- **NC GreenPower (NCGP):** North Carolina's voluntary green power program.

- **Net Present Value (NPV):** NPV is the sum of the future stream of benefits and costs converted into equivalent values today. This is done by discounting future benefits and costs using an appropriate discount rate.

- **Production Tax Credit (PTC):** A federal tax credit available to certain electric energy production facilities based on the facilities' kWh production.

- **Renewable Portfolio Standard (RPS):** A policy tool that establishes a requirement to have a certain portion of an electricity portfolio be supplied from renewable or alternative resources. The RPS is typically denoted as a percentage of electricity sold to retail customers and is often achieved by phased-in increases over time.

- **Supply Curve:** The ranking of potential supply options based on cost from lowest to highest showing their expected cumulative MWh contribution.

- **Utilities' Portfolio:** The Utilities' Portfolio represents the sum of anticipated new projects needed to meet load growth and retirements according to the State's utilities' 2006 IRP filings.

Bibliography

Citations

- "20-MW Wind Farm and Associated Energy Storage Facility Environmental Assessment." Apr. 2002. TVA. NC AG Roy Cooper Comments. <http://www.tva.gov/environment/reports/windfarm/appendix_h.pdf>

- "2004-2005 Agricultural Statistics, County Estimates." 18 Sep. 2006. NC Dept of Agriculture and Consumer Services. <http://www.ncagr.com/stats/cnty_est/ctybroyr.htm>

- "2004-2005 Agricultural Statistics, County Estimates." 19 Sep. 2006. NC Dept of Agriculture and Consumer Services. <http://www.ncagr.com/stats/cnty_est/ctytrkyr.htm>

- "2006 TRANSMISSION RANKING COST REPORT OF PG&E." (CPUC Decision 04-06-013 Attachment A and Decision 05-07-040, OIR 04-04-026.) 9 Nov. 2005. PG&E. <https://www.pge.com/regulation/RenewablePortfolioStdsOIR/Other-Docs/PGE/2006-01-Fwd/RenewablePortfolioStdsOIR_Other-Doc_PGE_20060315-01.pdf>

- "2006 World PV Industry Report Highlights." *Solarbuzz*. <http://www.solarbuzz.com/Marketbuzz2006-intro.htm>

- "A Primer on Developing North Carolina's Landfill Gas Utilization Potential." (EPA 430-R-00-010.) Feb. 2001. EPA. <http://www.epa.gov/lmop/>

- Anfinson, Reed. "$202 million Fibrominn financing deal completed. Construction to begin in the spring." *The Swift County Monitor News*. 15 Dec. 2004. <http://www.swiftcountymonitor.com>

- *Biomass Energy Data Book*. Oak Ridge National Labs. <http://cta.ornl.gov/bedb/appendix_a/Approximate_Heat_Content_of_Selected_Fuels_for_Electric_Power_Generation.xls>

- Bird, Lori et al. "Green Power Marketing in the United States: A Status Report (Eighth Edition)." (NREL/TP-620-38994.) Oct. 2005. NREL. <http://www.eere.energy.gov/greenpower/resources/pdfs/38994.pdf>

- Black & Veatch. "Economic Impact of Renewable Energy in Pennsylvania." Mar. 2004. Community Foundation for the Alleghenies. <http://www.bv.com/energy/eec/studies/PA_RPS_Final_Report.pdf>

- Camberato, Jim. "Land Application of Poultry Manure." <http://hubcap.clemson.edu/~blpprt/pasture/lpptable.html>

- "Case Study: Craven County Wood Energy." 1997. North Carolina Department of Energy and Natural Resources. <http://www.p2pays.org/ref/05/04271.htm>

- "Charting North Carolina's Clean Energy Future." Apr. 2003. Environmental Defense and the North Carolina Sustainable Energy Association.

- Conner, Alison M. "U.S. Hydropower Resource Assessment for North Carolina." (DOE/ID-10430(NC).) Oct. 1997. Idaho National Engineering and Environmental Laboratory. <http://hydropower.inel.gov/resourceassessment/index_states.shtml?id=nc&nam=North%20Carolina>

- "Cost and Returns Analysis of Manure Management Systems: Technology Report (Barham Farm)." *Smithfield Agreement*. Jul. 2005. North Carolina State University. <http://www.cals.ncsu.edu/waste_mgt/smithfield_projects/phase2report05/cd,web%20files/B1c.pdf>

- "The Costs and Impacts of Intermittency." 6 Apr. 2006. UKERC. <http://www.ukerc.ac.uk/content/view/258/852>
- "County Waste Disposal Report (04-05)." 2006. <http://www.wastenotnc.org/SWHOME/CtyWstdisp0405.pdf>
- "Determining Tax Credit for Investing in Renewable Energy Property." NC Solar Center. <http://www.ncsc.ncsu.edu/information_resources/renewable_energy_tax_guidelines.cfm>
- "Draft BACT Guidelines for Biomass Projects." 23 Jun. 2006. MA DEP. Memorandum to RPS Stakeholders. <http://www.mass.gov/dep/air/laws/biombact.pdf>
- "Economic Impact Analysis of New Jersey's Proposed 20% Renewable Portfolio Standard." Dec. 2004. Rutgers University. NJ Board of Public Utilities - Office of Clean Energy. <http://www.state.nj.us/bpu/reports/EIAreport.pdf>
- "Fibrominn Biomass Power Plant Exemption." (Docket No: 01-09-EXEM-Fibrominn.) Minnesota Public Utilities Commission. <http://energyfacilities.puc.state.mn.us/Docket.html?Id=2556>
- "How does electricity use affect the environment?" EPA. <http://www.epa.gov/cleanrgy/impacts.htm>
- "How North Carolina Agriculture Compares with Other States – 2004 Production." 2 May. 2005. NC Dept of Agriculture and Consumer Services. <http://www.ncagr.com/stats/nc_rank/ncrallyr.htm>
- "Implementation of the 'Clean Smokestacks Act'." 1 Jun. 2006. North Carolina Department of Environment and Natural Resources and the North Carolina Utilities Commission. <http://www.ncuc.commerce.state.nc.us/reports/csa2006.pdf>
- Gadomski, Chris. "Catch the Credits." *Project Finance*. Mar. 2006. <http://www.smidirect.net/published/catch%20the%20credits.htm>
- Grady, Dennis O. Ph.D. "Public Attitudes toward Wind Energy in Western North Carolina: A Systematic Survey." 9 Dec. 2002. Appalachian State University. <http://www.energy.appstate.edu/docs/wnc_pubsurvey.pdf>
- "Guidelines For Determining Tax Credit For Investing In Renewable Energy Property." NC Department of Revenue. <http://www.dor.state.nc.us/practitioner/individual/directives/renewableenergyguidelines.html>
- Hall, Douglas G. "Estimation of Economic Parameters of U.S. Hydropower Resources." (INEEL/EXT-03-00662.) Jun. 2003. Idaho National Engineering and Environmental Laboratory. <http://hydropower.inel.gov/resourceassessment/pdfs/project_report-final_with_disclaimer-3jul03.pdf>
- James Barker, Professor. "Methane Fuel Gas from Livestock Wastes: A Summary." 14 Mar. 2001. NCSU. <http://www.bae.ncsu.edu/programs/extension/publicat/wqwm/ebae071_80.html>
- Lichtenberg, Erik. "Economic Value of Poultry Litter Supplies in Alternative Uses." University of Maryland. <http://www.arec.umd.edu/agnrpolicycenter/Publications/Reports/Parker_PoultryLiter.pdf>
- "Market Opportunities for Biogas Recovery Systems." EPA. AgStar. <http://www.epa.gov/agstar/pdf/biogas%20recovery%20systems_screenres.pdf>
- "NC Energy Outlook, 2003." May. 2003. Global Insight. <http://www.energync.net/resources/docs/pubs/energyoutlook.pdf>
- "NC GreenPower Program Plan." Nov. 2002. *Advanced Energy*. <http://www.ncgreenpower.org/elements/pdfs/NCGreenPowerProgramPlan.pdf>

- "The NC Ridge Law Is No Obstacle to Wind Power." 24 Aug. 2003. Blue Ridge Environmental Defense League. <http://www.bredl.org/pdf/RidgeLaw-WindFactsheet24aug03.pdf>
- "North Carolina Energy Outlook 2003." May. 2003. Global Insight. NC State Energy Office. <http://www.energync.net/epc/docs/nceo2003.pdf>
- "The Potential for Biomass Cofiring in Maryland." (DNR 12-2242006-107 PPES-06-02.) Mar. 2006. Princeton Energy International, LLC. et al. Maryland Department of Natural Resources. <http://esm.versar.com/PPRP/bibliography/PPES_06_02/PPES_06_02.pdf>
- "Property Tax Rates and Latest Year of Revaluation for North Carolina Counties and Municipalities." 9 Sept. 2006. NC Dept. of Revenue. <http://www.dor.state.nc.us/publications/propertyrates.html>
- "RGGI: Electricity Sector Modeling Results (8-State Sensitivity Results)." 21 Dec. 2005. ICF. RGGI. <http://www.rggi.org/docs/ma_sensitivity_results_12_21_05.ppt>
- "Rhodhiss Hydro to Celebrate 75th Anniversary." Feb. 2000. Duke Energy News Release. <http://www.duke-energy.com/news/releases/2000/Feb/2000021801.html>
- Scanlin, Dennis. "Appalachian Wind Power." (Powerpoint.) Mar. 2005. Appalachian State University. <http://www.wind.appstate.edu/ppt/raleigh2005.ppt>
- Segrest, S. A., et al. "Biomass Co-Firing with Coal at Lakeland Utilities." 31 Jul. 1998. Department Of Energy. <http://www.treepower.org/papers/energycrops.pdf>
- Singh, Virinder, et al. "The Work That Goes Into Renewable Energy." Nov. 2001. Renewable Energy Policy Project. <http://www.crest.org/articles/static/1/binaries/LABOR_FINAL_REV.pdf>
- "State and Trends of the Carbon Market 2006." 2006. World Bank. <http://www.carbonfinance.org/docs/StateoftheCarbonMarket2006.pdf>
- "Summer 2006 Newsletter." NC GreenPower. <http://www.ncgreenpower.org/media/newsletters/2006/newsletter_summer2006.html?#update>
- "The Value of the Benefits of U.S. Biomass Power." (NREL/SR-570-27541.) Nov. 1999. NREL. <http://www.nrel.gov/docs/fy00osti/27541.pdf>
- Wiser, Ryan, et al, "Evaluating Experience with Renewables Portfolio Standards in the United States." Prepared for the Conference Proceedings of Global Windpower 2004 Chicago, Illinois. March 2004. Lawrence Berkeley National Laboratory. <http://eetd.lbl.gov/ea/ems/reports/54439.pdf>

References

- "A Brief Overview of U.S. Studies on the Local Economic Development Impacts of Wind Energy." (Presented to Canadian Wind Energy Association.) Nov. 2005. La Capra Associates.
- AgSTAR Digest. Winter 2006. AgStar. EPA. <http://www.epa.gov/agstar/pdf/2006digest.pdf>
- Cherry, Todd L. "The Net Benefits of Utility-scale Wind Generated Electricity in Western North Carolina." Jun. 2004. Appalachian State University. <http://www.wind.appstate.edu/reports/final_bcr_report.pdf>
- "Comparing Statewide Economic Impacts of New Generation from Wind, Coal, and Natural Gas in Arizona, Colorado, and Michigan." (NREL/CP-500-38154.) WINDPOWER 2005. Aug. 2005. NREL. <http://www.nrel.gov/docs/fy06osti/37720.pdf>

- "Dollars from Sense, the Economic Benefits of Renewable Energy." Sep. 1997. U.S. Department of Energy, National Renewable Energy Laboratory.
- "Economic Development Impacts of Wind Power - Summary of Case Study Results." Jun. 2004. National Wind Coordinating Committee. <http://www.nationalwind.org/publications/economic/casestudy_summary.pdf>
- Hadley, S.W. ORNL. "The Potential for Energy Efficiency and Renewable Energy in North Carolina." Apr. 2003. North Carolina Solar Center. <http://www.ornl.gov/~webworks/cppr/y2001/rpt/116643.pdf>
- Hag, Zia. "An Introduction to Biomass." (Presentation.) 28 Feb. 2006. EIA. <http://www.eia.doe.gov/oiaf/presentation/biomass/pdf/biomass.pdf>
- Kuhr, Reiner et al. "Investing in MegaProjects: Comparison of Costs and Risks." (Presented at Power Gen 2005.) 24 Aug. 2003. Stone & Weber Management Consultants.
- "Measuring the Economic Impact of Cooperatives in Minnesota." Dec. 2003. United States Department of Agriculture, Rural Business Cooperative Service.
- "Meeting Expectations: A Review of State Experience with RPS Policies." (Powerpoint Presentation.) Mar. 2006. Lawrence Berkeley National Laboratory, Energy Analysis Department.
- "Moving Poultry Litter in Alabama." Apr. 2006. Department of Agronomy & Soils, Auburn University. <http://www.aces.edu/timelyinfo/Ag%20Soil/2006/April/s-03-06.pdf>
- "New York Portfolio Standard Cost Study Report II." (CASE 03-E-0188.) Feb. 2004. SEA and La Capra Associates. NYDPS and NYSERDA. <http://www.dps.state.ny.us/03e0188_CostStudy_II.htm>
- Nogee, Alan. "Renewable Electricity Standards: Overview and Some Costs and Benefits." (Powerpoint Presentation.) Union of Concerned Scientists.
- "Portfolio Standards Act of 2004: Standards for the Participation of Demand Side Management Resources." (Docket No. M-00051865, Final Order.) Pennsylvania Public Utility Commission.
- Swenson, David et al. "Statewide Economic Values of Alternative Energy Sources and Energy Conservation." Mar. 2002. The Iowa Policy Project. <http://www.iowapolicyproject.org>

Appendices

Appendix A: June 30, 2006 Letter to Environmental Review Commission

State of North Carolina
Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4325

COMMISSIONERS
JO ANNE SANFORD, Chair
ROBERT V. OWENS, JR.
SAM J. ERVIN IV

COMMISSIONERS
LORINZO L. JOYNER
JAMES Y. KERR, II
HOWARD N. LEE
WILLIAM T. CULPEPPER, III

June 30, 2006

Sen. Charlie Albertson, Co-Chair
Sen. Daniel G. Clodfelter, Co-Chair
Rep. Pryor A. Gibson III, Co-Chair
Environmental Review Commission
545 Legislative Office Building
300 North Salisbury Street
Raleigh, North Carolina 27603

Dear Messrs. Albertson, Clodfelter, and Gibson:

On January 24, 2006, the Environmental Review Commission (ERC) of the North Carolina General Assembly adopted a motion requesting the North Carolina Utilities Commission (Commission) to undertake a study of the potential costs and benefits of enacting a renewable energy portfolio standard (RPS) in this State. The process proposed to and adopted by the ERC requires the Commission to issue a request for proposals (RFP) and to ultimately contract with an experienced consultant to perform the study under the direction and guidance of the Commission.

On February 23, 2006, we received a letter from George Givens, ERC Counsel, memorializing the above request. In his letter, Mr. Givens requested that the Commission provide the ERC with a status report on the study no later than July 1, 2006, and a final report on the study no later than December 1, 2006. We are pleased to provide the ERC with this status report of our progress to date, and we remain committed to provide our final report by December 1, 2006, as requested.

From the beginning, the Commission has recognized the importance of working with interested stakeholders and soliciting their input. Prior to the January 2006 ERC meeting, the Commission met with utility and environmental representatives to discuss options for performing a cost/benefit study. After the ERC meeting, the Commission formed an advisory group representing various stakeholder interests, including ratepayers, utilities, and environmental groups, to assist it in preparing its report for the legislature. The following nine persons have agreed to serve on the RPS Advisory Group:

430 North Salisbury Street • Raleigh, North Carolina 27603
Telephone No. (919) 733-4249
Facsimile No. (919) 733-7300

Messrs. Albertson, Clodfelter, and Gibson
Page 2
June 30, 2006

Mitch Williams, Progress Energy
David Beam, North Carolina Electric Membership Corporation
Ivan Urlaub, North Carolina Sustainable Energy Association
Kris Corasini, Environmental Defense
Sue Gouchoe, North Carolina Solar Center
Preston Howard, Manufacturers and Chemical Industry Council of NC
Dr. Ed Erickson, Professor of Economics, North Carolina State University
James McLawhorn, Public Staff-NCUC
Len Green, North Carolina Attorney General's Office

Because this project involves the expenditure of State funds, it was necessary to solicit competitive bids from consultants willing to perform the cost/benefit study. The Commission's initial task, therefore, was to prepare a memorandum for the Department of Commerce (Commerce) to seek approval from the Department of Administration, Division of Purchasing and Contracts (Administration), to issue a request for proposals (RFP) to engage an experienced consultant to perform the required study. This memorandum was prepared and sent to Commerce on March 10, 2006. Approval to issue an RFP was received on April 6, 2006.

While awaiting approval to issue an RFP, the Commission, with the assistance of the RPS Advisory Group, drafted an RFP. After reviewing efforts undertaken in other states, Commission Staff prepared a draft RFP and circulated it to the RPS Advisory Group for comment. A final draft RFP was sent to Commerce on April 21, 2006. Additional changes were made, and the final RFP was sent to Administration on April 27, 2006.

After approval by Administration, the RFP was posted on May 12, 2006, with bids due on June 5, 2006. A copy of the final RFP is enclosed. Notice of the issuance of the RFP was posted on the Commission's web site. In addition, based upon input from the RPS Advisory Group and inquiries from press reports, nineteen individuals representing sixteen consulting firms were specifically notified by email and invited to bid. The Commission ultimately received five bids in response to the RFP.

To most efficiently complete the evaluation process, the following balanced, representative subset of the RPS Advisory Group was selected to assist the Commission with evaluating the bids submitted in response to the RFP: James McLawhorn, Ivan Urlaub, Mitch Williams, and Dr. Ed Erickson. All members of the RPS Advisory Group, however, will participate and lend their expertise in the remaining phases of this project, both in providing input to define the parameters of the study as well as in reviewing the work performed.

The evaluators met on May 26, 2006, before the bids were due, to determine the criteria against which the bids would be evaluated. The group decided that technical merits

Messrs. Albertson, Clodfelter, and Gibson
Page 3
June 30, 2006

of the bids would be primarily evaluated against the non-cost criteria stated in Section 4.I of the RFP – "completeness, content, experience with similar projects, the ability of the offeror and its staff, proposed plan of action to carry out the requirements set forth herein" – and the bidder's references. The group further decided that bids would be evaluated by the group as a whole, rather than individually by each evaluator.

On June 6, 2006, copies of the bidders' proposals were distributed to evaluators, who then met on June 9, 2006, to evaluate the proposals. Based upon the results of the evaluation, a memorandum was sent to Commerce on June 15, 2006, requesting that the costs proposals be opened for those bidders who successfully passed the technical review. The required two days' notice was sent to those bidders on June 20, 2006, and the cost proposals were opened on June 23, 2006. Based upon a review of the cost proposals, a memorandum was sent to Commerce on June 23, 2006, recommending a bidder with which the contract should be awarded. The recommendation is currently being reviewed by Administration and a contract should be awarded shortly.

The Commission will meet with the consultant and the RPS Advisory Group within two weeks after the contract is awarded to discuss and determine the specifics of the study to be performed, including the analytical methods and models to be used, sources of data to be used as input for the study, assumptions to be made and used in the study, scenarios to be analyzed in the study, and sensitivity analyses to be performed as part of the study. Knowledgeable input from the consultant based upon prior similar research will be vital in determining the specific scope and details of the study and in maximizing the usefulness of the study to the legislature in its deliberations. The Commission expects the consultant, in gathering data for the study, to confer, to the greatest extent possible, with the State Energy Office, the North Carolina Solar Center, NC GreenPower, utilities, and others who have previously investigated or attempted to inventory the potential for renewable energy production in North Carolina. However, the consultant shall endeavor to independently verify the reasonableness of all data and assumptions used in the study.

The consultant shall deliver to the Commission an initial draft report, incorporating the results of the cost/benefit analysis, within twelve weeks after the contract has been awarded. The draft report will be circulated to members of the RPS Advisory Group for comment and critique. The consultant shall meet in Raleigh with the Commission and members of the RPS Advisory Group to discuss comments received and to determine final revisions necessary to the report, and shall deliver to the Commission a final report within three weeks thereafter. Lastly, the consultant shall assist the Commission in presenting the

Messrs. Albertson, Clodfelter, and Gibson
Page 4
June 30, 2006

results of the study to the ERC and shall remain available to meet with the Commission and others to present and discuss the results of the study.

Please feel free to contact me if you have any questions. With warmest personal regards, I am

Very truly yours,

Jo Anne Sanford (signature)

Jo Anne Sanford, Chair

JYK/LSW

Enclosure

cc: Environmental Review Commission Members
RPS Advisory Group Members
George F. Givens
Steven J. Rose
Robert P. Gruber
Commissioners

Appendix B: La Capra Team Background

The La Capra Associates Team responsible for this Report consists of La Capra Associates, Inc, GDS Associates, Inc., and Sustainable Energy Advantage, LLC (SEA). Each firm has a significant energy practice and has assisted numerous clients in renewable energy and/or energy efficiency policy issues and project review and development across the country. In addition, each company draws on decades of experience with conventional energy issues from understanding the intricacies of electric power systems to ratemaking and resource planning. The La Capra Associates Team has a broad base of experience that covers most of the states across the U.S. in both regulated and deregulated electric environments.

Corporate Background

La Capra Associates, Inc. is an employee owned, Boston-based consulting firm specializing in the electricity industry. Since its founding in 1980, La Capra Associates has earned a reputation for practical and objective advice and for timely, accurate, and innovative analyses. Over the years, La Capra Associates has provided strategic planning advice to policy makers and senior managers along with expert, technical analysis to support policy, investment, and operational decisions. La Capra Associates provides consulting services regarding energy planning and risk management, power market analysis, ratemaking, and regulatory policy in the electric industry. La Capra Associates has a thorough understanding of electric power systems and the costs and risks related to production of electricity from both renewable and non-renewable generation.

GDS Associates, Inc. is a multi-service engineering and management consulting firm, headquartered in Marietta, Georgia, with offices in Auburn, Alabama; Austin, Texas; Manchester, New Hampshire; and Madison, Wisconsin. GDS has served its energy industry clients since its inception in 1986. GDS has conducted numerous technical potential and economic analysis studies on energy efficiency and renewable energy measures for various state entities as well as electric and gas utility clients. GDS is also well-versed in conducting economic modeling of costs and benefits of public policy decisions related to the electric and natural gas industries. More specifically, GDS has worked for North Carolina clients since 1987, and GDS consultants are very familiar with the electric industry structure and operations in North Carolina.

Sustainable Energy Advantage, LLC has provided interdisciplinary support to private, public and non-profit organizations involved in developing competitive electricity market ventures and market infrastructure for environmentally preferable electricity supply since 1998. SEA provides strategic, policy, marketing, product development and pricing, negotiation, and analytical support to developing wholesale and retail renewable electricity businesses. SEA has also been instrumental in assessing, developing, and implementing public policies regarding renewable energy including various state Renewable Portfolio Standards and subsidy and incentive programs.

Relevant Renewable Energy Experience

The La Capra Associates Team has broad experience concerning renewable energy markets and state renewable portfolio standards ("RPS"). Below we summarize the types of renewables-related projects we have been involved with in the past that serve as the foundation of our experience.

1) **Renewables Supply and Cost Analysis.** La Capra Associates, SEA, and GDS have all conducted extensive studies on the potential renewable supply and economic analyses in various

states through work with state regulators, developers, and wholesale and retail buyers. La Capra Associates and SEA also provided all the renewables resource assumptions used in the Regional Greenhouse Gas Initiative (RGGI) that included the northeast and some mid-Atlantic states. This information was used as part of a modeling effort to determine RGGI policy costs. SEA and La Capra Associates have built an extensive database of resource costs and a methodology to assess resource potential in these states. GDS has also prepared technical potential and economic analyses of renewable energy options for several clients in the Southeast U.S.

2) **Rate Impacts of Renewables.** La Capra Associates and GDS have active regulatory practices and have participated in many rate-making cases involving both investor-owned and publicly-owned utilities. This work has included Integrated Resource Planning assessments that include renewables, determining how to set renewables/green rate riders or system benefit charges, and providing advice on how to determine rate recovery for such resources. Recently, SEA and La Capra Associates conducted studies that estimate the overall rate impact of RPS scenarios to consumers in Connecticut and New York. La Capra Associates has also been involved with ratemaking cases related to renewables procurement in regulated states. GDS has prepared studies on the rate impacts of solar energy systems for utility and governmental clients in the Southeast.

3) **RPS Design and Cost/Benefit Analysis.** La Capra Associates, GDS and SEA have been closely involved in the development of RPS legislation and policies in multiple states in the past five years. We have provided advice on RPS policy goals, structures, and potential impacts to policy makers, regulators, and market participants in Massachusetts, New York, Connecticut, Rhode Island, Delaware, Vermont, Wisconsin, Hawaii, New Hampshire, Maine, Texas, Georgia and California. As part of this work, we have provided cost/benefit analyses that capture many of the externalities of incorporating renewables and demand-side resources into a power mix.

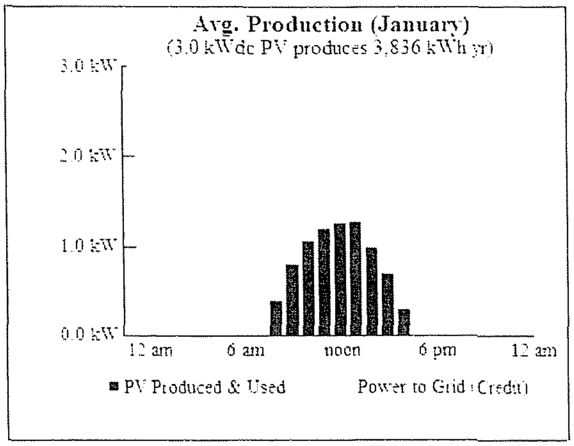
4) **RPS Implementation.** The La Capra Associates Team also has first-hand experience in various states in translating RPS policies to specific rules and regulations and addressing the full range of RPS implementation issues. La Capra Associates, GDS and SEA have helped states in the implementation phase on several fronts, including: defining eligibility rules, guidance on procurement methods, and contracting for renewable energy and renewable energy certificates.

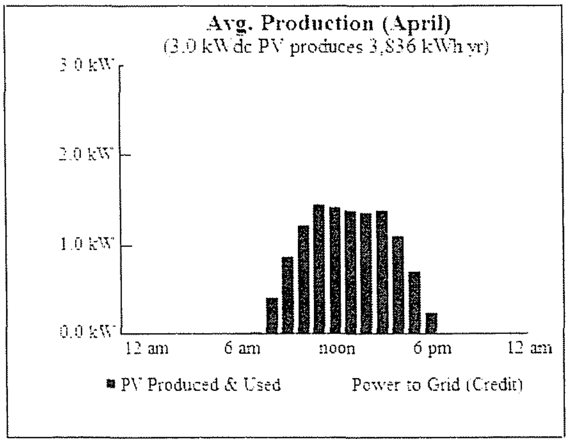
5) **Market/Portfolio Impacts of Renewables.** La Capra Associates also has a strong power supply analysis team and has performed detailed studies regarding the impact of renewables on regional power markets and power supply portfolios with respect to generation dispatch, cost and emissions/environmental impact. GDS has worked for the North Carolina Electric Membership Cooperative on power supply planning for many years and has knowledge of the North Carolina grid's design and operational characteristics.

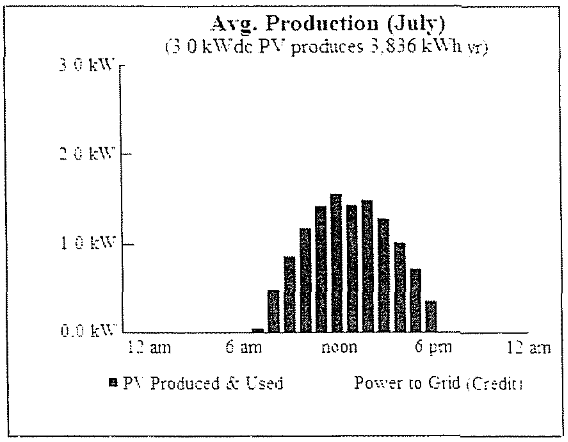
6) **Renewable Project Assessment.** All members of the La Capra Associates Team have provided financial feasibility assessments to a wide range of entities considering developing and purchasing the output of renewable energy resources. Our understanding of the financial and practical requirements faced by developers and potential wholesale and retail purchasers allows us to provide solid, practical policy advice that effectively and objectively assesses potential renewable energy resource development.

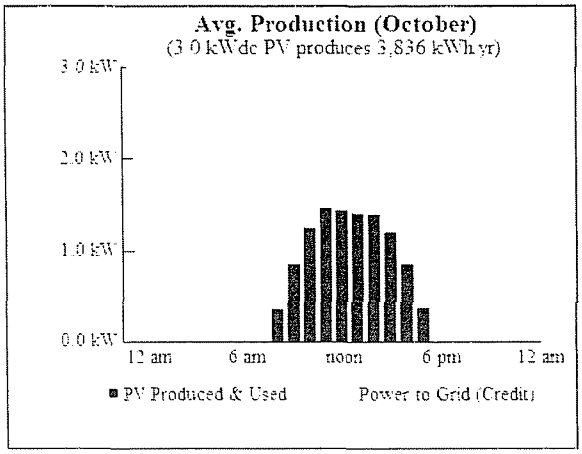
Appendix C: Solar Contribution

The following graphs illustrate solar photovoltaic energy production from a 3 kW DC system in winter, spring, summer, and fall for Raleigh, North Carolina. Local solar insolation data is used along with average residential load profiles. The graphs were generated using the North Carolina version of the *Clean Power Estimator*, a nationally-recognized PV economics evaluation tool, available at http://www.clean-power.com/nc/.









Source: North Carolina Solar Center

Appendix D: Comments to TVA from North Carolina Attorney General Roy Cooper

State of North Carolina
Roy Cooper
Attorney General

February 4, 2002

Ms. Anita Rose
Tennessee Valley Authority
P.O. Box 1649
Norris, TN 37828

Transmission by U.S. Mail, facsimile to (865) 632-[illegible]
and e-mail: akrose@tva.gov

Re: Environmental Assessment for the 20 MW Windfarm and Associated Energy Storage System Facility

Dear Ms. Rose:

I am making these comments on behalf of the State of North Carolina in my capacity as North Carolina's Attorney General. The State of North Carolina is pleased that TVA is considering wind-generated electricity alternatives. Like TVA, we are very interested in protecting the quality of our air and believe it is important to explore alternative ways to provide and conserve energy while pursuing that goal. It is, of course, also important when evaluating various alternatives in pursuit of this goal to balance them wisely with other important public values and concerns. It is mainly for this purpose that I write.

Unfortunately, the Environmental Assessment ("EA") has misinterpreted North Carolina's public policy with regard to mountain ridge top protection as set forth in "North Carolina's Mountain Ridge Protection Act of 1983" N.C. Gen. Stat. §§ 113A-205 et seq. This public policy should be given due consideration and weight, because the Stone Mountain site is almost on the Tennessee-North Carolina border, and the EA itself concludes that "construction and operation of the [Stone Mountain] windfarm facilities would permanently alter the visual landscape character resulting in a significant [adverse] visual impact [in Watauga County, North Carolina]" and "would create substantial visual discord and adverse contrast while reducing scenic attractiveness and tranquility." (EA 4-30, 4-31).

The North Carolina Mountain Ridge Protection Act of 1983 N.C. Gen. Stat. §§ 113A-205 et seq. (1999), prohibits the construction of buildings or structures over 40 feet tall on protected mountain ridges in North Carolina. According to the EA, "The North Carolina Act specifically excludes structures of a slender nature from being considered 'tall buildings or structures'"

[illegible]

Ms. Anita Rose
February 5, 2002
Page 2

regulated under the act." (EA 3-43) Apart from noting, correctly, that the windfarm will not actually be in North Carolina, this brief discussion is the EA's entire analysis of the North Carolina policy. It implies clearly, but incorrectly, that the North Carolina Mountain Ridge Protection Act would permit construction of the proposed windfarm in North Carolina. This is not the case.

The North Carolina Act must be interpreted in light of its purposes. These include the legislative finding that "Tall or major buildings and structures located on ridges are a hazard to air navigation and persons on the ground and detract from the natural beauty of the mountains." N.C. Gen. Stat. § 113A-207. In light of these findings, a windfarm such as that proposed here, with 13 to 15 300-foot high towers (including the rotors) with flashing stroboscopic lights, spaced an average [illegible] feet apart for two miles along the top of a 1400 foot high mountain ridge, cannot properly be construed to fall within the exception for "Structures of a relatively slender nature and minor vertical projections of a parent building, including chimneys, flagpoles, flues, spires, steeples, belfries, cupolas, antennas, poles, wires, or windmills." N.C. Gen. Stat. § 113A-206 (3)(b). The Legislature in 1983 had in mind the traditional, solitary farm windmill which has long been in use in rural communities, not windfarm turbines of the size, type or certainly number proposed here, especially when "*all the turbines would probably be seen together from most viewing locations.*" (EA 4-31)

The North Carolina Mountain Ridge Protection Act also has an exception for "any equipment for the transmission of electricity or communications or both," much like the Johnson County Act. N.C. Gen. Stat. § 113A-206 (3)(a). However, this exception would not apply to the proposed windfarm. The proposed windfarm would clearly be a "generating" facility. Traditionally, electricity generation and electricity transmission are viewed as distinct and separate concepts and functions. Indeed, separate certificates from our Utilities Commission are required for construction of electric transmitting lines and electric generating facilities. N.C. Gen. Stat. § 62-110; N.C. Gen. Stat. § 62-110.1. We believe that no interpretation of N.C. Gen. Stat. § 113A-206 (3)(a) is required. The windfarm would not be included within the exception by the plain meaning of the word "transmission." However, even if one were to conclude that there was some ambiguity requiring interpretation, we see no basis in the statute to read "transmission" more broadly. It is easy to see why the legislature would wish to make an exception for transmission lines which typically run up one side of a ridge, over the top at one point and down the other side. Such lines do relatively little to interfere with the beauty and integrity of a ridge line or create a potential safety hazard. The windfarm proposed here is a far cry from such a minimal intrusion.

The EA may well be correct that The Mountain Ridge Protection Act of Johnson County appears to be modeled after the North Carolina Mountain Ridge Protection Act and that the definition of protected mountain ridges used in the North Carolina statute is essentially the same as in the Johnson County Act. We do not purport to be experts in Tennessee law. However, for the reasons just mentioned, we question the validity of the EA's conclusion, apparently without analysis, that the exemption for equipment used for the "transmission of electricity" in the Mountain Ridge Protection Act of Johnson County exempts its application to the proposed windfarm "generating"

Ms. Anita Rose
February 5, 2002
Page 3

equipment. We would be surprised if Tennessee law, like North Carolina's and that of most states, generally does not distinguish between electric *generating* facilities and electric *transmission* facilities.

We hope that you will give these comments due consideration and weight when considering the Stone Mountain alternative.[1] Thank you for the opportunity to make these comments on behalf of the State of North Carolina.

Very truly yours,

Roy Cooper

RAC:bm

cc: The Honorable Michael F. Easley, Governor
State of North Carolina
The Honorable William Ross, Secretary
Department of Environment & Natural Resources

Appendix E: Additional Resource Discussions

Anaerobic Digesters

Current installations can cost anywhere between $50 to $200[137] per head depending on the farm size, animal weight, included components, and the type of operation. There are huge economies of scale with larger farms, as the electric generation system cost does not differ much between a 4320 head or 8800 head farm. The cost differential stems from the cost of a larger anaerobic digester and nitrification system needed for operations and the handling of more waste. For this analysis, the cost for a 12,000 head farm is assumed to be $600,000,[138] or $4000/kW for a 150 kW system, which is in-line with other sources of information. Anaerobic digesters also qualify for the North Carolina Renewable Energy Tax Credit of 35% of project cost that can be taken over 5 years.

Assessing the operation and maintenance costs is also difficult, because it is difficult to attribute which portion of costs should be allocated to electricity generation or normal farm operations. The O&M costs can range between $90/kW-year to $450/kW-year[139] depending on what costs are included. For our purposes, we assume the total costs are split evenly between electricity generation and normal farm operations.

The Barham Farm project uses the waste heat and effluent to feed a greenhouse, whose cost is not included in the cost estimates above. There is some cost benefit of utilizing the effluent in place of standard fertilizer applications, which is roughly 0.35 cents/kWh[140] in savings for a 12,000 head farm.

Poultry Litter

The estimate for total North Carolina state potential for firing poultry litter is derived as follows: [heat content of poultry litter (6200 btu/lb) * 1.415 million tons/year * (2000 lbs/ton)] / [(13,000 btu/kWh) * 8760 hours * 90% capacity factor] = 172 MW.

In estimating the cost of poultry litter as a fuel input, a 50-mile delivery radius ($0.25/ton-mile) is assumed for transportation costs as the poultry facilities are well scattered around the State. Additionally, $4/ton for cleanout and $13.50/ton is assumed for payment to poultry farmers for the value of the poultry litter. Since there is an inherent nutrient value of $20-$35/ton applied for poultry litter, biomass plants would need to compete with the fuel's alternative purpose. Thus, if

---

137 According to cost modeling for the Smithfield project that was based on the Barham farm anaerobic digester system, installation costs for a 4000 head farrow-to-wean operation may cost about $425,000 ($106/head) However, for a 4320 head feeder-to-finish operation, the cost is about $365,000 ($85/head) and an 8800 head feeder-to-finish operation cost is about $500,000 ($57/head).

138 In extrapolating to a 12,000 head farm, the cost is estimated to be about $600,000 ($50/head).

139 The Smithfield project estimates O&M to total about $55,000 for an 8800 head operation--about 50% is attributed to the nitrification/denitrification systems and about 30% is attributed to digester maintenance. Only the remaining 20% is related to electricity generation.

140 The Smithfield analysis also included a potential cost savings a year of $2380-$3090 per year for an 8800 head facility if the effluent is applied to row crops instead of standard fertilizer applications

poultry litter is used as a fertilizer, with cost of application and cleanout totaling \$8-\$25/ton, the net value to the poultry farmer can be anywhere between \$4-\$23/ton.[141] In this assessment, \$13.50/ton is used as payment to farmers for the poultry litter and the total delivered fuel cost is \$30/ton or \$2.40/mmbtu. However, the ash from biomass firing (about 5% of input material) can also be used as fertilizer, with more concentrated nutrients, with a value that has been estimated at \$30-\$50/ton. In the analysis, we assume a value of \$40/ton for the ash output, which offsets the cost of energy by about \$2/MWh.

Wind

The cost of wind projects today is about 30%-40% higher than two years ago. There are several reasons for this increase. To start, there has been a dramatic increase in demand in the U.S. over the past few years, partially as a result of the increase in RPS requirements, coupled with an expiring production tax credit (PTC). This put pressure on the supply of turbines, resulting in increased turbine prices. Additionally, the costs for raw materials and turbine components have also increased due to unfavorable exchange rates and supply shortages. Prices in the near term are likely to remain at these levels, but with expansion of manufacturing capabilities and additional technology improvements, the expectation is that prices will decline over the long term.

141 Lichtenberg et al, "Economic Value of Poultry Litter Supplies in Alternative Uses," October 2002, University of Maryland

Appendix F: Renewable Portfolio Assumptions and Results

Fuel Cost Assumptions

	Base Case (2005$)	Units	High Case (2005$)	Units
Biomass Fuel Costs Block 1	$40.00	$/dry ton		
Biomass Fuel Costs Block 2	$50.00	$/dry ton		
Chicken Litter (50 mile radius)	$30.00	$/dry ton		
C&D Avoided Cost	$14.00	$/dry ton		
Coal Price	$2.75	$/mmbtu	$3.00	$/mmbtu
Natural Gas Price	$8.00	$/mmbtu	$10.00	$/mmbtu
Natural Gas Price for Combustion Turbines	$7.20	$/mmbtu	$9.20	$/mmbtu
Oil Price	$7.25	$/mmbtu	$9.25	$/mmbtu
Nuclear Fuel Price	$0.50	$/mmbtu	$0.50	$/mmbtu

Case No. 2007-00477
Attach. STAFF-DR-006(b)(2)
Page 136 of 154

Model Cost Assumptions

Resource Type	Resource Block	Capacity Factor (2008 Assumption)	Modeled Project Size (MW)	Levelized Cost per MWh (2008)	Levelized Cost per MWh [illegible]	Nominal Installed Costs: Total Installed Cost [illegible]	Nominal Installed Costs: Total Installed Cost [illegible]	Installed Costs in 2008$: Total Installed Cost [illegible]	Installed Costs in 2008$: Total Installed Cost [illegible]	Technology Decline Rate
Wind Farms (10-50 MW)	Class III (Eastern)	29.0%	30	$72.29	$74.14	$1,786	$1,860	$1,700	$1,417	2.0%
Wind Farms (10-50 MW)	Class IV (Eastern)	32.0%	30	$62.99	$64.04	$1,786	$1,860	$1,700	$1,417	2.0%
Wind Clusters (2-10 MW)	Class III (Eastern)	29.0%	5	$90.79	$94.39	$2,101	$2,188	$2,000	$1,667	2.0%
Wind Clusters (2-10 MW)	Class IV (Eastern)	32.0%	5	$79.75	$82.39	$2,101	$2,188	$2,000	$1,667	2.0%
Wind Farms (10-50 MW)	Class III (Western)	29.0%	30	$72.29	$74.14	$1,786	$1,860	$1,700	$1,417	2.0%
Wind Farms (10-50 MW)	Class IV (Western)	32.0%	30	$62.99	$64.04	$1,786	$1,860	$1,700	$1,417	2.0%
Wind Farms (10-50 MW)	Class V (Western)	35.0%	30	$55.29	$55.67	$1,786	$1,860	$1,700	$1,417	2.0%
Wind Clusters (2-10 MW)	Class IV (Western)	32.0%	5	$79.75	$82.39	$2,101	$2,188	$2,000	$1,667	2.0%
Wind Clusters (2-10 MW)	Class V (Western)	35.0%	5	$70.61	$72.45	$2,101	$2,188	$2,000	$1,667	2.0%
Off-shore wind Class 4	Wind (Offshore)	32%	50	$105.19	$107.71	$2,522	$2,625	$2,400	$2,001	2.0%
Off-shore Wind Class 5	Wind (Offshore)	35%	50	$93.87	$95.59	$2,522	$2,625	$2,400	$2,001	2.0%
Biomass blended co-firing	Zone A Cost Block 1	75%	20	$5.14	$6.41	$79	$98	$75	$75	0.0%
Biomass blended co-firing	Zone B Cost Block 1	75%	20	$4.73	$5.90	$79	$98	$75	$75	0.0%
Biomass retrofit co-firing	Zone C	75%	0	$9.32	$11.64	$242	$302	$230	$230	0.0%
Biomass retrofit co-firing	Zone D	75%	49	$17.90	$22.35	$242	$302	$230	$230	0.0%
Biomass blended co-firing	Zone A Cost Block 2	75%	20	$17.90	$22.35	$242	$302	$230	$230	0.0%
Biomass blended co-firing	Zone B Cost Block 2	75%	20	$13.31	$16.61	$79	$98	$75	$75	0.0%
Biomass retrofit co-firing	Zone E Cost Block 2	75%	67	$17.90	$22.35	$242	$302	$230	$230	0.0%
New Biomass (gasification)	Wood Block 1 plus C&D	90%	25	$110.58	$120.78	$3,887	$3,866	$3,700	$2,946	2.5%
New Biomass (fluidized bed)	Wood Block 1 plus C&D	90%	25	$96.91	$112.25	$3,152	$3,436	$3,000	$2,618	1.5%
New Biomass (stoker)	Wood Block 1 plus C&D	90%	25	$89.52	$111.78	$2,837	$3,543	$2,700	$2,700	0.0%
New Biomass (gasification)	Wood Block 2	90%	25	$124.17	$137.74	$3,887	$3,866	$3,700	$2,946	2.5%
New Biomass (fluidized bed)	Wood Block 2	90%	25	$111.91	$130.98	$3,152	$3,436	$3,000	$2,618	1.5%
New Biomass (stoker)	Wood Block 2	90%	25	$103.65	$129.42	$2,837	$3,543	$2,700	$2,700	0.0%
New Hydro Cost Block 1	Hydro (new <10 MW ROR)	45%	2.5	$103.74	$129.55	$3,467	$4,330	$3,300	$3,300	0.0%
New Hydro Cost Block 2	Hydro (new >10 MW ROR)	45%	25	$80.59	$100.65	$2,889	$3,608	$2,750	$2,750	0.0%
Undeveloped Hydro Block 1	Hydro (new <10 MW ROR)	45%	2.5	$139.03	$173.62	$4,623	$5,773	$4,400	$4,400	0.0%
Undeveloped Hydro Block 1	Hydro (new >10 MW ROR)	45%	30	$115.88	$144.71	$4,045	$5,052	$3,850	$3,850	0.0%
Hydro Upgrades Cost Block 1	Hydro (new <10 MW)	45%	0	$44.68	$55.79	$1,734	$2,165	$1,650	$1,650	0.0%
Hydro Upgrades Cost Block 2	Hydro (new >10 MW)	45%	13	$24.61	$30.74	$1,156	$1,443	$1,100	$1,100	0.0%
Landfill Gas w/ collection	Landfill Gas	80%	5.0	$46.99	$58.67	$1,523	$1,903	$1,450	$1,450	0.0%
Fibrowatt Tech	Chicken Litter/Ag Waste	90%	35	$98.89	$123.48	$3,075	$3,841	$2,927	$2,927	0.0%
Anaerobic Gas (Hog Waste)	Anaerobic Gas (Hog Waste)	75%	0.150	$78.93	$91.66	$4,203	$4,376	$4,000	$3,335	2.0%
Solar PV	Residential	19%	0.002	$349.87	$390.05	$10,506	$11,452	$10,000	$8,728	1.5%
Solar PV	Commercial	19%	0.025	$202.79	$229.73	$8,405	$9,162	$8,000	$6,983	1.5%
				First Year Cost (not levelized)						
Conventional Resources										
Pulverized Coal (Supersub)		90%	750	$66.16	$82.62	$1,681	$2,099	$1,600	$1,600	
Combined Cycle		50%	250	$74.80	$93.41	$735	$918	$700	$700	
Combustion Turbine (Frame)		5%	150	$326.01	$407.14	$525	$656	$500	$500	
Nuclear		90%	1100	$52.48-$100.03	$65.54-$124.93	$2,101-$4,203	$2,625-$5,248	$2000-$4000	$2000-$4000	

Model Cost Assumptions (cont'd)

		Operating Cost Assumptions (2005$)						Levelized Operating Costs Before PTC	
Resource Type	Resource Block	Fixed O&M (2005$/kW-yr)	Variable O&M Costs (2005$/MWh)	Fuel Heat Rate (Btu/kWh)	Fuel Costs (2005$/mmBtu)	PTC Eligible? (%)	Byproducts ($/MWh)	Total Levelized Operating Costs ($/MWh 2005 Dollars)	[illegible]
Wind Farms (10-50 MW)	Class III (Eastern)	$45	$2	-	0.00	1.00		$23.96	$29.91
Wind Farms (10-50 MW)	Class IV (Eastern)	$45	$2	-	0.00	1.00		$21.94	$27.39
Wind Clusters (2-10 MW)	Class III (Eastern)	$55	$2	-	0.00	1.00		$28.75	$35.89
Wind Clusters (2-10 MW)	Class IV (Eastern)	$55	$2	-	0.00	1.00		$26.28	$32.81
Wind Farms (10-50 MW)	Class III (Western)	$45	$2	-	0.00	1.00		$23.96	$29.91
Wind Farms (10-50 MW)	Class IV (Western)	$45	$2	-	0.00	1.00		$21.94	$27.39
Wind Farms (10-50 MW)	Class V (Western)	$45	$2	-	0.00	1.00		$20.27	$25.31
Wind Clusters (2-10 MW)	Class IV (Western)	$55	$2	-	0.00	1.00		$26.28	$32.81
Wind Clusters (2-10 MW)	Class V (Western)	$55	$2	-	0.00	1.00		$24.23	$30.26
Off-shore wind Class 4	Wind (Offshore)	$65	$2	-	0.00	1.00		$30.61	$36.15
Off-shore Wind Class 5	Wind (Offshore)	$65	$2	-	0.00	1.00		$28.20	$33.31
Biomass blended co-firing	Zone A Cost Block 1	$12	$5	12,000	(0.37)	0.00		$2.91	$3.64
Biomass blended co-firing	Zone B Cost Block 1	$12	$5	12,000	(0.40)	0.00		$2.51	$3.13
Biomass retrofit co-firing	Zone C	$12	$5	12,000	(0.40)	0.00		$2.51	$3.13
Biomass retrofit co-firing	Zone D	$12	$5	12,000	0.19	0.00		$11.09	$13.84
Biomass blended co-firing	Zone A Cost Block 2	$12	$5	12,000	0.19	0.00		$11.09	$13.84
Biomass blended co-firing	Zone B Cost Block 2	$12	$5	12,000	0.19	0.00		$11.09	$13.84
Biomass retrofit co-firing	Zone E Cost Block 2	$12	$5	12,000	0.19	0.00		$11.09	$13.84
New Biomass (gasification)	Wood Block 1 plus C&D	$100	$10	12,500	2.05	1.00	1.47	$56.88	$71.02
New Biomass (fluidized bed)	Wood Block 1 plus C&D	$75	$10	13,800	2.05	1.00	1.62	$56.08	$70.01
New Biomass (stoker)	Wood Block 1 plus C&D	$75	$10	13,000	2.05	1.00	1.53	$54.20	$67.67
New Biomass (gasification)	Wood Block 2	$100	$10	12,500	2.94	1.00	1.47	$70.47	$87.98
New Biomass (fluidized bed)	Wood Block 2	$75	$10	13,800	2.94	1.00	1.62	$71.08	$88.73
New Biomass (stoker)	Wood Block 2	$75	$10	13,000	2.94	1.00	1.53	$68.33	$85.31
New Hydro Cost Block 1	Hydro (new <10 MW ROR)	$20	$5			1.00		$12.24	$15.29
New Hydro Cost Block 2	Hydro (new >10 MW ROR)	$10	$3			1.00		$6.73	$8.40
Undeveloped Hydro Block 1	Hydro (new <10 MW ROR)	$20	$5			1.00		$12.24	$15.29
Undeveloped Hydro Block 1	Hydro (new >10 MW ROR)	$10	$3			1.00		$6.73	$8.40
Hydro Upgrades Cost Block 1	Hydro (new <10 MW)	$0	$5			1.00		$6.08	$7.59
Hydro Upgrades Cost Block 2	Hydro (new >10 MW)	$0	$3			1.00		$3.65	$4.55
Landfill Gas w/ collection	Landfill Gas	$200				1.00		$34.69	$43.31
Fibrowatt Tech	Chicken Litter/Ag Waste	$75	$10	13,000	2.42	1.00	2.10	$59.40	$74.15
Anaerobic Gas (Hog Waste)	Anaerobic Gas (Hog Waste)	$270	$0	14,000	0.00	0.00	3.46	$45.74	$57.11
Solar PV	Residential	$75				0.00	0.00	$54.77	$68.38
Solar PV	Commercial	$75				0.00	0.00	$54.77	$68.38
Conventional Resources									
Pulverized Coal (Supersub)		$30	$5	9,100	2.75	0.00			
Combined Cycle		$12	$2	7,000	8.00	0.00			
Combustion Turbine (Frame)		$12	$8	10,200	7.20	0.00			
Nuclear		$60	$3	10,000	0.50	0.50			

Scenarios Annual Costs

($million)	10-year NPV	20-year NPV	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Utilities' Portfolio Cost	$7,028	$15,051	$0	$70	$224	$811	$1,312	$1,836	$1,915	$1,924	$2,773	$3,478
Scenarios												
I. NCGP Criteria (5%)												
Alternative Portfolio Cost	$7,646	$16,036	$15	$98	$277	$886	$1,395	$1,965	$2,128	$2,215	$2,934	$3,614
Avoided Marginal Energy	($243)	($258)	($5)	($11)	($20)	($31)	($33)	($62)	($101)	($142)	($40)	($5)
Delta Between Portfolios	$375	$727	$9	$16	$33	$44	$50	$67	$113	$150	$121	$131
II. Expanded Renewables (5%)												
Alternative Portfolio Cost	$7,484	$15,653	$15	$103	$278	$868	$1,371	$1,943	$2,062	$2,154	$2,862	$3,525
Avoided Marginal Energy	($251)	($283)	($5)	($14)	($22)	($30)	($31)	($65)	($101)	($145)	($41)	($12)
Delta Between Portfolios	$204	$319	$9	$19	$32	$27	$28	$42	$46	$86	$47	$35
III. Expanded Renewables Plus EE (5%)												
Alternative Portfolio Cost	$7,024	$14,632	$7	$81	$248	$831	$1,322	$1,854	$1,954	$1,999	$2,659	$3,285
EE Administration Costs	$157	$205	$22	$23	$24	$25	$26	$26	$27	$28	$30	$31
Avoided Marginal Energy	($248)	($264)	($6)	($12)	($22)	($31)	($34)	($63)	($104)	($143)	($37)	($5)
Delta Between Portfolios	($95)	($478)	$23	$21	$26	$14	$3	($18)	($38)	($39)	($122)	($167)
I. NCGP Criteria (10%)												
Alternative Portfolio Cost	$8,983	$18,492	$72	$220	$431	$1,139	$1,711	$2,070	$2,335	$2,584	$3,350	$4,096
Avoided Marginal Energy	($574)	($750)	($27)	($62)	($92)	($141)	($168)	($33)	($106)	($195)	($93)	($66)
Delta Between Portfolios	$1,381	$2,691	$45	$88	$116	$187	$231	$201	$314	$466	$484	$552
II. Expanded Renewables (10%)												
Alternative Portfolio Cost	$8,281	$17,286	$63	$198	$393	$1,062	$1,338	$1,977	$2,215	$2,401	$3,159	$3,882
Avoided Marginal Energy	($466)	($638)	($31)	($64)	($98)	($142)	$22	($35)	($109)	($190)	($93)	($64)
Delta Between Portfolios	$787	$1,597	$32	$63	$71	$109	$49	$106	$191	$287	$292	$340
III. Expanded Renewables Plus EE (10%)												
Alternative Portfolio Cost	$6,973	$14,632	$32	$120	$302	$919	$1,140	$1,738	$1,889	$1,993	$2,663	$3,306
EE Administration Costs	$314	$409	$44	$46	$48	$49	$51	$53	$55	$57	$60	$62
Avoided Marginal Energy	($436)	($567)	($25)	($59)	($99)	($142)	$29	($33)	($106)	($180)	($83)	($49)
Delta Between Portfolios	($177)	($577)	$50	$37	$27	$15	($92)	($78)	($76)	($54)	($133)	($158)

($million)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Utilities' Portfolio Cost	$3,450	$3,427	$3,407	$3,389	$3,374	$3,361	$3,351	$3,341	$3,333	$3,327
Scenarios										
I. NCGP Criteria (5%)										
Alternative Portfolio Cost	$3,592	$3,573	$3,557	$3,543	$3,531	$3,521	$3,512	$3,505	$3,499	$3,494
Avoided Marginal Energy	($5)	($6)	($6)	($6)	($6)	($7)	($6)	($7)	($7)	($7)
Delta Between Portfolios	$136	$141	$145	$148	$151	$153	$155	$157	$159	$160
II. Expanded Renewables (5%)										
Alternative Portfolio Cost	$3,502	$3,482	$3,465	$3,450	$3,438	$3,427	$3,418	$3,410	$3,403	$3,397
Avoided Marginal Energy	($12)	($12)	($13)	($13)	($13)	($14)	($14)	($14)	($15)	($15)
Delta Between Portfolios	$39	$43	$46	$48	$50	$52	$53	$54	$55	$55
III. Expanded Renewables Plus EE (5%)										
Alternative Portfolio Cost	$3,263	$3,244	$3,227	$3,213	$3,201	$3,191	$3,183	$3,175	$3,169	$3,164
EE Administration Costs	$12	$18	$19	$20	$22	$22	$23	$24	$25	$26
Avoided Marginal Energy	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($7)	($7)	($7)
Delta Between Portfolios	($181)	($171)	($166)	($161)	($157)	($154)	($151)	($149)	($146)	($144)
I. NCGP Criteria (10%)										
Alternative Portfolio Cost	$4,073	$4,052	$4,034	$4,016	$4,004	$3,991	$3,980	$3,970	$3,961	$3,952
Avoided Marginal Energy	($68)	($70)	($71)	($73)	($75)	($77)	($79)	($81)	($83)	($85)
Delta Between Portfolios	$554	$556	$557	$556	$555	$553	$551	$548	$545	$541
II. Expanded Renewables (10%)										
Alternative Portfolio Cost	$3,859	$3,839	$3,821	$3,805	$3,791	$3,778	$3,767	$3,757	$3,748	$3,739
Avoided Marginal Energy	($66)	($67)	($69)	($71)	($73)	($74)	($76)	($79)	($81)	($82)
Delta Between Portfolios	$343	$345	$345	$345	$344	$343	$340	$337	$334	$331
III. Expanded Renewables Plus EE (10%)										
Alternative Portfolio Cost	$3,285	$3,267	$3,251	$3,237	$3,224	$3,213	$3,203	$3,194	$3,186	$3,179
EE Administration Costs	$25	$36	$38	$41	$43	$45	$47	$47	$51	$52
Avoided Marginal Energy	($50)	($51)	($53)	($54)	($56)	($57)	($58)	($60)	($61)	($63)
Delta Between Portfolios	($191)	($176)	($171)	($166)	($163)	($161)	($159)	($160)	($157)	($159)

Sensitivities Annual Costs

($million)	10-year NPV	20-year NPV	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Sensitivities Test Against Reference Case (NCGP Critieria 5%)												
NCGP (no co-fire)												
Alternative Portfolio Cost	$7,875	$16,477	$64	$177	$378	$1,004	$1,544	$1,802	$1,951	$2,070	$3,128	$3,712
Avoided Marginal Energy	[illegible]	[illegible]	[illegible]	($48)	($77)	[illegible]	($115)	$59	$30	($14)	($101)	[illegible]
Delta Between Portfolios	$579	$1,106	$38	$59	$77	$94	$116	$25	$66	$132	$253	$216
5 Yr PTC												
Alternative Portfolio Cost	$7,755	$16,344	$15	$98	$277	$886	$1,395	$1,980	$2,159	$2,264	$3,003	$3,699
Avoided Marginal Energy	[illegible]	[illegible]	($5)	($11)	($20)	($31)	($33)	[illegible]	($101)	($142)	($40)	[illegible]
Delta Between Portfolios	$484	$1,036	$9	$16	$33	$44	$50	$82	$143	$199	$189	$216
PV Multiplier												
Alternative Portfolio Cost	$7,589	$15,948	$15	$98	$281	$873	$1,384	$1,958	$2,110	$2,205	$2,885	$3,601
Avoided Marginal Energy	[illegible]	($170)	($5)	($11)	($21)	($35)	($27)	($57)	[illegible]	($130)	($18)	$14
Delta Between Portfolios	$358	$726	$9	$16	$36	$37	$45	$66	$107	$151	$94	$137
High Fuel												
Utilities Portfolio Cost	$7,562	$16,322	$0	$75	$239	$868	$1,407	$1,972	$2,061	$2,075	$2,991	$3,753
Alternative Portfolio Cost	$8,103	$17,145	$12	$97	$266	$933	$1,476	$2,085	$2,258	$2,348	$3,123	$3,856
Avoided Marginal Energy	($274)	[illegible]	($6)	($12)	($23)	($35)	($37)	($70)	[illegible]	($160)	($46)	($6)
Delta Between Portfolios	$267	$533	$6	$11	$24	$30	$32	$44	$83	$113	$86	$98
Low Nuclear Cost												
Utilities Portfolio Cost	$6,904	$14,202	$0	$70	$224	$811	$1,312	$1,836	$1,915	$1,924	$2,693	$3,246
Alternative Portfolio Cost	$7,529	$15,649	$15	$98	$277	$886	$1,395	$1,965	$2,128	$2,215	$2,742	$3,522
Avoided Marginal Energy	[illegible]	[illegible]	($5)	($11)	($20)	($31)	($33)	($63)	($101)	($142)	$7	($2)
Delta Between Portfolios	$403	$1,220	$9	$16	$33	$44	$50	$67	$113	$150	$56	$274
High Nuclear Cost												
Utilities Portfolio Cost	$7,331	$16,174	$0	$70	$224	$811	$1,312	$1,836	$1,915	$1,924	$2,974	$4,043
Alternative Portfolio Cost	$7,754	$16,396	$15	$98	$277	$886	$1,395	$1,965	$2,128	$2,215	$3,023	$3,794
Avoided Marginal Energy	($222)	[illegible]	($5)	($11)	($20)	($31)	($33)	($63)	($101)	($142)	$7	($2)
Delta Between Portfolios	$200	($5)	$9	$16	$33	$44	$50	$67	$113	$150	$56	[illegible]

($million)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Sensitivities Test Against Reference Case (NCGP Critieria 5%)										
NCGP (no co-fire)										
Alternative Portfolio Cost	$3,689	$3,668	$3,650	$3,634	$3,620	$3,608	$3,598	$3,589	$3,581	$3,574
Avoided Marginal Energy	($20)	($20)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Delta Between Portfolios	$219	$221	$223	$224	$225	$225	$225	$224	$224	$223
5 Yr PTC										
Alternative Portfolio Cost	$3,677	$3,658	$3,642	$3,628	$3,616	$3,605	$3,597	$3,589	$3,583	$3,578
Avoided Marginal Energy	($5)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Delta Between Portfolios	$221	$225	$229	$233	$235	$238	$240	$242	$243	$244
PV Multiplier										
Alternative Portfolio Cost	$3,579	$3,560	$3,544	$3,530	$3,518	$3,508	$3,499	$3,492	$3,486	$3,480
Avoided Marginal Energy	$14	$14	$15	$15	$15	$16	$16	$17	$17	$0
Delta Between Portfolios	$143	$148	$152	$156	$159	$162	$165	$167	$169	$154
High Fuel										
Utilities Portfolio Cost	$3,733	$3,717	$3,704	$3,694	$3,686	$3,681	$3,679	$3,678	$3,678	$3,680
Alternative Portfolio Cost	$3,842	$3,830	$3,820	$3,813	$3,808	$3,805	$3,803	$3,804	$3,805	$3,808
Avoided Marginal Energy	($6)	($6)	($6)	[illegible]	($7)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Delta Between Portfolios	$103	$107	$110	$113	$115	$116	$118	$119	$120	$120
Low Nuclear Cost										
Utilities Portfolio Cost	$3,204	$3,159	$3,119	$3,082	$3,049	$3,019	$2,990	$2,962	$2,985	$3,052
Alternative Portfolio Cost	$3,493	$3,468	$3,446	$3,427	$3,409	$3,394	$3,380	$3,367	$3,404	$3,393
Avoided Marginal Energy	($2)	($2)	($2)	($2)	($2)	[illegible]	($3)	[illegible]	[illegible]	$0
Delta Between Portfolios	$287	$307	$325	$342	$358	$373	$387	$402	$416	$342
High Nuclear Cost										
Utilities Portfolio Cost	$3,972	$3,892	$3,818	$3,751	$3,689	$3,631	$3,575	$3,521	$3,516	$3,556
Alternative Portfolio Cost	$3,753	$3,716	$3,683	$3,653	$3,626	$3,601	$3,578	$3,555	$3,583	$3,563
Avoided Marginal Energy	($2)	($2)	($2)	($2)	($2)	($2)	($3)	[illegible]	[illegible]	$0
Delta Between Portfolios	($222)	($176)	[illegible]	($100)	($65)	[illegible]	[illegible]	$32	$64	$7

Appendix G: Energy Efficiency Measures

Excerpt from "A Study of the Feasibility of Energy Efficiency as an Eligible Resource as Part of a Renewable Portfolio Standard for the State of North Carolina," GDS.

Table 5-4: Total Annual Achievable Cost-Effective Potential kWh Savings for Electric Energy Efficiency In North Carolina By 2017

Residential Sector - Market Driven and Retrofit Savings

1	2	5	6	7	8
Measure #	Measure Description	Levelized Cost Per kWh SF	Levelized Cost Per kWh MF	Total Cumulative Annual kWh Savings by 2017 (Levelized Cost $0.10 per kWh)	Total Cumulative Annual kWh Savings by 2017 (Levelized Cost $0.05 per kWh)
1	Refrigerator Turn-in	0.075	0.075	162,732,169	0
2	Freezer Turn-in	0.078	0.078	29,921,244	0
3	Room AC Turn-in without Replacement	0.818	0.818	0	0
4	Room AC Turn-in with ES Replacement	2.338	2.338	0	0
5	Energy Star Single Room Air Conditioner	0.036	0.036	20,698,606	20,698,606
6	Energy Star Compliant Top Freezer Refrigerator	0.053	0.053	81,446,188	0
7	Energy Star Compliant Bottom Mount Freezer Refrigerator	0.049	0.049	15,539,075	15,539,075
8	Energy Star Compliant Side-by-Side Refrigerator	0.045	0.045	45,813,481	45,813,481
9	Energy Star Compliant Upright Freezer (Manual Defrost)	0.092	0.092	20,932,558	0
10	Energy Star Compliant Chest Freezer	0.098	0.098	18,626,619	0
11	Energy Star Built-In Dishwasher (Electric)	0.113	0.113	0	0
12	Energy Star Clothes Washers with Electric Water Heater	0.162	0.162	0	0
13	Energy Star Clothes Washers with Non-Electric Water Heater	1.593	1.593	0	0
14	Energy Star Dehumidifier (40 pt)	0.000	0.000	21,301,956	21,301,956
15	Standby-Power	0.023	0.023	424,192,135	424,192,135
16	Pool Pump & Motor	0.065	0.065	93,827,113	0
17	Energy Star Compliant Programmable Thermostat	0.008	0.008	1,122,063,781	1,122,063,781
18	High Efficiency Central AC	0.098	0.098	746,606,300	0
19	CFL's: Homes with partial CFL installation	0.003	0.003	613,275,147	613,275,147
20	CFL's: Homes without CFL installation	0.003	0.003	812,263,289	812,263,289
21	Water Heater Blanket	0.008	0.008	406,337,894	406,337,894
22	Low Flow Shower Head	0.008	0.008	552,619,535	552,619,535
23	Pipe Wrap	0.064	0.064	53,636,602	0
24	Low Flow Faucet Aerator	0.018	0.018	92,645,039	92,645,039
25	Solar Water Heating	0.085	0.085	0	0
26	Efficient Water Heating	0.035	0.035	0	0
27	Efficient Furnace Fan Motor (Fuel Oil)	0.021	0.021	100,476,279	100,476,279
28	Efficient Furnace Fan Motor (Natural Gas)	0.021	0.021	200,952,558	200,952,558
29	Efficient Furnace Fan Motor (Propane)	0.021	0.021	108,849,303	108,849,303
30	Energy Star Windows	0.033	0.033	4,305,096,788	4,305,096,788
31	Insulation and Weatherization	0.024	0.024	2,765,815,391	2,765,815,391
32	Residential New Construction (Electric)	0.116	N/A	0	0
33	Residential New Construction (Non-Electric)	0.163	N/A	0	0
34	Low Income Insulation & Weatherization	0.049	N/A	398,327,232	398,327,232

Maximum Achievable Cost Effective kWh Savings		13,213,996,282	12,006,267,489
Forecast 2017 North Carolina Residential kWh Sales		71,078,000,000	71,078,000,000
Savings as a percent of forecasted residential sales in 2017		18.6%	16.9%

Note The levelized costs were obtained from Appendix A, column 17. The kWh savings shown above are from table 5-3, and kWh savings in the last column in the above table are counted only for those measures that have a levelized cost less than $0.10/kwh saved.

Appendix G: Energy Efficiency Measures (cont'd)

Table 6-3: Commercial Measures – Levelized Cost per kWh Saved

Measure	Levelized cost $ per kWh saved
Space Heating	
High Efficiency Heat Pump	$0.0050
Ground Source Heat Pump - Heating	$0.3420
Water Heating End Use	
Heat Pump Water Heater	$0.0390
Booster Water Heater	$0.2477
Point of Use Water Heater	$0.0504
Solar Water Heating System	$0.0242
Solar Pool Heating	$0.0802
Envelope	
Double Pane Low Emissivity Windows	$0.0077
Space Cooling - Chillers	
Centrifugal Chiller, 0.51 kW/ton, 300 tons	$0.0513
Centrifugal Chiller, 0.51 kW/ton, 500 tons	$0.0513
Centrifugal Chiller, Optimal Design, 0.4 kW/ton, 500 tons	$0.0513
Space Cooling - Packaged AC	
DX Packaged system EER = 10.9, 10 tons	$0.0266
DX Packaged System, CEE Tier 2, <20 Tons	$0.0179
DX Packaged System, CEE Tier 2, >20 Tons	$0.0265
Packaged AC - 3 tons, Tier 2	$0.0488
Packaged AC - 7.5 tons, Tier 2	$0.0425
Packaged AC - 15 tons, Tier 2	$0.0405
Ground Source Heat Pump - Cooling	$0.2589
Space Cooling - Maintenance	
Chiller Tune Up/Diagnostics - 300 ton	$0.0339
Chiller Tune Up/Diagnostics - 500 ton	$0.0335
DX Tune Up/ Advanced Diagnostics	$0.1013
HVAC Controls	
Retrocommissioning	$0.0145
Programmable Thermostats	$0.0038
EMS install	$0.0951
EMS Optimization	$0.2968
Ventilation	
Dual Enthalpy Economizer - from Fixed Damper	$0.0483
Dual Enthalpy Economizer - from Dry Bulb	$0.0329

Measure	Levelized cost $ per kWh saved
Heat Recovery	$0.2215
Fan Motor, 40hp, 1800rpm, 94.1%	$0.0178
Fan Motor, 15hp, 1800rpm, 92.4%	$0.0064
Fan Motor, 5hp, 1800rpm, 89.5%	$0.0127
Variable Speed Drive Control, 15 HP	$0.0339
Variable Speed Drive Control, 5 HP	$0.0565
Variable Speed Drive Control, 40 HP	$0.0231
Motors	
Efficient Motors	$0.0153
Variable Frequency Drives (VFD)	$0.0979
Lighting End Use	
Super T8 Fixture - from 34W T12	$0.0494
Super T8 Fixture - from standard T8	$0.0427
T5 Fluorescent High-Bay Fixtures	$0.0315
T5 Troffer/Wrap	$0.0570
T5 Industrial Strip	$0.0626
T5 Indirect	$0.0570
CFL Fixture	$0.0234
Exterior HID	$0.0716
LED Exit Sign	$0.0461
Lighting Controls	$0.0308
LED Traffic / Pedestrian Signals	$0.0644
Electronic HID Fixture Upgrade	$0.0341
Halogen Infra-Red Bulb	$0.0996
Integrated Ballast MH 25W	$0.0643
Induction Fluorescent 23W	$0.0257
CFL Screw-in	$0.0023
Metal Halide Track	$0.0548
Lighting Controls	
Bi-Level Switching	$0.0783
Occupancy Sensors	$0.0296
Daylight Dimming	$0.0834
Daylight Dimming - New Construction	$0.1169
5% More Efficient Design	$0.0522
10% More Efficient Design	$0.0522
15% More Efficient Design - New Construction	$0.0174
30% More Efficient Design - New Construction	$0.0174
Refrigeration End Use	
Vending Miser for Soft Drink Vending Machines	$0.0159
Refrigerated Case Covers	$0.0098

Measure	Levelized cost $ per kWh saved
Refrigeration Economizer	$0.5605
Commercial Reach-In Refrigerators	$0.0217
Commercial Reach-In Freezer	$0.0248
Commercial Ice-makers	$0.0260
Evaporator Fan Motor Controls	$0.0531
Permanent Split Capacitor Motor	$0.0562
Zero-Energy Doors	$0.1627
Door Heater Controls	$0.0116
Discus and Scroll Compressors	$0.0610
Floating Head Pressure Control	$0.0597
Anti-sweat (humidistat) controls (refrigerator)	$5.0209
Anti-sweat (humidistat) controls (freezer)	$2.5439
High Efficiency Ice Maker	$0.0179
Compressed Air End Use	
Compressed Air – Non-Controls	$0.0205
Compressed Air – Controls	$0.0990
Monitor Power Management	
EZ Save Monitor Power Management Software	$0.5883
Water/Wastewater Treatment	
Improved equipment and controls	$0.0593
Transformer End Use	
Energy Star Transformers	$0.0187

Appendix H: Additional Economic Impact Discussion

The Economic Impact Model

The IMPLAN input-output economic model was used to assess the economic impacts of renewable energy development in the State of North Carolina.[1] This model is also used by the North Carolina Department of Commerce for economic impact analyses for the North Carolina legislature. The IMPLAN model is well documented and is used by many federal, state and local government agencies to assess economic impacts of economic policy and job development issues. A detailed description of the IMPLAN model is available in a report from the Minnesota IMPLAN Group (MIG) titled "The IMPLAN Input-Output System."[2]

IMPLAN was developed as a cost-effective means to develop regional input-output models. Input-output analysis uses mathematical models to examine the effects of a change in one or several economic activities on an entire economy. Such an impact analysis examines relationships between businesses and between businesses and final consumers.

There are two components to the IMPLAN system, the software and databases. The databases provide all information to create regional or state-specific IMPLAN models.[3] The software performs the calculations and provides an interface for the user to make final demand changes. We utilized the IMPLAN database developed by MIG for the state of North Carolina and its Input-Output analysis procedures to complete the economic impact assessment.

Modeling Assumptions

The economic impact analysis of an RPS for North Carolina is based on the following key assumptions:

- The economic input-output data and relationships for North Carolina provided by the Minnesota IMPLAN Group for use with the IMPLAN model are assumed to be applicable for the twenty-year analysis period for this study.
- The economic model constructed using IMPLAN for North Carolina is an input-output model and includes all of the standard input-output model assumptions:
  - *Constant returns to scale* – the production function for a given industry is linear, i.e., if additional output is required in an industry, all the inputs required to produce that output increase proportionately
  - *No supply constraints* – an industry has unlimited access to raw materials and its output is limited only by demand for its products

[1] The USDA Forest Service in the mid-70s developed IMPLAN for community impact analysis. The current IMPLAN input-output database and model is maintained and sold by MIG, Inc. (Minnesota IMPLAN Group). Over 1,500 clients across the country use the IMPLAN model, making the results acceptable in inter-agency analysis. GDS Associates, a subcontractor to La Capra Associates for this study, is a registered and licensed user of the IMPLAN model.

[2] "The IMPLAN Input-Output System." Scott A. Lindall and Douglas C. Olson. <http://www.implan.com/library/documents/implan_io_system_description.pdf>

[3] The IMPLAN database, created by the Minnesota IMPLAN Group (MIG), Inc., consists of two major parts: 1) a national-level technology matrix, and 2) estimates of sectorial activity for final demand, final payments, industry output and employment for each county in the U.S. along with state and national totals. New databases are developed annually by MIG, Inc.

- *Fixed commodity input structure* – changes in the economy will affect the industry's output but not the mix of commodities and services it requires to make its products
- *Homogenous sector output* – an industry will not increase the output of one product without proportionately increasing the output of all its other products
- *Industry technology assumption* – the assumption that an industry uses the same technology to produce all of its products

- Long-term electricity price changes are based on the difference in cost between a Utility Portfolio and Alternative RPS portfolios that contain both renewable and conventional generation.
- Rate impact is based on the present value (in 2006$) of the long-term impact (estimate of rate impact in 2017) of the RPS scenarios presented in previous section. *This is a conservative assumption given that the first nine years of an RPS do not necessarily experience the higher rate impact of the tenth year.*
- Purchase of energy efficiency equipment would be equally split between wholesale and retail suppliers.

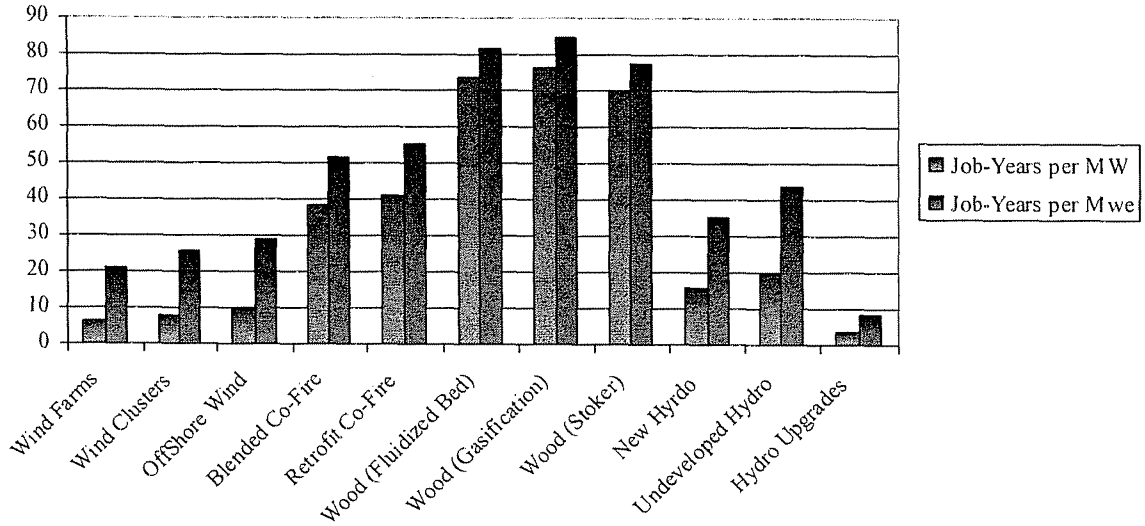
Job-Years Lost Through Price Impacts of RPS Over 20 Years

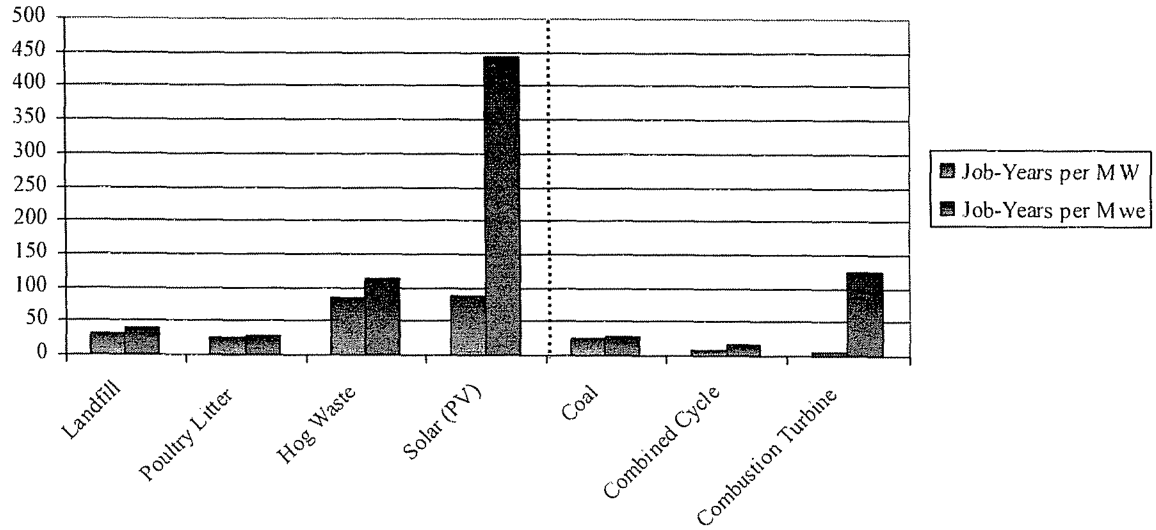
Portfolio	Long-Term Price Increase (2006 ¢/kWh)	Household Income Impacts	Business and Government Impacts	Total Job-Years* Lost
5% NCGP	**0.056¢**	**4,254**	**11,924**	**16,178**
5% Expanded	0.015¢	1,144	3,214	4,358
5% With EE	0.000¢	0	0	0
10% NCGP	0.237¢	17,866	50,080	67,946
10% Expanded	0.146¢	11,022	30,898	41,920
10% With EE	**0.000¢**	**0**	**0**	**0**
5% NCGP No Co-Fire	0.113¢	8,548	23,960	32,508
5% Expanded No Co-Fire	0.001¢	82	236	318
5% PV Multiplier	0.059¢	4,444	12,468	16,912

* 1 person working for twenty years equates to twenty job-years

The impacts for wind and hydro projects are relatively low due to their lack of a need for fuel and to their low capacity factors. If results are compared in terms of equivalent MW (MWe) where capacity factors are taken into account, wind project impacts can potentially triple and hydro impacts double. A significant impact is also created for Solar and Combustion Turbines. The figure below shows total job impacts (Construction, O&M, and Fuel) for each resource on a per MW and per MWe basis.

Job Impacts by MW and MWe





Appendix I: Net Metering and Interconnection Rules

Net-Metering

<http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NC05R&state=NC&CurrentPageID=1&RE=1&EE=1>

Excerpt from North Carolina Solar Center's description of Net Metering in North Carolina :

> *Utilities may not charge customer-generators any standby, capacity or metering fees, or other fees and charges in addition to those approved for all customers under the applicable time-of-use demand-rate schedule. North Carolina is the only state that requires customers to switch to a time-of-use tariff in order to take advantage of net metering. In its July 2006 order, the NCUC clarified that on-peak generation may be used to offset off-peak consumption (but not vice versa). Previously, the utilities' net-metering tariffs and riders only allowed excess on-peak production to be used to reduce on-peak consumption and excess off-peak production to be used to offset off-peak production. Net excess generation (NEG) is credited to the customer's next bill at the utility's retail rate, and then granted to the utility (annually) at the beginning of each summer season. Any renewable-energy credits (RECs) associated with NEG are granted to the utility when the NEG balance is zeroed out. This provision is designed to limit the size of individual facilities to match on-site power needs, according to the NCUC. Significantly, customer-generators who choose to net meter are not permitted to sell electricity under the NC GreenPower Program.*

Interconnection

<http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NC04R&state=NC&CurrentPageID=1&RE=1&EE=1>

Excerpt from North Carolina Solar Center's description of Interconnection Rules in North Carolina:

> *The North Carolina Utilities Commission (NCUC) adopted simplified interconnection standards for small distributed generation (DG) in 2005. The standards apply to renewable-energy systems and other forms of DG up to 20 kilowatts (kW) in capacity for residential systems, and up to 100 kW in capacity for non-residential systems. There is a $100 application fee for residential systems and a $250 application fee for nonresidential systems. Utilities may not require residential customers to carry liability insurance beyond the amount required by a standard homeowner's policy ($100,000 minimum coverage), but nonresidential generators are required to carry "comprehensive general liability insurance" ($300,000 minimum coverage). Significantly, generators are responsible only for upgrade and improvement costs associated directly with a system's interconnection. Utilities are prohibited from imposing indirect fees and charges. North Carolina's interconnection standards include provision for mutual indemnification. A redundant external disconnect switch is required, and the capacity of all interconnected generation is limited to a maximum of 2% of rated circuit capacity. Applications for interconnected systems that exceed this saturation limit may be reviewed on a case-by-case basis.*

Appendix J: Excerpts Related to RPS Purposes from Various States

California

<http://www.dsireusa.org/documents/Incentives/CA25R.pdf>

Senate Bill No. 1078

(a) In order to attain a target of 20 percent renewable energy for the State of California and for the purposes of increasing the diversity, reliability, public health and environmental benefits of the energy mix, it is the intent of the Legislature that the California Public Utilities Commission and the State Energy Resources Conservation and
Development Commission implement the California Renewables Portfolio Standard Program described in this article.
(b) Increasing California's reliance on renewable energy resources may promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels.
(c) The development of renewable energy resources may ameliorate air quality problems throughout the state and improve public health by reducing the burning of fossil fuels and the associated environmental impacts.

New Mexico

<http://www.dsireusa.org/documents/Incentives/NM05R2.htm>

New Mexico Administrative Code

17.9.572.6 OBJECTIVE

The purpose of this rule is to implement the Renewable Energy Act, NMSA 1978 Section 62-16-1 et seq, and to bring significant economic development and environmental benefits to New Mexico.

17.9.572.10 RENEWABLE PORTFOLIO STANDARD

A. Each public utility must develop a reasonable cost renewable energy portfolio. In developing its renewable energy portfolio, a public utility shall take into consideration the potential for environmental and economic benefits to New Mexico. The portfolio shall be diversified as to type of renewable resource, taking into consideration the overall reliability, availability, dispatch flexibility and cost of the various renewable resources made available by providers and generators. Renewable energy resources that are in a public utility's electric energy supply portfolio on July 1, 2004 shall be counted in determining compliance with this rule. However, renewable energy sold to customers through a premium-priced renewable energy tariff shall not be counted in determining compliance with this rule. Other factors being equal, preference shall be given to renewable energy generated in New Mexico.

Texas

<http://www.dsireusa.org/documents/Incentives/TX03R.pdf>

Chapter 25, Substantive Rules Applicable to Electric Service Providers

§25.173. Goal for Renewable Energy.

(a) **Purpose.** The purpose of this section is to ensure that an additional 2,000 megawatts (MW) of generating capacity from renewable energy technologies is installed in Texas by 2009 pursuant to the Public Utility Regulatory Act (PURA) §39.904, to establish a renewable energy credits trading program that would ensure that the new renewable energy capacity is built in the most efficient and economical manner, to encourage the development, construction, and operation of new renewable energy resources at those sites in this state that have the greatest economic potential for capture and development of this state's environmentally beneficial resources, to protect and enhance the quality of the environment in Texas through increased use of renewable resources, to respond to customers' expressed preferences for renewable resources by ensuring that all customers have access to providers of energy generated by renewable energy resources pursuant to PURA §39.101(b)(3), and to ensure that the cumulative installed renewable capacity in Texas will be at least 2,880 MW by January 1, 2009.

Illinois

<http://www.dsireusa.org/documents/Incentives/IL04R.pdf>

Illinois Commerce Commission: Docket : 05-0437
Response to Governor's Sustainable Energy Plan for the State of Illinois

By the Commission:
WHEREAS, the inflation-adjusted prices of fossil fuels have risen steadily in the last five years; and
WHEREAS, the prices of fossil fuels have a significant effect on the future price of electricity; and
WHEREAS, the price of fossil fuels are decided in national and international markets that are beyond the control of state jurisdiction; and
WHEREAS, on February 11, 2005, the Governor of the State of Illinois sent to the Illinois Commerce Commission a proposal for a Sustainable Energy Plan for Illinois; and
WHEREAS, the Governor's proposed Sustainable Energy Plan included a Renewable Portfolio Standard and an Energy Efficiency Portfolio Standard; and
WHEREAS, the Governor's proposed Sustainable Energy Plan included a recommendation that the Illinois Commerce Commission establish an Illinois Sustainable Energy Advisory Council, with members appointed by the Chairman; and
WHEREAS, the Illinois Commerce Commission commenced the Sustainable Energy Initiative, issuing a "Request for Public Comment Concerning the Implementation of Governor Blagojevich's Proposal for a Sustainable Energy Plan for Illinois" on March 2, 2005; and
WHEREAS, the Illinois Commerce Commission organized workshops to discuss potential issues and invited Illinois utilities to present proposed implementation plans consistent with the Governor's proposed Sustainable Energy Plan; and

WHEREAS, during the course of the workshops, the Illinois Commerce Commission learned that the use of renewable energy sources will lead to rural economic development and improve environmental quality; and
WHEREAS, the Staff of the Energy Division of the Illinois Commerce Commission produced a Staff report dated July 7, 2005 addressing the various issues surrounding the implementation of renewable energy, demand response and energy efficiency programs; and
WHEREAS, the Illinois Commerce Commission adopted a resolution accepting Staff's report on July 13, 2005.
IT IS THEREFORE RESOLVED by the Illinois Commerce Commission that the Commission hereby adopts the Governor's proposed Sustainable Energy Plan with modifications based on information gathered through the Sustainable Energy Initiative and Staff's Report.
IT IS FURTHER RESOLVED that the Renewable Portfolio Standard should be set as follows: 2% of the bundled retail load should be obtained from renewable energy resources as defined below in 2007, 3% in 2008, 4% in 2009, 5% in 2010, 6% in 2011, 7% in 2012 and 8% in 2013.
IT IS FURTHER RESOLVED that sources of renewable energy shall include wind, solar thermal energy, photovoltaic cells and panels, dedicated crops grown for energy production and organic waste biomass, methane recovered from landfills, hydropower that does not involved the construction of new dams or significant expansion of existing dams, and other such alternative sources of environmentally preferable energy.
IT IS FURTHER RESOLVED that the Illinois Commerce Commission recognizes the benefits to Illinois by implementing the Sustainable Energy Plan, including using renewable energy and energy efficiency as a hedge against rising fossil fuel costs, and demand response as a mechanism to maintain system reliability and lower prices for all customers. Additionally, the Sustainable Energy Plan will create economic benefits in rural areas, create jobs and reduce air pollutants.

Pennsylvania
<http://www.puc.state.pa.us/PcDocs/621947.doc>

Pennsylvania Utilities Commission: Docket No. L-00060180
Implementation of the Alternative Energy Portfolio Standards Act of 2004

Background
Governor Edward Rendell signed the Act into law on November 30, 2004. The Act, which became effective February 28, 2005, establishes an alternative energy portfolio standard for Pennsylvania. The Act includes two key mandates: one, greater reliance on alternative energy sources in serving Pennsylvania's retail electric customers; two, the opportunity for customer-generators to interconnect and net meter small alternative energy systems.

Delaware
<http://www.dsireusa.org/documents/Incentives/DE06R.doc>

Senate Bill No. 74

Section 1. Amend Chapter 1, Title 26 of the Delaware Code, by inserting therein, between subchapters III and IV thereof, the following new subchapter:
"Subchapter III-A. Renewable Energy Portfolio Standards.

§ 351. Short title; declaration of policy.

(a) This subchapter shall be known and may be cited as the Renewable Energy Portfolio Standards Act.

(b) The General Assembly finds and declares that the benefits of electricity from renewable energy resources accrue to the public at large, and that electric suppliers and consumers share an obligation to develop a minimum level of these resources in the electricity supply portfolio of the state. These benefits include improved regional and local air quality, improved public health, increased electric supply diversity, increased protection against price volatility and supply disruption, improved transmission and distribution performance, and new economic development opportunities.

(c) It is therefore the purpose and intent of the General Assembly in enacting the Renewable Energy Portfolio Standards Act to establish a market for electricity from these resources in Delaware, and to lower the cost to consumers of electricity from these resources.

Maryland
<http://www.dsireusa.org/documents/Incentives/MD05R.htm>

Code of Maryland Public Utility Companies

§ 7-702. Intent and findings

(a) Intent. -- It is the intent of the General Assembly to:

(1) recognize the economic, environmental, fuel diversity, and security benefits of renewable energy resources;

(2) establish a market for electricity from these resources in Maryland; and

(3) lower the cost to consumers of electricity produced from these resources.

(b) Findings. -- The General Assembly finds that:

(1) the benefits of electricity from renewable energy resources, including long-term decreased emissions, a healthier environment, increased energy security, and decreased reliance on and vulnerability from imported energy sources, accrue to the public at large; and

(2) electricity suppliers and consumers share an obligation to develop a minimum level of these resources in the electricity supply portfolio of the State.

Maine
<http://www.dsireusa.org/documents/Incentives/ME01R.htm>

Maine Revised Statutes
TITLE 35-A. PUBLIC UTILITIES
PART 3. ELECTRIC POWER

§ 3210. Renewable resources

1. POLICY. In order to ensure an adequate and reliable supply of electricity for Maine residents and to encourage the use of renewable, efficient and indigenous resources, it is the policy of this State to encourage the generation of electricity from renewable and efficient sources and to diversify electricity production on which residents of this State rely in a manner consistent with this section.

New York
<http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/85D8CCC6A42DB86F85256F1900533518/$File/301.03e0188.RPS.pdf?OpenElement>

New York Public Service Commission: CASE 03-E-0188

BY THE COMMISSION:
I. INTRODUCTION
This proceeding was instituted on February 19, 2003, to explore the development of a renewable portfolio standard (RPS), which is a program to increase the proportion of renewable energy that is consumed by retail customers in New York State.

The development of additional renewable energy resources is a long-standing energy policy objective of the State. The 2002 State Energy Plan (June 2002) warned of the possible consequences of New York's fossil fuel dependency, noting that the State's primary sources of energy are imported, to a large degree, from abroad, have significant long-term environmental effects, and ultimately face depletion. Since the institution of this proceeding, over 150 parties, Department of Public Service (DPS) Staff, other governmental agencies, and thousands of members of the public have participated to address the issues identified in the Instituting Order and to craft an RPS program for New York State. Based upon the voluminous record before us, we endorse a policy of encouraging the increased use of renewable resources and institute a program, including the adoption of a renewable portfolio standard (RPS), consistent with such a policy.

An RPS is a recognized means of increasing the proportion of non-fossil fuel electricity purchases in a given jurisdiction. Many states have commenced RPS program initiatives and comparable RPS programs are in place in the United Kingdom, Denmark, Germany, the Netherlands, and Japan. It is worth noting that the specifics of individual RPS programs vary from one jurisdiction to the next in terms of targets to be achieved, eligibility of resources, implementation mechanisms, and time frames for achieving goals based on the individual circumstances of those jurisdictions.

We believe the policy we are adopting herein addresses the energy, economic, and environmental objectives of New York State by creating the potential to build new industries in the State based on clean, environmentally responsible energy technologies that meet the needs of New York energy consumers as well as the growing global market for these kinds of technologies.

RPS programs generally require that renewable resources deemed eligible for participation are awarded a certain level of financial incentives to support their development. Currently, renewable resources are generally more expensive than non-renewable resources, such as fossil fuels. Therefore, without access to financial incentives to cover all or some of these above-market costs, renewable resources struggle to compete with resources using fossil fuels. However, as noted in the Final Generic Environmental Impact Statement (GEIS) related to this proceeding and issued by this Commission in August, 2004, renewable resources provide ancillary benefits such as increased fuel diversity and energy security, the potential for economic development as a result of growing industries that typically tap into indigenous resources and invest in local and regional economies, and reduced environmental impacts. Accordingly, they warrant a certain level of support to facilitate their growth. The program we are adopting will provide sufficient financial incentives for the development of renewable resources so that they may more readily compete with facilities that use natural gas, coal, and oil to generate electricity. Ultimately, this effort may result in reducing costs associated with renewable resources as technologies continue to advance.

In adopting this program, we affirm that system reliability is of paramount importance and concern. Thus, while we are proceeding with the RPS, we also acknowledge that the implementation phase should be sufficiently flexible to accommodate a process for review and analysis of the potential impacts of renewable generation on the electric grid, as well as the ability to reflect modifications, if any, that are necessary to protect the reliability of the electric system.

Currently, about 19.3 percent of the electricity retailed in New York State is derived from renewable resources, the vast majority coming from large-scale hydroelectric facilities in Western New York, upstate New York, and Canada. We seek to increase the proportion of electricity attributable to renewable resources to at least 25 percent of electric energy used in New York State by the end of 2013. We intend to accomplish this by implementing an RPS that will utilize revenues derived from delivery charges on electric utility customers. These revenues will be administered by the New York State Energy Research and Development Authority (NYSERDA). On a regular basis, NYSERDA will award financial incentives that are the minimum necessary to stimulate development of generating facilities that meet the eligibility requirements described herein.

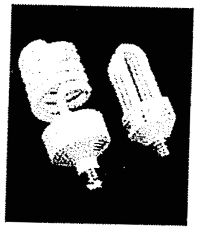
We believe an important objective of the RPS program is to stimulate and complement voluntary/competitive renewable energy sales and purchases (or "green markets") so that these competitive markets, not government mandates, sustain renewable activity after the RPS program ends. "Green power" is an industry term for electricity that is derived solely from renewable resources. Green marketing is the practice employed by energy service companies (ESCOs) or other marketers that promote the environmental and economic benefits of renewable resources to customers in the hopes that customers will, voluntarily, pay added costs associated with green power based on the value they place on these added benefits. The design and goals of this program demonstrate our support for fostering these competitive retail markets for green power to deliver greater choice and value to customers.

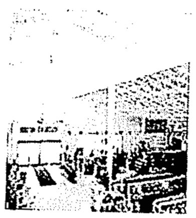
The policy and program adopted herein are designed to achieve the goal of at least 25 percent of the electricity used in New York State being provided by renewable resources.

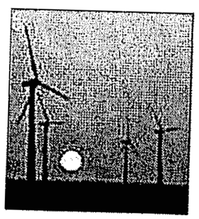
Specifically, the RPS delineated herein will mandate the collection of revenues, to be administered by NYSERDA, for the purpose of providing incentives to increase the percentage of electricity used by retail customers in the state that is derived from renewable resources from the current level of 19.3 percent to 24 percent. Hereafter, we will refer to this as the "mandatory" component of this renewable policy. We anticipate that at least an additional one percent of renewable energy sales will result from voluntary green market programs for a total goal of at least 25 percent. Hereafter, we will refer to this additional voluntary effort as the "voluntary" component of this renewable policy.

The additional new renewable electricity generation fostered by both of these components is expected to result in the displacement of some existing fossil fuel-based generation supply. Changes in generation resources due to implementation of these initiatives are expected to create greater diversity in the State's electric energy supply portfolio, and reduce the exposure to wholesale oil and natural gas price spikes and supply interruptions, thereby increasing the security of the State's electric energy supply.

We, therefore, adopt a policy of encouraging the retail use of renewables through implementation of a retail renewable portfolio standard pursuant to our authority to preserve environmental values and conserve natural resources (Public Service Law (PSL) §5(2));2 and a policy of encouraging and supporting green marketing efforts.





Analysis of Renewable Energy Potential in South Carolina

Renewable Resource Potential – Final Report

Prepared for: Central Electric Power Cooperative Inc.

September 12, 2007

GDS Associates, Inc.
Engineers and Consultants

La Capra Associates

La Capra Associates, Inc.
Energy Services Consultants

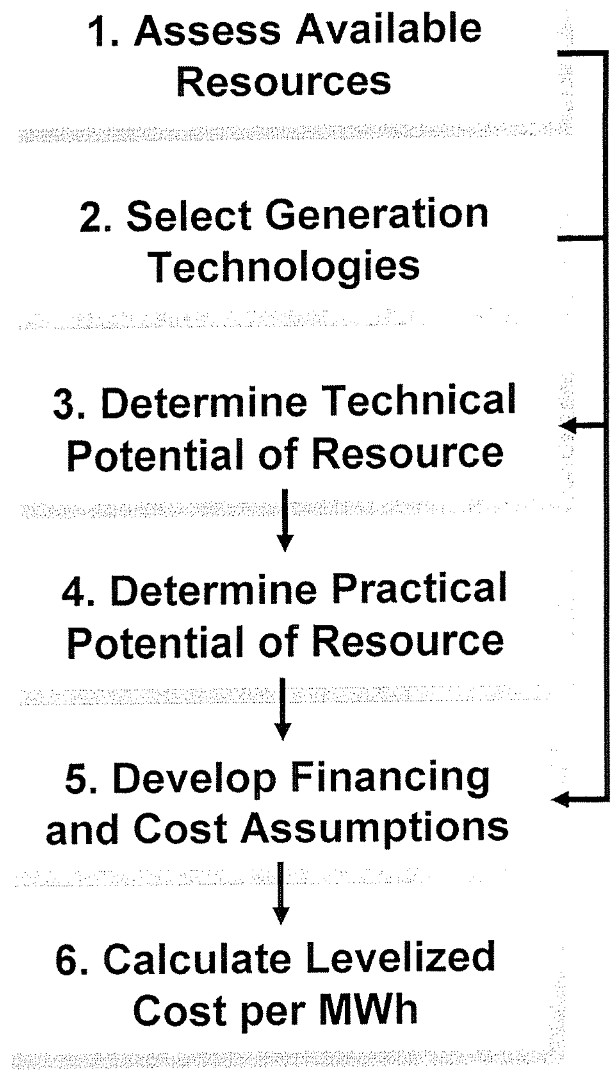
Table of Contents

Overview

This analysis seeks to quantify the renewable energy resource potential that can be used for electric generation within the state of South Carolina and to calculate the associated costs.

Approach

1. **Assess the total renewable resources or fuels (biomass, wind, landfill gas, etc...) available in the state.**
2. **Select generation technologies that can utilize the resources in the near-term.**
   - These technologies must be commercially available or the technologies themselves are mature, though they may be lacking mass deployment.
3. **Translate the resources into electric energy (and nameplate capacity) Technical Potential.**
   - Use performance characteristics of select technologies to estimate technical potential.
4. **Determine Practical Potential from Technical Potential.**
   - Criteria used for practical potential is different for each resource, but attempts to quantify the maximum potential that could reasonably be expected to be implemented.
5. **Develop financing assumptions, range of costs and operating characteristics for such technologies.**
6. **Calculate levelized costs ($/MWh) for electricity produced from selected renewable technologies given resource availability.**



Approach

Define Potential

Two levels of potential were estimated:

Technical Potential

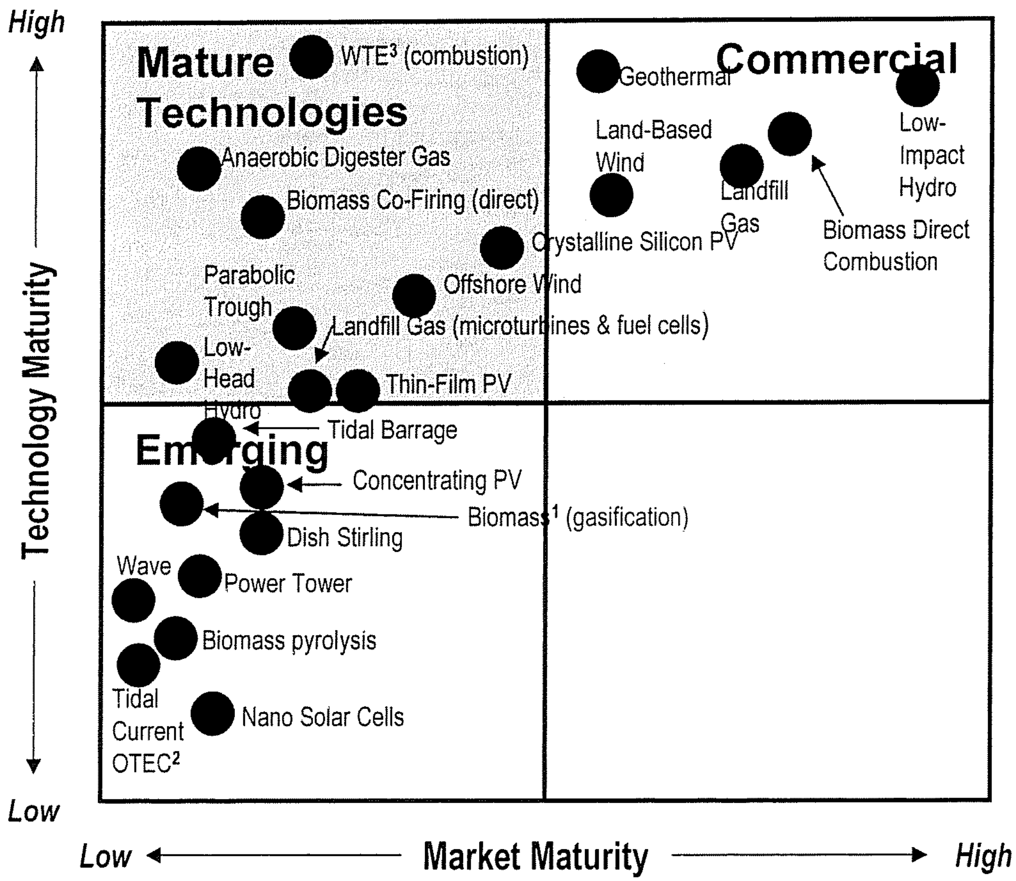
- Total renewable resources, located within the state, with the potential for electric energy conversion.
- Resource estimates are based on the utilization of commercial or mature technologies.
- The potential of offshore wind, solar and ocean power resources was <u>not</u> estimated because various factors currently limit their development, even though the resources themselves may be abundant.

Practical Potential

- The maximum potential that might reasonably be expected to be implemented based on currently available information and given assumed restrictions.
- Practical does <u>not</u> necessarily mean economic, nor does it imply any resource can be developed in a cost-effective manner when compared to conventional generation.
- The ability to access and develop each resource is considered, along with cost, but the criteria used are different for each resource.
- Limitations due to transmission constraints or permitting/siting barriers were <u>not</u> taken into account.

Renewable Energy Technologies

Technologies to capture renewable resources for electricity generation are quite diverse. Some are based on mature technologies that have demonstrated good market penetration while others are still in nascent stages of development.



1. Biomass integrated gasification combined cycle
2. OTEC = ocean thermal energy conversion
3. WTE = waste to energy

Renewable Technologies Reviewed

- **Mature Technologies**
  - **Anaerobic Digester Gas**
  - **Biomass Co-Firing (direct)**
  - **Crystalline Silicon PV**
  - **Offshore Wind**
  - Parabolic Trough
  - Landfill Gas (microturbines & fuel cells)
  - Thin-Film PV
  - Low-Head and Ultra Low-Head Hydro

- **Emerging Technologies/ Resource**
  - Tidal Barrage
  - Concentrating PV
  - Biomass (Gasification)
  - Dish Stirling
  - Wave
  - Power Tower
  - Biomass (Pyrolysis)
  - Tidal Current OTEC
  - Nano Solar Cells

- **Commercial Technologies**
  - Geothermal
  - **Land-Based Wind**
  - **Landfill Gas**
  - **Biomass Direct Combustion**
  - **Low-Impact Hydro**

In developing estimates of potential for renewable resources in the next decade, the focus is on using "**Commercial**" technologies that have both technology and market maturity and some "**Mature Technologies**" that show promise for market expansion in the near-term.

"**Emerging Technologies/Resources**" are not included in the analysis for several reasons. The technologies are typically in development or pilot testing stages, so many issues may still need to be resolved. The costs for developing these technologies are higher than more mature technologies. Often times, the steps needed to advance emerging technologies and reduce costs require active support of government and utilities in the near term.

Technologies that are underlined were reviewed or used in the assessment.

Technical vs. Practical Potential

- **Technical potential of new in-state renewable resources total about <u>2,360 MW</u>.**
  - Strong logging sector – wood fuel for renewable generation.
  - Modest hydro, agricultural waste, and landfill gas potential.
  - **The potential of offshore wind, solar and ocean power resources was <u>not</u> estimated** because various factors currently limit their development, even though the resources themselves may be abundant.

- **Practical potential of up to <u>665 MW</u> within the next decade.**
  - **There are some off-shore wind resources that may be developed**, but the magnitude can not be estimated since there has not been a permitted project in the U.S. to date.
  - **The potential for hydro may increase by about 90 MW**, but these additional impoundments have not been verified as existing.
  - Limitations due to transmission constraints or permitting/siting barriers are <u>not</u> taken into account explicitly.

Summary of Practical Renewable Potential

	Technical Potential (MW)	Practical Potential* (MW)	Practical Generation (GWh)
☐ Wood Biomass	1,599	423	3,148
☐ Agricultural By-Products	362	68	504
☐ Landfill Gas to Energy	90	70	518
☐ Hydroelectric (MWa)**	210	105	919
☐ Onshore Wind	100	-	-
Total***	2,361	up to 665	5,089
Offshore Wind	N/E	N/E	N/E
Solar PV	N/E	N/E	N/E
Ocean (Tidal, Wave, Current)	N/E	N/E	N/E

**Practical Potential is the maximum potential that might reasonably be expected to be implemented*

***Hydroelectric potential is measured in average MW based on annual mean flow rates or estimated annual production.*

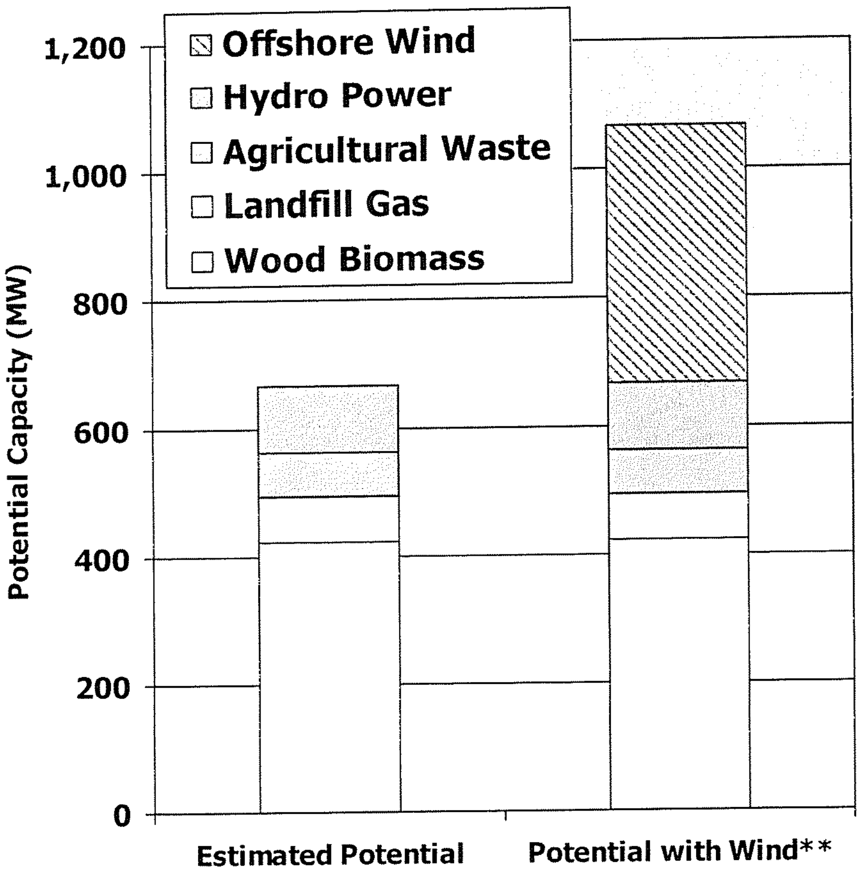
****Total may not add up due to rounding.*

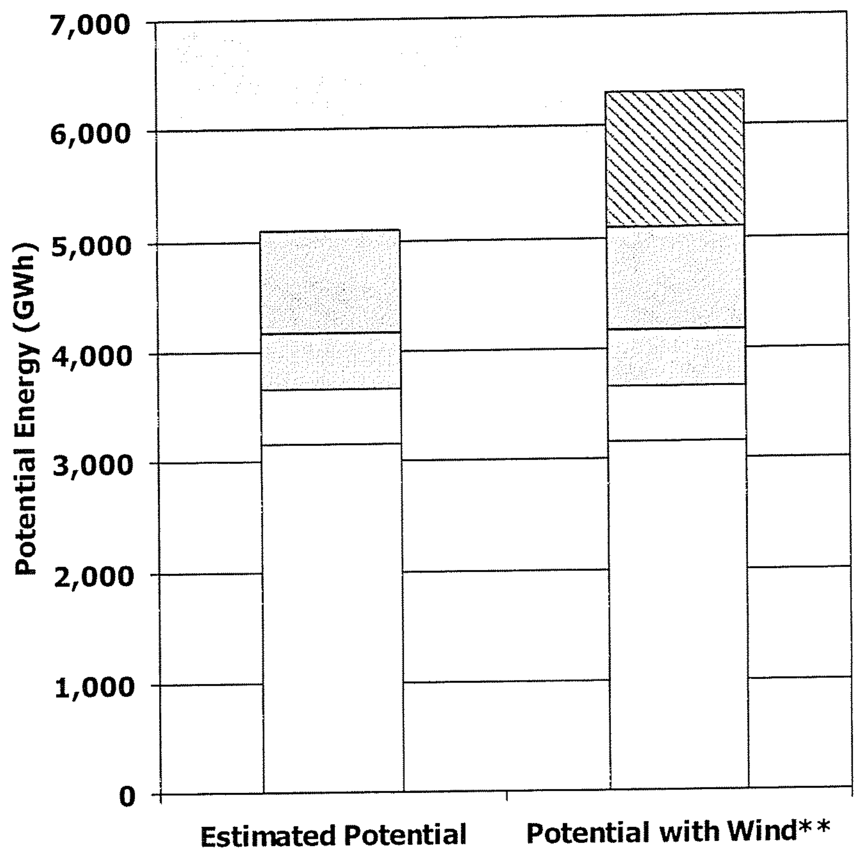
N/E: Off-shore Wind, Solar and Ocean power resource potential were not estimated because resources are abundant but available technologies have not achieved maturity or permitting issues introduce uncertainties for estimate.

Renewables

Practical Renewable Potential*

The biggest contributor to renewable energy production would derive from **biomass** (landfill gas, wood, agricultural by-products). The next would be **hydro. Offshore wind** may become a large contributor if projects can be permitted.





*Practical Potential is the maximum potential that might reasonably be expected to be implemented
**This example demonstrates the contribution from 400 MW of offshore wind if projects can be permitted.

Renewables

Wood Biomass

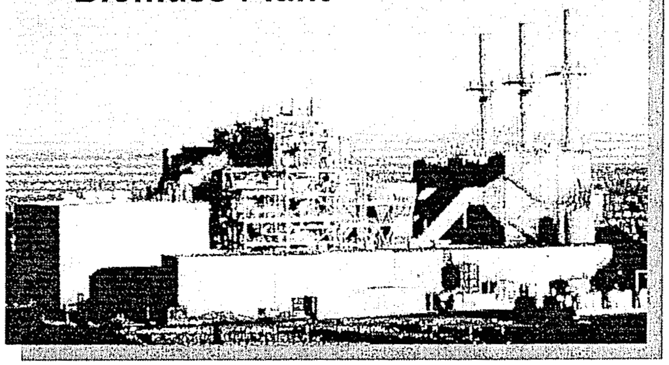
Description

Use of wood in direct-fired boilers for electricity generation is a well-established technology. Combined heat and power projects (CHP) also consume significant wood by-products, often co-located with industrial facilities.

National Installed Capacity: 5890 MW*

SC Installed Capacity: 360 MW*

Biomass Plant



Mature Technologies

- **Stoker Grate (direct-fire):** Most common direct-fire technology for biomass, recent improvements in efficiency and emissions controls.
- **Fluidized Bed:** Uses bed of inert material that is fluidized by high-pressure combustion air, reduces NOx emissions, capable of dealing with low-quality, high moisture content material.
- **Co-firing in Coal Plants:** While the technology is mature, co-firing is highly dependent on coal units' characteristics.

Emerging Developments

- **Biomass Gasification:** Syngas product can be used in combined-cycle or simple cycle generation.
- **Biomass Pyrolysis:** Multiple fuel products (liquids) that can also be used in combined cycle or combustion turbines.

** Estimates based on compilation of data from sources including Energy Information Agency, National Renewable Energy Laboratory, Environmental Protection Agency, and other web-based sources.*

Summary of Wood Biomass Potential

It is assumed that direct-fire biomass facilities would use a mix of Wood biomass, urban wood waste and agricultural by-products (discussed in next section) to generate electricity. The determination of practical potential includes fuels that would have a cost of **less than $65 per dry ton or about $4.00 per MMBtu.**

Wood Biomass Options	Technical Potential				Practical Potential*	
	Green Tons per Year	Dry Tons per Year[2]	Annual Heat Value[3] (MMBtu)	Technical Potential (MW)[4]	Practical Potential (MW)	Potential Energy (GWh)
Logging Residue	4,411,500	2,205,750	37,497,750	360	180	1,339
Pre-commercial Thinnings	8,555,796	4,277,898	72,724,266	698	-	-
Commercial Thinnings	5,336,000	2,668,000	45,356,000	435	217	1,617
Southern Scrub Oak[1]	48,792	24,396	414,732	4	-	-
Net Available Mill Residue	12,086	6,043	102,731	1	-	-
Urban Wood Waste	621,000	621,000	10,557,000	101	26	192
Total Wood Biomass				**1,599**	**423**	**3,148**

1. The potential of Southern Scrub Oak of 48,792 green tons per year assumes sustainable harvesting of the existing base at a rate of 2% annually.
2. To calculate dry tons of material, a moisture content of 50% of green biomass is assumed, except for urban wood waste which has relatively low moisture content.
3. The assumed heat content of wood biomass material is 8,500 btu/dry lb of biomass.
4. Potential MW calculation assumes direct-fired plants with 14,000 btu/kWh heat rate and a capacity factor of 85%.

**Practical Potential is the maximum potential that might reasonably be expected to be implemented*

Biomass

Description of Wood Biomass Categories

- Data from Forest Inventory and Analysis (FIA) and Timber Product Output (TPO).
  - Calculation of technical potential was based on estimates of wood residue and other wood products using sampled acres and applied to all timberland.
- To estimate **practical potential**, the technical potential was reduced by 50% to account for some inaccessible timberland.
- **Practical potential** was then further reduced through fuel cost considerations, which will be described later.

Wood Types	Definitions
Logging Residue	Unused portions of growing stock trees cut or killed by logging and left in the woods.
Thinnings	Silvicultural operation whereby smaller and less desirable trees are removed to enhance production of more valuable trees.
Pre-Commercial	Involves removal of saplings from a stand, usually <5.0 inches DBH*.
Commercial	Mainly merchantable-sized pulpwood >5.0 inches DBH, assumed 50% currently consumed by pulp and paper industry. Remaining available for fuel.
Southern Scrub Oak	Composed of low-quality hardwood species such as turkey oak that do not have timber value, so are not currently harvested.
Mill Residue	Bark and wood material that is generated in mills (i.e. slabs, edgings, trimmings, miscuts, sawdust, shavings, etc...) but most are consumed on site for heat and/or power.

Source: "Final Report to the South Carolina Forestry Commission on Potential For Biomass Energy Development in South Carolina," Harris, Robert et al. (2004)

* DBH = Tree diameter in inches (outside bark) at breast height (4.5 feet above ground level).

Biomass

Timberland by County

Timberland is defined as forestland that is producing or is capable of producing crops of industrial wood — and not excluded from timber utilization by statute or administrative regulation. Areas qualifying as timberland are capable of producing in excess of 20 cubic feet per acre per year of industrial wood in natural stands.

Acres

< 200000

< 300000

< 400000

< 500000

< 600000

Source: USDA Forest Service, Forest Inventory and Analysis 2001

Biomass

Description of Urban Wood Waste

- The calculation of technical potential of urban wood waste is calculated based on population and industrial activity by county.
- Due to diverse mix of clean and contaminated materials, the **practical potential** is assumed to be only 25% of the total estimated urban wood waste. This reflects clean (untreated and unpainted) and segregated wood waste for use in electricity generation.
- Avoided landfill tipping costs in South Carolina is about $36/ton.
  - However, the net cost of fuel from urban wood waste is assumed to be $0/ton including transportation costs.
- Expected growth in the resource as population grows with more availability in dense population centers.

Waste Types	Definitions
Municipal Solid Waste	Material discarded from individual residences/small businesses, such as tree service companies. Materials may include household yard waste, remodeling scrap, tree trimmings, and wooden shipping containers.
Industrial Wood Waste	Discarded material from companies that work with wood, such as pallet, cabinet, furniture, and custom building companies.
Clearing/ Demolition Waste	Wood originating from the clearing of land or demolition of buildings.

Source: "Final Report to the South Carolina Forestry Commission on Potential For Biomass Energy Development in South Carolina," Harris, Robert et al. (2004)

Methodology for Wood Biomass Supply Curve

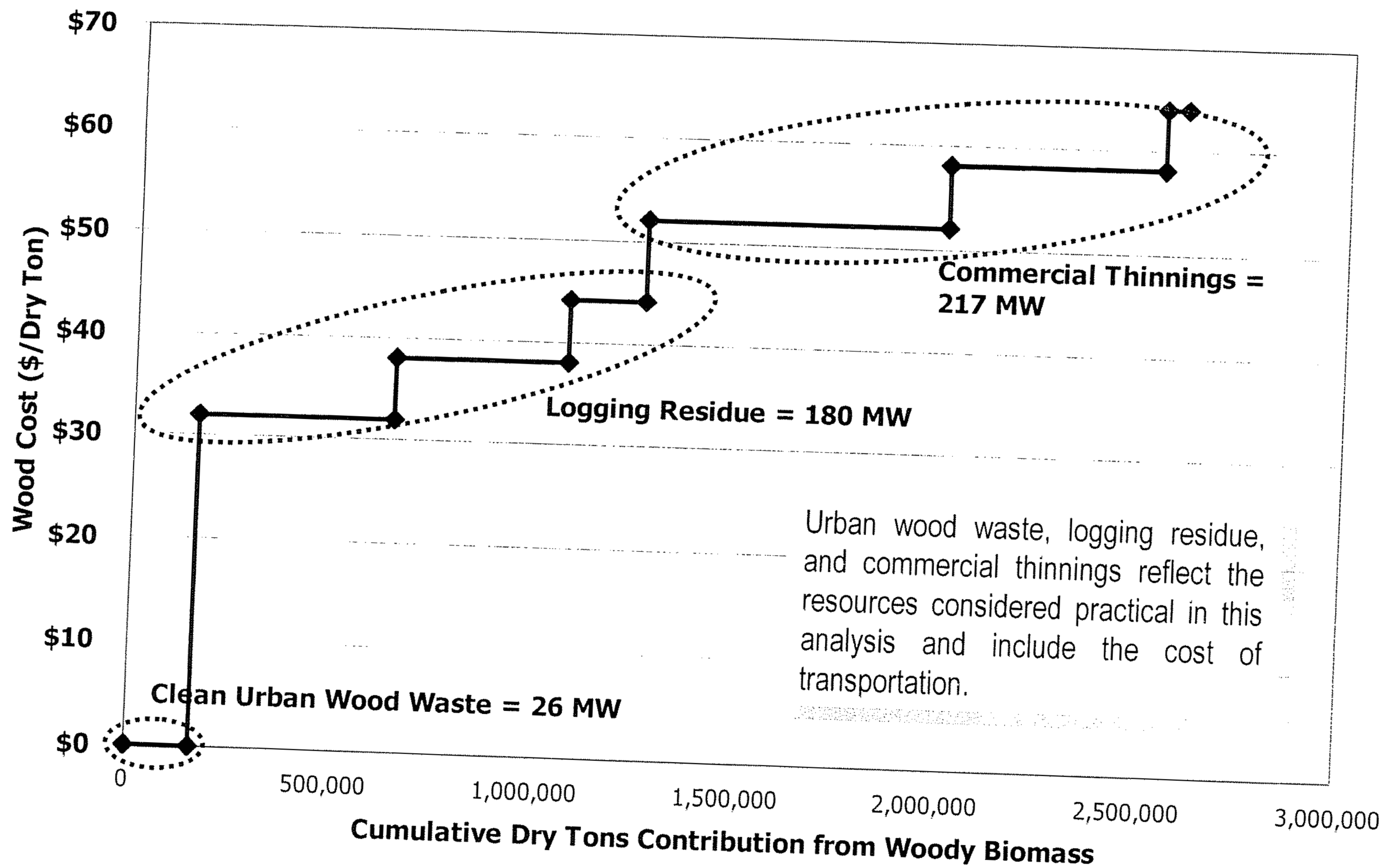
- **Fuel costs on the supply curve are differentiated by the following cost components for each biomass resource:**
  - Harvesting/gathering/collecting/chipping ($13–$23/green ton*)
  - Transport ($3/mile per shipment of 25 green tons)
- **Biomass resources are reviewed by county to determine transportation costs based on delivery radius.**
  - Counties are divided into three groups based on level of biomass resource potential and then assigned a transportation radius to determine cost of delivered fuel.**
    - High biomass potential: 25 miles
    - Medium biomass potential: 50 miles
    - Low biomass potential: 75 miles
  - Transportation costs for biomass from each group of counties are calculated based on transporting green tons within each delivery radius.
- **Fuel costs are then converted from $/green ton to $/dry ton,*** assuming 50% moisture content.**

**Green ton refers to the actual weight of biomass material, including moisture content.*

***The delivery radius represents the average distance that the biomass material in each county may need to be transported to reach the nearest biomass power facility. Typically, biomass facilities will try to locate as close to biomass resources as possible and, thus, closer to higher biomass potential counties.*

****Dry ton refers to the weight of biomass material with most of the moisture content removed.*

Wood Biomass Fuel Supply Curve



Biomass

Comments on Wood Biomass

- The lowest cost biomass fuels in the state will likely come from urban wood waste and logging residue.
- A higher cost, but still moderate, biomass fuel will be commercial thinnings.
- There may be opportunities for co-firing of these fuels in existing coal facilities, but compatibility will be unit specific and limited in the state.
- The preferred, mature technologies for burning biomass are stoker-grate and fluidized-bed technologies with appropriate emissions controls.
  - The biomass fuels used in these generators would be a mix of locally sourced biomass that may contain wood residue, urban wood waste, and agricultural by-products.
  - The mix of biomass fuels used at each facility will depend on which resources are within close proximity of the facility.
- An emerging technology that was not assessed – and may have some potential in the future – is biomass gasification. Gasification costs need to be reduced and gasification issues resolved before being competitive with more mature technologies that can utilize biomass.

Agricultural By-Products

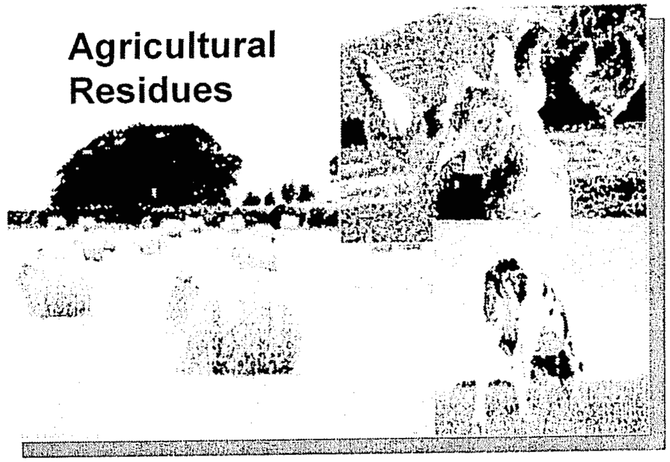
Description

Historically, agricultural residue and by-products, such as poultry litter and animal waste, have not been used to a significant degree in power generation. Reasons include low energy density, cost of collection, and use as soil amendments.

National Installed Capacity: **>75 MW***

SC Installed Capacity: **0 MW**

Agricultural Residues



Mature Technologies

- **Co-firing in Coal Plants:** While the technology is mature, co-firing with agricultural residues are still in mostly demonstration phases.
- **Stoker or Fluidized Bed:** Technology is the same as wood-fired generation, but sites must be adapted to handle agricultural products.
- **Anaerobic Digester Coupled with ICE or Microturbine:** Generation technologies are mature, but integration faces many obstacles.

Emerging Developments

- **Gasification and Pyrolysis:** Produces gas and liquid bio-fuels.
- **Anaerobic Digester Coupled with Fuel Cells:** Methane from digester is cleaned and used in fuel cells, which are still in pilot stages.

** Estimates based on data from the U.S. Environmental Protection Agency AgStar 2006 Report, anaerobic digesters totalled over 20 MW in 2005 representing about 100 installations. According to AgStar, another 80 installations planned for 2006 were not included in the total. Capacity estimate includes a 55 MW FibroMinn project utilizing poultry litter.*

Summary of Agricultural Resources Potential

It is assumed that these biomass resources are co-fired in direct-fire applications with other biomass fuels, such as wood residue, or in coal plants to generate electricity, except for Swine Waste which would utilize an anaerobic digester/combustion engine generator set configuration.

Agricultural Resources	Maximum Fuel (MMbtu)	Assumed Capacity Factor	Technical Potential (MW)	Practical Potential* (MW)	Practical Generation (GWh)
Agricultural Crop Residue					
Corn	7,480,346	85%	72	36	267
Wheat	3,370,815	85%	32	0	0
Soybean	3,337,936	85%	32	0	0
Cotton	4,145,582	85%	40	0	0
Switchgrass	16,790,918	85%	142	0	0
Poultry Litter	4,384,851	85%	42	31	230
Swine Waste	166,922	75%	2	1	7
Total Agricultural By-Products			**362**	**68**	**504**

**Practical Potential is the maximum potential that might reasonably be expected to be implemented*

Description of Agricultural Residues

- Crop residues are materials left in agricultural fields after harvest.
  - Most residues are plowed into soil for enrichment or burned prior to planting of next crop.
  - Residues are concentrated mainly in the Coastal Plains region.
- Estimates are derived from grain production and acreage values reports for each crop by the South Carolina Agricultural Statistics Services.
- Wheat, soybean, and cotton are likely not practical for direct-fire applications, so not included in the total practical resources.

Crop Residues	Definitions/Discussions
Corn	Most likely material for energy production, as no crop is planted after corn harvest. Currently used in co-firing with other wood biomass or coal. Assumed 50% are left on fields for enrichment and soil erosion control.
Wheat	Wheat is harvested in late May/early June, but soybean is generally planted immediately following the wheat harvest, which would not allow sufficient time for gathering wheat material for use in energy production. *(Excluded as practical)*
Soybean	No example of direct-firing of soybean residue for electric generation. Better feedstock for bio-fuel production or pyrolysis. *(Excluded as practical)*
Cotton	One demonstration project in Greece concluded cotton is too costly and requires extensive emissions controls. May be better feedstock for bio-fuel production or pyrolysis. *(Excluded as practical)*

Source: "Final Report to the South Carolina Forestry Commission on Potential For Biomass Energy Development in South Carolina," Harris, Robert et al. (2004)

Agricultural Waste

Description of Switchgrass

- Switchgrass is a perennial warm season grass native to North America and can grow in clumps of 3 to 6 feet tall.
- Estimate of technical potential assumes planting of switchgrass on all Conservation Reserve Program (CRP) land in the state .
  - About 1,500 acres are needed per 1 MW of generation.
  - There are over 200,000 acres of CRP land in the state.
- Switchgrass production costs exceed that of other biomass options currently.
  - Costs greatly depend on yield, land use costs, and farming conditions.
- Given the high cost of production, it is more likely a candidate for bio-fuel production rather than in direct-fire electricity generation.* *(Excluded as practical)*

Appendix 3. Cost summaries for the seven scenarios

Scenario	Yield (ton/acre)	Establishment costs (prorated) ($)	Reseeding costs (prorated) ($)	Yearly production costs ($)	Total cost per acre ($)	Total cost per ton ($)
1	1.5	24.47	4.48	168.80	197.75	131.84
	3.0	24.47	4.48	208.90	237.85	79.29
	4.0	24.47	4.48	235.64	264.59	66.15
	6.0	24.47	4.48	289.11	318.07	53.01
2	1.5	23.49	3.55	143.80	170.85	113.90
						70.32
						59.42
						48.53
3						134.83
						80.78
						67.27
						53.76
4	1.5	24.95	8.97	168.80	202.71	135.14
	3.0	24.95	8.97	208.90	242.82	80.94
	4.0	24.95	8.97	235.64	269.55	67.39
	6.0	24.95	8.97	289.11	323.03	53.84
5	1.5	23.50	8.97	168.80	201.27	134.18
	3.0	23.50	8.97	208.90	241.38	80.46
	4.0	23.50	8.97	235.64	268.11	67.03
	6.0	23.50	8.97	289.11	321.59	53.60
6	1.5	23.97	7.10	143.80	174.87	116.58
	3.0	23.97	7.10	183.90	214.98	71.66
	4.0	23.97	7.10	210.64	241.71	60.43
	6.0	23.97	7.10	264.11	295.19	49.20
7	1.5	24.19	7.10	143.80	175.09	116.73
	3.0	24.19	7.10	183.90	215.19	71.73
	4.0	24.19	7.10	210.64	241.93	60.48
	6.0	24.19	7.10	264.11	295.41	49.23

Costs of switchgrass production range between \$50 to \$135 per ton (2000\$) or **\$60 to \$165 per ton** in today's dollars, before transportation costs are included.

Source: "Costs of Producing Switchgrass for Biomass in Southern Iowa," Mike Duffy and Virginie Y. Nanhou. Iowa State University, (April 2001)

*There is a demonstration project in Chariton, Iowa that is testing co-firing of switchgrass at a coal plant. http://www.iowaswitchgrass.com/technical~agricultural.html

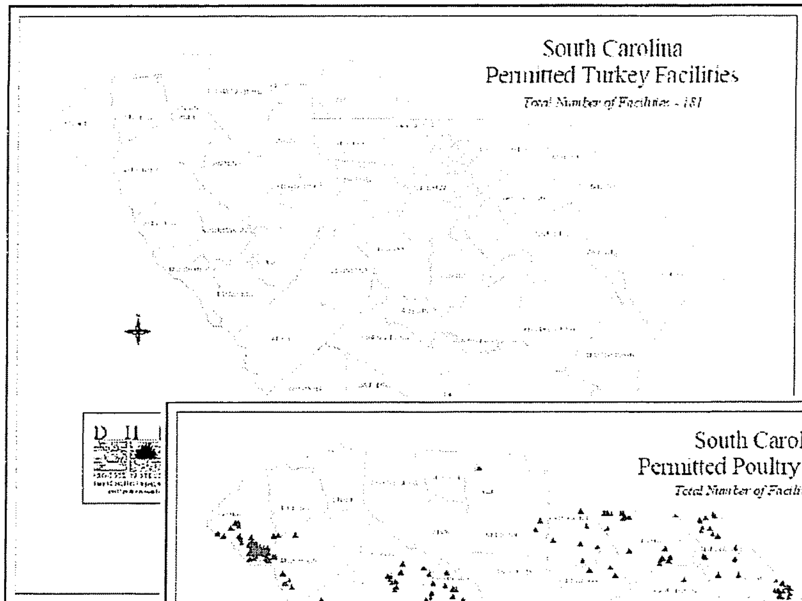
Agricultural Waste

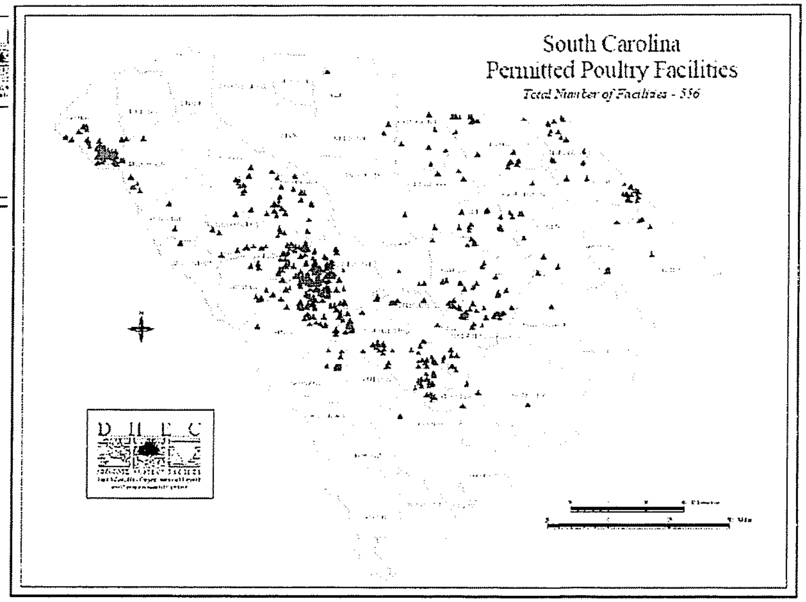
Description of Poultry Litter

- Estimated total potential of poultry litter is based on actual bird production in 2005.
  - Over 220 million birds processed.
  - Estimated over 350,000 tons of poultry litter produced *(about half of what will be consumed in FibroMinn project below).*
  - Practical potential based on top 10 counties of highest poultry litter production.
- Poultry litter is historically used in land applications for soil enrichment.
  - Some concerns over nutrient contamination of groundwater have regulators seeking alternative outlets.
  - Fertilizer value of material is estimated to be $38 to $52 per dry ton.

55 MW FibroMinn, a dedicated poultry-litter project in Minnesota, became the first commercial facility in 2007 in the U.S.

- Expected consumption of 700,000 tons of poultry litter per year, supplemented with wood and agricultural residue.
- Ash from plant will be processed and re-sold as fertilizer.



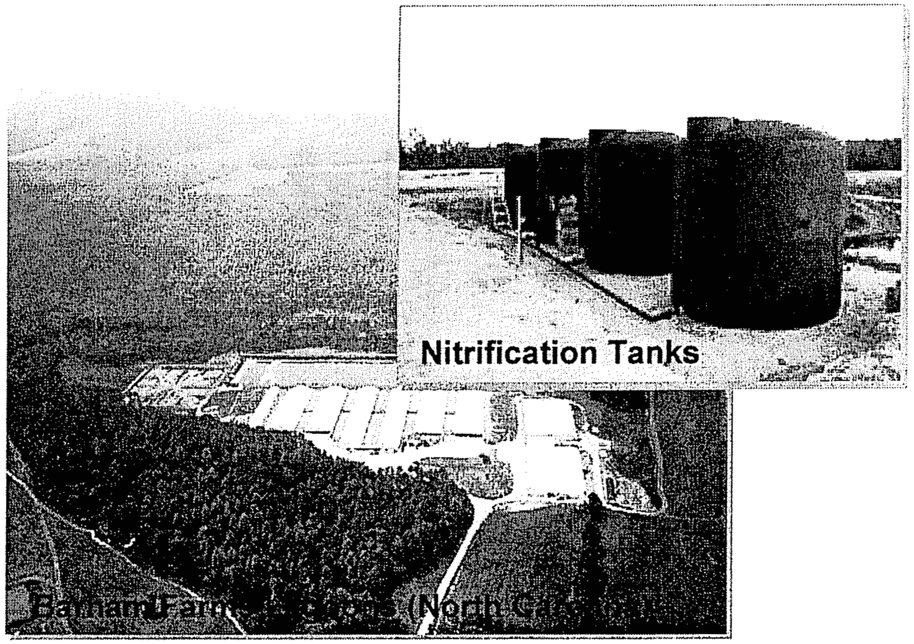


Source: Availability of Poultry Manure as a Potential Bio-Fuel Feedstock for Energy Production (SC Energy Office, September 2006) http://www.scbiomass.org/Publications

Agricultural Waste

Description of Swine Waste

- 900 Hog/Swine Farms in South Carolina
  - Only 37 have >2,000 head
  - Only 21 have >5,000 head
- AgStar (EPA) recommends >2000 head operations for anaerobic digesters.
  - Cost effective operations are likely to require >5,000 head, used in practical potential assessment.
  - Total methane production may support about 1 MW of total capacity in state, with average generators sized about 100 kW per site.
  - Opportunities are very limited in the state.
- Costs and designs are very site specific.
  - Combined heat and power opportunities
  - Some potential for aggregation of waste material or collection of methane from mulitiple sites.
  - Issues related to maintenance and training for farmers/operators



Barham Farms has an anaerobic digester coupled with a combustion engine generator.

- The farm operation is a 4,000 head farrow-to-wean operation located in Zebulon, North Carolina.
- Methane gas is used in electric generation and heating for a greenhouse.

Agricultural Waste

Comments on Agricultural By-Products

- Many of the agricultural by-products that are determined practical, may have more value as a fertilizer or an input to future biofuel production.
- The lowest cost agricultural by-products that can be co-fired with other biomass (wood) or coal in direct-fire applications will likely be poultry litter and corn stover.
  - However, both may pose problems related to opportunity costs related to fertilizer value in land application, management of increased ash content, and more emissions controls needed.
  - Also, availability of supply may be sporadic depending on season and growing cycles and, in the case of animal waste, disease may also limit supply.
- The costs related to planting and harvesting of switchgrass make the resource cost prohibitive for direct-fire electric generation in the near-term.
- There is limited potential for anaerobic digester development using swine waste due to few swine operations with the requisite herd size in South Carolina.

Agricultural Waste

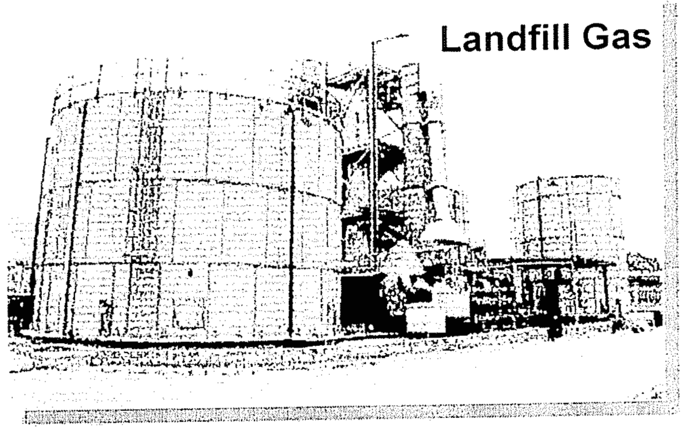
Landfill Gas-to-Energy

Description

Landfills produce a variety of gases, a majority being methane, as waste decomposes. The EPA now requires flaring of the gas at most landfill sites of a certain size in the U.S. Instead of flaring, the gas can be conditioned for use in electric generation or direct thermal use.

National Installed Capacity: **1250 MW***

SC Installed Capacity: **24 MW***



Technologies

- **Reciprocating Engines or Internal Combustion Engines (ICE):** Over 50% of installed capacity.
- **Gas Turbines:** A growing trend.
- **Cogeneration:** Co-locating with industrial load for heat and electricity consumption.

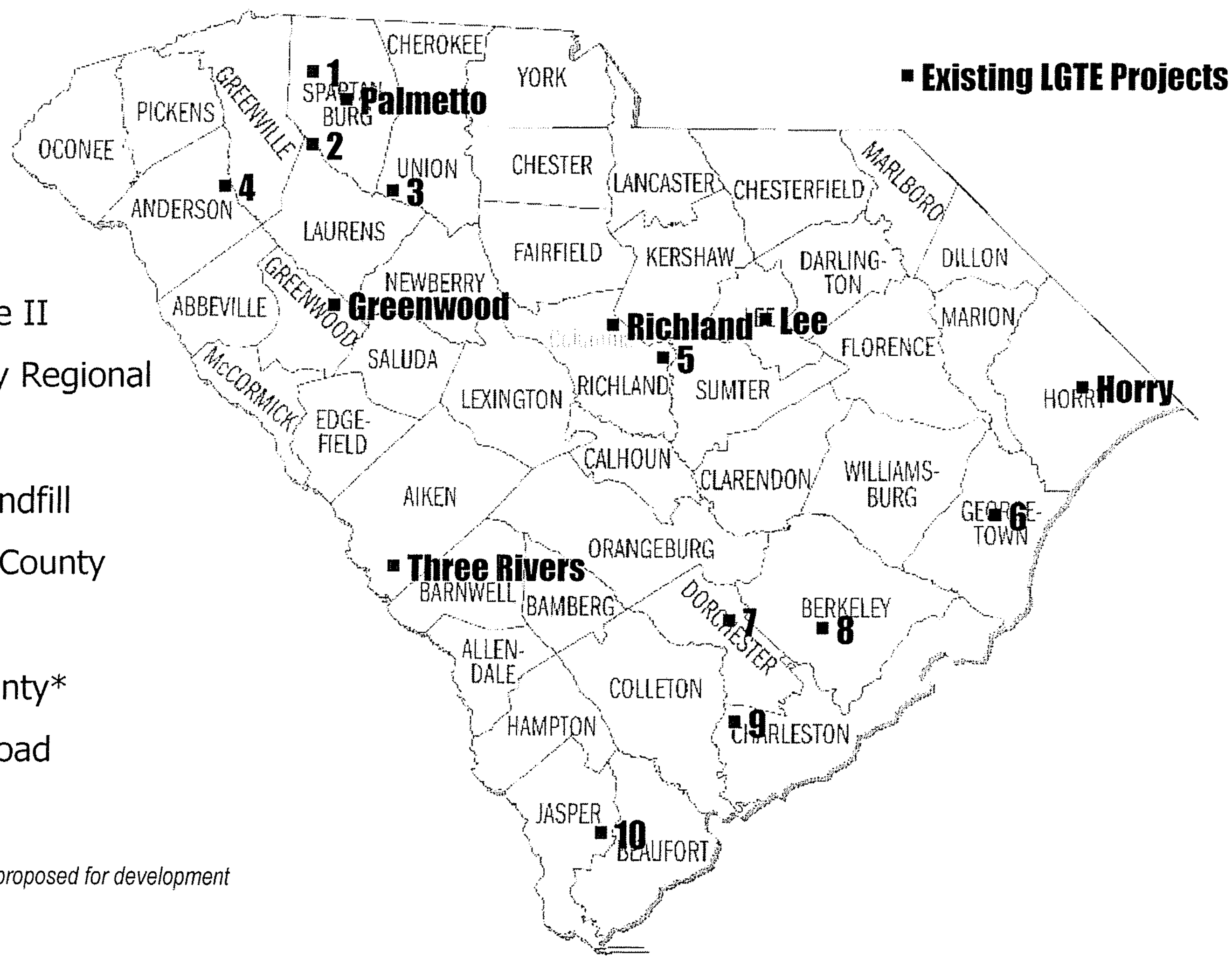
Emerging Developments

- **Fuel Cells and Microturbines:** May provide better efficiencies and lower emissions, but costs are still relatively higher for these technologies.

** Estimates based on compilation of data from sources including Energy Information Agency, National Renewable Energy Laboratory, Environmental Protection Agency, and other web-based sources.*

Landfill Gas

Potential Future Landfill Gas to Energy Sites



1. Wellford
2. Enoree Phase II
3. Union County Regional
4. Anderson*
5. Northeast Landfill
6. Georgetown County
7. Oakridge*
8. Berkeley County*
9. Bees Ferry Road
10. Hickory Hill*

** Under development or proposed for development*

Landfill Gas to Energy Projects *(Existing)*

Name of Site	County	On-line (MW)	Incremental Planned Expansions* (MW)	Use
Horry County MSWLF	Horry	3	2.0	Electricity
Lee County Landfill, LLC	Lee	5.4	9.1	Electricity
Richland Landfill, LLC	Richland	5.5	3.5	Electricity
Palmetto MSWLF	Spartanburg	10	2.0	Combined Heat and Power
Total Electric Generation at Existing Sites		**23.9**	**16.6**	
Three Rivers MSWLF	Aiken	N/A	N/A	Direct-use
Greenwood County MSWLF	Greenwood	N/A	N/A	Direct-use

*Planned expansions by 2011

Landfill Gas

Landfill Gas to Energy Projects *(Additional Potential)*

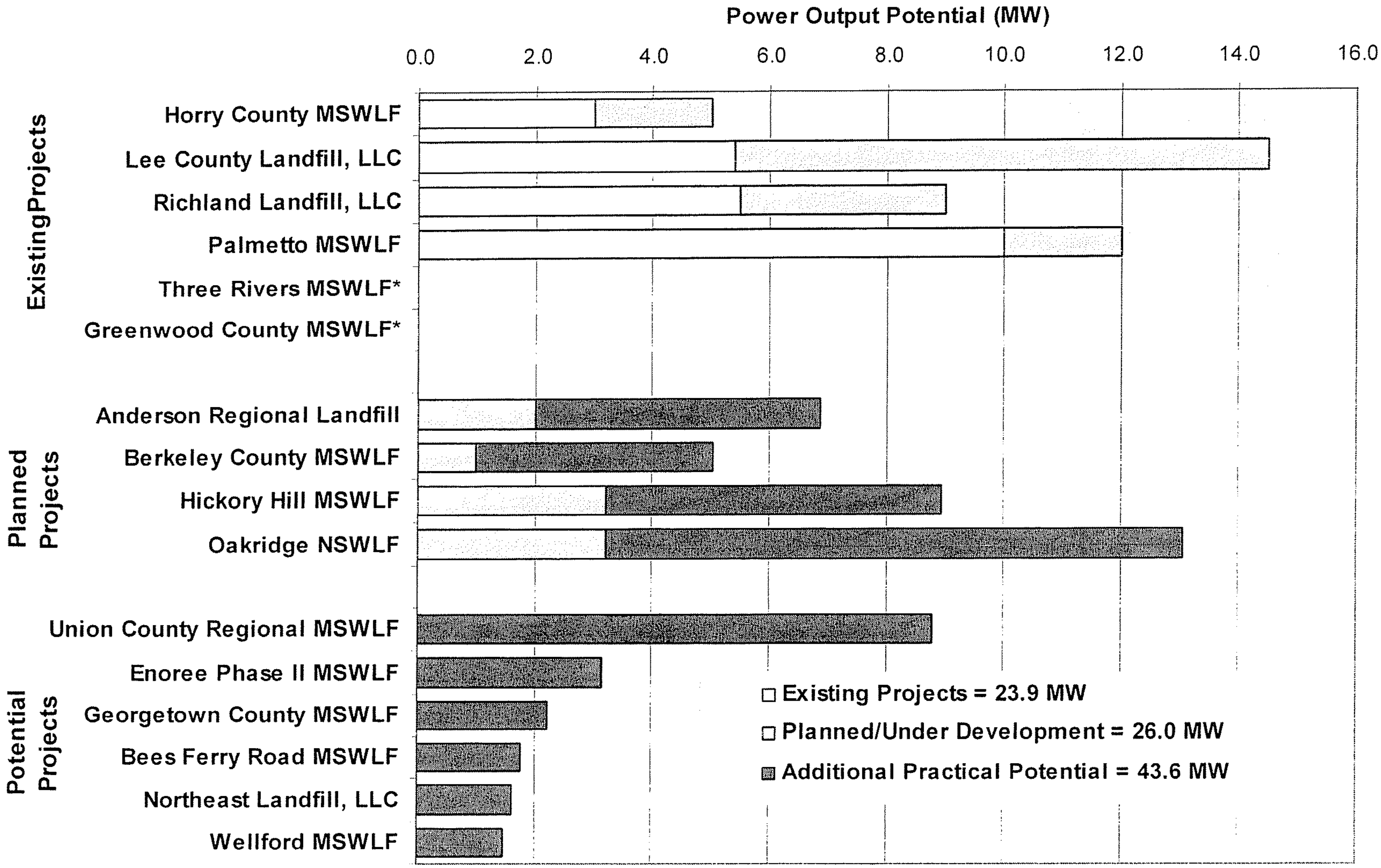
Name of Site	County	Technical Potential (MW)**	Practical Potential (Planned Development) (MW)***
1. Wellford MSWLF	Spartanburg	2.1	1.5
2. Enoree Phase II MSWLF	Greenville	4.5	3.2
3. Union County Regional MSWLF	Union	13.0	8.8
4. Anderson Regional Landfill*	Anderson	10.7	6.9 (2.0)
5. Northeast Landfill, LLC	Richland	2.6	1.6
6. Georgetown County MSWLF	Georgetown	2.5	2.2
7. Oakridge NSWLF*	Dorchester	17.6	13.1 (3.2)
8. Berkeley County MSWLF*	Berkeley	7.4	5.1 (1.0)
9. Bees Ferry Road MSWLF	Charleston	2.5	1.8
10. Hickory Hill MSWLF*	Jasper	10.9	8.9 (3.2)
11. Williamsburg County MSWLF	Williamsburg	too small	too small
12. Abbeville County MSWLF	Abbeville	too small	too small
Total New Landfill Gas		**73.5**	**53.0 (9.4)**

**Planned developments for electric generation by 2011 depicted in parenthesis. Increased developments may be possible after 2011.*

***Estimated technical potential derived from LandGem model that estimates landfill methane production potential. LandGem is a spreadsheet model developed by the EPA that allows users to estimate methane production levels given size and rate of disposal at landfills. Methane production measured over 2008–2027, with the assumption that projects are installed in the 2008–2017 time frame. An 85% capacity factor was assumed.*

****Practical Potential is derived using the lower range of methane production potential for a site for more conservative sizing of a facility. Practical Potential is the maximum potential that might reasonably be expected to be implemented.*

Landfill Development Practical Potential



*The landfill gas from these sites are utilized in direct use applications.

**Practical Potential is the maximum potential that might reasonably be expected to be implemented.

Landfill Gas

Comments on Landfill Gas to Energy

- Landfill gas for electric generation is likely the lowest cost renewable energy option in the state.
- Opportunities to develop projects at almost all of the state's MSW landfills (53 MW), along with expansions at existing sites (16.6 MW), for a total of almost 70 MW of additional capacity over time.
- Size of development will depend on level of waste disposal, build-out of gas collection systems, and methane production at each site currently and in the future.
- Some sites may face competition with direct-use applications of the landfill gas.

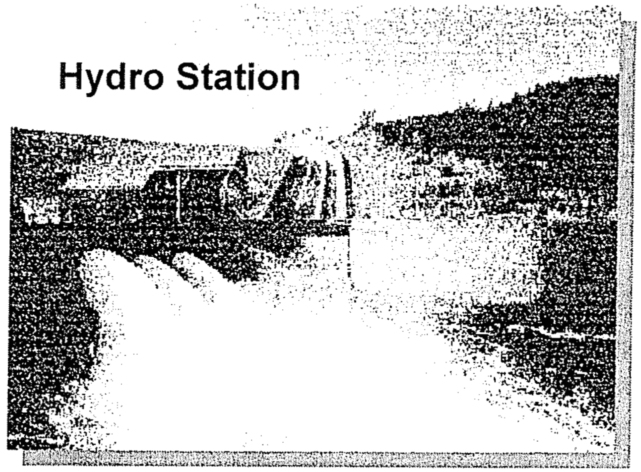
Hydro

Description

Hydroelectric generation has been in existence for over a century. It involves the conversion of kinetic hydro energy to electricity by turning a turbine.

National Installed Capacity: 78,700 MW*
SC Installed Capacity: ~3400 MW*

Hydro Station



Mature Technologies

- **Conventional with Impoundments**
- **Small Hydro (1 to 30 MWa)**
- **Low Power (Conventional) (<1 MWa)**

Emerging Developments

- **Low power (Unconventional) (<1 MWa)**
- **Microhydro (<100 kW)**
- **Ocean (Tidal, Wave, Current):** Highly site specific for tidal energy, some demonstration projects, but technological issues related to salt water and fish avoidance still need to be resolved.

** Estimates based on compilation of data from sources including Energy Information Agency, National Renewable Energy Laboratory, Environmental Protection Agency, and other web-based sources.*

Summary of Hydroelectric Potential

	Assumed Capacity Factor	Technical Potential (MW)	Practical Potential* (MW)	Practical Generation (GWh)	Notes
>5 MW Conventional	25%	169.1	0.0	0.0	Impoundments at sites listed have not been verified as existing.
1-5 MW Conventional	25%	15.9	3.5	7.7	Only two sites have been verified with existing impoundments.
1-30 MWa New Small Hydro**	N/A	153.0	100.0	876.0	Assumes top 15 of 45 sites are practical based on penstock length evaluation.
<1 MWa Low Power (Conventional)**	N/A	11.0	4.0	35.0	Assumes 14 sites of low-power conventional hydro are practical based on penstock length evaluation.
Total MWa**		**210.3**	**104.9**	**918.8**	

Practical Potential is the maximum potential that might reasonably be expected to be implemented

*** Measured in MWa (Average Megawatts) to reflect average energy production rather than capacity.*

Hydro Power

Potential Conventional Hydro Sites (>1MW)

Idaho National Laboratory (INL) uses a Project Environmental Sustainability Factor (PESF) to reflect the probability for development. The PESF is used here to reduce total ratings at sites for estimating practical potential. Additionally, many of the potential conventional hydro sites at existing impoundments, as described in INL's database, were unable to be verified as existing, so were not included in practical potential.

Plant Name	County	Dam Status	Rating (MW)	PESF	PESF* Rating (MW)
PARR SHOALS	Newberry	W	5.0	0.5	2.5
BLALOCK	Spartanburg	WO	2.1	0.5	1.0
Practical Potential Total			**7.0**		**3.5**
BLAIR	Newberry	U	109.0	0.5	54.5
COURTNEY ISLAND	Lancaster	U	50.6	0.5	25.3
BURNT FACTORY	Union	U	9.5	0.5	4.7
THOMPSON RIVER	Oconee	U	3.4	0.9	3.1
FORK SHOALS DAM	Greenville	U	2.0	0.9	1.8
VAN PATTON	Laurens	U	3.5	0.5	1.7
Unverified Potential Total			**178.0**		**91.2**

WO = Impoundment Without Existing Turbine Installation W = Impoundment With Existing Turbine Installation U =Unable to Verify Existence of Impoundment

PESF = Project Environmental Sustainability Factor (0.1 for lowest likelihood of development, 0.9 for highest likelihood). INL considered factors such as wild/scenic value, cultural value, fish presence value, geologic value, historic value, recreation value, wildlife value, and federal land in determining PESF

Source: Idaho National Lab (INL) Hydropower Resource Development for South Carolina, FERC Hydro License Database

Hydro Power

Small Hydroelectric Potential

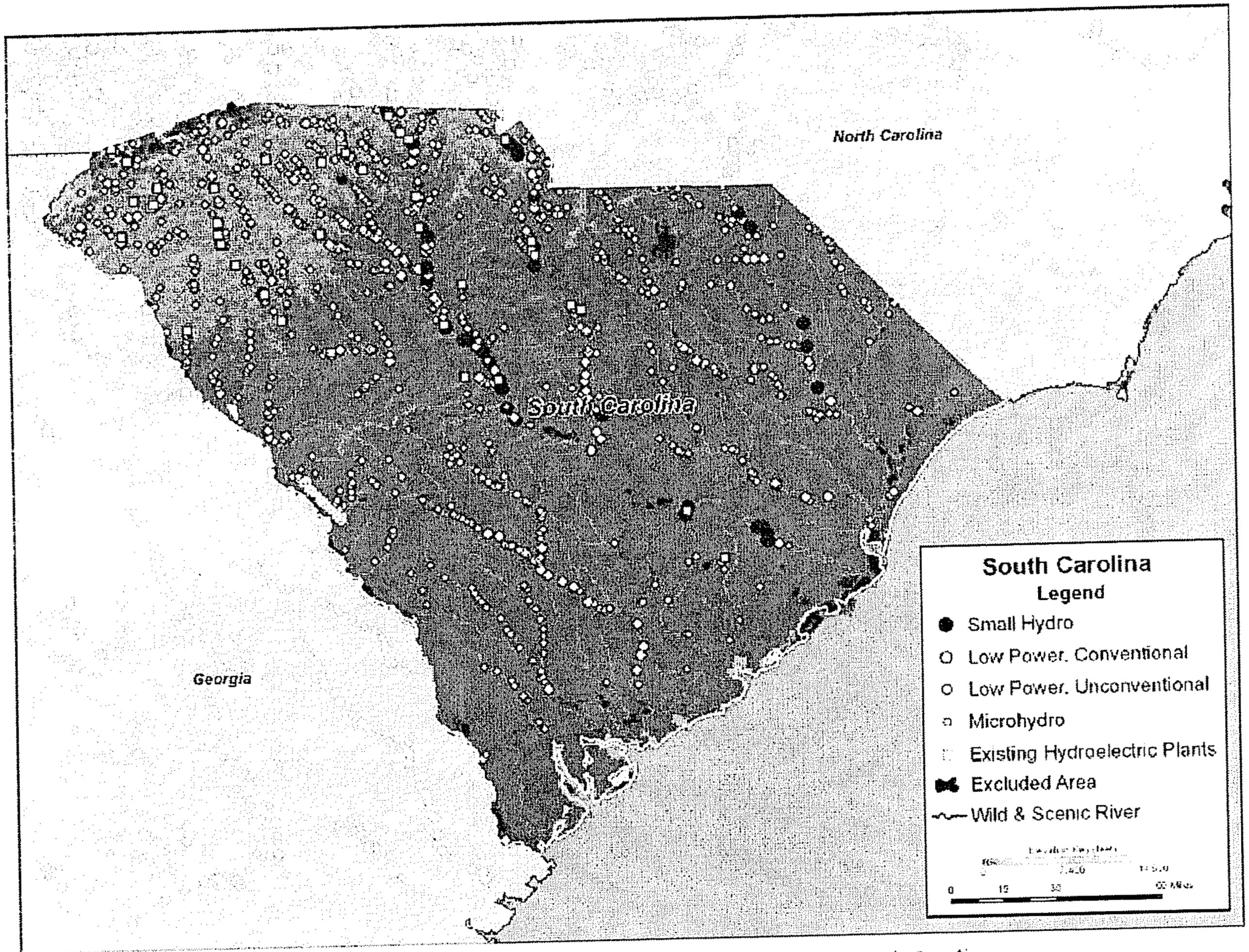


Figure B-200. Low power and small hydro feasible projects, and existing hydroelectric plants in South Carolina.

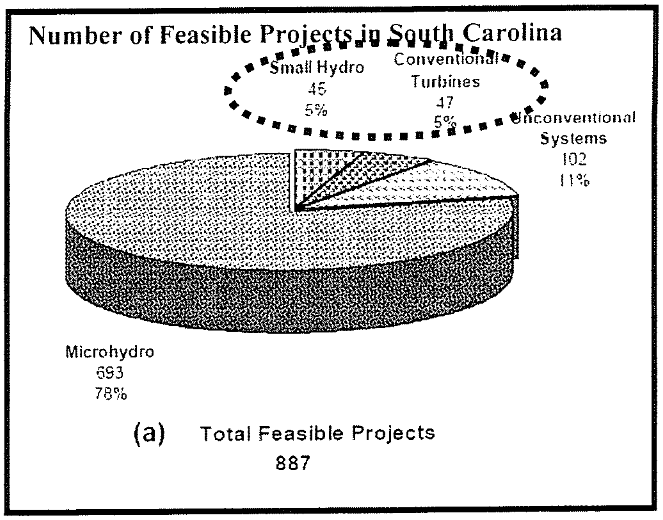
Source: "Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants," DOE-ID-11263 (January 2006)

Hydro Power

Small Hydroelectric Potential Methodology

Table B-82. Summary of results of feasibility assessment of water energy resources in South Carolina.

Power Class	[illegible]	Feasible Sites (MWa)	Feasible Projects (MWa)
Total Power	[illegible]	740	211
Total High Power	[illegible]	564	153
Large Hydro	[illegible]	111	0
Small Hydro	[illegible]	452	153
Total Low Power	[illegible]	176	58
Conventional Turbines	[illegible]	106	11
Unconventional Systems	[illegible]	54	25
Microhydro	[illegible]	16	22



Source: *"Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants," DOE-ID-11263 (January 2006)*

- Idaho National Laboratory considered the following for determining Feasible Sites:
  - Site accessibility and load or transmission proximity
  - Land use or environmental sensitivities that would make development unlikely
- Feasible Projects was used for Technical Potential in report.
  - Determined by assuming sites that do not require a dam obstructing the watercourse or the formation of a reservoir (low-impact).
- Practical Potential used in analysis assumes development is limited to conventional hydro technologies ONLY.
  - Unconventional systems and microhydro were excluded.
  - Sites were limited to those with ratios of penstock length (ft) to working head (ft) output that were deemed reasonable for development.

Hydro Power

Comments on Hydroelectric Generation

- Most of the conventional hydroelectric potential (at impoundments) in the state have already been developed.
- Many of the existing impoundments, according to Idaho National Laboratory, that may have development potential have not been verified as actual sites.
- Otherwise, there are about 15 out of 45 sites for small hydro (1–30 MWa*) run-of-river projects determined to be practical for development, totaling 100 MWa* of potential.
  - Hydro permitting continues to be difficult, but these sites may face less barriers as no impoundments are required.
- Additionally, 14 of 47 sites of low power (conventional) hydro may be practical, totaling about 4 MWa*.
- Ocean energy options were not assessed because there are limited studies of the resource potential and most technologies are still in pilot phases.

** New Small Hydro and Low Power are measured in MWa (Average Megawatts) to reflect average energy production rather than capacity.*

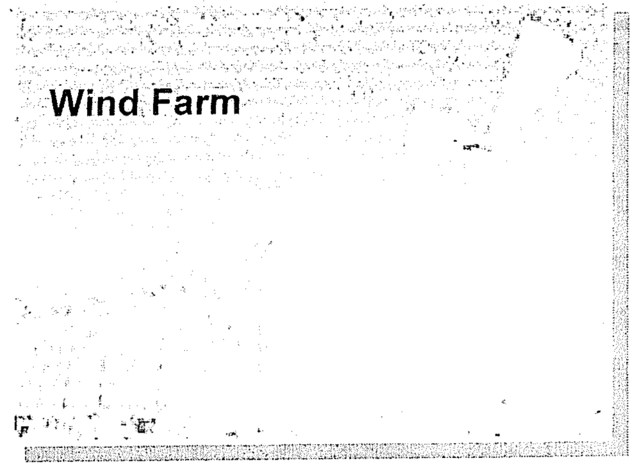
Hydro Power

Wind (On-Land and Offshore)

Description

A wind energy system transforms the kinetic energy of the wind into mechanical or electrical energy. Propeller-like wind turbines are most prevalent.

National Installed Capacity: **11,700 MW***
SC Installed Capacity: **0 MW**



Mature Technologies

- **Propeller (Horizontal) Wind Turbines:** Great advances have been made to these turbines to bring costs down significantly for land applications. Utility-scale turbines range 1 to 3 MW and are installed at about 75 to 100 meters high.
- **Offshore Wind Turbines:** Similar technology as on-land wind turbines, though typically larger (2.5–5 MW) and has added complexities of construction and weatherproofing for ocean conditions. Currently over 800 MW installed world-wide, but none in the U.S.

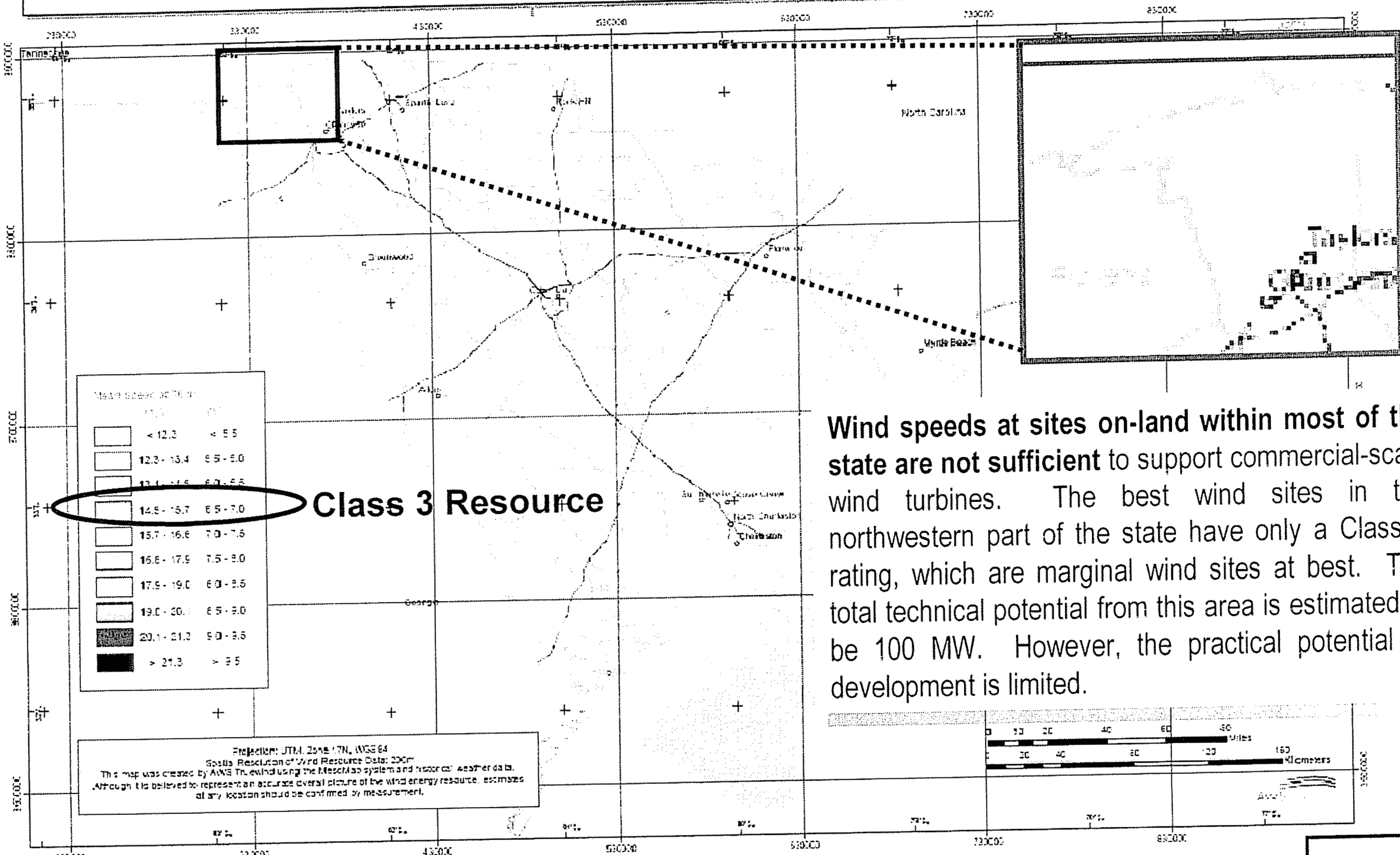
Emerging Developments

- **Vertical-axis Wind Turbines:** The horizontal nature of these turbines may allow for utilization of lower wind speeds and eliminate need for a tower.
- **Extendable Rotor Blades**: Able to adjust wing span of blades depending on wind speed.
- **Wind with Compressed Air Storage**: Mechanical wind energy pumps air into storage cavities underground, and pressure is released for electricity generation when needed.
- **Buoyed Wind Structure:** Wind turbines are placed on buoy-like devices for deep off-shore locations.

** Estimates based on compilation of data from sources including Energy Information Agency, National Renewable Energy Laboratory, Environmental Protection Agency, and other web-based sources.*

Onshore Wind Potential

Mean Annual Wind Speed of South Carolina at 70 Meters



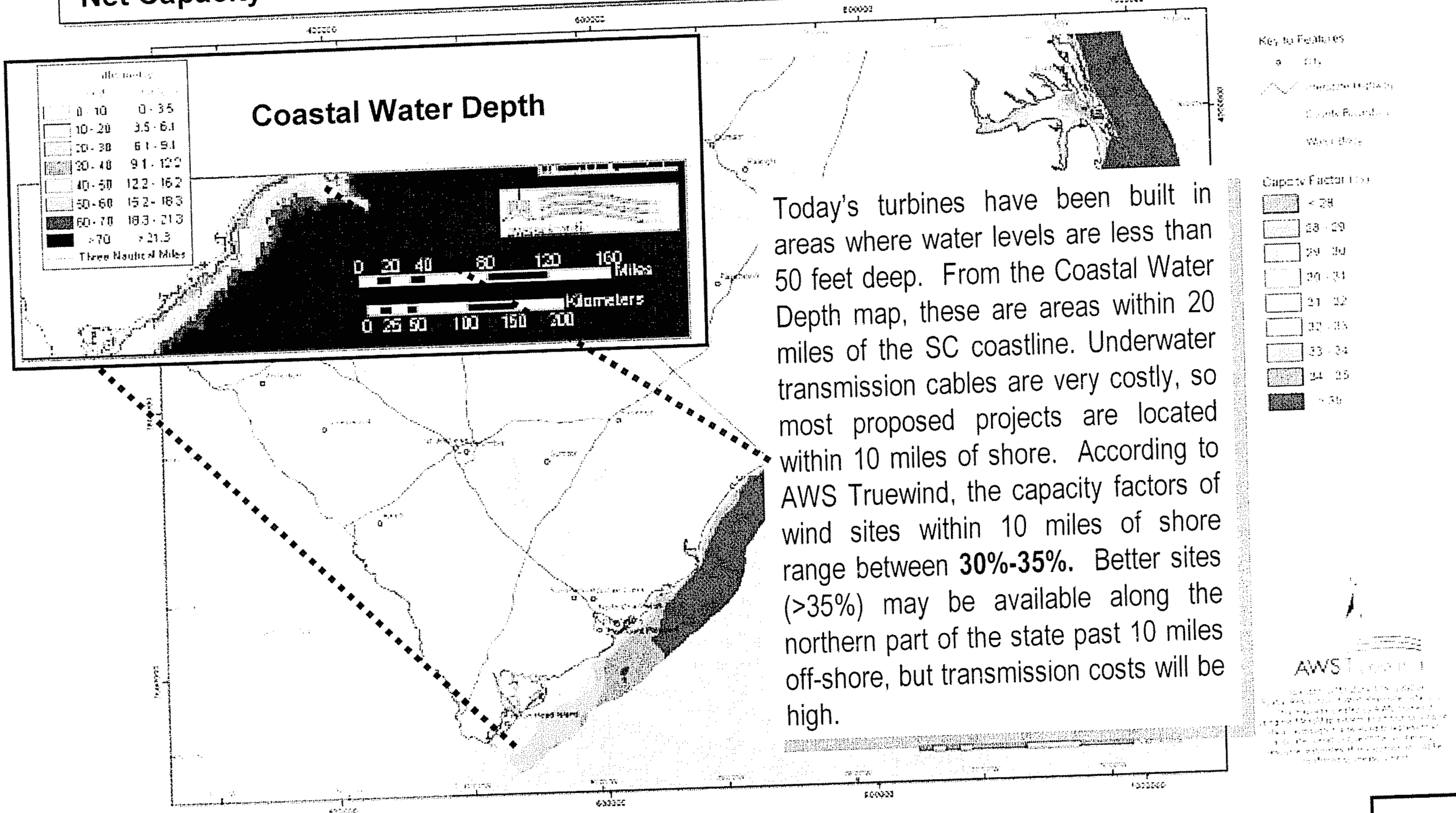
Wind speeds at sites on-land within most of the state are not sufficient to support commercial-scale wind turbines. The best wind sites in the northwestern part of the state have only a Class 3 rating, which are marginal wind sites at best. The total technical potential from this area is estimated to be 100 MW. However, the practical potential of development is limited.

Source: www.energy.sc.gov

Wind

Some Offshore Potential

Net Capacity Factor – GE 3.6 MW 90 m Hub Height, 111 m Rotor Diameter *(Assuming 15% Loss Factor)*



Today's turbines have been built in areas where water levels are less than 50 feet deep. From the Coastal Water Depth map, these are areas within 20 miles of the SC coastline. Underwater transmission cables are very costly, so most proposed projects are located within 10 miles of shore. According to AWS Truewind, the capacity factors of wind sites within 10 miles of shore range between **30%-35%.** Better sites (>35%) may be available along the northern part of the state past 10 miles off-shore, but transmission costs will be high.

Source: "Offshore Wind Power Potential of the Carolinas and Georgia," Presentation by Jeffrey Freedman, AWS Truewind

Wind

Offshore Wind Development Issues

- **Offshore permitting becomes more complicated when in federal waters (>3 miles offshore) due to approvals needed from both state and federal agencies.**
  - Several offshore wind projects in the U.S. are seeking permits through these agencies and have passed some hurdles already.
  - However, some agencies do not have standards in place or lack any precedence for dealing with offshore wind projects, so proposed projects have experienced delays.
- **Potential risks related to hurricanes.**
  - According to GE Wind, turbine designs currently can sustain up to 130 mph winds (equivalent to Category Three hurricane wind speed).*
  - South Carolina has experienced two Category Four hurricanes in the last 150 years.
- **Costs for underwater transmission and foundation structures will be highly site specific.**

Table 10. Hurricane direct hits on the mainland U.S. coastline and for individual states 1851-2004 by Saffir/Simpson category. Updated from Jarrell et al. (2001).

AREA	CATEGORY NUMBER 1	2	3	4	5	ALL	MAJOR HURRICANES
U.S. (Texas to Maine)	109	72	71	18	3	273	92
Texas	23	17	12	7	0	59	19
(North)	12	6	3	4	0	25	7
(Central)	7	5	2	2	0	16	4
(South)	9	5	7	1	0	22	8
Louisiana	17	14	13	4	1	49	18
Mississippi	2	5	7	0	1	15	8
Alabama	11	5	6	0	0	22	6
Florida	43	32	27	6	2	110	35
(Northwest)	27	16	12	0	0	55	12
(Northeast)	13	8	1	0	0	22	1
(Southwest)	16	8	7	4	1	36	12
(Southeast)	13	13	11	3	1	41	15
Georgia	12	5	2	1	0	20	3
South Carolina	19	6	4	2	0	31	6
North Carolina	21	13	11	1	0	46	12
Virginia	9	2	1	0	0	12	1
Maryland	1	1	0	0	0	2	0
Delaware	2	0	0	0	0	2	0
New Jersey	2	0	0	0	0	2	0
Pennsylvania	1	0	0	0	0	1	0
New York	6	1	5	0	0	12	5
Connecticut	4	3	3	0	0	10	3
Rhode Island	3	2	4	0	0	9	4
Massachusetts	5	2	3	0	0	10	3
New Hampshire	1	1	0	0	0	2	0
Maine	5	1	0	0	0	6	0

Notes:

State totals will not equal U.S. totals, and Texas or Florida totals will not necessarily equal sum of sectional totals. Regional definitions are found in Appendix A

Source: "Offshore Wind Power Potential of the Carolinas and Georgia," Presentation by Jeffrey Freedman, AWS Truewind

Wind

* *GE Info from http://www.clemson.edu/scies/wind/Presentation-Grimley.pdf*

Comments on Wind Power

- There are virtually no onshore wind sites that can be practically developed in South Carolina.
- There may be some opportunities for development of offshore wind projects, but projects must overcome permitting and performance barriers.
  - The anticipated capacity factors of sites less than 10 miles offshore are 30% to 35%, which are less than more optimal sites with 40% to 45% capacity factors in other parts of the country.
  - The low capacity factor estimates will directly impact the cost ($/MWh) of the generated electricity.
- Higher capacity factors may be achievable if located greater than 10 miles offshore along the northern part of the state.
  - Additional transmission costs and deep water structures may be needed which would increase the development cost of sites.
- Risks associated with Category Four and higher hurricanes will need to be considered in offshore wind development.

Solar for Electricity

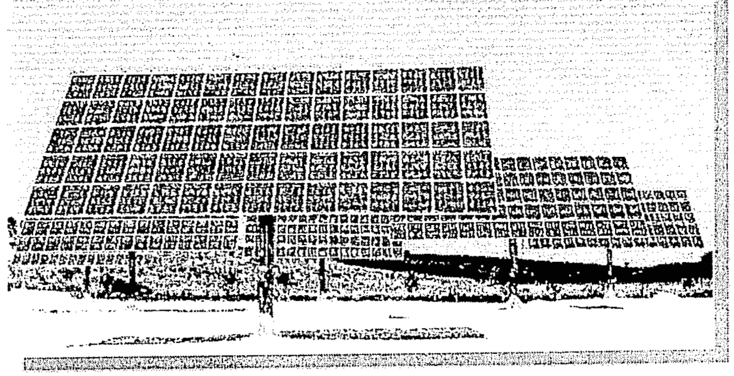
Description

Solar energy can be utilized in several ways, including direct electricity conversion, in-direct electricity conversion, or direct thermal applications. In this section, the focus is on solar for electricity generation.

National Installed Capacity: **450-500 MW***

SC Installed Capacity: **<1 MW**

Solar Panels



Technologies

- **Photovoltaic (PV):** Flat panel of silicon-based material that converts solar energy directly into electricity.
- **Concentrated Solar PV:** Reflective material used to focus light onto PV for increased electricity conversion for smaller area of PV material. Some technical issues still to overcome with heat management.

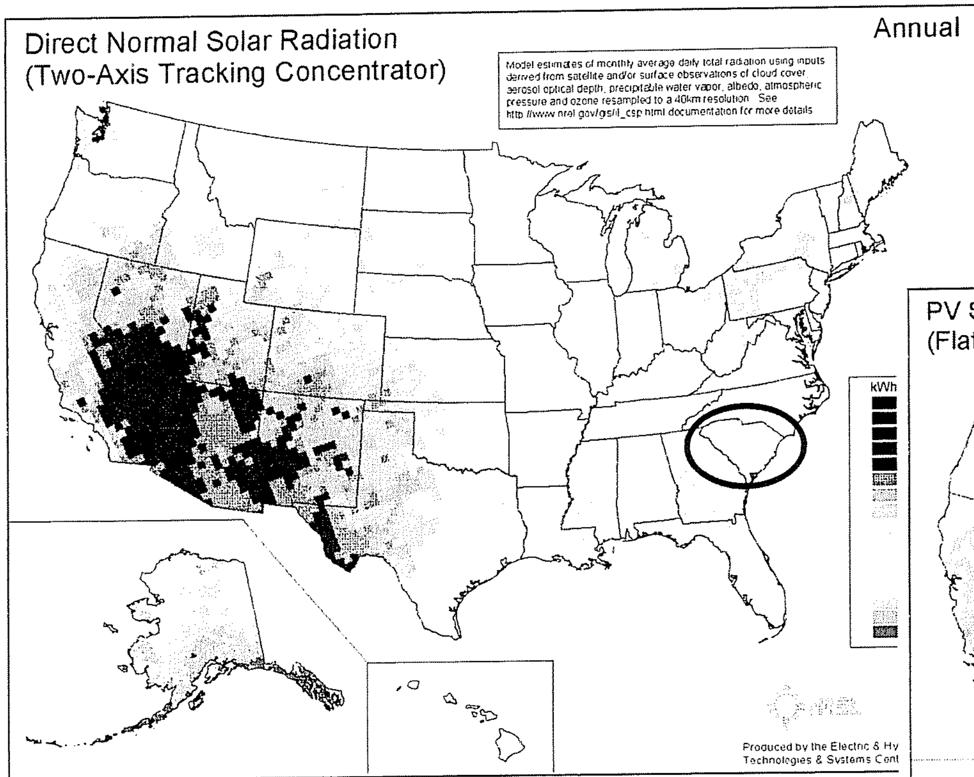
Emerging Developments

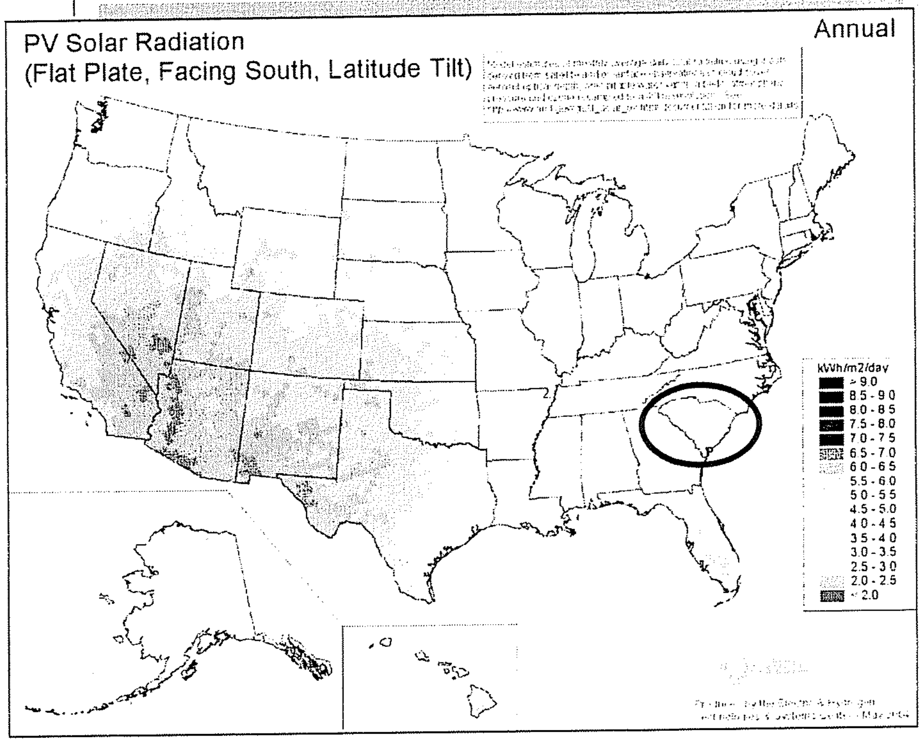
- **Thin-film Materials**
- **Nanosolar**
- **Dish/Stirling Engine**
- **Parabolic Trough System**
- **Power Tower System**

**Estimated from total cumulative historical sales of solar photovoltaic installations in the U.S. by EIA and other web-based sources. This does not include concentrated solar installations.*

National Solar Radiation

Solar Radiation in South Carolina is about average in the U.S., while southwestern states have superior resources. Direct normal solar radiation for concentrator applications range between 4.0 to 5.0 kWh/m2/day. **Solar radiation appears to be better for flat plate, fixed tilt PV systems in South Carolina relative to two-axis tracking concentrators.**

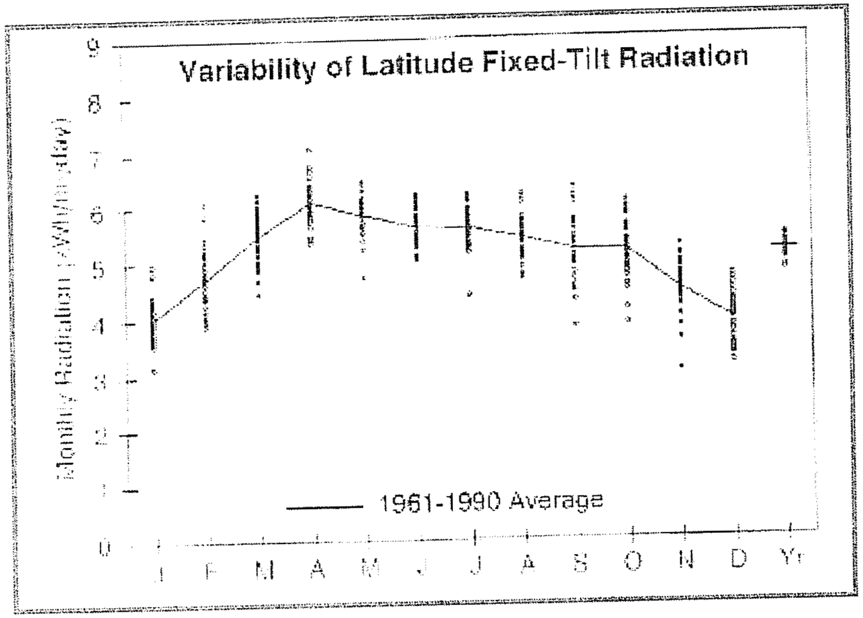




Solar

South Carolina Solar Radiation

Solar Radiation for Flat-Panel Fixed Tilt System for South Carolina



Source: "Solar Radiation Data Manual for Flat-Plate and Concentrating Collectors," NREL <http://rredc.nrel.gov/solar/pubs/redbook/>

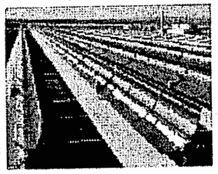
- **Current photovoltaic (PV) systems can achieve about 10% net energy conversion efficiency, after accounting for system losses.**
- **Range of average annual solar radiation is 4.6 to 5.1 kWh/m²/day in South Carolina.**
  - 0.46 to 0.51 kWh/m²/day of electricity production from a flat-panel fixed tilt system (average installation ~100 watts/m²).
  - Estimated capacity factor potential is 19% to 21% in the state.

Recently, there was a groundbreaking of the largest utility-scale PV system in the U.S. of **8.2 MW in Colorado on 82 acres**. That is equivalent to about 100 kilowatts (kW) per acre. The expected annual energy production is 17,000 MWh (equivalent to 23.6% capacity factor).

Solar

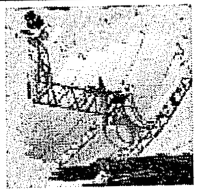
Emerging Concentrated Solar Power Technologies (CSP)

While there are a few CSP projects being planned in southwestern U.S., **the potential of CSP in South Carolina appears limited** due to a lack of consistent, high direct solar radiation (>6.75 kWh/m^2/day is recommended). The direct solar radiation in the state averages only 4.0 to 5.0 kWh/m^2/day.


Parabolic Trough

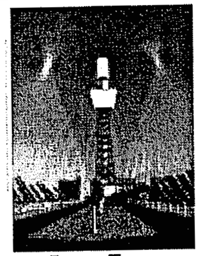
Parabolic-trough systems

- Concentrate solar energy through long rectangular, curved (U-shaped) mirrors.
- The energy heats oil flowing through the pipe, which is then used to boil water in a conventional steam generator to produce electricity.
- Requires direct normal solar radiation (>6.75 kWh/m2/day) and large flat land areas for cost-effective operation.
- A 65 MW solar trough is planned for Nevada.


Solar Dish

Dish/engine system
(Stirling Engine)

- The dish-shaped surface collects and concentrates the sun's heat onto a receiver.
- The heat causes fluid to expand against a piston or turbine to produce mechanical power, which then runs a generator or alternator to produce electricity.
- Stirling Engine has started construction of a test site (<1 MW) that may eventually grow to a 500 MW to 800 MW project in California.


Power Tower

Power tower system

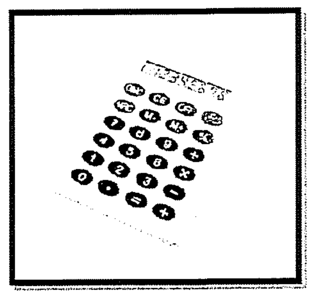
- Uses a large field of mirrors to concentrate sunlight onto the top of a tower, where a receiver sits.
- Molten salt flowing through the receiver is heated and the heat is used to generate electricity through a conventional steam generator.
- Previous demonstration projects were mothballed and no new systems planned in the U.S.

Comments on Solar Potential

- In general, solar PV deployment is not limited by resource availability but rather by cost and technological barriers. Therefore, the solar potential for electric generation was not estimated.
- CSP deployment does appear limited in the state due to insufficient direct solar radiation.
  - The direct solar radiation (4.0-5.0 kWh/m^2/day) in the state appears to be less than the recommended level for concentrator applications of 6.75 kWh/m^2/day or higher found in southwestern states.
  - Additionally, with very few CSP projects in existence, most being demonstration projects, the commercial costs associated with these projects are difficult to estimate.
- In some states, with substantial subsidies or tax incentives, the cost of energy produced from solar projects is becoming more cost-competitive with other generation options.
  - However, South Carolina does not offer solar incentives for electricity production, only for thermal water heating.

Financing and Cost Assumptions

1. Assess Available Resources
2. Select Generation Technologies
3. Determine Technical Potential of Resource
4. Determine Practical Potential of Resource
5. Develop Financing and Cost Assumptions
6. Calculate Levelized Cost per MWh



Financing Assumptions as Tax Exempt Entity

- Tax exempt ownership is assumed for most utility-scale generation.
  - Assumed Weighted Average Cost of Capital (WACC) = 6.0%
- Costs are calculated to estimate ratepayer impact.
- CREBs financing is not included in financial assessment since subsequent rounds are uncertain.

Clean Renewable Energy Bonds (CREBs)

- CREBs are non-interest bearing loans
- Taxpayer (holder of bond) credit is entitled to a tax credit instead
- 2006 Round provided $800 million
  - Average size of the 85 accepted cooperative projects was $6.5 million
- 2007 Round is for $400 million and deadline is July 13, 2007

Tax Benefits for Tax-Paying Entities

- **Production Tax Credit is due to expire by the end of 2008.**
  - Currently worth ~$20/MWh and increases with inflation adjuster.
  - Several bills proposed for another 5-year extension.
  - Projects receive PTC for 10 years.
- **5-Year Modified Accelerated Cost Recovery System (MACRS) allowed for some.**
- **It is assumed that non-tax paying (tax-exempt) entities are not able to take advantage of these tax incentives for purposes of this analysis.**

Financial Assumption	Production Tax Credit ($/MWh)*	Accelerated Depreciation
Biomass (Open-loop)	~$20	
Biomass (Close-loop)	~$10	
Wind	~$20	MACRS
Incremental Hydro	~$10	
Solar Residential**		MACRS
Solar Business**		MACRS

**This is the estimated level for the PTC in 2007, after taking into account inflation.*

***Solar installations receive other tax credits as discussed in next section.*

Financing Assumptions Used

- **Tax-exempt entity ownership is assumed for most utility-scale generation, so tax incentives are not utilized.**
  - CREBs financing is not included since availability after 2007 is uncertain.
- **Exceptions to tax-exempt entity ownership are for Solar PV and Anaerobic Digesters.**

Financial Assumption	Tax Exempt Entity	Merchant PV Owner	Residential PV Customer	Anaerobic Digester Owner
Weighted Average Cost of Capital (WACC)	6.0%	7.0% (after-tax equity req. for 100%)	4.8% (after-tax mortgage rate)	7.0% (after-tax equity req. for 100%)
Project Life	20 years	20 years	20 years	20 years
Tax Credits	None	30%/ (10% after 2007)	$2000 cap per panel	50% of PTC (~$10/MWh)
Depreciation	None	5-year MACRS	None	7-year flat
Discount Rate	6.0%	7.0%	7.0%	7.0%
Calculated Carrying Charge	**8.72%**	**6.63% (9.35%)**	**7.72%**	**11.08%**

Renewable Costs and Characteristics

Renewable Technologies	Size (MW)	Capacity Factors	Average Installed Cost (2006$/kW)	High Installed Cost (2006$/kW)	Fixed O&M (2006$/kW)	Variable O&M (2006$/MWh)	Heat Rate (Btu/kWh)
Landfill Gas ICE (>5 MW)[1]	5-10	80%-85%	$1,750	$2,000	$100	$12	9,500
Landfill Gas ICE (<5 MW)[1]	1-5	80%-85%	$2,500	$3,000	$100	$12	9,500
Biomass (Co-fire Blending)[2,3,5]	5%	70%-75%	$75	$100	$12	$5	12,000
Biomass (Co-fire Retrofit)[2,4,5]	15%-20%	70%-75%	$230	$300	$12	$5	12,000
Biomass (Stoker)[5]	25	80%-90%	$2,700	$2,970	$75	$10	13,000
Biomass (Fluidized Bed)[5]	25	80%-90%	$3,000	$3,300	$75	$10	13,800
Anaerobic Digester (Swine Waste)	0.10	70%-80%	$4,000	$6,000	$270	$0	14,000

1. Fuel cost range for Landfill Gas projects assumed to be $0.50 to $1.50/mmbtu (2006$).

2. Co-firing costs are calculated as incremental costs of avoiding coal consumption for generation ($2.25/mmbtu (2006$) coal cost assumed).

3. Blending refers to retrofitting coal plants with the ability to blend some biomass (up to 5% of fuel consumption of site) with coal fuel.

4. Retrofit refers to greater capital improvements needed to accommodate higher levels of biomass co-firing (15%-20% of fuel consumption of site) with coal.

5. Biomass fuel cost range assumed to be $1.88/mmbtu to $3.90/mmbtu (2006$).

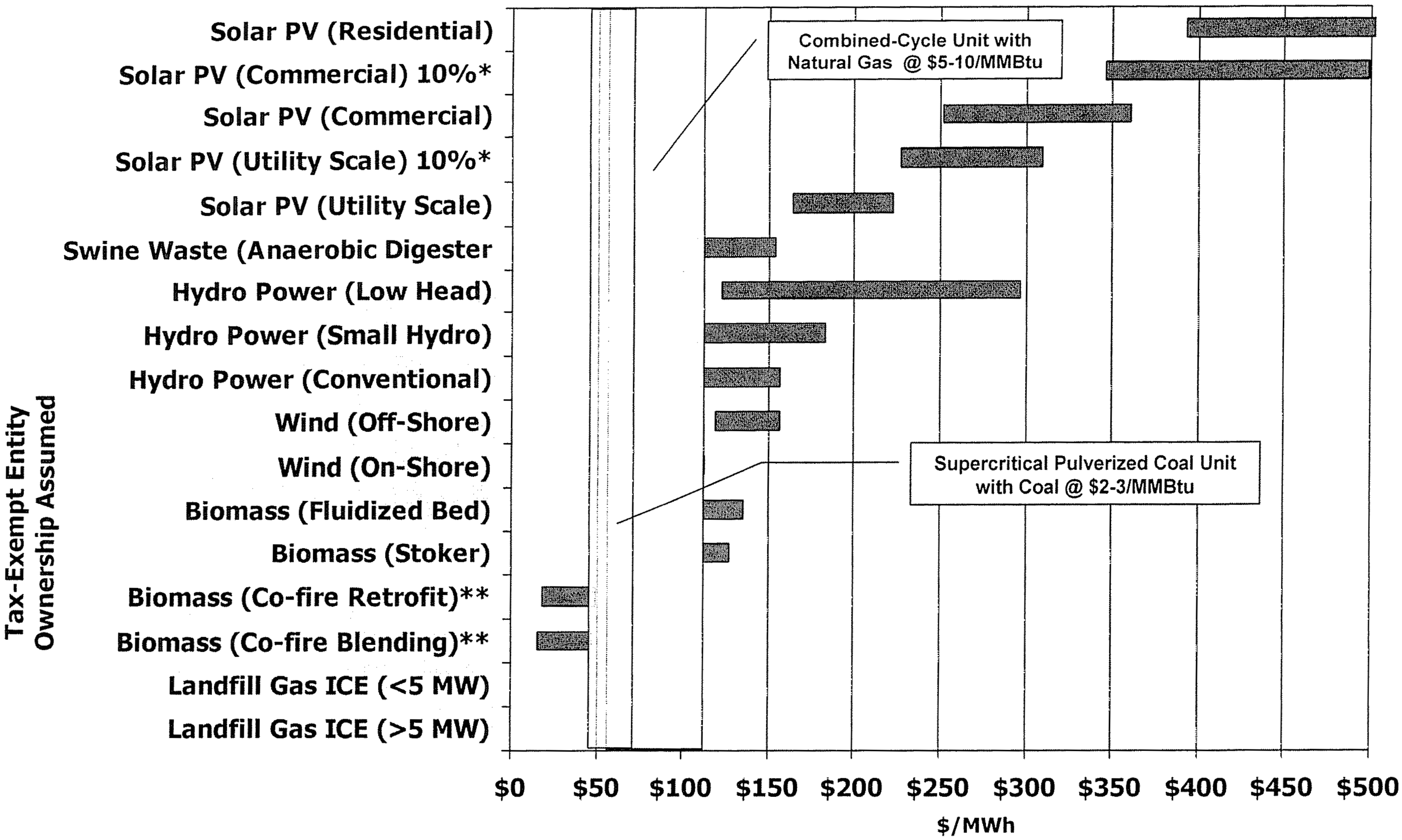
Renewable Costs and Characteristics

Renewable Technologies	Size (MW)	Capacity Factors	Average Installed Cost (2006$/kW)	High Installed Cost (2006$/kW)	Fixed O&M (2006$/kW)	Variable O&M (2006$/MWh)
Wind (On-Shore)	25-50	25%-28%	$1,800	$2,000	$45	$2
Wind (Off-Shore)	50-400	30-35%	$2,800	$3,300	$80	$2
Hydro Power (Conventional)	1-50	25%-35%	$2,000	$3,500	$12	$3
Hydro Power (Small Hydro)	1-30*	25%-35%	$3,000	$4,000	$20	$5
Hydro Power (Low Head)	<1*	20%-35%	$4,000	$5,000	$50	$10
Solar PV (Utility Scale)	1-10	19%-21%	$4,000	$5,000	$15	
Solar PV (Commercial)	0.025-0.050	19%-21%	$6,000	$8,000	$30	
Solar PV (Residential)	0.002	19%-21%	$8,000	$10,000	$50	

** Size of hydro facilities are measured in MWa, based on annual average flow rather nameplate capacity.*

Financing and Costs

Levelized Cost Comparison (2008$)



*Cost estimates include reduction of federal solar tax credits to 10% after 2007 for commercial/utility scale installations.
**Co-firing costs are calculated as incremental costs of avoiding coal consumption for generation ($2.25/mmbtu (2006$) coal cost assumed).

Financing and Costs

Conclusions

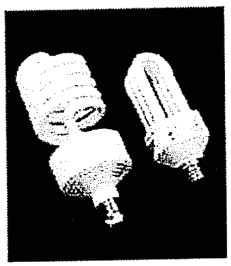
- **Landfill gas** is the state's lowest cost renewable energy option for electric generation; the practical potential is about 70 MW, with levelized costs of <$90 per MWh.
- **Biomass** (urban wood waste, logging residue, commercial thinnings, corn, and poultry litter) used in direct-fire generation can provide the next lowest cost renewable energy option for the state, contributing up to 490 MW in total, with costs ranging from $90 to $135 per MWh.
  - With incremental costs of $15 to $50 per MWh (above coal generation costs), **co-firing** may be an option, but will be limited by compatibility issues.
- **Small hydro (without impoundments)** may provide about 100 MWa of energy for the state, but costs may vary widely depending on site-specific issues and capacity factors. Permitting may also be an issue.
- There are virtually **no onshore wind sites** that can be practically developed in South Carolina.
- There may be some opportunities for the development of **offshore wind** projects, but projects must overcome permitting and performance barriers. The levelized cost of electricity range between $120 to $155 per MWh.
- In general, **solar PV** deployment is not limited by resource availability but rather by cost ($165 to $500+ per MWh) and technological barriers.

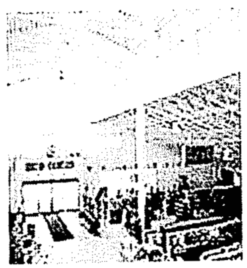
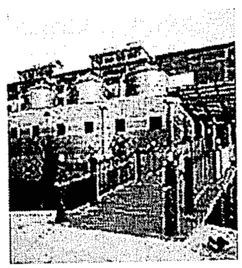
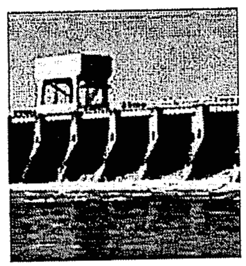
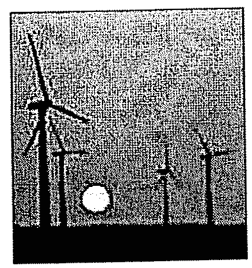
End of Report

■ ■ ■

Contact Information:

Mon-Fen Hong, Consultant
La Capra Associates
Twenty Winthrop Square
Boston, Massachusetts 02110
617-557-9100, ext. 117
mhong@lacapra.com



Appendix A: Detailed Summary of Resources

		Maximum Fuel (MMbtu)	Assumed Capacity Factor	Technical Potential (MW)	Practical Potential (MW)	Practical Generation (GWh)	Notes
Biomass	*Logging Residue*	37,497,750	85%	360	180	1,339	Most economic option. 50% reduction due to some areas being inaccessible.
	Precommercial Thinnings	72,724,266	85%	698	-	-	Costs for harvesting are higher due to smaller stands of 1-5 inches diameter.
	Commercial Thinnings	45,356,000	85%	435	217	1,617	Costs for harvesting are greater than logging residue but less than precommercial due to larger stand sizes.
	Southern Scrub Oak	414,732	85%	4	-	-	Low density and low distribution in SC, so uneconomic to harvest.
	Net Available Mill Residue	102,731	85%	1	-	-	Majority consumed on-site at mills.
	Urban Wood Waste	10,557,000	85%	101	26	192	Low cost alternative to tipping fees, must be clean wood (unpainted, untreated).
	Subtotal (Biomass)			***1,599***	***423***	***3,148***	
Landfill Gas	New Landfill-to-Energy	5,470,128	85%	73	53	394	Includes all large-size MSW landfills in South Carolina, except for two that are too small.
	Expansions of Existing	1,236,036	85%	17	17	124	Includes planned expansions to existing facilities.
	Subtotal (Landfill Gas)			***90***	***70***	***518***	
Agricultural Waste	Agricultural Crop Residue						
	Corn	7,480,346	85%	72	36	267	Some potential but must be co-fire with other fuels.
	Wheat	3,370,815	85%	32	-	-	Soybean planting immediately after wheat harvest makes timing difficult for collection.
	Soybean	3,337,936	85%	32	-	-	Limited demonstration projects for soybean, potential issues in firing.
	Cotton	4,145,582	85%	40	-	-	Limited demonstration projects for cotton, potential issues in firing.
	Switchgrass	16,790,918	85%	142	-	-	Current costs for harvesting are estimated to be $48-$132/ton (wet) which is more costly than other options.
	Poultry Litter	4,384,851	85%	42	31	230	Insufficient poultry litter to supply single dedicated plant economically. Likely to co-fire with other fuels from top 10 counties for practical potential.
	Swine Waste	166,922	75%	1.81	1.03	7	Only 37 farms in SC have >2,000 heads per farm. For practical potential, we use farms >5,000 heads per farm which is only 21 farms.
	Subtotal (Ag Waste)			***362***	***68***	***504***	

**Practical Potential is the maximum potential that might reasonably be expected to be implemented.*

Appendix A: Detailed Summary of Resources (cont'd)

		Maximum Fuel (MMbtu)	Assumed Capacity Factor	Technical Potential (MW)	Practical Potential (MW)	Practical Generation (GWh)	Notes
Hydro Power	>5 MW Conventional		25%	169	-	-	Impoundments at sites listed have not been verified as existing.
	1-5 MW Conventional		25%	16	4	8	Assumes conventional turbines at sites <5 MW with existing impoundments. Several sites have not been verified.
	1-30 MWa New Small Hydro*		N/A	153	100	875	Additional potential for new small hydro without impoundments (assumes top 15 of 45 sites are practical based on penstock length evaluation).
	<1 MWa Low Power*		N/A	11	4	31	Includes low-head, low-power hydro (14 sites of low-power conventional hydro assumed practical based on penstock length evaluation).
	Subtotal (Hydro Power) MWa*			***210***	***105***	***919***	
Wind	On-Shore (Class 3, 70 m)		28%	100	-	-	Rough estimate based on about 10 miles of ridgeline in northwest part of state with Class 3 resources, likely undevelopable due to transmission limitations and economics
	Off-Shore (Class 4, 90 m)		30%	N/E	N/E	N/E	Low capacity factors for off-shore wind may make projects uneconomic.
	Off-Shore (Class 5, 90 m)		35%	N/E	N/E	N/E	Farther off-shore wind with better capacity factors may require underwater transmission lines greater than 10 miles and face federal permitting.
	Subtotal (Wind)			***100***	**-**	**-**	
Solar	Photovoltaic or Concentrated Solar			N/E	N/E	N/E	Abundant resource is limited by cost and energy density. For PV, approximately 100 kW per acre has been achieved. For concentrated stirling installations, 25kW systems exist for about 1000 sq. ft of surface area.
Ocean	Tidal, Wave, or Current			N/E	N/E	N/E	Still in pilot stages, but there has been no studies conducted of South Carolina's specific potential.

**Hydroelectric potential is measured in average MW based on annual mean flow rates or estimated annual production.*

***Practical Potential is the maximum potential that might reasonably be expected to be implemented*

Appendix B: Levelized Cost of Renewables

Renewable Technologies	2008 Levelized Cost ($/MWh)	2008 High Levelized Cost ($/MWh)	Delta Range	Capacity Factor	Low Capacity Factor	Average Installed Cost (2006$/kW)	High Installed Cost (2006$/kW)	Fixed O&M (2006$/kW)	Variable O&M (2006$/MWh)
Landfill Gas ICE (>5 MW)	$59	$76	$17	85%	80%	$1,750	$2,000	$100	$12
Landfill Gas ICE (<5 MW)	$68	$90	$21	85%	80%	$2,500	$3,000	$100	$12
Biomass (Co-fire Blending)	$16	$46	$31	75%	70%	$75	$100	$12	$5
Biomass (Co-fire Retrofit)	$18	$49	$31	75%	70%	$230	$300	$12	$5
Biomass (Stoker)	$88	$127	$39	85%	80%	$2,700	$2,970	$75	$10
Biomass (Fluidized Bed)	$94	$135	$41	85%	80%	$3,000	$3,300	$75	$10
Wind (On-Shore)	$93	$112	$19	28%	25%	$1,800	$2,000	$45	$2
Wind (Off-Shore)	$119	$156	$37	35%	30%	$2,800	$3,300	$80	$2
Hydro Power (Conventional)	$69	$156	$87	35%	25%	$2,000	$3,500	$12	$3
Hydro Power (Small Hydro)	$105	$183	$78	35%	25%	$3,000	$4,000	$20	$5
Hydro Power (Low Power <1 MW)	$123	$296	$173	35%	20%	$3,000	$5,000	$50	$10
Anaerobic Digester (Swine Waste)**	$99	$154	$55	80%	70%	$4,000	$6,000	$270	-$12
Solar PV (Utility Scale >1 MW)	$164	$223	$58	21%	19%	$4,000	$5,000	$15	
Solar PV (Utility Scale >1 MW) 10%***	$227	$309	$82	21%	19%	$4,000	$5,000	$15	
Solar PV (Commercial 25-50 kW)	$252	$360	$109	21%	19%	$6,000	$8,000	$30	
Solar PV (Commercial 25-50 kW) 10%***	$346	$499	$153	21%	19%	$6,000	$8,000	$30	
Solar PV (Residential <2 kW)*	$393	$529	$136	21%	19%	$8,000	$10,000	$50	
Coal	$45	$65	$20	90%	80%	$1,500	$2,000	$15	$2
CCGT	$55	$110	$55	75%	50%	$500	$850	$8	$2

**Uses Residential/Commercial Carrying Charge*
***Uses Farmer's Return Requirements plus PTC Benefits*
****Uses Merchant Plant Carrying Charge and 10% Allowed Solar Tax Credit*

www.moodys.com

Moody's Corporate Finance

Special Comment

Table of Contents:

Analyst Contacts:

New York

Jim Hempstead 1.212.553.4318
Vice President / Senior Credit Officer
james.hempstead@moodys.com

W. Larry Hess 1.212.553.3837
Managing Director
william.hess@moodys.com

Michael Haggarty 1.212.553.7172
Vice President / Senior Credit Officer
michael.haggarty@moodys.com

Kevin Rose 1.212.553.0389
Vice President / Senior Analyst
kevin.rose@moodys.com

A.J. Sabatelle 1.201.915.8756
Vice President / Senior Credit Officer
angelo.sabatelle@moodys.com

Laura Schumacher 1.212.553.3853
Vice President / Senior Analyst
laura.schumacher@moodys.com

October 2007

New Nuclear Generation in the United States:

Keeping Options Open vs Addressing An Inevitable Necessity

Summary

The US electric utility sector is in the early stages of a massive new construction period to address its future base-load capacity needs. Given the practical realities associated with electric supplies, environmental trends and national energy security, we believe the sector will focus a considerable amount of attention on building new nuclear generation.

According to the Nuclear Regulatory Commission (NRC), there are approximately 12 companies developing 17 Construction and Operating License (COL) applications for 31 new reactors. Other sources, such as the Nuclear Energy Institute (NEI), count approximately 17 companies developing 21 COL applications for up to 31 new reactors. While we do not incorporate a view that all 31 reactors will be built, we observe that many companies have already begun to pre-condition their selected sites, and several have entered into arrangements with vendors to procure long-lead time items. While these companies range the spectrum from vertically integrated regulated electric utilities to wholesale merchant energy suppliers, we believe the regulated utilities will be in a more advantageous position to commence construction over the intermediate-term horizon.

From a credit perspective, business and operating risk profiles will increase for companies that pursue new nuclear generation. This increase in risk is attributable to the size and complexity of the project, the long-term nature of the construction cycle, the uncertainties associated with all-in costs, regulatory oversight and the ultimate rate impact to end-use consumers and the ability for a utility to recover costs and earn an appropriate return. We observe that most of the risks that will be discussed in this report also apply to advanced coal-fired generation, which also include uncertainties associated with carbon capture and sequestration.

The increase in business and operating risks will be gradual as companies transition from the evaluation stage, to the permitting stage to meaningful construction. Moody's does not believe the sector will bring more than one or two new nuclear plants on line by 2015 – a date cited by a majority of the companies currently highlighting their nuclear ambitions. The complexity associated with the permitting process as well as the execution risks associated with construction projects of this nature should not be underestimated.

There are other equally important issues associated with nuclear generation that should not be underestimated, the most important of which include the political realities concerning global warming (regardless of whether or not it is scientifically a reality) and the longer-term issues surrounding national energy security. These issues – carbon controls and energy security – could further stimulate interest in new nuclear investment.

In addition, because companies that build new nuclear generation will increase their over-all business and operating risk profiles, there will be a need to establish financial policies over the near-term aimed at producing very strong financial credit ratios in order to maintain a given rating. While a constructive regulatory relationship will help mitigate near-term credit pressures, Moody's will remain concerned over the prospects of construction delays, cost over-runs, the implications for rate-shock and future disallowances. Moody's observes that given the long-term time horizon associated with construction projects of this nature, there can be no assurances that tomorrow's regulatory, political, or fuel environments will continue to be as supportive to nuclear power as they are currently.

In this Special Comment, we describe our views around the prospects for new nuclear generation and the likely implications for credit.

Rating Rationale

In general, Moody's maintains a relatively favorable bias towards nuclear generation. In our opinion, nuclear generation represents a critical component of the nation's electric supply base. Nuclear units tend to be well run, maintain very high average annual capacity factors; are extremely economic from a marginal cost perspective; and, they do not emit any of the air pollutants that are emerging as a major political issue.

From a credit perspective, Moody's believes that one of the biggest risks associated with nuclear generation is an unanticipated extended outage. While the ownership of nuclear generating facilities brings a higher level of complexity associated with operating and maintaining the units, ownership also comes with additional regulatory oversight, primarily with respect to the NRC, which we view as a credit positive. We also incorporate a view that most companies will fare reasonably well in taking appropriate measures to mitigate nuclear-related risks and the average credit rating for the regulated nuclear peer group is well positioned within the investment grade **Baa** rating category.

Amount of electricity generated by a 1,000-MWe reactor at 90% capacity factor in one year:

7.9 billion KWh—enough to supply electricity for 740,000 households.
If generated by other fuel sources, it would require:

- Oil: 13.7 million barrels – 1 barrel yields 576 KWh
- Coal: 3.4 million short tons – 1 ton yields 2,297 KWh
- Natural Gas: 65.8 billion cubic feet – 100 cubic feet yields 12 KWh

(based on average conversion rates from the Energy Information Administration)

Source: NEI

Extended Outages

While the high costs associated with the ownership and operation of nuclear plants are offset by the robust earnings and cash flow they generate, an extended outage can significantly stress an owner's liquidity and over-all financial profile. We believe the best way to mitigate this risk is through diversity, operational excellence and predictive maintenance practices. We note that the vast majority of nuclear operators continue to amass large portfolios of units in different transmission and geographical regions. From a downside scenario planning perspective, Moody's continues to assess outage risk in relation to the experience of First Energy during the Davis Besse outage, which lasted approximately 26 months (from February 2002 until March 2004).

Quantity and Quality of Skilled Labor

While the actual production of electricity does not differ between a nuclear, coal or gas-fired generating plant, there is greater complexity associated with nuclear generation, as evidenced by the more advanced degrees and skilled labor required to operate a nuclear plant. The nuclear labor force includes both degreed-engineers (to design, build, and operate the plant) as well as skilled craftsmen, both of which are in short supply. Separately, Moody's views the continuous training requirements for the nuclear labor force favorably. Most operators maintain regular training and simulation training exercises for employees and the NRC is constantly re-qualifying the employee base.

Environmental concerns are a political reality

The single greatest benefit that nuclear generation can offer over coal is the clean air effects associated with emissions. Whereas coal-fired facilities produce a significant amount of nitrogen oxide (NOx), sulfur dioxide (SO_2), mercury and carbon emissions, nuclear facilities only produce steam as a by-product. On the other hand, there is a trade off with respect to the fuel waste, which will be addressed later in this report. Coal-fired waste, namely ash, can be recycled into cement or used as landfill; nuclear waste, namely radio-active ceramic pellet assemblies need to be stored in a pool of water for at least 5 years before they are transferred into above ground dry storage (steel or concrete casks) for as long as 100 years and ultimately either recycled or entombed in an underground disposal facility for approximately 10,000 years. Taken as a whole, however, Moody's observes that there has been a subtle shift in the stance of several environmental groups as the carbon-free nature of nuclear generation is increasingly recognized as a societal benefit. However, we observe that environmental opposition remains a concern as their primary motivational agenda appears to be aimed at reduced consumption.

Nuclear is a Critical Component of National Supply Mix

In our opinion, nuclear generation is a critical component of the US energy supply mix. According to the Nuclear Energy Institute (NEI), there are 104 licensed nuclear generating stations in the US, which account for roughly 19.4% or 787.2 billion kilowatt-hours (bkWh) of the total electrical production in the US. These facilities typically operate around the clock, and are an integral component of the base-load supply needs of the country. As can be seen in the table below, the nuclear component of the total US electric supply base has been reasonably steady over the past several decades.o

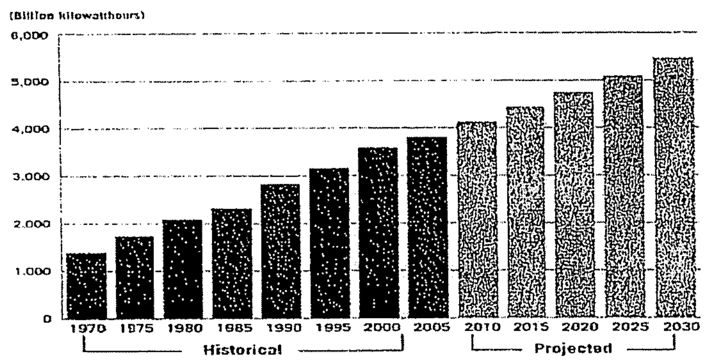
Year	Total Electricity Generation (MWh)	Nuclear Generation (MWh)	Nuclear Share (percent)	Capacity Factor (Percent)
1975	1,920,754,569	172,505,075	9.0	55.9
1985	2,473,002,122	383,690,727	15.5	58.0
1995	3,353,487,362	673,402,123	20.1	77.4
2005	4,055,422,744	781,986,365	19.3	89.3
2006*	4,052,967,852	787,218,636	19.4	89.8

**Preliminary*
Source: Global Energy Decisions / Energy Information Administration

Nuclear operators should continue to produce power at an average capacity factor of approximately 90%. We do not believe the US nuclear sector can achieve average capacity factors much higher than 90% on a sustainable basis or that the sector can meaningfully increase its electricity production from recent levels. This view is primarily based on our assumption that the vast majority of up-rates and performance improvements have been realized.

Supply / Demand fundamentals are favorable for new nuclear generation

According to the Energy Information Administration (EIA), there is a need for approximately 258 gigawatts of new electric generation capacity in the US by 2030 at a cost of approximately $412 billion (in 2005 dollars) for an average cost of approximately $1,600 per kw-capacity. This need for capacity is partly a function of organic demand growth and includes some expectations that older generation facilities will be retired and / or otherwise taken out of service. Existing nuclear units are, on average, approximately 20 years old and most of the base-load coal-fired fleet is approximately 35 years old. It is reasonable to assume that many of the oldest plants will eventually reach the end of their useful lives over the next ten to fifteen years, but many of the larger and older units continue to be refurbished to extend their life beyond the original design specifications. For example, there are two coal-fired facilities associated with the Ohio Valley Electric Corporation (OVEC) that are 1950's vintage plants that have recently been undergoing a massive refurbishment (and environmental upgrade) plan to extend their lives for another 20 years.

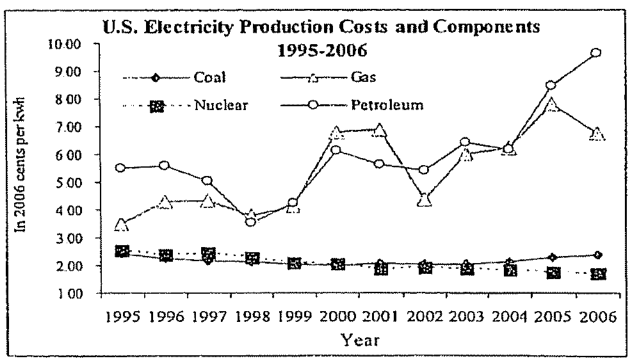


Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 2005* and *Annual Energy Outlook 2007 Early Release*

Assuming there is a real need to build new base-load generation, there are really only two fuel options that can readily meet that need: coal and nuclear. While we remain favorably biased to renewable sources of generation, such as wind, solar and bio-mass, ensuring reliability of power generation from renewable sources continues to be a matter of concern. Also, additions to hydro power generation appear to be limited by geographical considerations and environmental opposition.

Nuclear enjoys a very competitive operating cost structure

The existing nuclear generation fleet tends to be a very strong producer of earnings and cash flow. The average cost for fuel (including nuclear fuel) tends to hover around \$5 - \$6 per MWh (megawatt hour). Operating and maintenance costs tend to average around \$12 - \$13 per MWh and additional "to-go" costs (comprised of incremental capital costs, administrative and general costs, insurance costs and other fees) average around \$5 - \$6 per MWh, for a total dispatch cost of approximately \$22 - \$25 per MWh. Assuming the average wholesale price of power for the nation is approximately \$50 - \$55 MWh, these units tend to produce power with an approximately \$25 - \$30 MWh margin.



Source: Global Energy Decisions

Nuclear Fraternity Helps Ensure Safe, Reliable and Economical Operations

One of the more unique features of being a nuclear operator is that it provides access to the nuclear operator "fraternity" on both a national and international scale. For example, in the US, nuclear operators meet regularly and share an enormous amount of operational and safety-related data. This fraternity atmosphere is a large part of the success of the industry, and the industry recognizes that it is only as good as its weakest link. Through organizations such as the Institute of Nuclear Power Operations (INPO) and the World Association of Nuclear Operators (WANO), nuclear operators assess each other on both standards of excellence (operational) as well as standards of compliance (regulation). In our opinion, the nuclear fraternity has been an important component of the more recent operational successes experienced by these facilities.

Nuclear operating performance has been impressive

The nation's fleet of nuclear units has experienced a tremendous improvement from an operational perspective. As recently as the early 1980's, the US nuclear fleet was operating with average capacity factors in the mid to high 70% range, but has, over the past 20 – 25 years, dramatically improved the averages. From a credit perspective, Moody's incorporates a view that the 90% average capacity factor will be maintained over the near to intermediate term horizon, and that the current fleet is, essentially, maxed-out from an operating efficiency stand point. It bears noting that the original design specifications of the existing fleet incorporated a view that these plants would indeed operate at a 90% range capacity factor.

We believe these performance improvements can be attributed to the following:

- Outage management – The most significant factor contributing to the improved operating performance, in our opinion, is related to outage management. In the past, it was not unusual for an outage to last 90 – 100 days. Today, it would be unusual for an outage to last more than 30 days.
- Advancements with diagnostics – The analytical and diagnostic ability to monitor equipment and components has advanced tremendously over the past 10 years. These technologies provide an operator with an unprecedented ability to monitor system components. In addition, the industry maintains extensive industry wide data bases on equipment performance, which guides the scheduling of preventative and predictive maintenance. As a result, an operator can address potential issues before a component fails, thereby lowering the "mean time between failure" and improving operating performance.
- Risk Assessment Analytics – Similar to the diagnostic technology advancements noted above, these tools provide an operator with system performance probabilities that allow an operator to calculate when it is acceptable to conduct maintenance without taking a unit off-line and without compromising safety. This reduces the amount of maintenance work that must be performed during an outage, and thus reduces outage duration. An example would be repairing a feed water train.
- Personnel – There is now better management of facilities and skill sets of personnel enhanced through superior training and educational programs.

Nuclear Regulatory Commission Provides Additional Layer of Oversight

In general, Moody's views the oversight provided by the NRC as a credit positive as the NRC primarily regulates the safety of the operating fleet in the US; at the moment, approximately 100 plants.

One risk is that a fundamental problem or equipment failure at one plant could create significant stress for the entire industry, should the NRC decide that every operating license needs to be reassessed in some fashion. As a result, nuclear operators can only operate their plants with the blessing of the NRC, they are only as good as their weakest colleague. To mitigate this risk, the nuclear industry has engaged in a "best practices" effort for many years, and regularly cross-trains and shares operational and technical data. While this fraternity approach helps the over-all sector, Moody's can not ignore the potential for contagion risk. This risk was recently exhibited with the Davis Besse reactor vessel head problem that occurred a few years ago; although we acknowledge that the industry addressed that issue in a timely manner without experiencing undue financial or operational stress at any other units.

Regulatory Approval Process Still a Constraint...

Although we acknowledge the NRC licensing process is more enhanced today than it was in the 1970's and 1980's, we still believe that the regulatory approval process associated with pursuing a new nuclear facility will emerge as a potential constraint. The combination of the construction and operating process appears to be biased towards risk mitigation, and therefore is viewed as a credit positive. However, this new regulatory process remains untested and therefore deserves careful attention.

...But NRC is Experienced

The NRC is very experienced with license approvals. We observe that over the past several years the NRC has been active with four broad categories of license review and approvals with respect to: License Renewals; Power Up-Rates; Early Site Permits and Fuel Facilities. However, we can not ignore the fact that there are many countries that are equally as active with pursuing new nuclear generation and that the regulatory approval process is either non-existent or substantially less burdensome.

First COL filing expected to be litigated

We believe the first COL filing will be litigated, which could create lengthy delays for the rest of the sector. We note that while many in the industry believe this risk has largely been removed from the regulatory filing process, many are also reluctant to move forward without US governmental guarantees or other backstops to protect them from lengthy litigation or extended regulatory delays. Moody's will carefully monitor the potential for litigation related to NRG Energy's recent COL filing.

Other Agencies Need to Provide Approvals

Separately, there are still important state regulators and local governmental agencies that need to be convinced that new nuclear generation is an appropriate alternative. These include numerous permits from state agencies (i.e., air and water permits and certificates of public convenience and necessity from state public regulatory authorities), the US Army Corps of Engineers and other local authorities (i.e., construction permits) before meaningful construction can commence.

The NRC Review Team

The NRC has significantly increased its labor force in anticipation of many new COL filings. As a result, there are now essentially two different divisions at the NRC: one team to monitor the existing fleet of operating units (Nuclear Reactor Regulation) and another to review the license filings and inspect the new sites (New Reactor Office). The New Reactor Office is comprised of technical experts that will be divided up according to the technology selected by the licensee, that is, GE, Westinghouse or Areva. The teams (by technology) will then be broken down into expertise on civil / structural engineering, piping, environmental impact, security, emergency plans etc. These sub-teams will share their assessments and evaluations between technologies.

The COL permit

The NRC is committing to complete its review of the applications within a 42 month period (30 months for the application review and 12 months for hearings). Moody's notes, however, that the NRC clock does not start ticking when the COL is first filed but starts when the filing is docketed by the regulator. As a result, some companies that make their COL filing may get the filing sent back if the NRC feels it is deficient in some respect.

Once the filing is docketed, the NRC's staff will divide the filing into teams. The teams are formed by technology and sub-teams will be formed to review the various components of the filing. Although Moody's believes that the first filing may become mired in contentious litigation, we also believe the NRC will strive to meet its commitment to complete its review within the allotted 42 month timeframe and not be viewed as a major bottleneck organization. Instead, potential delays in the process may come from hearings before various licensing boards. We expect the industry and the NRC will gain from its experience with the first several COL filings and we expect the process to become shorter over time – especially with respect to the 12 months of hearings that are incorporated into the approval process.

Moody's believes there may be as many as three to five filings made in 2007. In our opinion, most of the filings will be pushed back into the late 2008 timeframe, due to the need to resolve several of the important open issues that will be highlighted in this report, the most important of which are the implications of investment recovery and the effect on consumer rates.

COL has a long-term shelf life

The COL permit does not have an "expiration date" for the construction portion. Once the COL is granted, a company can hold that license as long as no new significant information comes to light. Once a plant actually goes commercial, the operating license portion of the COL is good for 40 years, with the possibility of renewal for an additional 20 years. The Early Site Permit, which does not allow reactor-related construction, has a 20-year shelf life and can be renewed for an additional 20 years. This will provide a substantial amount of lead-time for companies to continue their evaluation and cost studies before commencing construction of a plant.

Nuclear New Build Economics

The prospects for building new nuclear generation in the US are very good. A significant number of large, well capitalized companies are publicly discussing their plans to build new nuclear generating facilities and a number of these companies are expected to make the necessary license filings with the NRC starting in October 2007.

Notwithstanding the favorable fundamentals associated with the need to add new nuclear generation into the nation's capacity supply, Moody's believes that many of the current expectations regarding new nuclear generation are overly ambitious. In fact, the timing associated with commencing construction and making the next nuclear unit commercially available could be well beyond 2015 and the costs associated with the next generation of nuclear build could be significantly higher than the approximately $3,500/kw estimates cited by many industry participants.

Short-Comings of Cost Estimates

All-in fact-based assessments require some basis for an overnight capital cost estimate, and the shortcomings of simply asserting that capital costs could be "significantly higher than $3,500/kw" should be supported by some analysis. That said, Moody's can not confirm (and all of our research supports our conclusion) definitive estimates for new nuclear costs at this time. Moody's can assert with confidence that there is considerable uncertainty with respect to the capital cost of new nuclear and coal-fired generating technologies, and that companies may decide not to proceed with financing and construction unless and until they have satisfied themselves (and, where necessary, their boards and regulators) that the investment is justified and that the plant can produce electricity and recover costs at a price that will not be overly burdensome to consumers.

Massive Construction Projects Are Complex

The over-all risks associated with building a new nuclear facility are essentially the same as the execution risks associated with most major construction projects, such as chemical plants or refineries. These construction projects are massive in scale and scope, require a tremendous amount of planning (and execution) and take years to complete. As a result, companies that pursue these kinds of projects take on a much higher level of business and operating risk, since there are no practical ways to mitigate away the gremlins that live in large, complex construction projects. There are ways to mitigate the risks associated with large construction projects, including highly skilled construction management, the terms and conditions of EPC contracts, completion of design work before construction starts, a disciplined licensing and permitting process completed before major capital outlays, liquidated damages provisions, etc.

We observe that the nuclear construction sector has made significant strides with modular construction design, which can meaningfully cut down on the construction schedule, particularly when coupled with the significant improvements in construction techniques since the last nuclear construction cycle in the 1970's and 1980's. As evidence, it has been reported that a recently completed nuclear facility in Japan was constructed in approximately 40 months (from first concrete pour to fuel load).

Increased Risks Associated with Escalation Assumptions

Dramatic increases in commodity prices over the recent past, exacerbated by a skilled labor shortage, have led to significant increases in the over-all cost estimates for major construction projects around the world. In the case of new nuclear, the very detailed specifications for forgings and other critical components for the construction process can add a new element of complexity and uncertainty. As noted previously, labor is in short supply and commodity costs have been extremely volatile. Most importantly, the commodities and world wide supply chain network associated with new nuclear projects are also being called upon to build other generation facilities, including coal as well as nuclear, nationally and internationally. Nuclear operators are also competing with major oil, petrochemical and steel companies for access to these resources, and thus represent a challenge to all major construction projects.

Significant Bottlenecks to Construction Add to Execution Risk

There are significant bottlenecks to construction that have not yet been resolved. In our opinion, there are five key bottlenecks that should not be assumed away from a planning perspective. Moody's notes that some of these constraints are widely recognized and being factored into some of the planning and construction schedules. In the case of nuclear engineers, for example, enrollment in nuclear engineering programs at many universities have been increasing across the country over the last several years, which suggests that the market is responding to perceived increased demand.

- Ultra Heavy / Ultra Large Forgings - There are numerous long-lead time items that need to be ordered (or reserved) now in order to meet a construction timetable for any project of this magnitude. These items include the ultra-heavy steel forgings required for a generating station (regardless of whether its coal or nuke) and include the reactor vessel, the steam generator shell and the bottom head (which is welded to the shell). At the moment, the only ultra heavy forgery in the world is located in Japan, at a Japan Steel Works facility. There may also be capacity developing in France (Creusot Forge) and possibly South Korea, but we have not independently verified those claims. Moody's observes that each generating facility may require a number of ultra heavy forgings, in some cases between 6 and 12 forgings per plant; and that Japan Steel Works can only produce a limited number of forgings of this size per year. As a result, it is questionable whether the 2015 timeframe is realistic, since Japan Steel Works is also taking orders from other industry sectors (like petrochemicals) and other countries that have already committed to building new nuclear plants (China, India and several countries in Europe).
- Large Manufactured Components – these items include the steam turbines and reactor pressure vessels
- Engineering Resources – this is part of the skilled labor shortage issue noted previously. Nuclear engineers are required for the detailed design work for a new nuclear facility.
- Logistics – As with any major construction project, there are massive logistical issues that need to be managed, including the procurement of cranes and ships (to transport the ultra heavy forgings). Properly managing the logistical aspects of a major construction project will be critical to delivering a plant on time and within budget.
- Site Labor - Another component to the skilled labor shortage issue. Site labor includes the construction force, welders and other trained professionals. Moody's observes that if the federal government is proactive with carbon emission legislation and the desire to build new nuclear units becomes more compelling over the near to intermediate-term horizon, this issue could become a major obstacle for the industry.

Costs Associated with New Nuclear Build are Early Best Estimates

Throughout our due diligence process, Moody's has not been able to make a finite determination of the range for the all-in cost associated with new nuclear. As a result, we believe the ultimate costs associated with building new nuclear generation do not exist today – and that the current cost estimates represent best estimates, which are subject to change.

There is empirical data that suggests a possible range for new nuclear plant costs based on experience overseas, but firm cost estimates are not available at this time in the US (including both new nuclear and new coal technologies). We believe that in order to support corporate decisions on whether or not to proceed with new nuclear projects, the industry will work with all possible speed to complete the detailed design and engineering work that will permit firm cost estimates based on a substantially complete design and that many regulatory authorities may require this information as part of their approval process. Therefore, it is reasonable to assume that companies will not move forward with new nuclear construction projects until and unless they have a high degree of confidence in the capital cost, a solid EPC wrap, and with construction and other risks adequately hedged or otherwise mitigated. Similar uncertainty attends virtually all other base load generating technologies, although the sources of the uncertainty may vary from technology to technology.

Many companies planning to build new nuclear generation freely acknowledge considerable uncertainty regarding new nuclear plant costs. More firm cost estimates will not be available until the vendors / suppliers have secured their own cost estimates, which will require a detailed review of the world wide supply network, the availability of commodities and labor supplies.

There are some figures available in the marketplace that claim new nuclear generation can be procured at approximately $2,500/kw - $3,500/kw, but it remains unclear as to what was included in the estimate, and more importantly, what was left out. This concept, creating an "apples-to-apples" cost comparison, could become an important determinant for various state regulatory authorities as they attempt to assess the ultimate impact on rates for end-use consumers.

Potential Owner's Costs Associated with New Nuclear Units:

Transmission upgrades / refurbishments

Access to transmission right-of-ways (ROW's)

Site Specific Costs

- Security
- Cooling Towers
- Roads / Other infrastructure
- Underground utilities

Administrative

- Dormitories
- Training Facilities
- General Administrative Buildings

From a credit perspective, Moody's is indifferent as to what the "overnight" cost of the actual nuclear generating plant might be – as overnight costs often exclude owner's costs and price escalation. Instead, we are concerned with the total all-in costs of the nuclear generating facility. An analogy would be the purchase price of a house (the over-night cost), which excludes the costs of appliances, furnishings, and landscaping (the all-in cost). Capitalized interest, other owner's costs (which include site preparation, administrative buildings and other administrative costs) and transmission upgrades / refurbishments could add several hundred more dollars per kw-capacity.

The potential costs associated with transmission upgrades / refurbishments appears to be getting very little attention at this time – possibly due to Federal Energy Regulatory Commission (FERC) rules and regulations which make management teams leery of engaging in public discourse too early.

Moody's believes the all-in cost of a nuclear generating facility could come in at between $5,000 - $6,000/kw. While we acknowledge that our estimate is only marginally better than a guess; it is a more conservative estimate than current market estimates and represent a substantial premium to the current estimates for new IGCC coal-fired generation. For example, AEP's filing in West Virginia for an IGCC plant is estimated to cost approximately $3,500 kw capacity. As noted previously with respect to these estimates, it is unclear as to whether or not capitalized financing costs and other owner's costs are included in the estimate.

Estimated Valuations for Generation

	$ / kw capacity	
	Low	High
Nuclear		
Existing fleet	$2,700	$3,500
New build - market estimates	$3,000	$4,000
New build - Moody's estimates	**$5,000**	**$6,000**
Coal		
Existing fleet	$1,700	$2,200
New build - Traditional	$2,500	$2,900
New build - IGCC	$3,300	$3,700
Natural Gas		
Combined Cycle (non-city)	$700	$900
Peakers	$600	$800

State regulatory arrangements

Moody's observes that many state legislatures and regulatory authorities continue to work in a constructive manner with their electric utilities to address the need for new base load plant. In addition, many states appear to be favorably disposed to new nuclear generation – especially if it can be located within their state.

We believe the first new nuclear unit is likely to become commercially available in the southeast region. In our opinion, the states in the southeast (Florida, Virginia, North Carolina, South Carolina, Georgia) have been most supportive of designing cost recovery mechanisms that encourage new nuclear investment, and this supportiveness may also be a function of the limited renewable resources available in the southeastern region.

The implications for end-use rate payers / customers

From a credit perspective, Moody's remains concerned about the prospects of steadily rising rates for end use customers, regardless of whether new nuclear generation is built or not. It is clear to us, however, that the need to recover the construction costs associated with a new nuclear unit (or coal-fired unit) over the construction period could help to mitigate rate shock that would otherwise occur when the plant is finally brought on-line. These plants are likely to add approximately $5 to $10 billion to rate base, in some cases doubling the existing rate base, and there will be a need to recover both the operating expenses as well as the high capital costs through new base rates. Eventually, end use customers may find it very difficult to balance their family budgets if the average electric bill continues to go up by roughly 10% a year over the next 5 years, which could raise the level of potential regulatory / political intervention risk.

Who Will Build the Next New Nuclear Facility?

The majority of the companies looking at building new nuclear generation are regulated utilities such as Duke Energy, Dominion, Entergy and Southern Company. There are several merchant energy companies looking at new nuclear as well, such as Constellation Energy, Public Service Enterprise, Exelon and NRG Energy, but the majority of merchants appear to be waiting for the second wave.

New Nuclear Plants Under Consideration[1]

Company	Site	Design	Number of Reactors	Date for Filing COL[2] Application
Alternate Energy Holdings	Bruneau, ID	TBD	TBD	TBD
Amarillo Power	Amarillo, TX vicinity	EPR	1	FY[3] 2008
Ameren UE	Callaway, MO	EPR	1	FY 2008
Detroit Edison	Fermi, MI	TBD	TBD	FY 2009
Dominion[4]	North Anna, VA	ESBWR	1	FY 2008
Duke Energy	William States Lee Cherokee County, SC	AP1000	2	FY 2008
Entergy	River Bend, LA	ESBWR	1	FY 2008
Entergy (NuStart Energy[5])	Grand Gulf, MS	ESBWR	1	FY 2008
Exelon	Clinton, IL	TBD	TBD	TBD
Exelon	Texas	TBD	1	FY 2009
Florida Power & Light	TBD	TBD	TBD	FY 2009
NRG Energy/STPNOC	Bay City, TX	ABWR	2	FY 2008
PPL	Susquehanna, Pa	TBD	1	TBD
Progress Energy	Harris, NC;	AP1000	2	FY 2008
Progress Energy	Levy Co., FL	AP1000	2	FY 2008
South Carolina Electric & Gas	Jenkinsville, SC	AP1000	2	FY 2008
Southern Company	Vogtle, GA	AP1000	2	FY 2008
TVA (NuStart Energy[5])	Bellefonte, AL	AP1000	2	FY 2008
TXU	Comanche Peak, TX	APWR	2	FY 2008
UniStar Nuclear[6]	Calvert Cliffs, MD plus 2 additional sites	EPR	3	First Submittal - FY 2008

[1] *This compendium is based on public announcements as of July 2007.*
[2] *Construction/Operating License*
[3] *Fiscal Year*
[4] *This consortium includes Dominion, General Electric, Bechtel.*
[5] *NuStart Energy includes Constellation, Duke, EDF International North America, Entergy, Exelon, FPL Group, General Electric, Progress, SCANA, Southern, Tennessee Valley Authority, Westinghouse.*
[6] *UniStar Nuclear is a joint venture of Constellation Energy and Areva.*
SOURCE: NEI

In our opinion, it makes more sense for regulated utilities to pursue new nuclear generation in the first wave of applications. This is largely premised on the traditional Integrated Resource Plans (IRP) that many utilities file (and review) with their respective state regulators. As a result, value can be ascribed to fuel diversity and environmental benefits that may not be as transparent in a merchant market. More importantly, the risks associated with construction can be mitigated through creative cost recovery designs that would not be available to a merchant operator. However, merchant companies may be able to achieve a lower risk profile (but usually not approaching a regulated utility) by using project finance structures, supported by Federal guarantees of the debt, vendor financing and, in some cases, guarantees from foreign export credit agencies, and/or robust off-take agreements. Some utilities may also seek many of these kinds of financing provisions.

From a credit perspective, there are still significant regulatory risks associated with building a nuclear plant in rate base. These risks will become exacerbated if there are lengthy construction delays or cost escalation. In addition, there are no accurate methods to assess what the political, environmental and fuel-commodity environments will look like in five to seven years time. If, at the end of construction, fuel is cheap, environmental concerns have abated and the political mood becomes contentious (for example, over the steady rate increases experienced over the previous five to seven years), utilities could be at risk with their regulatory / political constituents. Moody's is unable to assess the magnitude of this risk at this time, but we will continue to recognize its potential existence into our longer-term assessments. In addition, we also recognize that these factors may break in favor of nuclear development which can further stimulate new build.

Two Critical Near-Term Decision Points

There are two critical near-term decision points that companies need to make after they have decided that pursuing new nuclear generation is an option / alternative that they wish to explore: selecting an appropriate site and selecting a technology. Once these two decisions have been made, a company can commence developing its COL application for the NRC.

Site selection

The location of a site for a new nuclear facility will be one of the most important near-term decisions that a company has to make before committing to a major construction project (and the filing of its COL). In our opinion, the selection of a site where an existing nuclear facility is already operating (a brown field site) will be a lower risk decision than a pure green-field site.

Brown field sites, in general, have a clear advantage over green field sites due to their existing infrastructure which includes water supplies, transmission connections and administrative facilities. The current nuclear operators also have emergency and security plans in place and a local population more receptive to an additional unit at a pre-existing facility.

Brown field site advantages:

During the last nuclear construction cycle, in the 1970's and 1980's, many companies applied for construction permits to build multiple generating units at a given site. However, because of the events that unfolded during this period, namely Three Mile Island, inflation and regulatory reviews and disallowances, a number of the second or third units were never built. As a result, for those companies looking to build new nuclear units in the next construction cycle, there could be many advantages associated with the next new plant being sited at an existing facility. These sites, commonly referred to as "brown-field" sites, could provide an operator with the following benefits:

- An existing comfort level with the local community
- An existing transmission infrastructure with access to ROW's
- An existing supply of water / water rights
- Existing security and emergency management plans
- Existing on-site spent-fuel storage facilities
- The availability of historical environmental data
- An existing labor force

Technology Selection

The selection of a technology is also a major decision. At this time, only GE's Advanced Boiling Water Reactor (ABWR) and Westinghouse's AP1000 technology have been fully certified as a nuclear plant by the NRC. NRG plans to use the ABWR technology. However, the certification does not apply to GE's most advanced next generation passive design technology. We observe that GE is still working through data discovery with the NRC on its newer ESBWR technology. Areva's current design has not yet been certified either. Westinghouse's AP1000 technology has been certified by the NRC from a design perspective, but it still needs to fully certify its total plant design. While the technologies still need certification work, most utility and merchant generation companies are willing to pursue their strategies of filing COLs' under the assumption that the selected technology will be certified within their over-all construction timeframes.

As an aside, Moody's observes that the GE's ESBWR and Westinghouse's AP1000 designs are passive in nature from a safety perspective (ie, relying on gravity) as opposed to Areva (ie., relying on redundancy). As a result, it is our understanding that the GE and Westinghouse designs will require a smaller footprint for the facility and use less cement, steel and other commodities to build.

Design	Supplier	Background and Current Status
Advanced Boiling Water Reactor	General Electric	This large (1,350 MW) boiling water reactor is an evolutionary improvement on the boiling water reactors that make up approximately one-third of the U.S. nuclear power plant fleet. The first models of this design were deployed commercially by Tokyo Electric Power Co. at its Kashiwazaki-Kariwa generating station in Japan. TEPCO and other Japanese utilities continue to build ABWRs. This design was certified by the NRC in 1997.
AP1000	Westinghouse	The AP1000 is a 1,150-MW reactor, the first approved by the NRC to employ so-called "passive" safety features. The passive designs substitute natural forces like gravity to deliver cooling water to the reactor. The improved design eliminates a number of the pumps, valves, piping and other components that increase the complexity and the capital cost of today's nuclear plants. The AP1000 received its final design approval from the NRC in late 2004, and the final certification rule became effective in January 2006.
ESBWR	General Electric	The ESBWR is GE's new 1,500-MW design incorporating "passive" safety features. By simplifying the design of the ESBWR compared to the ABWR, GE expects to reduce the capital cost of the plant by approximately 20 percent. GE filed its application for design certification with the NRC in August 2005. The application has been accepted and the Final Design Approval (FDA) is scheduled for late 2008, with certification to follow in 2009.
EPR	Areva (in the U.S. market: UniStar, a joint venture of Areva and Constellation)	The EPR is a large (1,600 MW) design developed by Areva, the reactor supplier formed by Framatome (France) and Siemens (Germany). Areva has formed a joint venture with Constellation Energy Group called UniStar Nuclear to deploy the EPR technology in the United States. The first EPR is now being built in Finland, and it will be the next generation of nuclear plants built in France by Electricité de France. The EPR is an advanced light water reactor. The EPR design includes additional safety features not in today's light water reactors, including four safety trains instead of two, bunkered safety systems, double containments, and additional severe accident management features. Areva plans to make a design certification submittal to the NRC for the EPR in 2007.
ESBWR	General Electric	The ESBWR is GE's new 1,500-MW design incorporating "passive" safety features. By simplifying the design of the ESBWR compared to the ABWR, GE expects to reduce the capital cost of the plant by approximately 20 percent. GE filed its application for design certification with the NRC in August 2005. The application has been accepted and the Final Design Approval (FDA) is scheduled for late 2008, with certification to follow in 2009.

Source: NEI

International Markets Appear More Active

While the US continues to evaluate and assess the longer-term benefits and risks associated with building new nuclear generating facilities, in many other parts of the world, companies and / or governments are much more active with their nuclear new build plans. This is most obvious in Asia, where China is pursuing four new nuclear units (Westinghouse technology), and where Japan and Taiwan have also been active. China, in particular, may be interested in building over a dozen new nuclear plants over the near to intermediate term horizon and may use multiple technology designs (as opposed to the US's strategy of using a "standardized" design). In Europe, there has been activity in France, Finland and several Eastern European countries (Romania, Bulgaria and Russia).

In addition, Moody's observes that there are several Middle-Eastern countries that would like to build new nuclear facilities. For many of these countries, nuclear facilities are viewed as a great source of energy for water desalination, and they clearly have the capital to make the necessary investments. From a construction and operating risk perspective, these countries face the same set of issues that would be faced in the US, including the need to procure long lead time items over the very near-term horizon.

Nuclear Units under Construction Worldwide

Country	Total MWe
Argentina (1)	692
Bulgaria (2)	1,906
China (5)	3,220
China, Taiwan (2)	2,600
Finland (1)	1,600
India (6)	2,910
Iran (1)	915
Japan (1)	866
Pakistan (1)	300
Russia (7)	4,585
South Korea (2)	1,920
Ukraine (2)	1,900
Total (31)	**23,414**

Source: International Atomic Energy Agency PRIS database

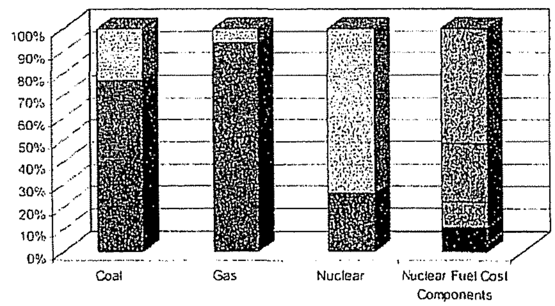
Fuel Fundamentals

Uranium is the primary fuel source for nuclear generation. It is located primarily in Canada, Australia, Africa, Russia and some of the Central Asian Republics that were formerly part of the Soviet Union. It is our understanding that the fuel conversion cycle has four primary components:

- Mining – uranium is contained in rock, which needs to be mined primarily in underground mines.
- Milling – the uranium ore (U235) is separated from the rock at a mill, similar to how copper and iron are milled, resulting in a powder, which is commonly referred to as "yellowcake".
- Conversion – the yellowcake is converted into a gas (uranium hexafluoride, or UF6).
- Fabrication – the uranium hexafluoride gas is a feedstock for an enrichment plant, where the uranium is enriched 3% - 5% and converted onto solid ceramic pellets. The enrichment process is a critical component of the nuclear fuel cycle. Many companies (including two in the US), and governments, are either building new enrichment capacity or are actively looking at ways to enhance enrichment capacity, but it may be several years before additional capacity becomes available (i.e., 2012)
- The pellets are assembled into tubes and the tubes are bundled into assemblies and shipped to the nuclear generating facility.

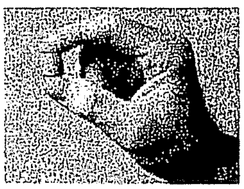
Once the fuel assemblies arrive at the nuclear plant, they are put into the reactor. During a refueling, operators will typically withdraw the oldest one-third of the fuel assemblies and rearrange the remainder and blended with the new assemblies. This is not unlike rearranging batteries in a large flashlight. Approximately 90% of the energy remains in fuel rods that are removed from the fuel assemblies and classified as "spent" fuel.

Fuel as a Percentage of Electric Power Production Costs 2006



Source: Global Energy Decisions

On September 11th, 2007, Duke Energy held an analyst meeting in New York where they presented the picture below. It was stated that the ceramic pellet has an equivalent amount of energy as one ton of coal.



Source: Duke Energy

Storage and Disposal

The storage and ultimate disposal of spent nuclear fuel continues to represent a major issue in the United States. There is roughly 50,000 metric tons of spent nuclear fuel in the US, but the industry does not view the issue as a critical path item. At the moment, spent fuel is primarily stored in large pools of water, usually for at least 5 years, then placed into dry cement or steel casks and stored on site. While this creates some local issues and emergency planning obstacles, Moody's incorporates a view that most sites are well equipped to manage the safe storage of spent nuclear fuel.

Some countries recycle their spent nuclear fuel, including France, Japan, Russia and the United Kingdom. Other countries bury their spent nuclear fuel, such as Sweden and Finland. Regardless of which path the US decides to pursue, it appears that many within the industry are confident that a solution can be found. Currently, the industry is working with the Global Nuclear Energy Partnership (GNEP) to design solutions for the 50,000 metric tons that exists throughout the country.

Federal Initiatives

One of the biggest near-term challenges associated with new nuclear generation construction in the US involves financing, including whether or not the Federal government will provide loan guarantees and / or otherwise encourage investment, much of which was encompassed in the Energy Policy Act (EPA) of 2005. Several large companies – both regulated as well as merchant have very clearly stated that they would not pursue their new nuclear plans if the Federal government did not provide an appropriate investment stimulus and investment protection. Moody's observes that the EPA provided four key incentives for the nuclear industry:

- Extension of Price-Anderson Act by 20 years
- Risk insurance / Stand-by support for risks beyond the control of management (delays due to licensing or litigation) of approximately $2.0 billion in total – up to $500 million for the first 2 new plants and up to $250 million for the next 4 plants.
- Production Tax Credits (PTC's) – in the amount of 1.8 cents per kwh for the first 6GW's of new nuclear capacity. However, in order to be eligible, an operator must submit the COL application and start construction by specific dates (end of 2008 and beginning of 2014, respectively).
- Loan Guarantees – Federal loan guarantees are authorized but the current rulemaking associated with how big of a guarantee and how much of a guarantee is still under debate. In addition, the calculation regarding how the government's subsidy costs has not yet been determined. This appears to be a particularly important issue for the merchant operators.

While it is understandable why the Federal loan guarantees are of particular interest to the merchant companies given the high level of risks associated with nuclear construction, it is debatable whether the Federal government should be *involved in enhancing the profitability of the merchant market* by socializing the up-front costs. However, the merchant generator would be responsible for paying the cost for the loan guarantee – the formula for which has not yet been determined. Moody's notes that some of the regulated electric utilities may also seek these Federal guarantees to help them facilitate their construction needs.

Moody's would view Federal loan guarantees positively from a construction perspective, but we observe that these guarantees, by themselves, will not be enough to completely mitigate the increased business and operating risk profile of a company seeking to build new nuclear generation. These guarantees are currently proposed to be made available to a specific number of companies considering new nuclear generation on a first-come-first-serve basis. From a potential off-balance sheet credit perspective, we question how serious a problem will need to be before a company decides to abandon its project and how these Federal guarantees will be structured from a risk sharing perspective. Notwithstanding these issues, we believe Federal loan guarantees could be very helpful in keeping the all-in costs down for a new nuclear project, which should help end-use consumers with rate shock.

Moody's also observes that the Federal loan guarantees are intended (according to the statute) to offset the technical, financial and market risks associated with building new, cleaner energy production facilities, including new nuclear power plants). The theory is that once the capital markets become more familiar with new nuclear construction, the market will be able to assess and price risk accordingly. Moody's does not fully subscribe to this philosophy. First, we believe the capital markets are capable of assessing the risk of new nuclear construction. To the extent that the capital markets price nuclear construction risk at extremely high levels, companies might consider injecting a larger component of equity into the project or find partners to share the risk. Secondly, there are several regulated utilities that are not basing their plans on the availability of these guarantees. Instead, the decision to pursue new nuclear generation was a result of their long-term resource plans, and in some cases, was made well before the Energy Policy Act even contemplated authorizing Federal guarantees.

September 25, 2007 - **Department of Energy Releases Conditional Agreement for New Nuclear Power Plants** - *Marks initial step for sponsors of new nuclear plants to qualify for up to $2 billion in federal risk insurance*

WASHINGTON, DC– The U.S. Department of Energy (DOE) Secretary Samuel W. Bodman today released a **Conditional Agreement** for companies building new nuclear power plants in the United States to qualify for a portion of $2 billion in federal risk insurance. Risk insurance covers costs associated with certain regulatory or litigation-related delays - which are no fault of the company - that stall the start-up of these plants. Authorized by the Energy Policy Act of 2005 (EPAct), risk insurance provides incentive and stability in spurring construction of new nuclear power plants and meeting our energy needs in a clean, safe, economical manner. Secretary Bodman made today's announcement while in Chicago speaking to the World Association of Nuclear Operators and United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry.

"To meet the world's growing demand for electricity and confront climate change, safe and emissions-free nuclear energy must play an integral role in our energy mix," Secretary Bodman said. "Conditional Agreements pave the way for risk insurance contracts that will provide the first project sponsors constructing new nuclear power plants with assistance if they face delays in expanding the use of nuclear energy across the nation."

Providing risk insurance is part of President Bush's bold energy agenda and allows the first of several sponsors of new nuclear power plants to be backed by the U.S. government should a sponsor undergo lengthy and unnecessary delays preventing operation.

EPAct authorizes DOE to enter into contracts with the first six sponsors that begin construction of new nuclear facilities and meet all other contractual conditions to provide risk insurance for certain regulatory and litigation delays in the full power operation of their facility. Up to $500 million in coverage is available for the initial two plants for which construction is started and up to $250 million is available for the next four plants. The Conditional Agreement, the first step in the process toward a risk insurance contract, is available to sponsors of advanced nuclear facilities once its application for a Construction and Operating License (COL) is docketed by the Nuclear Regulatory Commission (NRC). Companies can enter into a Conditional Agreement with DOE, however, only the first six that are issued a COL and begin construction are eligible for the risk insurance contract with DOE.

The Conditional Agreement announced today details the rights and responsibilities of potential sponsors to become eligible for risk insurance contracts. Events that would be covered by the risk insurance contract include delays associated with the NRC's reviews of inspections, tests, analyses and acceptance criteria, as well as certain delays associated with a pre-operational hearing or litigation in federal, state or tribal courts. Insurance coverage is not available for normal business risks such as employment strikes and weather delays. In August 2006, DOE issued a final rule that outlines a two-step process to apply for risk insurance coverage, which requires entering into a Conditional Agreement first and, if eligible, then a risk insurance contract.

Today's announcement closely follows previous progress through the Department's Nuclear Power 2010 program, which is a joint government/industry cost-shared effort to identify sites for new nuclear power plants, develop and bring to market advanced nuclear plant technologies, evaluate the business case for building new nuclear power plants, and demonstrate untested regulatory processes. In March of this year the first two Early Site Permits were issued by the NRC. These permits were funded through a 50-50 cost share by DOE and industry. Through the Nuclear Power 2010 program, DOE is partnering with industry to promote the expansion of nuclear power in the United States and work toward the submission of COL applications for new nuclear plants to the NRC.

Financial Metrics / Valuation

The key financial credit metrics for the power sector are strong given the average Baa-rating. These metrics, which include cash flow to adjusted total debt ratios in the mid to high-teen's are expected to remain in this range over the near to intermediate term horizon, and is incorporated into our stable rating outlook for the industry.

Prospectively, there is a concern developing over the industry's current expectations for significantly increased capital investment and how the financing of that investment will be executed (primarily with debt). With respect to new nuclear generation, Moody's incorporates a view that companies will approach the financing plans associated with new nuclear generation as conservatively as they are approaching the site and technology assessments. Specifically, we believe new nuclear facilities that are included in a utility's rate base are likely to be financed on an approximately 50% debt / 50% equity basis – reasonably consistent with its existing rate base.

To the extent that a company develops a financing plan that overly relies on debt financing, which effectively reduces the consolidated key financial credit ratio's, regardless of the regulatory support associated with current cost recovery mechanisms, there is a reasonably high likelihood that credit ratings will also decline.

It has been noted in this report that the companies that are actively considering new nuclear generation have been evaluating the option for several years. While we acknowledge that it will be several more years to finalize all of the necessary regulatory approvals to commence and complete construction, in order to maintain current ratings, these companies may decide to commence an ***aggressive balance sheet strengthening program*** going into the construction period. The most effective method to protect current credit ratings for a company entering into a nuclear construction phase is the issuance of common equity at the front end of the construction cycle or, at a minimum, limiting the amount of shareholder dividends or other shareholder return alternatives. Given the numerous regulatory overhang and construction execution risks identified in this report, Moody's will be less inclined to hold a given rating over the course of a long-term construction cycle (such as that associated with a new nuclear generation facility) if a company as been active with aggressive shareholder return strategies.

The importance of partnerships

Many companies claim that the Federal loan guarantees are necessary because the companies, by themselves, are not large enough to handle the construction of a multi-billion project on a stand-alone basis. This raises a very obvious question: Why not pursue a program with multiple partners to share the risk? From a credit perspective, if a board feels that their company is too small to handle a project like a new nuclear facility, Moody's would be very concerned if the company attempted to pursue the program without adequately allocating risk within the constraints of their balance sheet.

Is there a role for Securitization Bonds?

Given some of the industry's desire for Federal loan guarantees, the need to spread risk and the size of many of the companies considering building new nuclear generation, securitization might represent a reasonable alternative to assist with the financing of the next new nuclear facilities. We observe that securitization has been successfully used within the sector to finance conservation investments, environmental mandates, stranded costs and storm recoveries. A product structured for nuclear generation could emerge as another viable financing tool.

5 Year Average Metrics

Regulated Nuke Parent Company	Unsecured / Issuer Rating	FFO / Int (x)	FFO / Debt	RCF / Debt	RCF / Capex	Debt / Cap
FFO = CFO-W/C						
RCF = CFO-W/C-Dividends						
FPL Group, Inc.	A2	5.2	22.7%	17.4%	107.4%	46.5%
SCANA Corporation	A3	4.0	17.7%	13.2%	94.9%	52.9%
Southern Company	A3	5.2	21.2%	14.4%	87.1%	49.4%
Ameren Corporation	Baa2	4.9	21.5%	13.7%	92.2%	44.6%
American Electric Power Company	Baa2	3.8	16.3%	12.2%	89.5%	55.3%
Dominion Resources Inc.	Baa2	4.0	17.5%	12.8%	74.5%	53.5%
DTE Energy Company	Baa2	3.5	14.9%	11.2%	105.9%	60.7%
Duke Energy Corporation	Baa2	4.1	19.9%	10.0%	65.8%	41.3%
Progress Energy, Inc.	Baa2	3.6	15.5%	10.3%	89.2%	57.5%
Entergy Corporation	Baa3	5.0	24.3%	20.3%	120.0%	44.1%
PG&E Corporation	Baa3	3.7	29.1%	27.7%	126.8%	54.3%
Pinnacle West Capital Corporation	Baa3	4.2	18.4%	14.4%	81.2%	50.5%
	Average	4.3	19.9%	14.8%	94.5%	50.9%

Non-Regulated Nuke Parent Company	Unsecured / Issuer Rating	FFO / Int (x)	FFO / Debt	RCF / Debt	RCF / Capex	Debt / Cap
FPL Group, Inc.	A2	5.2	22.7%	17.4%	107.4%	46.5%
Constellation Energy Group, Inc.	Baa1	4.3	19.6%	16.4%	126.3%	51.8%
Exelon Corporation	Baa1	5.2	25.1%	20.1%	159.0%	57.0%
Dominion Resources Inc.	Baa2	4.0	17.5%	12.8%	74.5%	53.5%
PPL Corporation	Baa2	3.6	15.9%	12.4%	125.2%	59.7%
Public Service Enterprise Group	Baa2	2.9	13.0%	9.2%	109.7%	60.6%
Entergy Corporation	Baa3	5.0	24.3%	20.3%	120.0%	44.1%
FirstEnergy Corp.	Baa3	3.6	16.0%	12.5%	144.4%	57.7%
TXU Corp.	Ba1	4.0	18.2%	15.1%	173.6%	71.4%
NRG Energy, Inc.	B1	1.7	5.9%	5.8%	203.1%	70.2%
	Average	3.9	17.8%	14.2%	134.3%	57.2%

Non-Nuclear Regulated Parent Company	Unsecured / Issuer Rating	FFO / Int (x)	FFO / Debt	RCF / Debt	RCF / Capex	Debt / Cap
OGE Energy Corp.	Baa1	4.9	25.0%	18.5%	109.7%	46.3%
IDACORP, Inc.	Baa2	4.4	19.1%	14.3%	102.9%	43.8%
Cleco Corporation	Baa3	4.7	22.1%	16.4%	149.0%	47.6%
Allegheny Energy, Inc.	Ba1	2.3	10.0%	9.5%	128.6%	67.3%
Puget Energy, Inc.	Ba1	3.3	16.0%	12.8%	93.8%	53.0%
TECO Energy, Inc.	Ba1	2.4	8.8%	4.6%	34.7%	70.4%
Sierra Pacific Resources	B1	2.0	7.8%	7.6%	50.7%	66.0%
	Average	3.4	15.6%	12.0%	95.6%	56.3%

Regulated Nuke Utility Company	Unsecured /Issuer Rating	FFO / Int (x)	FFO / Debt	RCF / Debt	RCF / Capex	Debt / Cap
Florida Power & Light Company	A1	9.5	43.4%	28.4%	74.6%	32.5%
Alabama Power Company	A2	5.6	23.5%	13.9%	84.6%	44.4%
Georgia Power Company	A2	5.6	23.0%	12.6%	77.6%	42.5%
South Carolina Electric & Gas Co	A2	4.4	21.5%	14.9%	84.3%	44.6%
Duke Energy Carolinas, LLC	A3	6.1	22.6%	14.8%	97.3%	47.6%
Progress Energy Carolinas, Inc.	A3	6.0	28.4%	17.0%	99.0%	48.3%
Progress Energy Florida, Inc.	A3	6.0	24.6%	17.1%	75.5%	48.5%
Southern California Edison	A3	7.0	41.2%	33.9%	159.4%	46.9%
Detroit Edison Company	Baa1	4.3	18.6%	13.3%	102.6%	57.8%
Pacific Gas & Electric Company	Baa1	3.8	28.7%	26.9%	114.5%	49.9%
Virginia Electric and Power	Baa1	5.0	21.8%	13.9%	92.4%	46.2%
Arizona Public Service Company	Baa2	4.2	18.4%	13.5%	82.3%	49.6%
	Average	5.6	26.3%	18.4%	95.3%	46.6%

Merchant Nuke Generator	Unsecured /Issuer Rating	FFO / Int (x)	FFO / Debt	RCF / Debt	RCF / Capex	Debt / Cap
Exelon Generation Company, LLC	A3	11.4	53.1%	38.8%	134.1%	50.8%
PSEG Power L.L.C.	Baa1	4.3	18.7%	18.7%	129.5%	60.4%
PPL Energy Supply, LLC	Baa2	4.6	19.0%	6.2%	50.8%	51.3%
Texas Competitive Electric Hlds.	Baa2	5.9	40.1%	22.6%	244.0%	40.7%
NRG Energy, Inc.	B1	1.7	5.9%	5.8%	203.1%	70.2%
	Average	5.6	27.4%	18.4%	152.3%	54.7%

Cross Industry	Unsecured / Issuer Rating	FFO / Int (x)	FFO / Debt	RCF / Debt	RCF / Capex	Debt / Cap
Exxon Mobil Corporation	Aaa	17.1	98.8%	80.1%	209.8%	19.8%
BP plc	Aa1	19.1	76.8%	57.7%	148.7%	27.4%
Royal Dutch Shell Plc	Aa1	18.1	104.4%	77.2%	135.5%	23.4%
Chevron Corporation	(P)Aa2	14.4	62.2%	49.7%	149.3%	27.7%
European Aeronautic Defence	A1	5.1	38.7%	32.9%	92.9%	28.5%
Nucor Corporation	A1	42.6	149.7%	116.3%	356.4%	20.3%
Boeing Company (The)	A2	7.7	39.8%	32.6%	432.0%	112.8%
E.I. du Pont de Nemours	A2	7.6	33.0%	22.4%	190.8%	61.8%
Praxair, Inc.	A2	7.5	33.2%	28.4%	154.2%	52.0%
Dow Chemical Company (The)	A3	5.0	23.1%	15.9%	160.1%	62.6%
Weyerhaeuser Company	Baa2	3.5	17.9%	14.2%	189.9%	49.6%
International Paper Company	Baa3	3.5	15.9%	12.5%	145.5%	60.6%
United States Steel Corporation	Baa3	6.3	46.2%	43.7%	165.0%	61.1%
Temple-Inland Inc.	Ba1	5.4	25.8%	22.3%	250.0%	58.1%
	Average	11.6	54.7%	43.3%	198.6%	47.6%

Moody's Related Research

Special Comments:

- Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector, August 2007 (103941)
- Credit Risks and Benefits of Public Power Utility Participation in Nuclear Power Generation, June 2007(103522)
- Moody's Comments on the Credit Implications Associated with North American Utility Consolidation, December 2006 (101392)
- Moody's Comments on the Back to Basics Strategy for the North American Electric Utility Sector, November 2006 (100660)
- U.S. Nuclear Assets Remain Attractive Acquisition Targets; With Potentially Favorable Credit Implications for Efficient Operators, September 2004 (89008)
- Nuclear Power Trends in the United States, February 2004 (81342)
- Standardized Designs for Nuclear Plants Beneficial for U.S. Power Industry But Waster Disposal Is an Unresolved problem, December 2003 (80790)
- Nuclear Update: A Buyer's market for nuclear Plants, June 1999 (39917)
- Moody's Assesses Nuclear Power Risk in a More Competitive Market, April 1997(20929)

Rating Methodology

- Rating Methodology: Global Regulated Electric Utilities, March 2005 (91730)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

To order reprints of this report (100 copies minimum), please call 1 212.553.1658.

Report Number: 104977

Author(s)	Associate Analyst	Editor	Production Associates
Jim Hempstead	Indu Sambandam, CFA	Scott Stearns	Sarah Warburton
	Ryan Wobbrock		Tara Cheparev

Moody's Investors Service

STANDARD
&POOR'S

RATINGSDIRECT®

July 24, 2007

The Forces Behind Growing U.S. Public Utility Interest In Wind Power

Primary Credit Analyst:
Peter V Murphy, New York (1) 212-438-2065; peter_murphy@standardandpoors.com

Secondary Credit Analyst:
Paul Dyson, San Francisco (1) 415-371-5079; paul_dyson@standardandpoors.com

Table Of Contents

The Forces Behind Growing U.S. Public Utility Interest In Wind Power

Growing concerns over climate change, energy security, rising fossil fuel costs, and ongoing state and federal regulation that enables utilities to recover costs of new investment have ignited the U.S. power industry's renewed interest in fuel diversification and renewable energy.

Although public power comprises a significant part of the industry (15.2% of total U.S. electricity sales in 2005), and is focused on renewable energy as part of their power portfolios, they currently own a very small share of U.S. wind projects (2% in 2006). Still, they often set portfolio standards for renewable energy initiatives, despite the fact that, unlike investor-owned utilities in some states, state laws don't require public power utilities to do so.

Wind Energy's Emerging Growth

Wind energy has emerged as the leading option among renewable technologies due to:

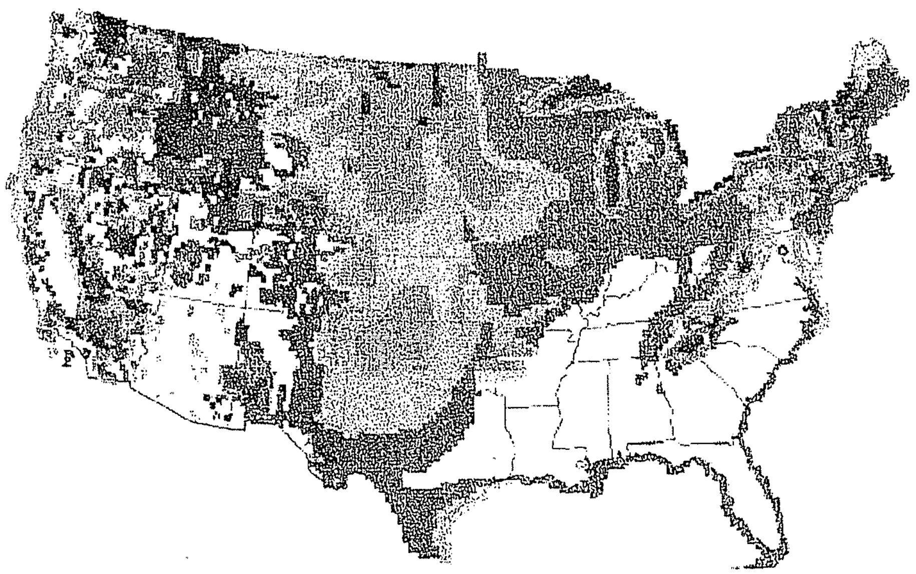
- Its vast untapped potential, with widespread range of suitable sites;
- Stable and increasingly competitive cost structure;
- The relatively short project construction timeframe; and
- The absence of carbon or other harmful emissions.

Chart 1

Wind Resource Potential

Power Classification

Outstanding Excellent Good Fair Marginal Poor

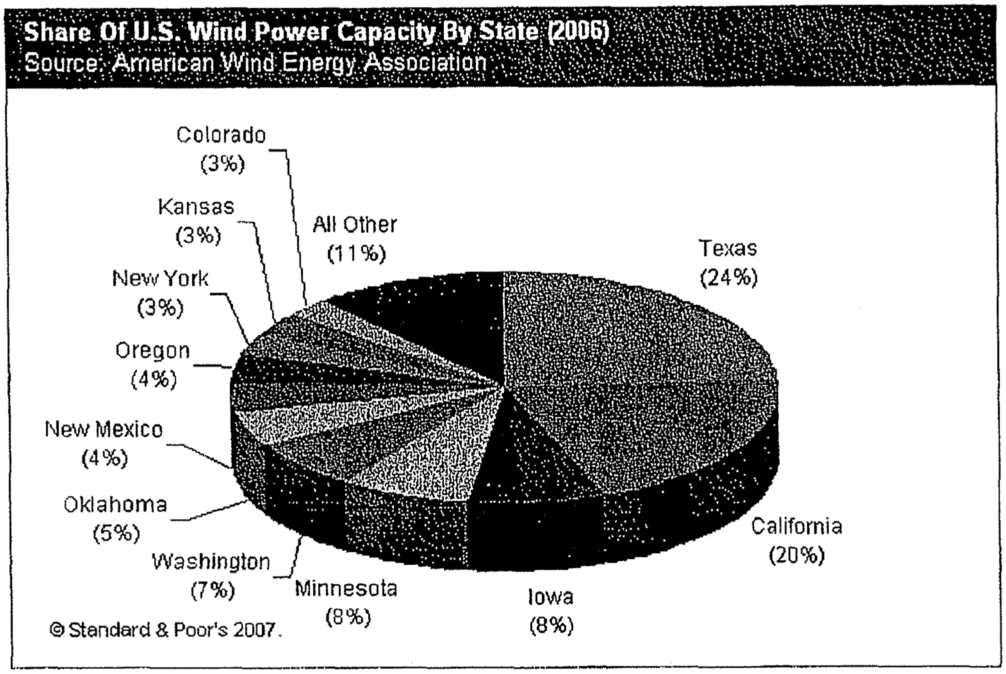


Source: National Renewable Energy Laboratory, U.S. Dept. of Energy.

The American Wind Energy Association (AWE) expects that the wind power segment of the electricity industry will add about 3,000 MW of capacity in 2007, after adding 2,454 MW in 2006, and 2,431 MW in 2005. This will bring total U.S. wind capacity to about 15,000 MW. While this seems relatively insignificant, domestic wind potential is enormous, with untapped production capability of more than 10 billion MWh hours annually, according to AWEA estimates, or about three times current domestic generation from all sources.

While the potential is widespread, certain regions are more suitable for wind energy than others. The AWE estimates that Kansas, Montana, North Dakota, South Dakota, and Texas each have over 1 billion MWh of annual potential (See map). Through the end of 2006, however, Texas and California, which both have large public power presences, were far ahead of the rest of the country with installed capacity of 2,768 MW and 2,361 MW, respectively. Iowa, Minnesota, and Washington round out the top five (See Chart 2).

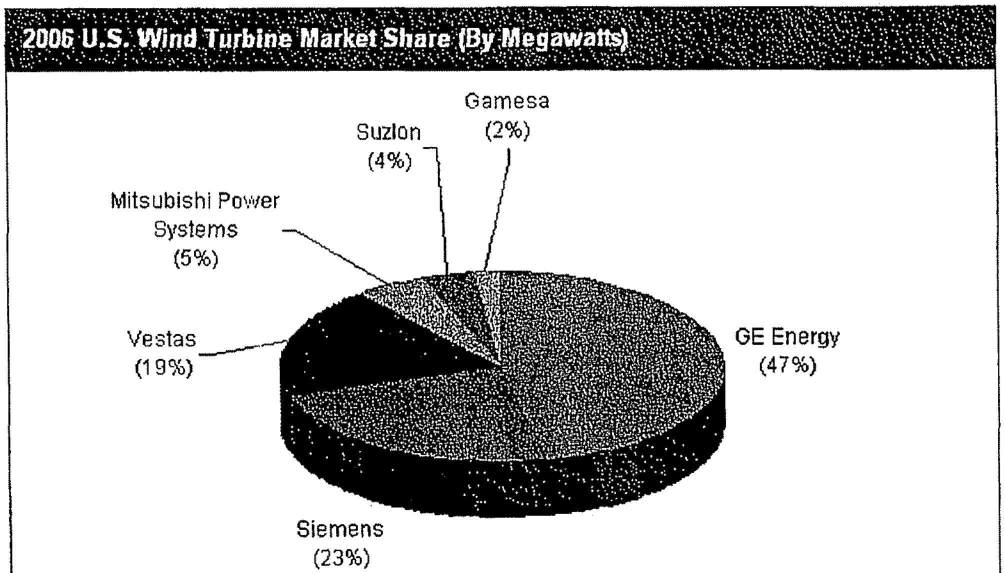
Chart 2



After falling dramatically from the 1980s through the early 2000s, installed costs of wind power projects increased by 18% in 2006 to $1,480 per Kilowatt, with the U.S. Department of Energy estimating average costs on proposed future projects at $1,680. This increase is largely a result of higher turbine prices, as shortages have allowed manufacturers to increase profitability and pass along higher materials costs, and the exchange rate effects of a weaker dollar. Installation costs vary by region, with New England and California at the high end, and the Upper Midwest and Texas at the low end.

GE Energy was the dominant producer of wind turbines in the U.S. in 2006, with almost 50% market share. With 764 units, the GE Energy 1.5 MW model was the nation's most widely installed model. Multinational wind turbine manufacturers supplying U.S. wind projects include Siemens, Vestas, Mitsubishi Power Systems, Suzlon, and Gamesa (See Chart 3). The average capacity of new wind turbines has approximately doubled since 2000 to 1.6 MW in 2006. The largest installed turbine in the United States is the Vestas 3 MW turbine, employed at a wind project owned by Sacramento Municipal Utility District. FPL Energy, manages the greatest amount of wind capacity by far, with about 4,000 MW of installed capacity domestically at the end of 2006. PPM Energy is the only other entity with more than 1,000 MW of installed capacity.

Chart 3



Source: American Wind Energy Association

© Standard & Poor's 2007.

All U.S. wind capacity currently in operation is land-based, but offshore sites also have potential and are attractive because utilities can reduce transmission distances by building close to load. A small number of offshore wind projects are up and running in Europe. Although they come with unique construction and ongoing maintenance challenges, utilities have shown substantial interest in developing offshore wind projects, especially along the Atlantic Coast and in the Gulf of Mexico, near Texas. Active proposals for offshore projects totaled 2,455 MW at the end of 2006. Long Island Power Authority's proposed 140 MW site off Long Island's south shore has met with opposition from local governments concerned with the cost to ratepayers and, as with many wind projects, the impact of the project on scenic views.

Wind Development Might Not Be A Breeze

While support for wind energy is strong, and we expect the development of capacity to continue at a rapid rate, numerous hurdles hinder the completion of energy producing wind projects.

Wind blows intermittently, and sometimes not at all, so utilities can't count on a wind project as a baseload resource. Wind turbine capacity, therefore, isn't as dependable as coal, gas, nuclear, or even hydro projects. Consequently, utilities must often augment the addition of wind capacity with another dependable source, which can add to total portfolio costs. For this reason, wind isn't suitable for every resource portfolio.

After finding viable locations for wind energy production, site ownership, permitting, and access to transmission are added considerations. Utilities must make lease or purchase arrangements for the site. Permitting issues vary by jurisdiction -- often a city or county, but state regulations may also govern. Opposition from unofficial parties, such as local residents or environmental groups concerned with the impact on views, weather, noise, and cattle or migratory birds can prevent, delay the construction of, or drive up the cost of a project.

While the physical construction of a single wind turbine is not overly complicated or time consuming, utilities must address many issues prior to construction. They need to first iron out contractual provisions designed to protect both parties. From the project sponsor's side, liquidated damages, incentives to complete work on time and on budget, and post-construction performance measures are key to mitigating construction and operating risks. If the project sponsor is selling project output to others, they need to work out purchased power agreements. Many utilities buying wind power also seek firming provisions, whereby the supplier must deliver a certain amount of energy from another source should the project output be below some threshold. The complexity of building transmission to deliver project output will vary, based on distance, additional permitting requirements, and the status of existing infrastructure.

The cost and availability of component is another emerging issue with wind development. A typical wind turbine has thousands of individual parts. The supply of these components hasn't kept up with soaring demand, which has slowed some projects, and impeded the sector's development.

Incentives And Regulation

The federal government has provided several financial incentives to develop wind energy. Until recently, the Renewable Energy Production Incentive (REPI) was the primary form of subsidies for renewable energy to public utilities, and is similar to the production tax credits for private generators.

Originally enacted in 1992, and reauthorized as part of the Energy Policy Act of 2005, the REPI provides annual incentive payments of 1.8 cents per kWh (the current amount, indexed to inflation) to state and local governments, municipal utilities, rural electric cooperatives, and tribal governments for the production of electricity from eligible renewable technologies including wind, solar, geothermal, ocean, biomass, landfill, or livestock methane technologies.

The REPI offers incentive payments for the first 10 years of operation, but requires annual appropriations from Congress. Without sufficient congressional appropriations, 60% of all funds distributed by the government must be allocated for wind, ocean, solar, biomass, or geothermal projects, with the remaining 40% distributed for other projects. Because of funding shortfalls, the program isn't meeting the demand. In 2005, only about 47% of requests were funded among the group of project types that includes wind.

The Energy Policy Act (EPACT) of 2005 gave rise to a new incentive, Clean Renewable Energy Bonds (CREBs) that generate tax credits for bond investors in lieu of interest payments. This means the bond issuer doesn't have to pay interest, creating an incentive to invest in renewable energy. Congress has authorized $1.2 billion for the program in 2006 and 2007, including $800 million under EPACT and an additional $400 million under the Tax Relief and Health Care Act of 2006. The deadline for issuing current CREBs allotments is Dec. 31, 2008. Of the $800 million of approvals made in November 2006, about $270 million were for wind projects. Applications for CREBs far exceeded the program authorization, with the smallest projects having preference.

Two Congressional bills would extend the program for public power utilities (H.B. 1821) and for cooperatives (H.B. 1965). Given the popularity of the REPI and CREBS programs and the likelihood that support for renewables is politically an easier response to carbon reduction than would be a carbon cap or tax, ongoing support in Congress is likely. Individual states are likely to put forth their own tax credit incentives for renewables, which will also spur wind investments.

Twenty-three states have adopted some form of Renewable Portfolio Standard (RPS), the bulk of which call for renewable energy to supply between 10% and 20% of installed capacity. The implementation dates to achieve these standards range from 2010 to 2025, but states have often made revisions and called for higher percentages, sooner. In three states, Hawaii, Illinois, and Minnesota, participation in the RPS is strictly voluntary, and in most other participating states, the RPS only applies to investor-owned utilities.

Five states mandate RPS for all public power utilities: Maryland, New Jersey, Texas, Vermont, and Wisconsin. In two others, Colorado and Washington, the standard only applies to medium to larger utilities, and coincidentally, these states' RPS were the result of voter referendums, rather than legislation. Despite the fact that California municipals aren't compelled to adopt the state standard, the Los Angeles Department of Water and Power (LADWP) is planning to meet 20% of retail sales with renewables by 2010. Wisconsin Public Power Inc., through several purchased power agreements, expects to comply with Wisconsin's standard by 2009, six year's in advance of the state's 2015 RPS deadline.

Mandates, in general often limit issuers' financial and operational flexibility, thereby increasing costs and affecting net income. The kinds of penalties that will accompany the failure to meet specific mandates remain uncertain.

Table 1

Cost Of Power From Competing Technologies

($/MWh)	Pulverized coal	Natural gas combined cycle	IGCC Eastern	IGCC PRB	Nuclear	Wind	Solar	Biomass
Plant capital cost	35	13	42	44	69	62	113	36
Plant fuel cost	15	50	14	9	7	N/A	N/A	27
Plant operations and maintenance	8	6	12	12	13	9	39	28
Cost of power	58	68	68	65	89	71	151	91

IGCC-Integrated gasification combined cycle. MWh-Megawatt hour. PRB-Powder River Basin. N/A-Not applicable.

Public Power Investment

To date, public power's entrée to wind is generally through purchased power agreements, with few utilities owning significant amounts directly (See Table 2). Public utilities also have and will continue to invest in wind through joint-action agencies. For example, Energy Northwest has sponsored the Nine Canyon Wind project, which calls for 10 public utility districts to share the costs of and output from 95 MW of wind power in south-central Washington (Phases I, II, and III, each separately rated 'A-'/Stable).

Among public power utilities, Sacramento Municipal Utilities District and Nebraska Public Power District also have sizeable wind assets, and are looking to add more. Unlike project financings, where the project cash flows are critical to debt service, public power utilities support their obligations to wind projects or contracts through a system-wide pledge, either as an operating expense in the case of purchased power contracts, or by way of debt service, if the utility owns the project.

On balance, wind power investments by public power utilities are modest when compared to the issuer's total energy supply, which reduces the risk that failure of a wind project to meet projected generation will threaten debt repayment. Moreover, it wouldn't be accurate to describe any public power retail system as being wind-dependent.

Public power has been a leader in addressing renewable portfolio standards, even as most public power utilities remain exempt from state guidelines. A key challenge for public power is to incorporate wind energy into its resource portfolio in a timely and cost-effective way. As the demand for renewable energy picks up and if supply doesn't keep up, pricing of wind power may become more expensive. Rising component costs could also offset savings from evolving technologies that can produce wind power more efficiently.

Table 2

Utilities and Power Companies Purchasing Wind Through Long-Term Contract (At Least 100 MW)

Power Company	Megawatts
Xcel Energy	1,297
Southern California Edison	1,026
Pacific Gas & Electric	793
TXU Energy	705
AEP	373
Alliant	338
MidAmerican	268
City Public Service, San Antonio *	260
Exelon	259
Austin Energy *	215
Public Service New Mexico	204
Reliant	198
Seattle City Light *	175
Los Angeles Department of Water & Power *	169
Northwestern Energy	135
San Diego Gas & Electric	132
Basin Electric	131
Lower Colorado River Authority, Texas *	116
Aquila	112
Oklahoma Gas & Electric	111
Great River Energy	106

Source: American Wind Energy Association. * Public Power Utility.

Wind Energy's Benefits And Risks

Benefits

Adding wind to a utilities resource portfolio can reduce pollution and contribute toward a utility's RPS goals, whether voluntarily established by the utility's governing body, or state mandated. Wind energy can also play a role in meeting future carbon regulations. Since wind is a free resource, it can reduce dependence on fossil fuels, which have been subject to price volatility and supply uncertainty in recent years. Wind can also support power supply diversification efforts. Financial incentives such as CREBs and REPI may make investments in wind cost-competitive with other alternatives, although dependence on the REPI to make a project viable introduces appropriation risk. For the host community, wind farms provide a modest economic benefit during construction and can reduce the site owner's property taxes. Farmers are often willing lessees because they can earn as much income from wind project operators as they would from raising crops.

Risks

Since public power utilities investing in wind typically do so for a relatively small proportion of their total energy needs, the risks to the utility's bondholders are much less than those associated with wind project financings, since the impact of adverse wind investments on total utility net income should be manageable.

Construction risk, while meaningful, is lower for wind projects than for most other generation asset types, such as pulverized coal and combined cycle gas plants, due to wind's relative lower complexity, scale, and construction timeframe. Using new, unproven technologies will introduce a measure of performance risk, versus a tried-and-true technology. Likewise, using a contractor with a strong track record can also reduce construction risk. In any case, public power utilities should seek contract terms that contain sufficient liquidated damages and incentives to attain desired schedules, budget, and operating performance targets.

One of the major risks associated with wind projects is the variability of wind. Wind blows intermittently, and not always within the optimal range of speeds that can produce the amount of energy anticipated when the project was designed. Consequently, utilities should be prepared for the possibility that project output won't meet targeted amounts. Utilities should therefore combine wind capacity investments with other more dependable capacity additions, although these can add to total portfolio costs. Public power utilities have sought wind power purchase contracts that contain firming provisions that make up for lost energy from lower-than-expected project output or wind turbine failures. Negotiating wind variability risk into the power purchase agreement is one way of offsetting risk.

As with any power purchase agreement, or engineering, procurement and construction contract, utilities expose themselves to counterparty risk. Prudent utilities mitigate these risks by establishing credit thresholds for companies they interact with and negotiating performance guarantees where possible.

Table 3

Wind Capacity Ownership by Public Power Systems

Utility	State	Project	Capacity Owned (MW)
Energy Northwest	WA	Nine Canyon	63.70
Nebraska Public Power District	NE	Ainsworth Wind	59.40
Nebraska Public Power District	NE	Springview	0.86
Total			60.26
Sacramento Municipal Utility District	CA	Solano Wind	13.20
Municipal Energy Agency of Nebraska	NE	MEAN Wind Project	10.50
Municipal Energy Agency of Nebraska	NE	Springview	0.07
Total			10.57
Southern Minnesota Municipal Power Agency	MN	Fairmont Wind	5.40
Southern Minnesota Municipal Power Agency	MN	Redwood Falls Wind	3.40
Total			8.80
Eugene Water & Electric Board	WY	Foote Creek I	8.78
Platte River Power Authority	WY	Medicine Bow	6.10

Table 3

Wind Capacity Ownership by Public Power Systems (cont.)			
Lamar	CO	Lamar Plant	4.50
Worthington Public Utilities	MN	Worthington	3.80
Wisconsin Public Power Inc	MN	Worthington	1.80
Lincoln Electric System	NE	Salt Valley	1.20
Lincoln Electric System	NE	Springview	0.41
Total			1.61
Arkansas River Power Authority	CO	Lamar Plant	1.50
Cedar Falls	IA	Iowa Distributed Wind Generation Project	1.50
Moorhead	MN	Wind Turbine	1.40
Algona	IA	Iowa Distributed Wind Generation Project	0.25
Montezuma	IA	Iowa Distributed Wind Generation Project	0.21
Estherville	IA	Iowa Distributed Wind Generation Project	0.18
Fonda	IA	Iowa Distributed Wind Generation Project	0.09
Ellsworth	IA	Iowa Distributed Wind Generation Project	0.05
Auburn	NE	Springview	0.03
Grand Island	NE	Springview	0.03
Westfield	IA	Iowa Distributed Wind Generation Project	0.02
KBR Rural Public Power District	NE	Springview	0.01
Grand Total			188.39

Source: Energy Information Administration (Dec. 31, 2005)

Russell Bryce provided valuable research for this report.

STANDARD
&POOR'S

RATINGSDIRECT®

October 11, 2005

Is Alternative Energy A Viable Alternative In The U.S.?

Primary Credit Analyst:
Terry A Pratt, New York (1) 212-438-2080; terry_pratt@standardandpoors.com

Table Of Contents

Is Alternative Energy A Viable Alternative In The U.S.?

Sky-high oil and gas prices may be creating the best environment yet for alternative energy companies. These have been--and for the most part, still are--small players whose markets enjoy less favorable economics than those of traditional energy producers. But the high price of fossil fuels, concerns over the environment, the need to diversify America's sources of energy, improved technologies, and the forces of corn-belt politics are combining to create the best investing environment ever for renewable power.

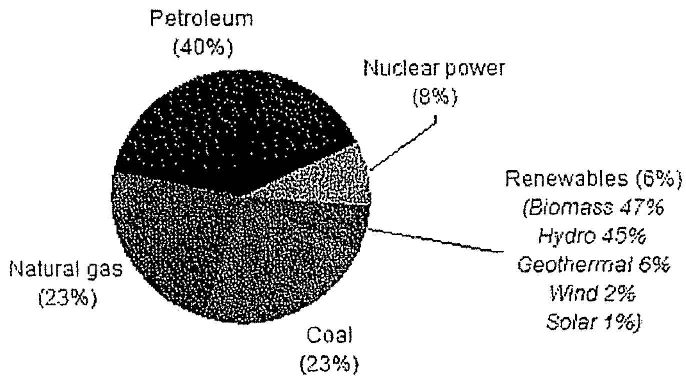
Over the years, Standard & Poor's Ratings Services has rated numerous such companies and projects--including wind, solar, geothermal, biomass, and hydropower--issuing credit scores that range from investment grade to highly speculative. In the current lending and oil price environment, any rating at all seems sufficient to secure financing. So we expect to see a higher volume of alternative energy ratings in the medium term, provided that regulators, politicians, and consumers continue to support such projects.

The Big Picture

Alternative energy is any power source that is not based on nuclear reactions or fossil fuels. A good example is electricity generated from wind, solar, geothermal, biomass, or hydro, though alternative fuels can also include ethanol from corn, biodiesel made from vegetable crops, and methane from human or animal waste. In 2004, such alternative sources accounted for about 6% of total U.S. energy consumption, a share that has been fairly stable for years. Chart 1 includes a breakdown of nonfossil fuels, as tracked by the U.S. Energy Information Administration (EIA).

Chart 1

U.S. Energy Consumption By Source

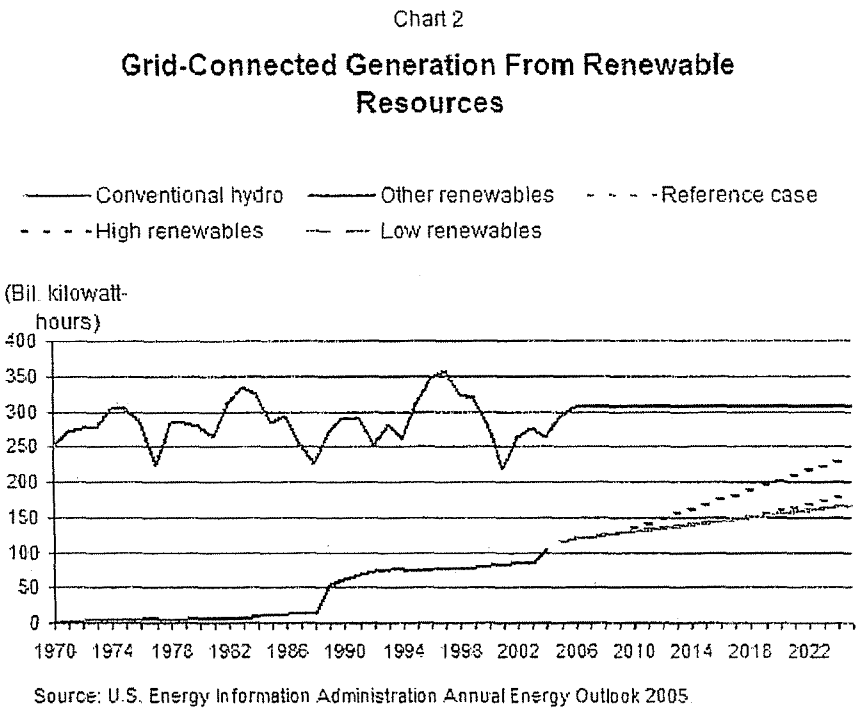


Source: U.S. Energy Information Administration Annual Energy Outlook 2005.

Alternative Electricity

When and if this percentage will grow depends on many variables, including government financial support, state and federal energy policy, and further technology improvements. In its Annual Energy Outlook 2005--issued before the most recent spikes in oil and natural gas prices--the EIA forecast several possible scenarios, as shown in Chart 2. In the most likely case, alternative power's contribution to electricity consumption over the next two decades will remain flat, implying that alternative electricity production would grow about 1.9% per year. However, it could rise faster if critical impediments melt away and robust regulatory support continues.

Chart 2



Growth requires relative efficiency improvements...

Alternative electricity has a small share nationally for many reasons. Generally, its plants cost more to build than oil- or gas-fired generators. In addition, technologies such as wind, solar thermal, and solar photovoltaics frequently operate at less than capacity because the wind does not always blow and the sun does not always shine.

Another problem is that good renewable resources may be far from customers, which increases transmission costs. Table 1 provides a summary of relative economics for different electricity generation options. A gas-fired combined-cycle (CC) plant has the lowest efficiency cost and solar thermal the highest, by a huge margin. This is why there are a lot of gas plants but little solar capacity. And because of their modest size, several alternative projects would have to be built to match the output of a single CC plant, although such calculations ignore the cost of fuel, which at recent prices erodes natural gas's advantage.

Table 1

Cost Characteristics Of Different Electricity Technologies

Technology	Overnight capital cost* ($/kW)	Typical capacity factor (%)	Ratio: cost to capacity factor	Project size limit
Combined cycle	569	96	593	Large
Landfill gas	1,475	90	1,639	Small
Biomass	1,731	83	2,086	Small
Geothermal	2,003	86	2,329	Medium
Wind	1,015	39	2,603	Medium
Photovolatic	3,961	24	16,504	Small
Solar thermal	2,625	15	17,500	Small

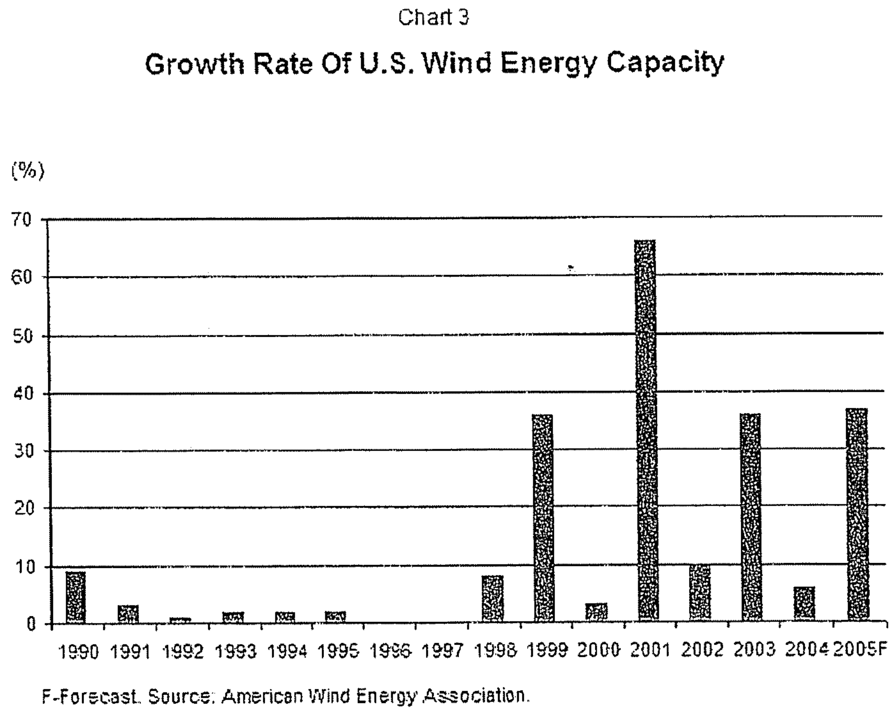
*In year 2003 dollars Source: Energy Information Administration Annual Energy Outlook 2005; Standard & Poor's.

...and continued subsidies

Federal subsidies remain the key to closing the gap, however. Currently, Section 45 of the U.S. tax code provides a 10-year, 1.9-cent (escalating) tax credit for each kilowatt-hour (kWh) produced by certain renewable projects that start up before Dec. 31, 2006. The credit applies to wind, biomass, small hydro, and geothermal projects, among others. The goal is to attract investment that will improve these technologies and make them more competitive.

This production tax credit (PTC) could provide 50% to 60% of a project's cash flow and help it secure long-term contracts by offering a below market price--sometimes below 2 cents/kWh--to prospective customers. One drawback of the PTC program is that it is designed to expire, after which Congress can extend it. This start-and-stop dynamic reduces long-term investment in the sector, as shown in chart 3, and explains the boom-or-bust cycle of the U.S. wind energy industry. One benefit of the program, however, is that the PTC does not depend on annual appropriations. This gives Standard & Poor's more confidence when determining a project's credit profile that it will have reliable cash flow.

Chart 3



Supportive environment for growth

Beyond that, many states have told the utilities they regulate to add electricity from renewable resources to improve reliability and cut emissions. Currently, 19 states have issued such mandates under what are usually termed Renewable Portfolio Standards (RPS), and more states are likely to do so soon. For example, New York adopted an RPS in September 2004 that requires the share of energy from renewable resources to reach 25% by 2013, up from 18% currently. In November 2004, Colorado became the first state to adopt an RPS program by referendum. It requires an increase in renewable production to 12% from 2% currently--and 4% must come from solar projects. Most RPS programs support a variety of technologies, except large hydro projects.

Meanwhile, better technology is reducing costs and making alternative energy more competitive. Wind power is a good example. A single wind turbine delivers about 5 MW of power today, compared with just 660 kW in 1995. In fact, large wind farms can now produce in excess of 300 MW of electricity, the same as a midsize power plant. This has helped make wind power the dominant choice for generating electricity from renewable resources (see table 1).

Many of the alternative energy projects to which Standard & Poor's has assigned ratings benefit from incentives of some kind. We assign investment-grade ratings to about $1.05 billion in bond debt issued for three wind project portfolios--FPL Energy American Wind LLC (BBB-/Stable/--), FPL Energy National Wind LLC (BBB-/Stable/--), and Max Two Ltd. (BBB-/Stable/--).

The incentives are necessary because wind projects usually get paid only for electricity they deliver, which can dwindle during periods of calm. This introduces the risk that cash flow might be insufficient to repay debt, an uncertainty that is heightened by the lack of long-term (20 years worth) of wind data at most sites. Wind projects with investment-grade ratings mitigate this risk to a large extent by pooling cash flow from a broad portfolio of projects that use different wind regimes and turbine technologies. Also, we rate to a scenario in which we have 90% confidence from year to year that the wind will blow with sufficient regularity.

The EIA also expects that geothermal capacity will rise substantially in the next two decades, and Standard & Poor's has rated several such projects. We currently have a speculative-grade rating on Salton Sea Funding Corp. (BB+/Positive), a portfolio of California geothermal projects totaling about 327 MW. Until recently, we assigned an investment-grade rating on the debt issued by Caithness Coso Funding Corp., which holds three projects with a total of 270 MW capacity. This debt has been repaid. Geothermal projects usually have a better credit profile than wind because they operate at a higher rate of capacity and often benefit from a better understanding of how the geologic resource will perform over time.

Solar power seems the least likely technology for meeting RPS goals because it is costly, but substantial investment is pouring into the sector, especially in California, where the sun shines often and the state's Self-Generation Incentive Program supports such projects. The Energy Policy Act of 2005 also provides substantial tax breaks for businesses and homeowners when they invest in solar equipment.

Although solar power projects often are small, they don't have to be. Standard & Poor's holds an investment-grade rating on one solar project, FPL Energy Caithness Funding Corp. (BBB-/Stable/--), which has two 80 MW solar thermal projects in California's Mohave Desert. A key feature of this project (other than robust financial performance) that enables it to achieve an investment-grade rating is a sales contract whose formula reduces the risk of lower-than-expected cash flows due to unfavorable solar conditions. A sign of the potential for solar power is the recent agreement between Southern California Edison Co. (BBB+/Stable/A-2) and Stirling Energy Systems Inc. to build a 500 MW solar facility that will be financed on the back of a 20-year sales agreement.

Investment potential for alternative electricity

It is difficult to estimate the potential of alternative energy, but early data suggests that it could be large. The American Wind Energy Association estimates that developers will install 2,500 MW of U.S. wind power in 2005 thanks in part to the PTC program. We estimate that this activity will involve an investment of at least $3 billion in 2005 alone. Activity in 2006 and 2007 should also be robust, but thereafter investment will depend on retaining the PTC.

The total investment in renewable power also will depend on which technologies win out. We have assessed the annual capital spending for alternative projects in New York necessary to meet that state's new RPS goal by 2013. The results, shown in table 2, indicate that different technologies could lead to very different investment levels. In its outlook for renewable electricity, the EIA forecasts that some technologies will fare better than others over the next two decades (see chart 4). Solar will grow quickly, from a miniscule base, but developers are most likely to select wind, biomass, and geothermal technologies to meet growing demand.

Table 2

Annual Investment By Technology To Meet New York RPS Goal

Technology	Annual investment (mil. $)
Combined cycle	98
Landfill gas	280

Table 2

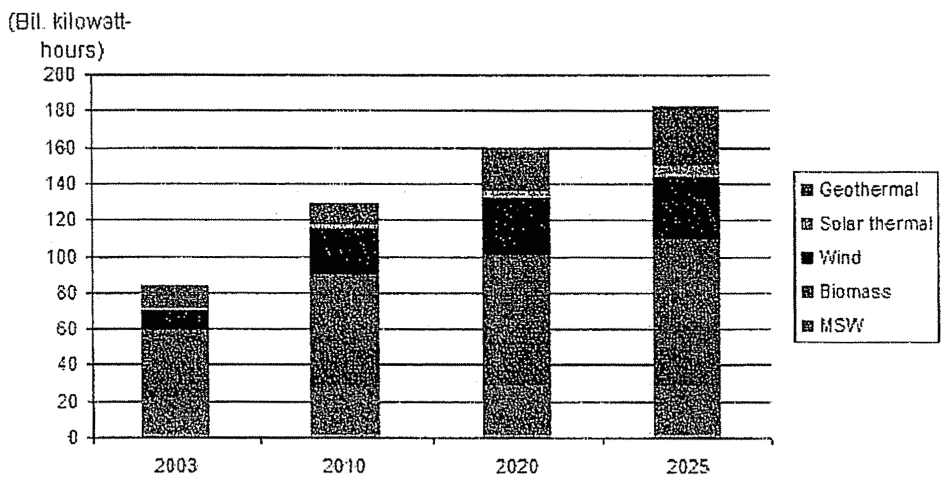
Annual Investment By Technology To Meet New York RPS Goal (cont.)	
Biomass	357
Geothermal	398
Wind	469
Solar photovolatic	2,823
Solar thermal	2,994

Source: Standard & Poor's. RPS--Renewable portfolio standards

Chart 4

Chart 4

Nonhydroelectric Renewable Electricity Generation By Energy Source 2003-2025



Source: Energy Information Administration Annual Energy Outlook 2005. MSW--Municipal solid waste.

Alternative Fuels

Of the alternative fuels, ethanol has attracted the most attention. It has strong political support, and the Energy Policy Act of 2005 provided additional incentives to produce this corn-based fuel. Ethanol output rose to 3.5 billion gallons in 2004 from 1.6 billion gallons in 2000 as producers sought to provide a lower cost oxygenate for gasoline and pocket a federal production subsidy of about 51 cents per gallon. The 2005 energy act mandates the use of 7.5 billion gallons of renewable fuel by 2012, most of which will be ethanol.

As of September 2005, according to the Renewable Fuels Association, there were 91 U.S. ethanol plants in operation, 20 under construction, and three major expansions under way. This trend is further supported by a favorable financing climate that has enabled ethanol developers to tap into bank and bond markets to secure construction funds despite high credit risk. Standard & Poor's has rated $465 million in debt at three projects--Aventine Renewable Energy Holdings Inc. (B-/Stable/--), Hawkeye Renewables LLC (B/Stable/--), and Nordic Biofuels of Ravenna LLC (B/Stable/--)--and expects to see much more rating activity in the near term.

We view the creditworthiness of these projects and the ethanol business as highly speculative for many reasons, but technology, construction, and operations are not among them. There is margin risk, given the lack of correlation between corn feedstock prices and ethanol prices, which could lead to a default under a scenario where corn prices are high and ethanol prices are low. Also, many facilities use natural gas to produce ethanol, which also increases margin risk. In addition, the sector's rapid expansion could easily lead to overproduction and depressed ethanol prices. Finally, without the federal subsidy, many ethanol projects would fail. This is troublesome from a credit perspective because corn politics may not remain as favorable they are today. However, despite this high credit risk profile, these projects remain able to attract medium-term financing from both bank and capital markets.

Investment potential

Future investment in alternative fuels remains hard to predict. But an assessment of the ethanol industry's potential suggests that volumes will be significant. Based on the debt-to-production ratio of recently rated ethanol transactions, the additional 4 billion gallons of ethanol production required by the energy act could translate into $5 billion or so in total lending to the industry for new plant by 2012.

Can anything go wrong?

The boost alternative fuels are enjoying will decline when oil and gas prices moderate, which history says they will at some point. The growth of renewable power also depends heavily on the PTC, which expires at the end of 2007 and will not be extended automatically.

Many in the industry note the need to become less dependent on the PTC, but a counter argument is that a permanent subsidy would greatly increase long-term investment in the sector and help it stand on its own. The PTC is also important to state RPS programs because it enables utilities to buy renewable energy at lower cost. Without the PTC, the state mandates could increase the cost of electricity to consumers, many of whom are already being hammered by high electricity and gas prices. While consumers in many parts of the country have shown a willingness to pay extra to support green energy programs, a significant rise in green costs could sour their appetite. This could place RPS programs at risk and deflate a major driver for alternative energy.

Some alternative electricity technologies could also be sidelined by faster development of sources such as clean coal technology, nuclear energy, and hydrogen. Many large investor-owned utilities are opting for clean coal and nuclear, and many clean coal plants are already in development.

The outlook for renewable power would improve greatly if the U.S. or states adopted policies to reduce carbon emissions because of global warming. The Bush Administration has shown little interest in this. But Europe illustrates what could happen if that changed. The EU recently adopted the Emissions Trading Directive in part to reduce carbon emissions from generating plants and meet its compliance requirements under the Kyoto Treaty, which combats global warming. This program will result in high compliance costs for traditional fossil fuel plants--and make renewable power more competitive.

The outlook for alternative fuels--especially ethanol--appears more straightforward. The worst thing that could happen to the ethanol industry would be for corn to lose its political pizzazz. Without the 51-cent federal subsidy, ethanol production would plummet.

For now, that sums up the future of alternative energy: It is prospering, but not without a helping hand.

The McGraw-Hill Companies

STANDARD
&POOR'S

RATINGSDIRECT®

May 11, 2007

The Cost Of Potential Climate Change Laws And Its Effect On U.S. Utility Credit

Primary Credit Analysts:
Daniel Welt, New York (1) 212-438-6344; daniel_welt@standardandpoors.com
Swami Venkataraman, CFA, San Francisco (1) 415-371-5071; swami_venkataraman@standardandpoors.com
Ralph A DeCesare, CFA, New York (1) 212-438-4682; ralph_decesare@standardandpoors.com

Secondary Credit Analyst:
Grace D Drinker, New York (1) 212-438-7458; grace_drinker@standardandpoors.com

Contributors:
Steve Piper, Boulder, Col. (1) 720-548-5627; Steve_Piper@platts.com
Robert Whaley, Boulder, Col. (1) 720-548-5512; Robert_Whaley@platts.com

Table Of Contents

The Cost Of Potential Climate Change Laws And Its Effect On U.S. Utility Credit

In evaluating the effect that federal climate change regulations will have on the power sector, Standard & Poor's Ratings Services' main concern will be the credit implications for the industry. It's premature to make rating changes before any federal legislation takes shape; however, the economic cost of compliance will be a key consideration in our analysis. For regulated utilities the most important credit factor will be the extent to which regulators allow cost recovery. For unregulated power generators, which have more exposure to market pricing, the actual cost of compliance will be a major credit influence. In the absence of climate change legislation, Standard & Poor's analysis will focus on what drives the cost of compliance. Those factors will include:

- Climate change legislation itself,
- The details of a cap-and-trade system or other mechanisms used to curtail carbon emissions,
- The characteristics of the power markets in which companies operate, and
- The nature of each company's generation portfolio.

Measuring the impact of the last two factors is key for credit and the focus of this article.

Methodology Employed

By using a dispatch model licensed from EPIS by Platts, which, (like Standard & Poor's, is a unit of The McGraw-Hill Cos.), we were able to identify aspects of the power markets that we expect will drive compliance costs. To us, this is more important than any cost estimates that the model determines because the details of legislation almost certainly will differ from initial assumptions and may change over time. Rather than focus on the nominal cost of compliance, we've concentrated our analysis on the change in EBITDA that a power plant (or portfolio of plants) earns under a base case with no carbon controls and under a second case where emissions restrictions serve as a proxy for the total cost of compliance.

Some generators have rates that regulators set, others are unregulated but sell electricity under contract, and yet others are "merchant" generators that sell power on the open market. Analytically, we ignore these specific details and assume that all assets get market prices for power in both the base case and the climate legislation case. The change in EBITDA from the base case represents the economic costs to generators. For our analysis we've ignored any contracts or regulatory mechanisms that mitigate those costs because we view the gains from these as temporary.

To calculate equilibrium power prices, we made assumptions for demand growth, gas prices, and the costs of building new generation. The model employs a supply curve formed by the marginal costs of existing generators and "dispatches" all units (i.e., causes them to generate power) as market prices dictate.

We dispatched all regions of the U.S. under a base case and two greenhouse gas (GHG) scenarios, each modeled after one piece of pending Senate legislation--the Carper/Feinstein bill (GHG1), and the somewhat more stringent Boxer/Sanders bill (GHG2). We chose these two proposals because they represent a range of options, from less to more GHG mitigation, and are relatively compatible to the modeling exercise. For instance, the latter scenario proposes long-term stabilization of GHG levels at 450 to 550 parts per million of carbon dioxide (CO_2) equivalent.

Our analysis goes out to 2026 under each scenario.

We calculated the change in EBITDA in two ways: the change for the portfolio of 10 large power companies we chose for our scenarios and the change in EBITDA for generic coal, gas, and nuclear units in all U.S. regions. While the former will provide an estimate of the impact on existing generating portfolios of large companies and how one technology's strengths may offset another's weakness, the latter method can gauge the effect on virtually any company.

We made assumptions on load growth, energy efficiency, gas price response, renewable portfolio standards set forth by some states, availability of offsets, and the economic build-out of nuclear-, coal-, and gas-fired power plants. (See Appendix below for a detailed list of assumptions used in the modeling.) In brief, we assume that any GHG scenario fully meets all current state renewable portfolio mandates and that new nuclear units would be built only in the Midwest, Southeast, or Texas, and we capped total nuclear MWs at 25% of currently proposed projects listed on the Nuclear Energy Institute Web site. (1)

Carbon Credit Prices Drive The Analysis

For each of the GHG scenarios, the price of carbon credits drives the reduction in emissions. We used the model to determine the prices at which the proposed targets were met. Charts 1 and 2 show these prices and the resulting emissions.

Chart 1

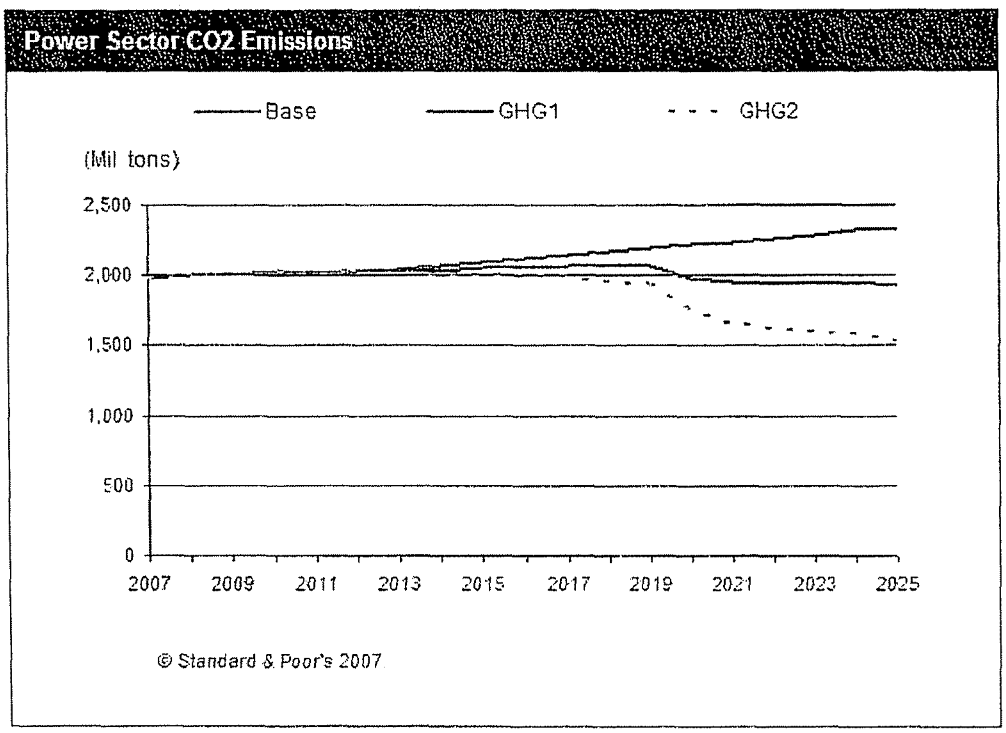
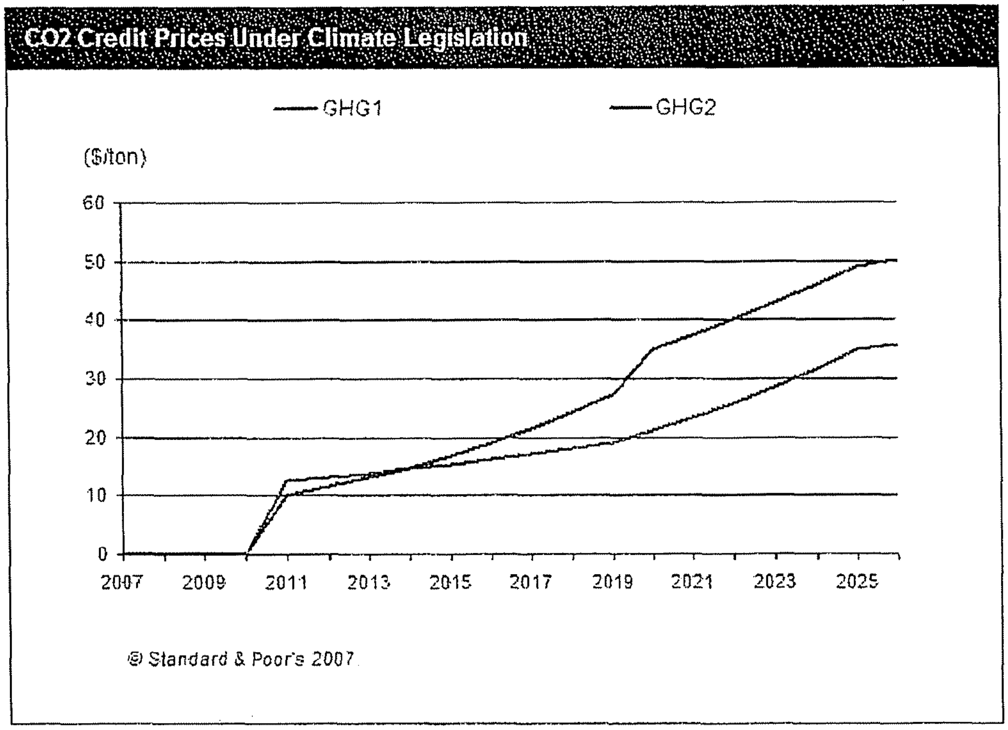


Chart 2



GHG1 likely won't require carbon capture and sequestration (CCS) and, under it, energy efficiency, renewables, offsets, and fuel-switching will be enough to meet the required emissions reduction. In fact, under GHG1, absolute utility emissions of GHG in 2026 remain roughly the same as in 2007.

At the carbon credit prices envisioned under GHG1, Platts estimates that 200 million tons of offsets could be available and contribute to emission reductions. Offsets represent credits for emissions reductions outside the U.S. financed by U.S. companies. Without them there would be higher carbon credit prices and--to the extent meeting the emissions targets without the benefit of offset would require more fuel switching from coal- to gas-fired generation--higher demand for natural gas. Because in our GHG1 scenario offsets account for almost all emissions reduction, our results are very sensitive to our assumption that offsets would be allowed. Were they not allowed, carbon credit prices would likely be materially higher. Also, in this scenario, carbon credit prices aren't high enough to justify building integrated gasification combined-cycle (IGCC) units based on the economic merits alone, although regulatory mandates and specific scenarios such as an IGCC plant established inside a refinery with lower operating and construction costs could lead companies to build IGCC.

Achieving the emission reductions targeted under GHG2 requires CCS, and carbon credit prices will have to rise to levels that would support it. This would include the cost of building a CO2 pipeline network, as well as storage and monitoring costs. The higher prices in chart 2 reflect this. However, to the extent that technology advancements lower CCS's overall costs, carbon credit prices could be lower.

Changes In Power Sector Fuel Mix

The three scenarios show the ways that generators' fuel mix could change by 2026, with coal use exhibiting the biggest decline. Table 1 shows the share of electricity produced by various fuel sources in 2007 and 2026 under each of the scenarios.

Table 1

Fuel Mix Changes

	2007	2026		
(%)		Base	GHG1	GHG2
Coal	51	46	37	30
Gas	16	28	25	25
Nuclear	19	15	17	18
Water	8	6	6	6
Wind	1	1	6	6
IGCC	0	0	0	3
Geothermal	1	0	0	0
Other (mostly biomass, landfill gas, wood, fuel cells)	2	3	3	3
Residual oil	3	0	0	0
Energy efficiency	0	0	5	8

The first observation concerns the effect that energy efficiency has on demand for power. It represents the amount by which consumption from the grid is lower in 2026 under GHG legislation compared with the base case 2026 consumption. Thus, energy efficiency represents a 0.35% reduction in annual demand growth in GHG1 and 0.6% under GHG2. While slowing electricity demand growth may have only modest effects in any given year, cumulatively it can have a large impact on demand for power. Based on historical econometric regressions, Platts estimates that about 25% of this reduction represents a price elasticity response, with the remainder attributable to proactive energy efficiency. While we didn't break out assumptions concerning distributed generation, rooftop solar, etc., these would be incorporated into the model just as an efficiency gain would be: as a reduction in demand from the grid.

Under either scenario, renewable energy's contribution (excluding hydro) grows from about 4% of all energy in 2007 to about 10% in 2026. This occurs because of existing state renewable portfolio standards rather than based purely on economics, which explains why the outcome is the same in both scenarios. Our assumed gas prices decline from current levels according to the forward curve, and this tends to make gas more competitive with wind. If gas prices increased instead, utilities could build more wind generators for narrow economic reasons. They might also build more renewables for regulatory or public relations considerations that our model doesn't capture, and our recent survey of utilities suggests that there may in fact be more interest in wind than our model would indicate.

In either case, a tremendous decline in coal-fired power occurs, with about a 6% decline in absolute megawatt-hours (MWh) under GHG1 and about a 16% decline under GHG2 from 2007 levels. This is the result of fuel-switching and retiring old units. Coal generation is actually flat to moderately rising until around 2020, when GHG1 and GHG2 would require significant reductions in emissions. This suggests that any legislation that provides for a fairly long initial period of modest emission abatement (perhaps to allow for R&D and to allow an international regime to develop) will provide significant cushion for coal-based generation owners to adjust.

Nuclear would have grown much more substantially in our scenarios if not for our restriction on the number of new nuclear plants that utilities might build. IGCC with CCS could contribute 3% of the nation's energy by 2026 under legislation such as GHG2 and more if IGCC technology advances and costs decline. Economically, IGCC, nuclear, and gas-fired plants are the key competitors to supply base load generation. We expect that utilities will add as much new nuclear capacity as regulators will allow because this option is economically attractive. The split between IGCC and natural gas will depend mainly on advances in IGCC technology and the price response of natural gas to the increased demand. We assumed gas prices are 5% higher than the base case in GHG1 and 10% higher in GHG2. However, if gas prices rise further, carbon credit prices would be higher and utilities would be likely to build more IGCC. Also, the margins of existing traditional coal plants would benefit because power prices would rise along with gas prices.

Results For Large Power Generators

We examined the change in EBITDA for the current generation portfolio of 10 large power companies. We're not naming the companies because the results are also applicable to other companies with similar portfolios, and it's not our intent to single out the particular companies analyzed. Table 2 shows the ratio of 2026 EBITDA to the 2007 EBITDA (both nominal dollars) under each of the three scenarios for the 10 companies. We've divided the results into three groups: fossil-heavy portfolios, diversified portfolios, and carbon-light portfolios.

Table 2

Ratio Of 2007 To 2026 EBITDA

(%)	Base	GHG1	GHG2
Fossil-heavy portfolios			
Company 1	208	97	79
Company 2	201	102	91
Company 3	293	117	80
Company 4	173	103	94
Diversified portfolios			
Company 5	255	184	181
Company 6	166	115	115
Company 7	259	199	200
Carbon-light portfolios			
Company 8	190	206	238
Company 9	173	171	184
Company 10	402	259	249

Not surprisingly, carbon-light portfolios (those heavy in nuclear, hydro, and renewables), benefit the most from carbon legislation--the more stringent the legislation, the better for such portfolios. The question here really is whether these companies will be required to pass benefits on to their customers or if they will be able to keep some of the benefits for themselves. Nevertheless, climate change legislation should, at worst, be neutral to their credit quality. These are the only companies that will be better off with climate change legislation.

Company 10 stands out in this sample. Although not strictly "carbon-light," its gas-heavy portfolio will likely benefit from fuel-switching and clearly performs better than its fossil-heavy counterparts. This is because we expect gas-fired generation in general to grow significantly even in our base case (see table 1), and the growth of Company 10's EBITDA is the greatest because it has the most gas-heavy portfolio among the sample. Gas-fired generation benefits in our analysis in part because we restrict the number of new nuclear plants to reflect permitting and siting constraints.

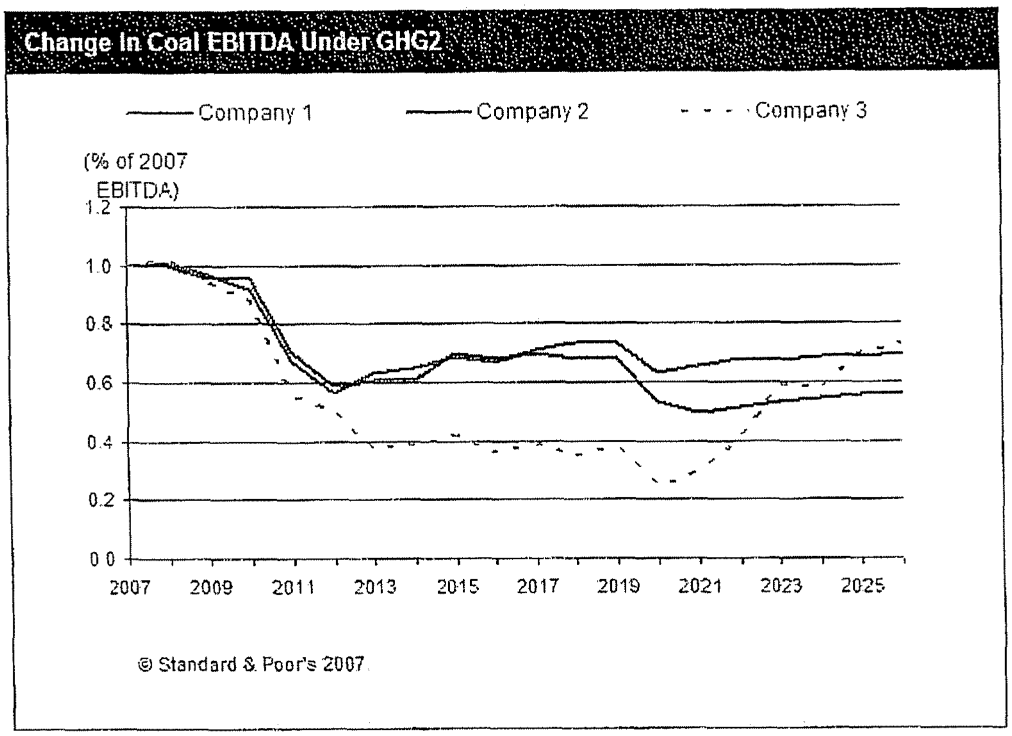
Fossil-heavy portfolios clearly suffer the most. Their EBITDA is basically flat 20 years from now and even 10% to 20% lower under GHG2. Such companies face three areas of concern:

- The lack of growth in EBITDA (in nominal dollars) will be a concern for investor-owned utilities,
- Even maintaining this EBITDA will likely require significant ongoing capital spending not captured by our modeling, and
- A flat-to-declining nominal EBITDA means that existing assets contribute almost no cash flow toward meeting future load growth, implying greater reliance on external financing.

The credit impact here clearly depends on how regulatory mechanisms allow these companies to recoup costs. In our calculations, these companies benefit from the power price increases resulting from higher gas prices, but lose out due to the cost of carbon credits. If these credits are assigned free of cost, as in Europe in the past two years, fossil-heavy portfolios may actually do better than without carbon legislation because they will continue to benefit from higher power prices while being reimbursed for the costs. However, such assignment will likely not last over the long term if emission reductions are to be achieved.

Company 2 illustrates that one can't generalize based simply on a company's portfolio but rather must examine the entire picture, even in a carbon-constrained world. Chart 3 compares the performance of the coal portfolios of Companies 1, 2, and 3 under GHG2 (GHG1 is similar).

Chart 3



Company 3's coal-fired plants suffer more than those of Companies 1 and 2 in the initial years. However, they come back strongly in the later years of both scenarios to finish better than the others, with 2026 EBITDA under GHG1 (not shown) greater than its 2007 EBITDA. This is counterintuitive if you consider that Company 3 has a much greater carbon intensity (tons/MWh) than the other two and should be expected to suffer the most. But a large exposure to the Western Electricity Coordinating Council (WECC) region--where competition from other coal-fired plants is limited, coal supply costs are very low, and there's no competition from new nuclear plants--offsets the cost of carbon intensity. Company 3 would benefit from margin expansion in the outer years if, as the scenario assumes, gas prices rise. It also appears that Company 3's presence in both the eastern and western interconnection allows it to benefit from higher prices in each region at various times.

Diversified portfolios are perhaps the most interesting. They do suffer under climate legislation, but much less so than the fossil-heavy portfolios. In fact, perhaps the most interesting aspect about diversified portfolios revealed by table 2 is that these companies may be indifferent to either GHG1 or a scenario such as GHG2. The change in their EBITDA is virtually the same in both cases. The gains in the carbon-light part of the portfolio compensate for the losses of the fossil-heavy parts. As shown in table 3, these companies also undergo the greatest transformation in terms of the fuel that contributes to cash flow, and thus in terms of the operational issues that are key to credit quality. When assessing the business risk posed by the fuel composition of a generating portfolio, it's critical to consider the potential for a diversified portfolio to significantly shift the portion of its EBITDA that comes from "at-risk" fuel sources. As table 3 shows, diversified generators that are mostly coal-driven today become nuclear- or gas-driven under the more stringent GHG2.

Table 3

Fuel Share Of EBITDA Under GHG2 – Diversified Portfolios

	Company 5		Company 6		Company 7	
(%)	2007	2026	2007	2026	2007	2026
Coal	59	20	52	20	46	21
Nuclear	36	50	34	36	38	50
Gas	1	21	13	42	0	6
Other	4	8	2	2	16	24

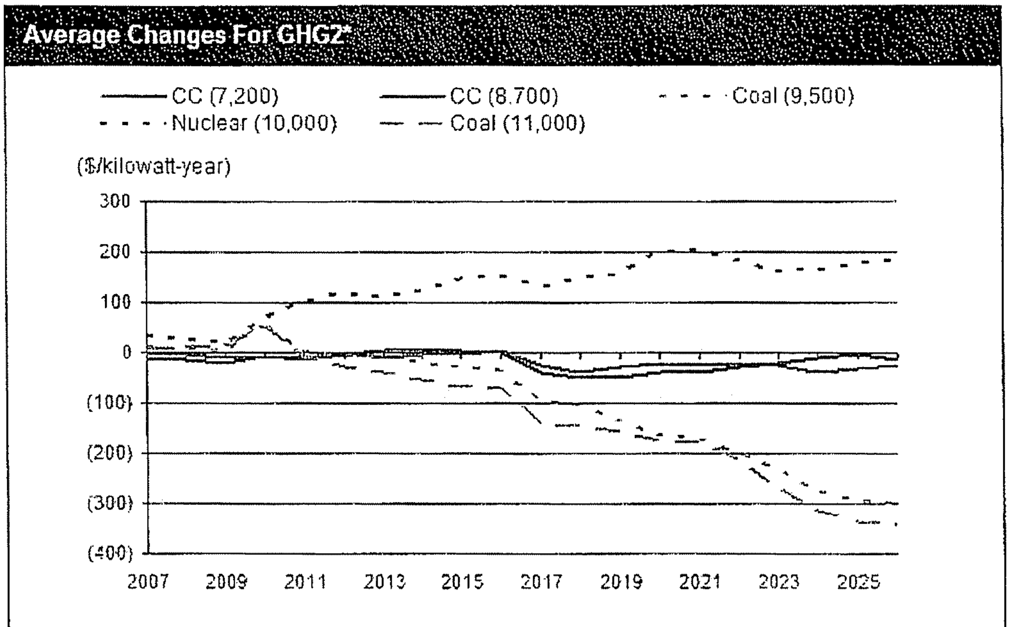
Analysis Of Generic Power Plants

To address more specifically the effects of various carbon-cost scenarios on generators, we created generic units in each of the areas in Platts' dispatch model, using the same assumptions we used for our analysis of utility generating portfolio economics. We created 10 MW units (i.e., small enough not to affect prices) with the following general characteristics and average variable operations and emissions costs:

- 7,200 heat rate (a measure of plant fuel usage--the inverse of efficiency--BTU/kilowatt (kW)-year) combined-cycle gas,
- 8,700 heat rate combined-cycle gas,
- 11,400 heat rate gas turbine,
- 10,000 heat rate nuclear,
- 9,500 heat rate coal, and
- 11,000 heat rate coal.

Across all zones, chart 4 presents the average results for all generic units for GHG2 minus the base.

Chart 4



*Minus base case. CC-Combined cycle. Note: The numbers in the legend refer to heat rate (heat rate = BTU/kilowatt-hour)

© Standard & Poor's 2007.

The general trend isn't particularly surprising: nuclear generation does better, gas is roughly neutral, and coal fares worse. And coal EBITDA doesn't drop dramatically until the price of carbon has had time to increase. But this average outcome hides very different outcomes by area. Conceptually, one would expect effects on unit EBITDA to be a function of the marginal fuel in a market, since the marginal cost of the fuel on the margin sets the power price. Emissions costs will directly increase these marginal costs. But power prices during hours when gas is on the margin (i.e., when the plant that is just efficient enough to produce power at the market clearing price is gas-fired) will reflect the carbon cost of gas (roughly 40% to 45% the cost of carbon emissions for coal), so while costs for coal plants will reflect 100% of their emissions costs, price increases will only reflect 40% to 45% of those costs. On the other hand, hours with coal on the margin pass through 100% of the cost for a unit that is as efficient as the marginal unit. Therefore, whether a coal plant receives closer to 40% or to 100% of its cost increase in the form of a price increase will depend on the number of hours gas is on the margin in its market and the number of hours coal is on the margin. Similarly, power prices in gas-driven markets will reflect much more of the demand-driven increase in gas prices, which increases the marginal costs of gas-fired generators but not of coal-fired generators. This can partly offset the higher carbon tax for coal units. Whether coal-fired generators are better off in markets dominated by gas or by coal would depend on which of these drivers dominates, though given our gas price sensitivity assumptions, the carbon price effect is likely to dominate.

Further complicating this conceptual framework is the transformation in market structure. Table 4 shows the time on the margin by fuel type under the GHG2 scenario in 2026. Coal replaces natural gas as the marginal fuel in many hours under GHG2 as gas displaces less-efficient coal: Across the markets listed in table 4, gas combined cycles are on the margin an average of 48.5% of hours under GHG2 (versus 56.8% in the base case), and coal is on the margin 34.1% of hours, versus 21.1%. As the marginal fuel changes as a result of carbon emissions prices, power prices alone don't change--market structure changes. This means that factors such as volatility and the correlation between power prices and other commodity prices also shift, and these shifts could increase or alter credit risk. For instance, in markets like Southeastern Electric Reliability Council-South, coal and gas virtually share the margin in 2026 under GHG2. The likely result will be increased EBITDA volatility and increased error in forecast EBITDA for generators, since relatively small changes in fuel prices can have large impacts on dispatch (as the marginal fuel shifts back and forth). This would increase credit risk for noncontracted plants (i.e., those that receive market prices as opposed to fixed contractual prices).

Table 4

Hours On The Margin Under GHG2 Scenario--2026

(%)

Geographic zone	Coal	Gas CC	Gas CT	Gas ST	Nuclear	Oil	Other
ERCOT-North	15.6	66.4	1.1	17	0	0	0
FRCC	8.8	69.4	6.5	4.5	0	10.8	0
ISO-NE-Boston	27.3	64.4	3.7	0.1	0	3.1	1.4
ISO-NE-North Ex-Boston	7.4	67	3.1	0.7	4.3	4.4	13.1
ISO-NE-Norwalk+SW CT	4.3	87.1	0.8	0	0	5.8	2
NYISO East	14.4	64.6	1.9	0.9	0	2.1	16.2
NYISO Zone J (NYC)	0	14.8	32.8	22.2	0	30.1	0
RFC-AEP	80.3	15.2	3.2	0.9	0	0	0.3
RFC-Cinergy	74.4	20.5	4.1	0.3	0	0.6	0.1
PJM-East	64.3	29.9	2.7	1.1	0.4	1.8	0.1
PJM-West	74	21.2	2.9	0.7	0	0.9	0.3
SERC-Entergy	14.2	78.2	3.6	3.3	0	0.1	0
SERC-South	51.1	43.2	4.5	1.1	0	0.2	0
SERC-TVA	74.6	20.6	3.9	0	0	0.7	0.2
NP-15	7.4	62.3	1.1	6.2	0	0	23.1
SP-15	10.9	60.5	0.3	7.9	0	0	20.3
WECC-Wyoming	51.3	39.7	8.9	0	0	0.1	0

CC--Combined-cycle. CT--Combustion turbine. ST--Steam turbine.

Table 5 shows changes in EBITDA in 2026 (in $ per kW-year) under GHG2. As expected, the percentage of time gas is on the margin in 2007 is negatively correlated to changes in EBITDA for 9,500 and 11,000 BTU per kilowatt-hour (kWh) coal plants (roughly minus 65% correlated). To a lesser extent, the percentage of time coal is on the margin correlates to the change in EBITDA in marginal (8,700 BTU/kWh) gas combined cycle (minus 40% correlated), 11,000 BTU/kWh coal (47.5%), and 9,500 BTU/kWh coal (35%). Nonetheless, other correlations are weak, and regressions show that fuel on the margin in 2007 and 2026 doesn't adequately explain changes in EBITDA.

Table 5

Change In 2026 EBITDA In GHG2 Versus Base Case

($/kilowatt-year)

Geographic zone	CC (7,200)	CC (8,700)	Coal (11,000)	Coal (9,500)	CT (11,400)	Nuclear (10,000)
ERCOT-North	(39 66)	(23.39)	(315.27)	(315.97)	(1.61)	76.34
FRCC	(43.61)	(30.7)	(310.1)	(315.83)	(12.29)	74 93
NPCC-isoNE-MassachusettsBoston	10.27	3.62	(305 98)	(269.79)	0 36	122 12
NPCC-isoNE-ConnecticutSouthwest	13 32	4.53	(311 14)	(262.57)	0.39	129 03
NPCC-isoNE-MassachusettsWest	(1.7)	4.07	(259.19)	(243 48)	0 22	136.22
NPCC-NYiso-F-Capital	(3.49)	(0.61)	(226 21)	(234.93)	0 17	141.86
NPCC-NYiso-J-NYC	(10.43)	(2.52)	(338.23)	(284.41)	(1.89)	104.48
RFC-AEP	(26.54)	(14.9)	(289 85)	(270.06)	(2.95)	122.79
RFC-PJME	(36.07)	(16.28)	(303.96)	(317.19)	(3 72)	67.11
RFC-Cinergy	(26.06)	(14.77)	(279.85)	(265.09)	(2.9)	126.51
RFC-PJMW	(25.74)	(13.76)	(263 04)	(281.27)	(2.16)	101.9
SERC-Entergy	(26 68)	(16.39)	(287.12)	(285.07)	(3.96)	110.8
SERC-TVA	(23.57)	(19.32)	(304.13)	(264 9)	(5.04)	126.07
SERC-South	(16.67)	(16.83)	(281 54)	(264.21)	(3.24)	128.82
WECC-CA-PG&E-North+	(30.34)	(1.75)	(367 39)	(343)	0	32 4
WECC-CA-SCE+	(12.64)	(1 62)	(348.82)	(300 71)	0.03	89.96
WECC-Wyoming	(15.71)	(3.16)	(341 72)	(304.13)	(0.09)	87.79
Average	(20.18)	(10 07)	(303 44)	(286.12)	(2.13)	102 09
Minimum	(43.61)	(30.7)	(367.39)	(343)	(12.29)	32.4
Maximum	13.32	4 53	(226.21)	(234.93)	0 39	141.86

CC-Combined-cycle. CT—Combustion turbine. Note: Note: The numbers in the column headings refer to heat rate (heat rate = BTU/kilowatt-hour).

When you look at the minimum and maximum value rows in table 5, material differences between markets emerge. Gas units on the West Coast and in the Northeast can even benefit under this scenario, though most see losses relative to the base case. These negative effects are significantly smaller than those of coal plants. Nonetheless, as coal becomes more marginal, a greater percentage of the carbon cost passes through to the power price, which keeps many coal plants in service, albeit during hours when they are earning less. The decrease in EBITDA for inefficient coal plants (11,000 BTU/kWh) is roughly the same as the decrease for more efficient units (9,500 BTU/kWh). However, this implies that the absolute value of the EBITDA for inefficient units will be close to zero. In fact, these units' capacity factors are in the single digits in most markets in the country and never exceed 20%.

Summing Up

While regulation and contracts will heavily influence actual changes in utility EBITDA, even before we know what potential carbon legislation will look like it is clear that the fuel mix of the generation portfolio and market structure (including changes in that structure that result from any carbon restrictions) will drive the economic costs of complying with GHG legislation. Before changing utility credit ratings, we will likely wait for greater clarity on the allocation of these costs between ratepayers, lenders, utility owners, and taxpayers, but estimating the costs under various scenarios gives us a preliminary sense of the potential risks.

Appendix: Key Definitions And Assumptions

We've calculated costs (or change in EBITDA) in two ways:

- For the portfolios of 10 large power generators, both regulated and unregulated, including those that may benefit from GHG legislation as well.
- For generic coal, gas, and nuclear machines for all the different power markets in the U.S. We believe the results of the "generics analysis" can then be applied to any company's fleet of assets.

We performed these calculations by dispatching all the markets in the U.S. using a model that Platts licenses from EPIS.

In the analysis of large generators, we assume that the portfolios remain static over time, i.e., while utilities will certainly build new power plants, we don't know which ones the 10 companies in question will build. Hence, we limit ourselves to measuring the impact on the companies' existing portfolio of assets.

Thus, the actual EBITDA (or change in EBITDA) for the companies will differ from our results on account of the following factors:

- Companies will build new assets.
- The bottom line impact will vary depending on whether these companies have carbon credits assigned to them and whether regulators pass costs through to customers. However, we believe that it will be useful to measure the impact on existing assets because it will indicate the costs that need to be recovered either through regulation or through an assignment of credits.

Our results extend only through 2026. During this period, the dispatch model builds new generation based on economics to meet demand, subject to restrictions on renewables and nuclear power outlined below, while also forcing the power sector to achieve its share of the emission reductions that each legislative act would require.

We assumed an equity hurdle rate of 15% and a cost of debt of 8.5%. Federal loan guarantees would potentially affect the cost of debt.

Other important assumptions include:

- The model incorporates demand-driven gas price increases in the two GHG cases beginning in 2011 compared with the base case--5% under GHG1 and 10% under GHG2.
- Demand growth assumption of 1.4% per year.
- Energy efficiency assumption.
- Renewables assumption: We assume all existing state renewable portfolio standards are only 50% satisfied in the base case and 100% satisfied in the two GHG scenarios.
- Nuclear assumption: No new nuclear units can be built in the WECC or in the Northeast. Nuclear units in other regions are limited in number to 25% of all currently proposed units. We have also modeled two different nuclear scenarios--one that assumes significant retirement of existing nuclear units in the 2020-2025 period and one that assumes no retirement. GHG1 and GHG2 assume no retirements.
- Capital costs assumptions: Capital costs for various new technologies are generally consistent with our assumptions in the article titled " Which Power Generation Technologies Will Take The Lead In Response To

Carbon Controls? ," published May 11, 2007 on RatingsDirect.

- Availability of offsets: 200 million tons under GHG1 and 770 million tons (including international offsets) in GHG2.

We've determined carbon credit prices using a model that is independent of the power dispatch model, which incorporates emission reduction requirements under GHG1 and GHG2, Platts' estimates availability of offsets, gas prices, and other options such as CCS.

Note

(1) http://www.nei.org/documents/2007%20Wall%20Street%20Brief_Slides&Script_03%2008.pdf

Click on this link to see other articles in "Special Report: The Credit Impact Of Climate Change."

Click on this link to go to the Special Report Archive.

STANDARD
&POOR'S

RATINGSDIRECT®

May 9, 2007

Public Power Explores Ways To Reduce Emissions As Federal Regulation Looms On The Horizon

Primary Credit Analyst:
Jeffrey Panger, New York (1) 212-438-2076; jeff_panger@standardandpoors.com

Secondary Credit Analysts:
Peter V Murphy, New York (1) 212-438-2065; peter_murphy@standardandpoors.com
Theodore Chapman, Dallas (1) 214-871-1401; theodore_chapman@standardandpoors.com

Table Of Contents

Public Power Explores Ways To Reduce Emissions As Federal Regulation Looms On The Horizon

As the debate over global warming escalates, the combination of public opinion and scientific findings may prompt the U.S. Congress to address greenhouse gas emissions in some form, building on steps already taken by several states.

The primary focus will likely be on reducing carbon dioxide (CO_2) emissions from the nation's power plants. Public power utilities are examining a range of methods to reduce emissions in anticipation of such legislation. Although the cost of reducing emissions is uncertain, it will probably be substantial. Therefore, remediation will likely represent a significant operational and financial challenge to the public power industry, and to ratepayers who will ultimately bear some of the costs.

Standard & Poor's Ratings Services remains concerned that CO_2 legislation may impose a new paradigm on the industry in general, and certain utilities in particular, especially those with significant carbon footprints, by rendering some generating units uneconomic and some utilities uncompetitive. We have begun to assess public power utilities' exposure to the potential new regulation in light of their operational and financial profiles, and we are focusing on management's efforts to evaluate the range of remedial options.

Surveying The Largest U.S. Public Power Utilities

To seek their views on the prospects for, and the form of potential legislation, Standard & Poor's conducted a survey of the nation's largest public power utilities. The survey sought to determine the industry's degree of reliance on coal-fired generation, the emission reduction strategies it is examining, and the potential costs associated with legislation and/or mitigation strategies.

We have yet to factor into ratings the costs of addressing potential regulation because of the ongoing uncertainties. First and foremost is that Congress has not yet enacted legislation. Thus, it's unclear how much reduction the law will require, when it would take effect, and whether it would mandate specific means. Second, utilities can take a wide range of remedial actions to curb emissions, each with varying operational and financial impacts. Third, developing technologies that control CO_2 emissions is just beginning, and carbon capture and sequestration (CCS), which many believe holds great promise, doesn't yet exist commercially, although it may be viable by the time reduction legislation takes effect.

In some ways, public power utilities are well positioned to address global warming. They will likely have an easier time of passing costs on to ratepayers than other utilities, which must apply for approval for the costs to be included in their rate bases. The ability to issue tax-exempt debt will also reduce remediation costs. Given its core value of serving customers (versus a focus on building rate base and investor returns), public power is probably better positioned to achieve conservation and other demand side reductions.

However, public power isn't as well positioned in other ways. It hasn't been at the forefront in adopting unproven capital-intensive technology. Since public power is tax exempt, it is more difficult to qualify for tax incentives that promote renewables or other CO2 reduction programs that may be adopted by the federal government.

Exploring Possible Strategies

In any event, many public utilities are acting in anticipation of potential legislation. For some, this has meant accelerating coal fired generation projects in an attempt to get them in under the wire of new mandates. However, this approach may not succeed given the possibility that new laws could apply retroactively. Others are pursuing operating efficiencies to drive down fuel usage or increase electric output. Some are exploring green power sources that don't emit carbon dioxide, and even nuclear energy is back on the table, though public utilities are less inclined than others to go that route. Some utilities are considering integrated gasification combined cycle (IGCC) technology for new generation, while others are looking at new environmental systems that, although they don't directly reduce carbon emissions, may be adaptable for future carbon capture and sequestration.

The majority, however, are currently only studying their options and taking a wait-and-see approach. Should the federal government adopt a cap-and-trade (C&T) program, establishing a market driven process for buying and selling emission allowances to reduce CO2 emissions, it's likely that the bulk of these utilities will more actively pursue CO2 mitigation options until market equilibrium is reached and investment in new technologies becomes economical.

It's clear from the survey responses that utilities expect to adopt a variety of measures to reduce CO2 output and drive down the need to purchase expensive emission allowances if a C&T program is adopted. No single strategy appears to offer the potential to reduce emissions to levels new federal regulations are likely to mandate. Therefore, these utilities are exploring a combination of strategies:

- Operating efficiencies;
- Conservation/demand-side management;
- Fuel switching;
- Investment in renewable energy, including wind power, hydropower, solar, and biomass; and
- Investment in clean coal technologies, including IGCC and CCS.

Each of these strategies present technological, operational, and financial hurdles. Ultimately, the associated costs will determine the nature of the strategies utilities will pursue.

The Search For Operating Efficiencies

Virtually all surveyed utilities are examining some form of energy efficiency program, largely because it makes good business sense. Creating operating efficiencies not only leads to a reduction in CO2, it can fit in nicely with a utility's overall business strategy.

In general, the potential for CO2 reduction from operating efficiency directly correlates to the scale and cost of the approach adopted. Low cost actions can run the gamut and are achievable in relatively short order. Higher cost actions require greater lead times but can produce more substantial emission reduction. They include building new generating units with lower heat rates (and greater fuel efficiency) and retiring older, less efficient units.

Today's generation of subcritical pulverized coal units are far more efficient than older units, and the efficiency is substantially greater for supercritical units. A number of public power utilities are building, or participating in, new generating facilities. These include:

- JEA , Tallahassee , Reedy Creek , and Florida Municipal Power Agency , which are partnering in the Taylor Energy Center, an 800 MW supercritical pulverized coal/petcoke blend facility, in northern Florida;
- Indiana Municipal Power Agency (IMPA) and Illinois Municipal Electric Agency (IMEA), which are both purchasing ownership shares in Trimble County Unit #2, and Prairie State Energy Campus coal projects;
- Wisconsin Public Power Inc. (WPPI) which is participating in Wisconsin Energy's Elm Road Generating Station;
- City Utilities of Springfield, Mo. , which is building Southwest Power Station unit #2, a 275 MW sub-critical pulverized coal unit; and
- City Water, Light and Power (CWLP) of Springfield, Ill., which is building Dallman 4, a 200MW coal unit, enabling the retirement of existing inefficient units.

Investment in renewable energy and other zero emission options

Often referred to as "green power", renewable energy includes hydropower, wind, and photovoltaic, better known as solar power. As is also the case with nuclear energy, renewables produce no greenhouse gases.

Most survey respondents are pursuing some form of renewable energy but with significant limitations. Of the renewable energy sources, hydropower offers the greatest potential for scale and reasonably certain availability, although some variability is inherent resulting from water flows. However, given the costs and constraints associated with long-range transmission, as well as other environmental, political and operational hurdles, only a few utilities are able to develop hydropower.

Wind energy is moderately expensive, generally small in scale (though larger projects exist), and has poor capacity factors due to variability in wind speeds. Biomass projects have greater (but limited) scale, reliability, and capacity factors than wind but often uncertain fuel supply. Photovoltaic is prohibitively expensive and small in scale, but more reliable than wind.

Twenty-three states have adopted some form of Renewable Portfolio Standard (RPS), the bulk of which call for renewable energy to supply between 10% and 20% of installed capacity. The implementation dates to achieve these standards range from 2010 to 2025. In three states, participation in the RPS is strictly voluntary. In most of the participating states, the RPS only applies to investor-owned utilities, although in some states, participation is voluntary for public power utilities. The RPS is mandatory for all public power utilities in only five states: Maryland, New Jersey, Texas, Vermont, and Wisconsin. In two others, Colorado and Washington, the standard only applies to medium to larger-size utilities.

U.S. State Renewable Initiatives

State	Renewable Portfolio Standard (% of total installed capacity)	Implementation Date	Other Requirements	Public Power Required to Participate?
Arizona	15%	2025	N/A	No
California	20%	2010	N/A	Only at their own direction
Colorado	10% target for munis, co-ops	2020	20% by 2020 for IOU's	Yes for those with more than 40,000 customers
Connecticut	10%	2010	N/A	Voluntary
Washington, D.C.	11%	2022	N/A	Not applicable
Delaware	10%	2019	N/A	No, unless the utility is already open to retail choice

U.S. State Renewable Initiatives (cont.)

Hawaii	20%	2020	Voluntary	Voluntary
Illinois	8%	2013	Voluntary	Voluntary
Massachusetts	4%	2009	+1% per year thereafter	No
Maryland	7.5%	2019		Yes
Maine	30%	2030		No
Minnesota	25%	2025	Xcel 30% by 2020. All voluntary	Voluntary
Montana	15%	2015	N/A	No, but sector is encouraged to take similar actions
New Jersey	22.5%	2021	N/A	Yes (public power in the state is limited)
New Mexico	10% for munis, co-ops	2020	20% by 2020 for IOU's	Co-ops only
Nevada	20%	2015	N/A	No
New York	24%	2013	N/A	No, but sector is encouraged to take similar actions
Pennsylvania	18%	2020	N/A	Voluntary
Rhode Island	15%	2020	N/A	Yes (public power in the state is limited)
Texas	5,880 MW	2015	N/A	Yes
Vermont	Renewable energy must equal annual load growth	2012	N/A	Yes
Washington	15%	2020	No credit for existing hydro	Yes, for those with more than 25,000 customers
Wisconsin	10%	2015	N/A	Yes

Source: Database of State Incentives for Renewables & Efficiency. N/A - Not applicable

Despite the fact that California municipals aren't compelled to adopt the state standard, the Los Angeles Department of Water and Power (LADWP) is planning to meet 20% of retail sales with renewables by 2010. Wisconsin Public Power Inc., through several purchased power agreements, expects to comply with Wisconsin's standard by 2009, six year's in advance of the state's 2015 RPS deadline.

Conservation/demand-side management

Conservation or demand-side management works as a corollary to operating efficiencies. It's based on the premise that a MWH not demanded is a MWH that doesn't need to be produced. While conservation is cost effective, it can only produce a limited reduction in greenhouse gases. Conservation's greatest potential exists when it enables a utility to change its dispatch patterns from a baseload coal unit to another unit powered by a more environmentally friendly fuel. Several survey respondents are exploring establishing or expanding existing demand side management programs, but only as a small part of a broader effort to address CO2 emissions.

Fuel switching

Several of the utilities surveyed believed that the only way to achieve meaningful reductions in CO2 emissions was by switching from a reliance on coal to less-carbon intensive fuels, such as natural gas or oil. In addition, although such a strategy would achieve reduction in a carbon-constrained world, it would require retrofitting existing units or constructing new units. Both are very costly from a fixed capital cost perspective and, relative to coal, the variable commodity costs for gas and oil are substantially higher and subject to historic volatility. However, should the cost of compliance with future CO2 regulations change this dynamic, fuel switching might make sense for some utilities.

For the first time in more than 30 years, utilities are beginning to discuss nuclear power as a means of reducing both greenhouse gases and reliance on foreign energy. However, the capital costs associated with nuclear power are significant, and the long lead-time necessary to finance, permit, build and place a nuclear plant in service makes this a poor short-term solution for emissions reduction. Standard & Poor's doesn't believe that a new nuclear facility will be put into service any sooner that 2015. Nevertheless, certain public power utilities are exploring partnering for new projects on existing sites, while others hope to gain capacity from up-rates (capacity improvements) on existing projects.

Investment in clean coal technologies

While fuel switching offers the greatest near-term promise for CO2 emission reduction, clean coal technologies offer perhaps the greatest long-term potential.

Integrated gasification combined cycle (IGCC) generators create, from coal, a synthetic gas that is used to run a turbine. To date, IGCCs have proven effective at reducing SO2 and NOx emissions. However, technological glitches still exist and the units are very costly, and as such, require subsidization to make their power cost competitive. Only a few of these units are in operation in the U.S. The Orlando Utilities Commission (OUC), in a project partnership with the Southern Company and the U.S. Department of Energy, is likely to become the first public power entity to use this technology when it's placed into service in 2010.

As the technology improves and the costs come down, it's likely that IGCCs will gain more acceptance. This is because IGCC's offer greater potential for carbon capture and virtual elimination of CO2 than do conventional pulverized coal units.

Carbon capture and sequestration (CCS) doesn't yet exist on a commercial scale, and if and when it does, it will presumably add costs. As with IGCCs, utilities will likely need additional subsidies to fund development of the technologies. However, retrofitting existing pulverized coal units with carbon capture and sequestration technology would significantly reduce the efficiency and capacity of existing generation units, and will likely require additional expense to replace the lost power. Further complicating the issue is disposal of the captured carbon. Sequestration, or the injection of the CO2 into deep underground (or underwater) cavities requires the availability of geological formations not readily available to all utilities.

Recognizing these near-term limitations, only a few survey respondents are actively exploring CCS as a means of reducing CO2 emissions.

Carbon Reduction Comes At A Price

Survey participants unanimously believe that federal regulation is inevitable and will likely be costly. All utilities participating in our survey are in the process of measuring CO2 emissions and most have projected future emissions levels. On average, survey respondents expect their CO2 emissions to increase 8% to 16% between 2005 and 2015. A notable exception to this pattern is Springfield, Ill.'s City Water, Light and Power (CWLP), which has developed a unique emission reduction strategy (see Springfield, Ill. section). However, CWLP is the exception, and utilities that are adding new generation without an offsetting reduction from retiring units expect growth that's more substantial.

Many survey respondents believe that based on the success of existing programs addressing other pollutants, a cap-and-trade (C&T) approach is likely, establishing a market driven process for buying and selling emission allowances. Others suggest that state measures, such as more widespread adoption of renewable portfolio standards, or regional C&T programs might precede ultimate federal action to establish a broader C&T, carbon taxation, or clean energy portfolio programs.

Standard & Poor's agrees that regulation is likely to impose significant costs on the power industry. The market price for allowances under a C&T program would depend on both the program's structure and the timeline for its implementation, including such details as the number and allocation of allowances, economic sectors covered, offsets allowed, and licensing, among other requirements. It would also depend on the existence of, and costs associated with, alternative means to reduce emissions -- including carbon capture and sequestration or other technology, demand side management, fuel switching, investment in renewables, and other efficiencies that increase electric output without increasing commensurate levels of fuel use. Conceptually, the allowance cost would need to be high enough to change operation and resource planning, but reasonable enough not to cause a significant shift away from the existing resource mix.

Because Congress hasn't adopted a federal mandate, estimated remediation costs are speculative. Due to the uncertainties, many respondents were unwilling to posit a cost of allowances under a hypothetical C&T program. However, some respondents are modeling their CO2 reduction strategies assuming a range of costs, from a minimum of $5/ton of CO2 emissions equivalent to roughly $5/MWH, to in excess of $50/ton. Other respondents cited studies suggesting the cost of power could more than double for the average utility.

Springfield, Ill.

Last November, Springfield, Ill.'s City Water, Light & Power (CWLP; 'A+') entered into an innovative agreement that enabled it to add generation to meet load growth, reduce CO2 emissions, and better position itself to meet potential regulation. The agreement also gained buy-in from the Sierra Club, whose opposition had threatened to cause serious delays and result in rapidly escalating construction costs.

The agreement with the Sierra Club enabled CWLP to begin constructing a 200 MW subcritical pulverized coal unit that would operate on high sulfur Illinois coal on a brown field site, a restricted use or development site, under a traditional engineering procurement and construction contract.

Under the settlement, the city agreed to:

- Lower CO2 emissions by purchasing 120 MW of wind capacity and retire inefficient Lakeside units (76 MW);
- Set aside $4.80 per ton of CO2 emissions associated with wholesale transactions (roughly $6 million to $8 million per year) in a special fund to finance customer efficiency programs and offset some costs of the wind energy; and
- Increase efficiency on Dallman units 1-3, thereby reducing greenhouse gas and other emissions.

The settlement requires the city to lower its carbon dioxide emissions to 7% below 1990 carbon dioxide emission levels by Dec. 31, 2012. Because of the agreement, CWLP estimates that its composite operating profile will eventually come close to meeting standards set in the Kyoto Protocol. Furthermore, CWLP officials estimate that the settlement cost the utility $23.6 million, but enabled it avoid $137 million in costs it would have incurred had the Dallman 4 project faced a delay of a year or more.

Springfield's settlement may spur other utilities to look into such agreements. In March 2007, Kansas City Power and Light (KCP&L), an investor-owned electric utility serving customers in Kansas and Missouri, entered a similar