Page 2 shows the average price per ton for all Black Hills Plants including Neil Simpson Unit #2. If the dispatch discount comes into play, then the price will be reduced further by the amount of the discount.

Q: After Neil Simpson Unit #2 becomes operational will the Company continue to pay Wyodak Resources

a coal price higher than the Statement R calculation so as to continue to require refunds?

A: No. As the Coal Agreement (Exhibit RRB-3) states, after Neil Simpson Unit #2 becomes commercially operational, Black Hills will pay Wyodak Resources an estimated coal price for all coal purchased by Black Hills, including Black Hills 20 percent interest in the Wyodak Plant, based upon a forecasted Statement R calculation. On each April 1, Wyodak Resources shall calculate the purchase price for coal sold to Black Hills for the preceding calendar year. Appropriate charges and credits will then be made for coal sold during the previous calendar year in order that the actual purchase price paid for coal during that calendar year is in accordance with the formula in the February 12, 1993 Coal Agreement. In effect, the coal agreement for the new plant will determine the coal price for all coal purchased by Black Hills from its subsidiary.

Q: How does Black Hills report the cost of coal on the FERC Form 1?

A: Because the Statement R adjustments have been made at the revenue level without adjustment to the coal expense recorded in Black Hills' financial

statements, the "net" coal cost to Black Hills customers in 1993 after adjustment for Statement R refunds is approximately 10 percent lower than the amount reflected as coal expense in Black Hills' accounting records and in the FERC Form No. 1.

Q: How do coal costs for Black Hills' power plants compare with coal costs for other utilities?

A: Exhibit RRB-5 shows the delivered coal cost per million BTU for Black Hills' generating plants after the Statement R adjustment. Exhibits RRB-6 is a table taken from the 1993 Edison Electric Institute's Statistical yearbook that summarizes the cost of fossil fuels used for electric generation by geographic division.

Q: What conclusions do you draw from Exhibits RRB-5 and RRB-6?

A: Exhibit RRB-5 shows the delivered cost of coal for all Black Hills' plants for 1993 was 70.87 cents per million BTU. Exhibit RRB-6 shows the 1993 delivered cost of coal used in electric generation in the United States was 144.8 cents per million BTU, 108.8 cents per million BTU for the West North Central division and 117.0 cents per million BTU for the mountain division. The West North Central division includes Montana, Iowa, Missouri,

North Dakota, South Dakota, Nebraska and Kansas. The mountain division includes Montana, Idaho, Wyoming, Colorado, New Mexico, Arizona, Utah and Nevada. From the statistics shown in these exhibits it is very easy to see the delivered coal costs for Black Hills Corporation are among the lowest in our geographic regions and in the country.

Q: What were the coal cost comparisons for 1994?

A: The Delivered cost of coal for all of Black Hills' plants for 1994 was 76 cents per million Btu. I haven't been able to locate 1994 statistics for the delivered cost of coal to other regions, but when those statistics are available, I will furnish a late-filed exhibit.

Q: Please explain why you believe your comparison of delivered coal costs to be valid to support your conclusion that Black Hills' coal costs are among the lowest in the nation, when delivery costs to each plant in the nation are based on materially different mine-to-plant distances.

A: Coal must be delivered to the plant before it has any value. Delivered cost of coal is the only valid comparison to determine fair coal pricing because that is the cost the customer pays.

Locating a less costly source of coal from a mine far from the plant does not provide a benefit if the transportation costs and costs of constructing and operating coal load-in facilities are more than the mine-mouth coal purchase savings.

Q: Is it your testimony that comparing the cost of delivered coal to other plants is the method this Commission should use to determine the fairness of the Company's coal purchases from its subsidiary? Please explain.

A: No. In my opinion, this Commission's methodology through the Statement R calculation restricting the Company from passing through any coal costs to customers that would yield Wyodak Resources a return above the threshold as provided is the fairest and most workable method. This is especially true in this case where 170 MW of Black Hills' generation is constructed at the mine mouth with conveyor systems in place to supply the coal and where no load-in facilities are available. In addition, Wyodak Resources has made an unusual commitment to supply coal to Black Hills for the life of the plants. This means that Wyodak Resources gives up any opportunity that might come about within a time span of over one-half of a

century to sell the committed coal reserves at a price that may yield substantially more profit than the return allowed by Statement R. I compared Black Hills' delivered cost of coal to other plants only as another fairness check to illustrate to the Commission that the Statement R methodology imposed by this Commission when coupled with Wyodak Resources' life-of-the-plants commitment does assure our customers a long-term cost of delivered coal substantially below what other utilities are paying with long-term protection against energy price increases.

Q: Ms. Basham, are you familiar with the sale of power to Sheridan, Wyoming?

A: Yes, beginning January 1, 1997, Black Hills will supply the electric power and energy for ten years for all of Montana-Dakota Utilities electric service requirements for its Sheridan, Wyoming service territory.

Q: Have you calculated the benefits to Black Hills' other customers resulting from the sale?

A: Yes, I am submitting BHPL Exhibit RRH-7. This exhibit shows the forecasted revenue from the sale for the ten years of the contract and the forecasted associated costs of serving the

Sheridan area. The amount of forecasted benefits from the sale shown in the exhibit is before federal income taxes.

Q: How were the fuel and purchased power figures derived?

A: Black Hills system control department ran two dispatch scenarios, one with the Sheridan sale and one without the sale, through their ENPRO model to determine the amount of energy that would be generated and the amount of energy that would need to be purchased which we call our resource forecast. The resource forecast for each dispatch scenario was then put into financial spreadsheets to determine the fuel and purchased power costs. The difference in the costs of the two scenarios is the forecasted cost of serving the Sheridan sale. Tom Ohlmacher will lay the foundation for this calculation in his testimony.

Q: Does this conclude your testimony?

A: Yes.