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BEFORE THE
PUBLIC SERVICE COMMISSION OF MISSOURI

Joint Application of American Transmission Company of Illinois LLC and, For Authority to Construct and Operate a New 345 kV Transmission Line from Ottumwa to Adair to Palymra, Missouri	Docket No: EA-2015-0146

REBUTTAL TESTIMONY OF WILLIAM E. POWERS, P.E. ON BEHALF OF NEIGHBORS UNITED

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RESPONDENT'S EXHIBIT
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I. Introduction

Q. Mr. Powers, please state your name, position and business address.

A. William E. Powers, P.E., principal of Powers Engineering, 4452 Park Blvd., Suite 209, San Diego, California, 92116.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Neighbors United of Kirksville, Missouri.

Q. Mr. Powers, please summarize your educational background and recent work experience.

A. I am a consulting energy and environmental engineer with over 30 years of experience in the fields of power plant operations and environmental engineering. I have permitted numerous peaking gas turbine, microturbine, and engine cogeneration plants, and am involved in siting of distributed solar PV projects. I began my career converting Navy and Marine Corps shore installation power plants from oil-firing to domestic waste, including woodwaste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo. I wrote "San Diego Smart

Energy 2020" (2007) and "(San Francisco) Bay Area Smart Energy 2020" (2012). Both of these strategic energy plans prioritize energy efficiency, local solar power, and combined heat and power systems as a more cost-effective and efficient pathway to large reductions in greenhouse gas emissions from power generation compared to conventional utility procurement strategies. I have written articles on the strategic cost and reliability advantages of local solar over large-scale, remote, transmission-dependent renewable resources. I have a B.S. in mechanical engineering from Duke University, an M.P.H. in environmental sciences from the UNC – Chapel Hill, and am a registered professional engineer in California. My complete resume is provided as Exhibit PE-02.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to evaluate: 1) of the electricity demand of Ameren Missouri (MO) customers in Northeast MO, 2) the likelihood of wind projects moving forward in the Adair Wind Zone over the next decade, 3) solutions other than the proposed ATXI 345 kV transmission line to the modeled Category C North American Electric Reliability Corporation (NERC) violation on the existing 161 kV lines serving the project area, 3) the feasibility and cost of reconductoring with high capacity composite conductors the 161 kV line segment that would experience an overload if 450 to 500 MW of wind power was constructed in the Adair Wind Zone, and 4) the feasibility and cost-effectiveness of substituting local solar for wind power to allow Ameren MO to meet its 2021 Renewable Portfolio Standard (RPS) obligation without building the proposed ATXI 345 kV transmission line. My rebuttal testimony primarily responds to the testimony of David Kramer and to a lesser extent to the testimony of Todd Schatzki, Ph.D.

II. Summary and Conclusions

Q. What documents have you reviewed as part of your investigation?

A. The principal documents I have reviewed include: MTEP11 Report and MTEP14 Triennial Review, 2012 MVP Report, 2010 MISO Regional Generation Outlet Study, 2011 and 2014 Ameren MO Integrated Resource Plans (IRP), 2010 MISO Regional Generation Outlet Study, U.S. Department of Energy (DOE) evaluation of current and near-term solar costs, DOE evaluation of near-term wind power additions, and the May 29, 2015 opening testimony of ATXI witnesses Dennis D. Kramer and Todd Schatzki, Ph.D.

Q. Please summarize your findings and conclusions.

- There are few Ameren MO customers in the Northeast Missouri project area, less than 13,000, about 1 percent of the 1.2 million Ameren MO customer base.
- There is no peak load growth forecast by Ameren MO for its service territory over the 2015-2034 period.
- The NERC Category C contingency that AXTI asserts will be mitigated with the proposed $224 million project can be mitigated with planned and controlled load shedding at no cost to Ameren MO customers.
- ATXI's claim that the Category C event will occur too fast to permit controlled load shedding is unsupported by any evidence. The amount of load drop that ATXI assumed for the event is about five times higher than the peak load projected (by Powers Engineering) for the affected substation.
- Several alternatives to mitigate the contingency that would not require a new 345 kV line, such as voltage regulation, demand response, and the addition of local solar generation, were not studied by ATXI.

- The modeled overloading of the Adair-Novelty 161 kV line when 450 MW of wind power is assumed at the Adair Substation may be an error due to use of a line capacity assumption that is too low. In any case, the overload condition could be mitigated by reconductoring the Adair-Novelty 161 kV line, a length of 30 miles, with composite conductor to double the capacity of the line.
- TradeWinds Energy, Inc., a major regional wind power developer, terminated a proposed 300 MW wind project in the Adair Wind Zone in 2012, the Shuteye Creek project, after eight years of development effort, citing no interest on the part of utilities in the area in pursuing wind power projects as the principal reason for terminating the project.
- TradeWinds Energy, per MISO standard interconnection queue cost responsibility requirements, would have paid for all transmission upgrades necessary in the project area to make the wind power fully deliverable. The projected cost of the necessary transmission upgrades would be on the order of a maximum of 1 to 1. 5 percent of the estimated wind project capital cost.
- ATXI ignores the current economic competitiveness of solar power with wind power, and the better match of solar output with summer peak demand, it its economic analysis of the benefits of the proposed ATXI 345 kV line.
- There are viable and cost-effective alternatives to constructing the proposed ATXI 345 kV line that achieve the project objectives described in the ATXI CPCN application while avoiding the environmental impacts that may be caused by the project.

III. Legal Framework for the Proposed ATXI 345 kV Transmission Line

Q. What are the justifications that ATXI identifies for the proposed 345 kV transmission line?

A. The ATXI Certificate of Public Convenience and Necessity (CPCN) application provides the following justifications for the proposed project:[1]

"*There is a need for the transmission capacity to be provided by the Mark Twain Project, and the Project is in the public interest in that it will provide for the integration of wind energy in Missouri to increase the amount of electricity available from renewable resources, including wind energy that would be transported to aid Missouri public utilities in complying with Missouri's Renewable Energy Standard, section 393.1020, RSMo., et seq. The Project is also part of improvements to the regional transmission system under MISO's functional control and will improve the overall reliability of the regional transmission system and reduce transmission system congestion. The Project will provide the additional benefit of providing a remedy to several reliability issues which can result in unacceptable low voltage conditions in the Kirksville area.*"

Q. What is the basis for the assumption by ATXI that Ameren MO will contract for 400 MW to 500 MW of wind power in the Adair Wind Zone in Northeast Missouri?

A. The Ameren MO 2014 Integrated Resources Plan (IRP). The 2014 IRP states that Ameren MO will contract for 400 MW of new wind power and 45 MW of new solar power, along with hydropower and biomass resources, by 2021 to meet its 15 percent renewable portfolio standard (RPS) obligation in 2021.[2]

Q. What are the requirements of the Missouri RPS law?

A. The RPS applies only to the state's investor-owned utilities and does not place any requirements on municipal utilities or electric cooperatives. The RPS standard is 15

[1] ATXI Application for Certificate of Public Convenience and Necessity for 345,000-volt Electric Transmission Line, Application EA-2015-0146, p. 5.
[2] **Exhibit PE-03**, Ameren MO 2014 IRP webpage summary: https://www.ameren.com/missouri/environment/renewables/ameren-missouri-irp

percent by 2021 for electric utilities based on annual electricity sales. The RPS contains a solar electricity carve-out equal to 2 percent of the RPS requirement. Utilities with renewable energy obligations under the standard are required to offer a solar rebate program. Self-generated solar power is RPS-eligible. Utilities own the solar renewable energy certificates (SRECs) of any system that receives a rebate for a period of 10 years. In-state renewable energy generation receives a multiplier of 1.25 compared to out-of-state generation (i.e., in-state generation is worth 25 percent more for compliance purposes).[3]

Q. Can out-of-state RECs be used to comply with the RPS standard?

A. Yes. Compliance with the objective can be achieved through the procurement of renewable energy or renewable energy credits (RECs). Solar RECs, known as "SRECs," may be used to comply with the solar standard, or with the portion of the standard not specifically devoted to solar resources.

Q. Is the price of RECs from existing renewable generation sources consistently lower than the cost of contracts for new renewable generation, even in-state generation worth 25 percent more for RPS compliance purposes?

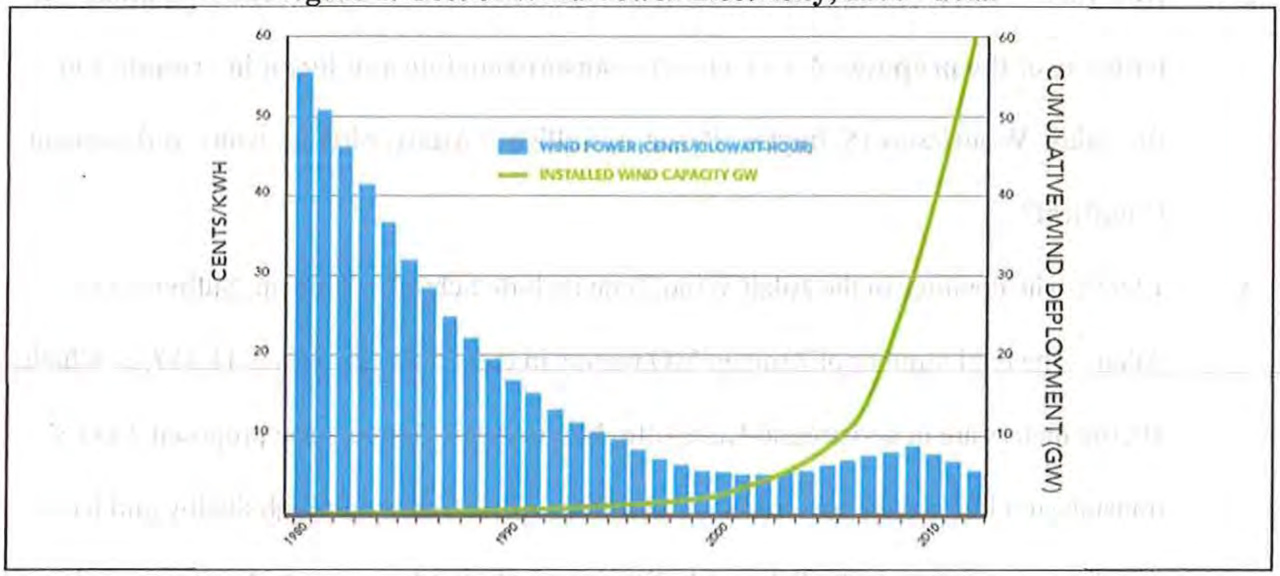
A. Yes. The average 2014-2015 cost of RECs in the Western U.S. was $16.55 per megawatt-hour ($/MWh).[4]

Q. What is a typical price range and the price trend for wind power, according to the Department of Energy?

A. The typical current price range of wind power is $50/MWh to $60/MWh, or $0.05 per kilowatt-hour (kWh) to $0.06/kWh, as shown in Figure 1. The price of wind power at the end of 2012 was almost unchanged from the price of wind power in 2000.

[3] Missouri Revised Statutes, Section 393.1030.1, August 28, 2014.
[4] **Exhibit PE-04**, 2014-2015 DOE survey of REC prices in Western U.S.

Figure 1. Cost of Wind Power Electricity, 1980 - 2012[5]



Q. Does the Missouri RPS law structurally favor lower-cost RECs from existing sources, primarily existing wind farms, at the expense of new renewable energy construction in Missouri or elsewhere?

A. Yes. There are no restrictions on the use of RECs to meet RPS targets in Missouri.

Q. Therefore, is new wind development of any kind by investor-owned utilities likely in Missouri absent some restrictions on the use of RECs to meet RPS obligations?

A. No.

IV. Ameren MO Has Very Few Customers in the Project Area and No Projected Peak Demand Growth

Q. How many customers does Ameren MO have?

A. Ameren MO has 1,190,821 customer meters.[6]

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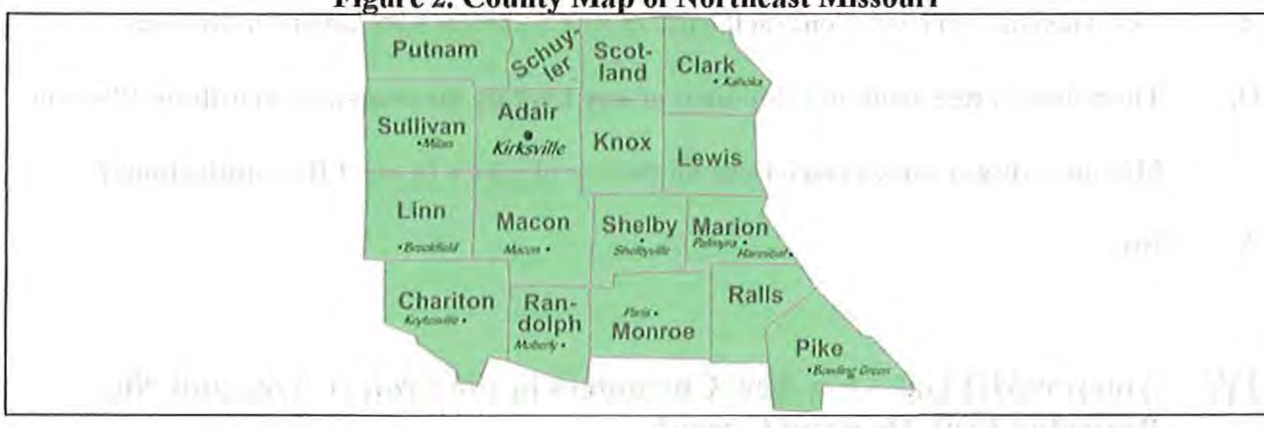
[5] **Exhibit PE-05**, U.S. DOE, *Revolution Now - The Future Arrives for Four Clean Energy Technologies*, September 17, 2013, p. 2.

[6] **Exhibit PE-06**, Ameren MO number of meters by county.

Q. How many Ameren MO meters are located in Northeast Missouri counties along the pathway of the proposed ATXI 345 kV transmission line and including counties in the Adair Wind Zone (Schuyler, Putnam, Sullivan, Adair, Shelby, Knox and Marion Counties)?

A. 12,946. The counties in the Adair Wind Zone include Schuyler, Putnam, Sullivan, and Adair. The total number of Ameren MO meters in these four counties is 11,557, of which 10,308 meters are in and around Kirksville, MO in Adair County. The proposed 345 kV transmission line would continue southeast from Adair County through Shelby and Knox counties, terminating at the Palmyra Substation in Marion County. Shelby, Knox, and Marion counties have 1,389 Ameren MO meters. A county map of Northeast Missouri is provided in Figure 2.

Figure 2. County Map of Northeast Missouri[7]



Q. The number of Ameren MO meters in Northeast Missouri counties along the pathway of the proposed ATXI 345 kV transmission line, and including the adjacent Adair Wind Zone, is about 1 percent of Ameren MO total number of meters?

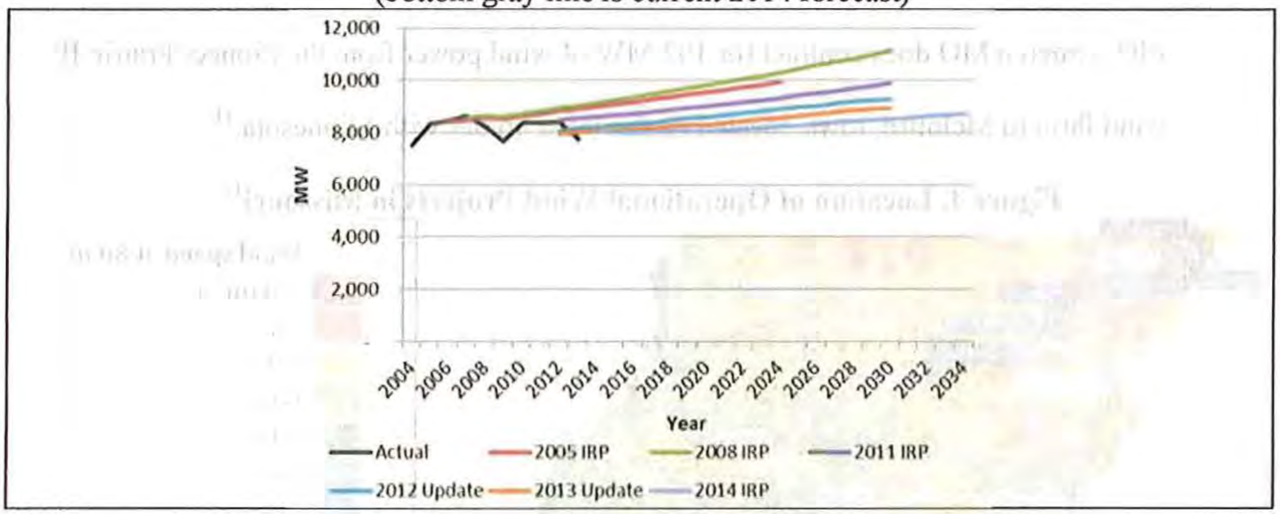
A. Yes.

[7] Source of NE Missouri county map: http://northeastmissourirealty.com/northeast-missouri-real-estate-maps-links/

Q. Does Ameren MO forecast any peak load growth through 2034?

A. No. The Ameren MO all-time actual peak load was 8,784 MW in 2007.[8] The Ameren MO peak load forecast included in the 2014 IRP does not return to the all-time actual peak load level until after 2034. This is shown in Figure 3. The current forecast is the gray line identified as "2014 IRP". Peak load is forecast to remain relatively constant at about 8,000 MW, 10 percent below the historic peak in 2007, until 2024.

Figure 3. Ameren MO Peak Load Growth Forecast Through 2034[9]
(bottom gray line is current 2014 forecast)



Q. Therefore the Northeast Missouri fraction of 2021 projected peak load should be about 1 percent of 8,000 MW, or about 80 MW, correct?

A. Yes.

Q. How much of this 80 MW regional load would be at the Adair Substation?

A. About 64 MW. About 80 percent of the Ameren MO customer meters in the project area, 10,308 of 12,946, are located in Adair County.

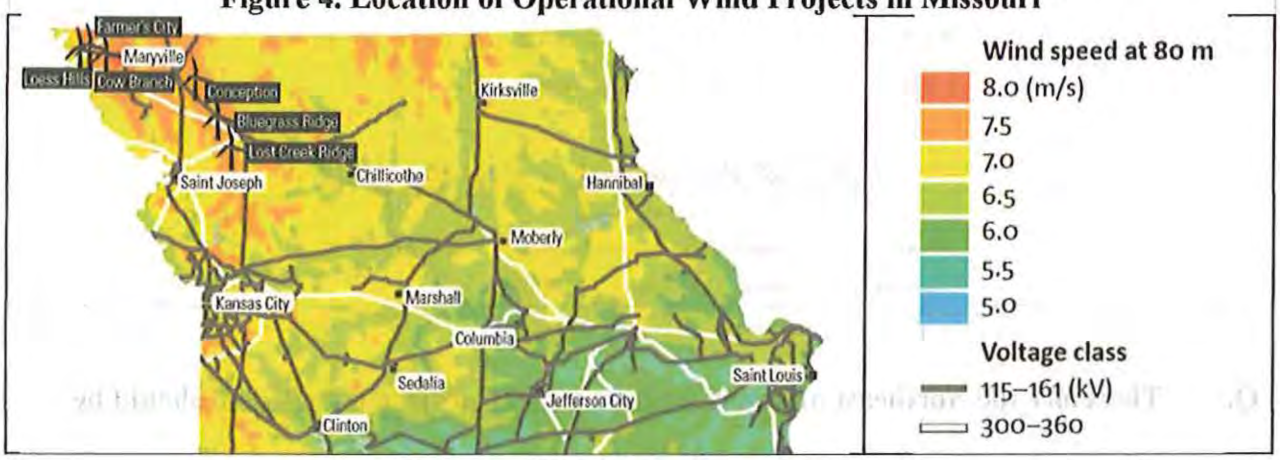
[8] **Exhibit PE-07**, Ameren MO 2014 IRP, Table 3-7, p. 51.
[9] Ibid, p. 6.

V. No Wind Projects Proposed in Northeast Missouri, that Have Completed the MISO Interconnection Study Process, Have Been Stalled by Lack of Transmission Capacity

Q. How much wind capacity is operational in Missouri and where is it located?

A. The six operational wind projects in Missouri, totaling 458 MW, are located in Northwest Missouri as shown in Figure 4. Approximately two-thirds of this wind power output is contracted to Missouri electric cooperatives, and one-third is supplied to MidAmerica Energy Corporation.[10] No wind power generated in Missouri is contracted to Ameren MO. Ameren MO does contract for 102 MW of wind power from the Pioneer Prairie II wind farm in McIntire, Iowa, located on the Iowa border with Minnesota.[11]

Figure 4. Location of Operational Wind Projects in Missouri[12]



Q. Has any wind developer completed the MISO interconnection study process for a project in Northeast Missouri?

A. Yes. The MISO interconnection study process was completed in 2007 for one project, TradeWind Energy's proposed 300 MW Shuteye Creek wind farm, that would connect with the Adair Substation.[13]

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[10] **Exhibit PE-08**, Missouri Partnership, *Missouri's Advantages for Wind Energy*, September 2014, p. 11.
[11] **Exhibit PE-09**, Ameren "Utility Scale Wind-Powered Electric Generation" webpage, October 19, 2015: https://www.ameren.com/missouri/environment/clean-energy/wind
[12] **Exhibit PE-08**, p. 11.

Q. Isn't it true under Missouri RPS accounting rules that in-state renewable energy generation is credited with a 25 percent multiplier, such that a 300 MW in-state wind project has the RPS value of 375 MW out-of-state wind project?

A. Yes.

Q. What were the results of the MISO interconnection study?

A. The result was that the project developer would need to pay for \$10.9 million in upgrades to the existing Associated Electric Cooperative Inc. (AECI) 161 kV transmission and 69 kV sub-transmission systems to make the project fully deliverable per MISO network resource interconnection requirements.[14]

Q. What percentage is \$10.9 million of the total cost of a 300 MW wind project?

A. The mean wind power capital cost identified in the MTEP14 Triennial Report Update is \$2.4 million per MW. Therefore, the capital cost of a 300 MW project would be: \$2.4 million/MW × 300 MW = \$720 million.

Q. So the \$10.9 million cost to upgrade the existing transmission system to make the wind power fully deliverable would be about 1.5 percent of the overall \$720 million cost, correct?

A. Yes.[15]

Q. Is it your opinion that a transmission system upgrade cost that is about 1.5 percent of the overall wind project capital cost would have little or no impact on the financial viability of the wind project?

A. Yes.

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[13] MISO Interconnection Queue, Missouri wind projects, October 19, 2015: https://www.misoenergy.org/PLANNING/GENERATORINTERCONNECTION/Pages/InterconnectionQueue.aspx.
[14] **Exhibit PE-10**, 2007 MISO interconnection study, 300 MW Shuteye Creek wind farm p. 4.
[15] \$10.9 million ÷ \$720 million = 0.015 (1.5 percent).

Q. Under MISO interconnection requirements the project developer is responsible for the interconnection costs to make the project fully deliverable, correct?

A. That is correct.[16]

Q. There would be no cost to the Ameren MO ratepayers, correct?

A. That is correct.

Q. The cost of the proposed ATXI 345 kV transmission line is $224 million, correct?

A. Yes.[17]

Q. Ameren MO customers will pay 8 percent of this $224 million, or approximately $18 million, whether or not any wind power is ever built in the Adair Wind Zone, correct?

A. Yes.[18]

Q. Was the Shuteye Creek wind project built?

A. No.

Q. Why not?

A. Lack of interest on the part of any Missouri utility to contract for the wind power. The CEO of TradeWind Energy, Inc. stated at the time the project was terminated in April 2012 that, "*TradeWind has invested millions of dollars to lease and develop the Shuteye project area, including funding transmission interconnection studies, collecting wind data, conducting environmental studies, and developing engineering plans. Unfortunately it has become increasingly evident that the wind energy market in Missouri will simply*

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[16] **Exhibit PE-10**, p. 4.
[17] ATXI J. Jontry opening testimony, May 29, 2015, p. 11, lines 10-11.
[18] ATXI M. Borkowski opening testimony, May 29, 2015, p. 6, lines 5-10. 0.08 × $224 million = $17.92 million.

not develop in the foreseeable future given the lack of interest in wind energy in the state."[19]

Q. Is it true that Ameren MO opted not to pursue a 300 MW wind project in the Adair Wind Zone, despite the fact that the project output would be fully deliverable via the existing 161 kV transmission system at no cost to Ameren MO customers?

A. Yes.

VI. The Existing Ameren MO and AECI 161 kV Transmission Lines Are Sufficient to Address Reliability Justifications for ATXI 345 kV Line

Q. What are the two reliability justifications offered by ATXI to construct the proposed 345 kV line?

A. The two reliability contingency conditions that ATXI states the proposed 345 kV transmission line would resolve are: 1) on-peak low voltage Category C NERC contingency at the Adair Substation if the two Ameren MO 161 kV lines go out-of-service at the same time with a 300 MV load on the substation, and 2) shoulder peak capacity violations if 450 MW of wind power is dispatched into the 161 kV transmission system at the Adair Substation.[20]

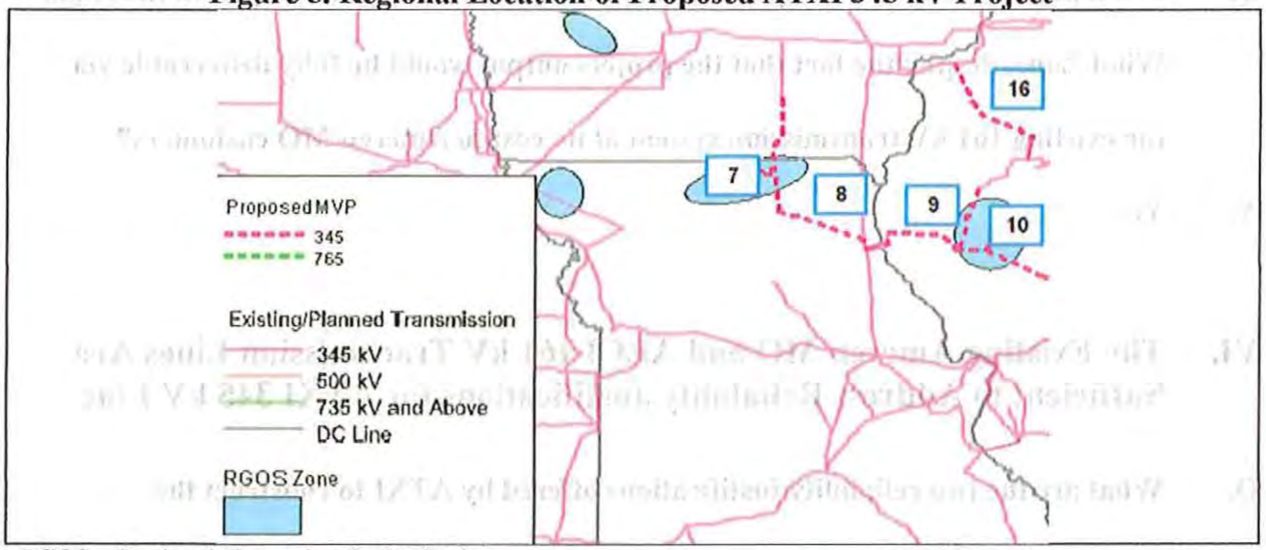
Q. Where is the proposed ATXI 345 kV project located?

A. A map showing the regional location of the proposed transmission project, as well as regional wind resources and nearby MVP transmission projects, is provided in Figure 5. The proposed ATXI 345 kV project under consideration by the Missouri PSC consists of the Missouri portion of MVP Project 7, and MVP Project 8. The Adair Wind

[19] **Exhibit PE-11**, KTVO.com, *Economic hopes blow away as wind farm falls through*, April 5, 2012.
[20] For the purposes of this testimony, "MVA" and "MV" are assumed to be equivalent.

Zone, with a projected potential of 450 to 500 MW of wind capacity, is shown in Figure 5 as a blue oval under the box containing the MVP project number "7".[21]

Figure 5. Regional Location of Proposed ATXI 345 kV Project[22]



RGOS = Regional Generation Outlet Study

Q. How many transmission lines currently serve the proposed project area in Northeast Missouri?

A. Three 161 kV lines, two owned by Ameren MO and one owned by AECI. All three transmission lines interconnect at the Adair Substation near Kirksville, MO. See Figure 6. The proposed pathway of the ATXI 345 kV line is also shown in Figure 6.

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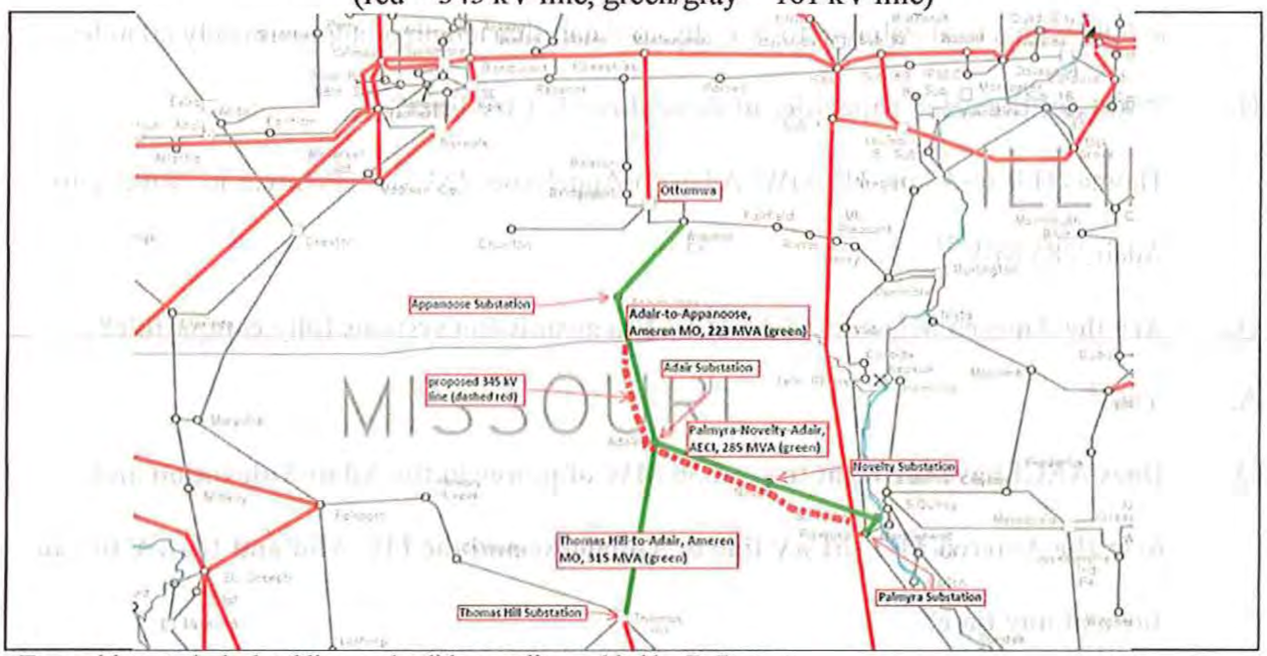
[21] MISO, *Multi Value Project Analysis Report*, Appendix B: Powerflow Modeling Approach, January 20, 2012, Table 20, p. 9. The Adair Wind Zone is also known as the "MO-C" wind zone.
[22] MTEP11 Report, Figure 4.1-11, p. 58.

Figure 6. Transmission Map of Northeast Missouri and Southeast Iowa[23]

(red = 345 kV line, green/gray = 161 kV line)



Tags with text, dashed red line, and solid green lines added by B. Powers

A. The Category C NERC Violation Modeled by ATXI Can Be Mitigated Without Constructing the Proposed 345 kV Line

Q. Who owns which 161 kV line interconnecting at the Adair Substation and how long are these lines?

A. Ameren MO owns and operates the Thomas Hill-to-Adair 161 kV line. This line has a length of 44 miles.[24] The Missouri portion of the Adair-to-Appaloose 161 kV line is also owned by Ameren MO. The Missouri portion of this line has a length of 41 miles.[25] ITC Midwest owns the extension of this 161 kV line on the Iowa side of the border to the Appaloose Substation.[26] AECI owns and operates the Palmyra-to-Novelty and

[23] **Exhibit PE-12**, ATXI DR-001 response, October 16, 2015.

[24] **Exhibit PE-13**, ATXI DR response NU-A10, October 10, 2015.

[25] Ibid.

[26] Ibid, ATXI DR response NU-A1, October 10, 2015.

Novelty-to-Adair 161 kV lines. Each of these AECI lines is approximately 30 miles in length, with a total Palmyra-to-Novelty-to-Adair line length of approximately 60 miles.

Q. What are the rated capacities of these three 161 kV lines?

A. Thomas Hill-to-Adair, 315 MW; Adair-to-Appaloose, 223 MW; Palmyra-to-Novelty-to-Adair, 285 MW.[27]

Q. Are the Ameren MO and AECI 161 kV transmission systems fully compatible?

A. Yes.[28]

Q. Does AECI have the right to send 50 MW of power to the Adair Substation and over the Ameren MO 161 kV line to Appaloose and the ITC Midland 161 kV line in Iowa at any time?

A. Yes.[29]

Q. Can AECI send more than 50 MW of power over the Ameren MO 161 kV line with Ameren MO authorization?

A. Yes.[30]

Q. Are Ameren MO and AECI obligated by their interchange agreement to assist to the extent possible in an emergency condition to protect the stability of their respective systems?

A. Yes. The interchange agreement states "*in case of an emergency or other unusual operating condition, the Party supplying the Delivery Point Service, as hereinafter described, may attempt to deliver power and energy in excess of the contractual amount*

[27] **Exhibit PE-13**, ATXI DR response NU-A1, October 10, 2015. Note that "MW" and "MVA" are used interchangeably in this rebuttal testimony.
[28] **Exhibit PE-14**, Ameren MO – AECI interconnection agreement, p. 6.
[29] Ibid, p. 25.
[30] Ibid, p. 25.

if it, in its sole judgment, has additional transmission capacity available at that time."[31]

Q. What does this mean in common language?

A. This means that, for example, if Ameren MO were to lose both of its 161 kV line connections to the Adair Substation at the same time for any reason while serving a 50 MW on-peak load in the Kirksville area, AECI would immediately serve that 50 MW load if it had sufficient available capacity on its Palmyra-to-Adair 161 kV line.

Q. What percentage of AECI peak system load does 50 MW represent?

A. About 1 percent. The historic AECI summer system peak load was 4,400 MW in 2011.[32] The historic winter peak load was 4,600 MW in 2014.[33] Both summer and winter peak loads were less than 4,000 MW in 2013.[34] AECI projects the summer and winter peaks will be at about 4,600 MW in 2020.[35]

Q. Is the AECI system be able to adjust to an instantaneous load increase equal to 1 percent of system load without compromising the reliability of the AECI transmission system, assuming a 64 MW load is suddenly placed on the AECI system at the Adair Substation?

A. Yes. AECI must maintain voltage within a range, meaning some level of supply and demand imbalance is permissible, and also maintain a certain amount of spinning reserve, meaning generation sources that are online and immediately available to supply power, to assure the AECI grid can adjust to out-of-balance conditions between supply

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[31] Ibid, p. 4.
[32] **Exhibit PE-15**, AECI overview PowerPoint to Missouri PSC, January 2014, p. 6.
[33] Ibid, p. 6.
[34] Ibid, p. 6.
[35] Ibid, p. 6.

and demand while staying within its post-contingency voltage deviation limits and voltage response requirements.

Q. What load does ATXI assume must be dropped at the Adair Substation in the event of loss of both Ameren MO 161 kV transmission lines interconnecting at the Adair Substation, described as a NERC Category C contingency by ATXI?

A. 300 MVA (300 MW).[36]

Q. Is the magnitude of this assumed load drop credible in light of the number of Ameren MO customers being served by the Adair Substation?

A. No. 300 MW is nearly five times higher than the actual Ameren MO peak load on the Adair Substation of 64 MW estimated by Powers Engineering.

Q. The burden of proof in a CPCN proceeding rests with the applicant, correct?

A. Yes.

Q. Has ATXI provided any evidence to explain the source of the 300 MW of load it assumes will be dropped at the Adair Substation during the Category C contingency event?

A. No.

Q. Therefore, has ATXI met its burden of proof regarding the reasonableness of the modeled Category C contingency?

A. No.

Q. What is the mission of the NERC?

A. NERC is a regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces reliability standards.

[36] MW and MVA are used interchangeably in this testimony.

NERC is the electric reliability organization for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC).[37]

Q. Are ATXI, Ameren MO, and AECI subject to NERC reliability standards?

A. Yes.

Q. Please summarize the NERC reliability standards to which the Ameren MO and AECI 161 kV systems are subject to in Northeast Missouri.

A. NERC reliability standards require the simulation of a range of potential conditions from no contingencies (Category A) to extreme events (Category D). The two intermediate categories of contingencies, Category B, events resulting in the loss of a single element and Category C, event(s) resulting in the loss of two or more elements constitute the majority of contingencies examined. An example of a Category B contingency is the fault and loss of one transformer bank. An example of a Category C contingency is the fault and simultaneous loss of two transmission lines that share a common tower. Category D contingencies are extreme events with no specific performance requirements other than an evaluation for risks and consequences.[38]

Q. Is Ameren MO required by NERC reliability standards to fully mitigate a Category C contingency involving the simultaneous loss of the two Ameren MO 161 kV lines interconnected at the Adair Substation?

A. No. Ameren MO is required to fully mitigate, meaning no loss of customer load, the loss of a single transmission element (Category B), for example loss of one of the two 161 kV lines. However, Ameren MO is allowed to utilize planned and controlled load

[37] NERC "About NERC" webpage, October 19, 2015: http://www.nerc.com/AboutNERC/Pages/default.aspx
[38] **Exhibit PE-16**, SCE Opening Testimony, 2012 Long-Term Procurement Proceeding Track 4, August 2013, pp. 21-22.

shedding to address a more serious, and presumptively under NERC requirements a far less likely, Category C contingency.

Q. Has ATXI provided any evidence or testimony that the simultaneous loss of its two 161 kV lines interconnected at the Adair Substation have ever been lost simultaneously under peak load conditions?

A. No. ATXI is not asserting that the project will resolve a real deficiency in the reliability of the existing 161 kV system, only that a low probability hypothetical contingency event, one that has apparently never occurred in decades of successful operation of the existing 161 kV system, would be resolved without loss of load if the proposed ATXI 345 kV line is built.

Q. But don't NERC requirements allow controlled load shedding in the Kirksville area to address this low probability Category C event, instead of building new transmission, or new generation, to mitigate the impacts of the event?

A. Yes. ATXI acknowledges this, stating: "*The NERC Reliability Standard does allow planned and controlled load shedding for a NERC Category C event.*"

Q. If that is the case, given controlled load shedding – an operational tool that has apparently not been needed for this specific contingency over many decades and may never be needed – is a no-cost solution to this Category C event, why is ATXI proposing a $224 million transmission solution?

A. ATXI implies that the Category C event in question, without explicitly defining it as such, is the simultaneous loss of its two 161 kV lines interconnected to the Adair Substation. ATXI states by way of explanation that "*the loss of two 161 kV lines in northeastern Missouri results in a significant and very rapid low voltage condition* *that does not provide adequate time to implement a controlled load shedding response.*"

Q. Isn't the very rapid low voltage condition also an artifact of ATXI assuming a load on the Adair Substation at the moment of the loss of the two 161 kV lines that is about five times higher, at 300 MW, than the projected actual peak load of the Ameren MO customer being supplied by the substation of about 64 MW?

A. Yes.

Q. Also, haven't multiple Western utilities successfully petitioned NERC (via the Western Electricity Coordinating Council – WECC) to reclassify the simultaneous loss of two transmission lines that are not on the same transmission pole or immediately adjacent to each other in the same right-of-way as an extreme low probability Category D contingency that does not require a mitigation plan?

A. Yes. Seven high voltage transmission line corridors with two or more transmission lines in parallel in the same corridor in the Western U.S. were reclassified between 2002 and 2012 from generic Category C contingencies to specific Category D contingencies on the basis of the low probability of the likelihood of simultaneous outages between 2002 and 2012.[39]

Q. Are the Ameren MO Thomas Hill-to-Adair and Adair-to-Appaloose 161 kV lines on the same pole or in the same right-of-way?

A. No. One line runs south from the Adair Substation, the other runs north from the Adair Substation.

Q. Therefore, wouldn't the simultaneous loss of both of these 161 kV lines at peak demand, at least in the WECC jurisdiction where a formal reclassification

[39] **Exhibit PE-17**, WECC, PURC White Paper, February 2013. Attachment 2, p. 12.

procedure has been in place for years, qualify for reclassification from Category C to Category D?

A. Yes. This would be an extreme low probability event. The two Ameren MO 161 kV lines interconnected at the Adair Substation are physically isolated from each other, do not share a common corridor, and in the opinion of Powers Engineering are less likely as a result to experience a simultaneous outage than the Western transmission lines that were re-categorized from Category C to Category D contingencies.

Q. Is it reasonable and prudent for the MO PSC to approve a CPCN for a $224 million transmission line, of which $18 million will be paid by Ameren MO ratepayers, to address a contingency that, in the unlikely event that it actually occurs, could inconvenience 10,308 customers, about 1 percent of Ameren MO's customer base, for minutes or hours?

A. No.

B. The Shoulder Peak Overload Condition Modeled by MISO with 450 MW of Wind Power at Adair Substation Can Be Mitigated Without Constructing the Proposed 345 kV Line

Q. What did MISO assume in its modeling when it asserted wind power interconnected at the Adair Substation would overload the existing 161 kV lines in Northeast Missouri?

A. MISO assumed that wind generation connected at the Adair Substation, with 450 MW dispatched in off-peak conditions, would overload the 161 kV line from Adair to Novelty in the base case, and during other contingencies overloads the 161 kV lines to the north and south, as well as some nearby transformers.

Q. Why does MISO assume that the overload occurs when the lines have, but for the assumed inflow of wind power, moderate or light off-peak loads?

A. Because wind power output is predominantly an evening and night-time resource that is a poor match for afternoon on-peak electricity demand periods. The capacity factor of Missouri wind power that MISO estimates for summer on-peak periods is only 6 percent.[40]

Q. Is 450 MW or 500 MW of wind power development likely in the Adair Wind Zone?

A. No. As previously explained a major regional wind energy developer, TradeWind Energy, spent eight years attempting to construct a 300 MW wind project in the Adair Wind Zone. Neither Ameren MO nor any other utility showed interest in contracting for the 300 MW of wind power proposed by TradeWind Energy. The fact that Ameren MO can meets its RPS requirements with inexpensive RECs makes it unlikely that Ameren MO will contract for a more costly power purchase agreement for new wind power in the Adair Wind Zone.

Q. Assuming for sake of argument that 500 MW wind project would be developed in the Adair Wind Zone, isn't the wind energy developer responsible under MISO interconnection requirements for paying for all transmission system upgrade costs necessary to make the wind power from the proposed project fully deliverable?

A. Yes.[41]

Q. So Ameren MO customers would not pay any charge for the wind developer to interconnect to the existing Ameren MO transmission system?

A. That is correct.

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[40] **Exhibit PE-18**, MISO, *Regional Generator Outlet Study*, November 19, 2010, Appendix 1, Figure A1.3-3, p.13.
[41] **Exhibit PE-10**, p. 5.

Q. Didn't MISO state that 450 MW of connected wind power would overload the 161 kV line from Adair to Novelty in the base case?

A. Yes. MISO assumes that the Adair-to-Novelty line has a rating of 167 MW and experiences a load that is 154.6 percent of maximum loading.[42] Therefore the loading on the line imposed by 450 MW of wind power at the Adair Substation, if the line was capable of transporting it, would be 167 MW × 1.546 = 258 MW.

Q. But didn't ATXI confirm in a data response that the rated capacity of the Adair-Novelty-Palmyra 161 kV line is 285 MVA, or approximately 285 MW, which is greater than the projected 258 MW load?

A. Yes. No information has been provided by ATXI to explain why ATXI identifies the carrying capacity of the Adair-Novelty-Palmyra line as 285 MVA and MISO assumes the Adair-Novelty segment is capable of carrying only 167 MW.

Q. If MISO had assumed that the Adair-Novelty line could carry at or near 285 MW, would MISO have identified an overload condition on the line with 450 MW of wind power being dispatched at the Adair Substation?

A. No.

Q. What is one transmission upgrade that TradeWind Energy, or any other wind developer, could have proposed to make 450 MW of wind power flowing into the Adair Substation fully deliverable over the Adair-to-Novelty 161 kV line?

A. Standard "aluminum conductor steel reinforced" (ACSR) conductors are used on the two Ameren MO 161 kV lines interconnecting with the Adair Substation.[43] Powers Engineering assumes the AECI Adair-Novelty-Palmyra 161 kV transmission line is also ACSR of comparable conductor size to the Ameren MO Thomas Hill-to-Adair 161

[42] **Exhibit PE-19**, MISO, Candidate MVP Reliability Analysis, Appendix CMVP TSTF, July 28, 2011.
[43] **Exhibit PE-13**, ATXI DR response NU-A3, October 10, 2015.

kV line, due to the similar capacities of these lines as reported by ATXI.[44] The original ACSR conductor can be replaced with "aluminum conductor composite core" (ACCC) or "aluminum conductor composite reinforced" (ACCR) conductor to approximately double the capacity of a transmission line.[45] Reconductoring the AECI Adair-to-Novelty 161 kV line segment with ACCC or ACCR conductor would increase the capacity of the line from 285 MW to approximately 570 MW.[46]

Q. Has reconductoring of ACSR 161 kV lines to ACCC conductor taken place in the region?

A. Yes. See examples of where ACSR conductor has been replaced with ACCC conductor on 161 kV lines in the region in Table 1.

Table 1. Examples of 161 kV Lines that Have Been Reconductored with ACCC Conductor[47]

Client	Project	Location	Voltage, kV	Conductor	Year
AEP	Chamber Springs Substation	Rogers, AR	161	Drake	2006
AEP	Chamber Springs - Tonitown	Rogers, AR	161	Drake	2006
KAMO	Springfield - Brookline	Springfield, MO	161	Cardinal	2007
Flour Alliance - Tapoco APGI	Santeetlah Bus Upgrade	Robbinville, NC	161	Bittern	2009
Entergy	Ano - Russellville North Rebuild	Russellville, AR	161	Cardinal	2009
Entergy	Dardanelle Dam - Russellville South 161kV	Russellville, AR	161	Munich	2011
Entergy	Ano - Russellville North Rebuild	Russellville, AR	161	Cardinal	2012

[44] Ibid. Thomas Hill-to-Adair line segment conductor is 954 kcmil ACSR 45/7 Rail.
[45] **Exhibit PE-20**, CTC Global, ACCC conductor capacity and cost.
[46] **Exhibit PE-13**, ATXI DR response NU-A1, October 10, 2015.
[47] **Exhibit PE-20.**

Q. What is the distance from the Adair Substation to the Novelty Substation?

A. About 30 miles.

Q. What would be the equipment cost of 30 miles of three-phase 161 kV ACCC conductor?

A. About $4 million.[48]

Q. If it is assumed that the installed cost of the reconductoring project is double the $5 million ACCC conductor equipment cost, such that the total cost of the Adair-to-Novelty ACCC reconductoring project would be on the order of $10 million, what percentage is this $10 million of the total cost of the 500 MW wind project it would support?

A. The mean wind power capital cost identified in the MTEP14 Triennial Report Update is $2.4 million per MW. Therefore, the capital cost of a 500 MW project would be: $2.4 million/MW × 500 MW = $1.2 billion.

Q. So the approximate $10 million cost to upgrade the existing 161 kV line that would otherwise experience an overload would be about 1 percent of the overall $1.2 billion cost of the 500 MW wind project?

A. Yes.

Q. Is it your opinion that a transmission system upgrade cost that is about 1 percent of the overall wind project capital cost would have little or no impact on the financial viability of the wind project?

A. Yes.

Q. Who would pay this transmission upgrade cost?

A. The wind project developer.

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[48] **Exhibit PE-20.** $1.5 million for 12 miles of 3-phase 161 kV line (38 miles ÷ 3 conductors per mile = ~12 miles). Therefore, cost of 30 miles of 3-phase 161 kV ACCC conductor = 30 miles/12 miles × $1.5 million = $3.75 million.

VII. Ameren MO has Multiple Options at its Disposal to Address a Category C Contingency at the Adair Substation Without Building the ATXI 345 kV Line

Q. Did the interconnection study for 300 MW of wind power at the Adair Substation determine there was no need for reactive power (voltage regulation) at the Adair Substation to accommodate 300 MW of wind power?

A. That is correct.[49]

Q. So the entirety of the need for voltage regulation at the Adair Substation would be in response to the Category C event modeled by MISO that results in a low voltage condition at the substation when 300 MW of load is abruptly dropped?

A. Yes.

Q. What are options are available other than a new 345 kV transmission line to address a Category C contingency along the Thomas Hill-Adair-Appaloose 161 kV transmission pathway?

A. Options, in addition to planned and controlled load shedding as permitted by NERC, include the addition of voltage regulation hardware at the Adair Substation, demand response to rapidly shed load as needed at times of peak demand on the Adair Substation, the addition of local generation – conventional or solar, and energy efficiency measures to reduce demand overall.

Q. What are the benefits of adding voltage regulation hardware at the Adair Substation?

A. Voltage regulation equipment installed at the Adair Substation would allow Ameren MO to "buy time" in an emergency contingency situation like the Category C contingency modeling by MISO, so the utility could initiate planned and controlled reduction of

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[49] **Exhibit PE-21,** 2006 Interconnection Feasibility Study, 300 MW Shuteye Creek, p. 3.

load (load shedding), such as air conditioning load, in response to the contingency situation. The voltage regulation equipment could also provide time for AECI to adjust its system, through the Palmyra-Novelty-Adair 161 kV line, to meet the demand at the Adair Substation without shedding load.

Q. What are some examples of voltage regulation equipment that can address low voltage conditions?

A. A series capacitor or a static VAR compensator can address the abrupt low voltage Category C contingency described by ATXI.[50]

Q. How much voltage regulation, also known as reactive power, should be available to address the low voltage event?

A. Assuming a load on the substation of approximately 64 MW at the time of the Category C contingency, the maximum summer peak demand load on the Adair Substation estimated by Powers Engineering, and a 1:1 ratio of real power in MVA to reactive power in MVAR (MVA Reactive), assume 64 MVAR of reactive power is located at the Adair Substation to address the contingency.

Q. What are the costs of adding voltage regulation hardware at the Adair Substation?

A. The capital cost of a 64 MVAR series capacitor would be in the range of $2 million. The cost of a 64 MVAR static VAR compensator would be about $5.5 million.

Q. Which piece of voltage regulation equipment could address the abrupt low voltage condition in near real-time?

A. The static VAR compensator. The series capacitor would require a switching action.

[50] **Exhibit PE-22**, B&V, *Capital Costs for Transmission and Substations*, October 2012, p. 3-3 & p. 3-4.

Q. How does the cost of adding a 64 MVAR static VAR compensator to the Adair Substation to address the Category C contingency compare to the cost to Ameren MO ratepayers of constructing the proposed ATXI 345 kV transmission line?

A. At a cost of $5.5 million, the static VAR compensator would be less than one-third the $18 million cost to Ameren MO ratepayers to pay for Ameren MO's share of the proposed ATXI 345 kV transmission line.

Q. What are the benefits adding demand response measures in the Kirksville area to reduce peak load on the Adair Substation.

A. About 75 percent of Ameren MO residential summer peak load is air conditioning load. About 85 percent of Ameren MO summer peak load is residential and commercial load, with residential about 50 percent of total peak load and commercial about 35 percent of peak load. See Figures 7 and 8. It is reasonable to assume that combined residential and commercial cooling load is at least 50 percent of the Ameren MO summer peak load based on this data. Automatic central air conditioner cycling devices are used by many utilities around the country to reduce peak summer loads, including in states that border Northeast Missouri. See Table 2. Assuming most or all of the 10,308 Ameren MO customers served by the Adair Substation were equipped with automatic air conditioner cycling devices that could be accessed in emergency conditions to drop air conditioning load, the load on the Adair Substation could be reduced in emergency contingency conditions by about half almost instantly.

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Figure 7. Cooling Is Major Contributor to Ameren MO Residential Summer Peak Load[51]

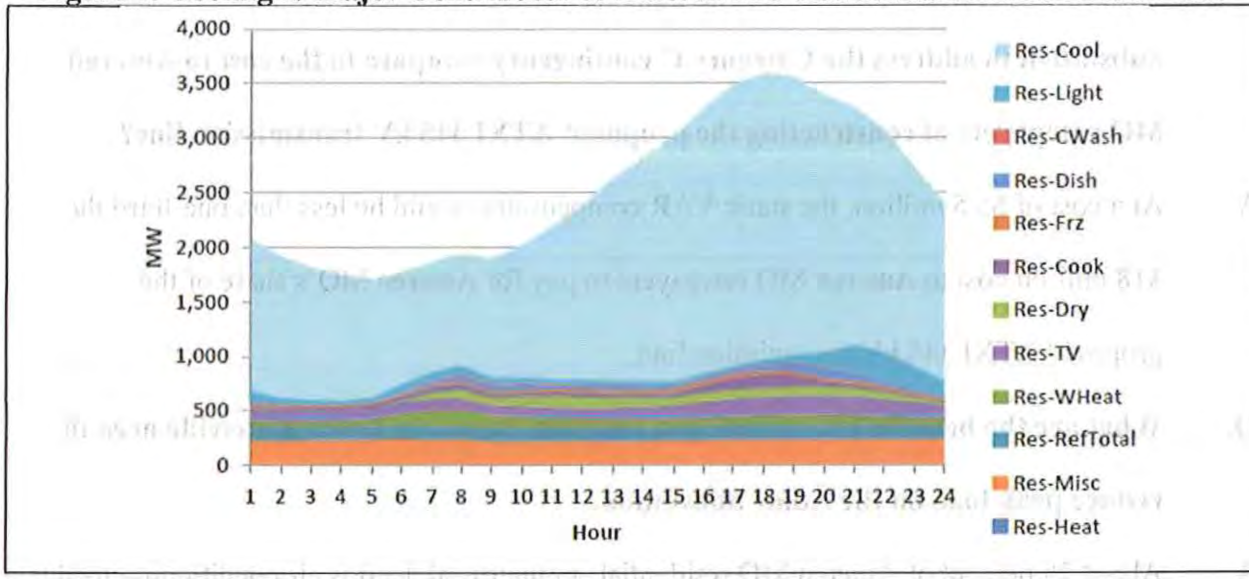

Figure 8. Residential and Commercial Load Is ~85% of Ameren MO Summer Peak Load[52]

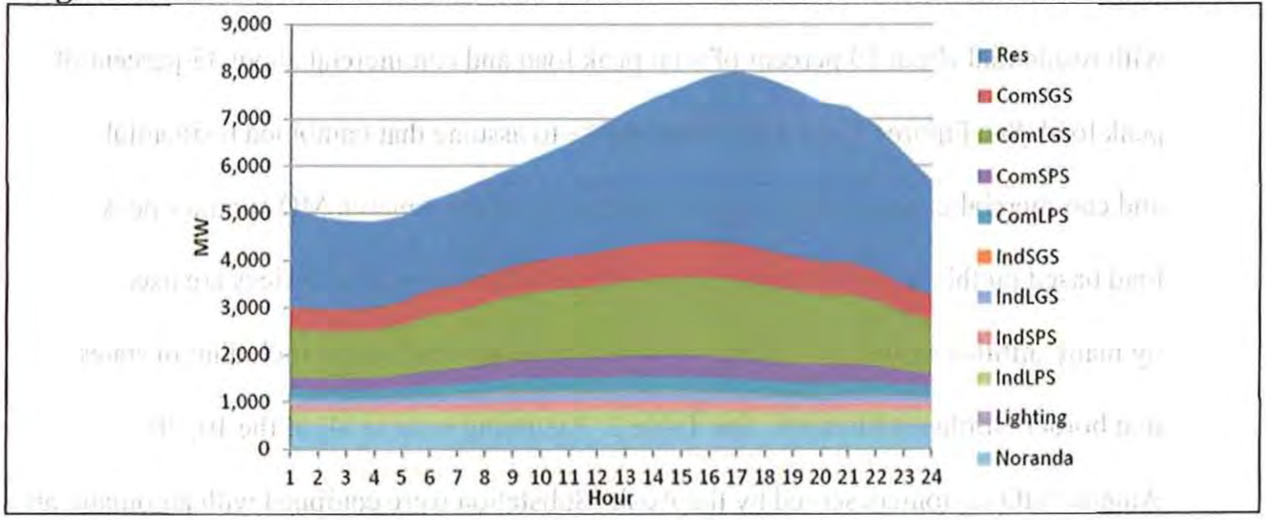

Table 2. Utility Central Air Conditioner Cycling Programs[53]

Utility	Program description	Financial terms
Iowa – MidAmerican Energy	MidAmerican Energy installs a small cycling device on the siding or your home near the central air conditioning unit. From June 1 to Sept. 30, the device will, on peak usage days, govern the degree to which your air conditioning operates. Air conditioners are cycled between approximately 2 and 7 p.m., but not on weekends or holidays.	$40 at end of first year, $30 at end of following years.

[51] **Exhibit PE-07**, Figure 3.24, p. 50.
[52] Ibid, Figure 3.25, p. 51.
[53] ClearlyEnergy website, state-by-state demand response program summaries: https://www.clearlyenergy.com/residential-demand-response-programs.

Ohio – First Energy Ohio Edison	Easy Cool Rewards Program — you can help ease peak demand for electricity on the hottest summer days.	professionally-installed Honeywell programmable thermostat (a $250 value)

Q. Wasn't Ameren MO going to implement a demand response program in 2016?

A. Yes. In its 2011 IRP, Ameren MO proposed to initiate a demand response program in 2016 that would reduce peak load on Ameren MO's system by 100 MW by 2021.[54]

Q. Is Ameren MO in the process of launching the demand response program?

A. No. In the 2014 IRP, Ameren MO stated that the demand response program would not meet its cost-benefit requirements in the 2016-2018 time period and has delayed implementation of its demand response program.[55]

Q. What is the cost of the automatic central air conditioner cycling controllers?

A. About $250 per controller.[56]

Q. Assuming all 10,308 Ameren MO customers served by the Adair Substation were equipped with automatic central air conditioners at $250 each (per Table 2) to reduce Adair Substation load by about 50 percent during peak summer conditions, what would be the cost of this demand response program?

A. The cost would be $250 per controller × 10,308 controllers = $2,577,000, or about $2.6 million.

Q. So the cost to reduce the peak load on the Adair Substation by half would be on the order of one-seventh the Ameren MO $18 million share of the proposed ATXI 345 kV line?

A. Yes.[57]

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[54] **Exhibit PE-23**, Ameren MO 2011 IRP, Chapter 7 DSM, p. 6, p. 54 (Figure 7.14).
[55] **Exhibit PE-24**, p. 1.
[56] See Table 2 of rebuttal testimony.
[57] $2.6 million ÷ $18 million = 0.144 (~1/7).

Q. What are the benefits of adding local renewable generation in the Kirksville area to reduce peak load on the Adair Substation?

A. The primary benefit, from an emergency contingency standpoint, is lowering power imports over the transmission lines connected to the Adair Substation during times of peak load.

Q. What type of generation would be inherently online at the summer peak, requiring no action by Ameren MO to provide power to address a contingency condition?

A. Solar power connected directly at the Adair Substation or located on rooftops and parking lots in the Kirksville area on distribution circuits connected to the Adair Substation.

Q. Would this solar power have the added benefit of contributing to Ameren MO achieving its 15 percent RPS target?

A. Yes.

Q. Could the 30 MW of uncommitted solar generation that Ameren MO is planning to add to meet its 45 MW solar target by 2021 be located at or near the Adair Substation?

A. Yes.

Q. Would the location of 30 MW of solar at the Adair Substation imposed any additional costs on Ameren MO customers?

A. No. This 30 MW of solar capacity is already a component of Ameren MO's RPS compliance strategy.

Q. Can a focused effort to locate customer-owned solar on homes, businesses, and farms in the Kirksville area contribute to reducing load on the Adair Substation at summer peak conditions?

A. Yes. There would be no additional cost to Ameren MO ratepayers, as customer-owned generation is a net-metering program open to all Ameren MO customers.

Q. What are the benefits of focused deployment of energy efficiency measures by Ameren MO on residences and business served by the Adair Substation?

A. The primary grid reliability benefit is reduced load on the Adair Substation and of contingency events that could lead to loss of load. Another benefit is lowered greenhouse gas emissions associated with electricity use by Ameren MO customers in the Kirkville area.

Q. What is the budget and energy saving targets of the Ameren MO energy efficiency program?

A. Ameren MO plans to spend $148 million from 2016-2018 to achieve 426 GWh of energy savings and 114 MW of peak demand savings.[58]

Q. Is the 2016-2018 Ameren MO energy efficiency program sufficient to allow focused energy efficiency investments in the Kirksville area to reduce summer peak demand loading on the Adair Substation?

A. Yes. These funds will be collected by Ameren MO from its ratepayers and directed at energy efficiency projects in its service territory. The number of Ameren MO customers in the project area is about 1 percent of Ameren MO customers. Assuming proportionate distribution of Ameren MO energy efficiency spending, about 1 percent of the targeted 114 MW of peak load savings, or 1.1 MW, would occur in the Kirksville area.

Increasing the targeted peak demand savings in the Kirksville area substantially, to 5 to 10 MW, would significantly reduce the potential for grid reliability issues at the Adair Substation. It would also be a significant factor in reinforcing local grid reliability and

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[58] **Exhibit PE-24**, p. 1.

avoiding Ameren MO's $18 million share of the cost of the proposed ATXI 345 kV transmission line.

VIII. The Economic Benefit of Wind Power Over Solar Power Presumed by MISO and ATXI Is Obsolete, Invalidating the MVP Cost-Benefit Analysis

Q. Does MISO presume that the overwhelming majority of renewable energy developed in MISO territory will be wind power?

A. Yes. MISO has assumed as an article of faith that the overwhelming majority of RPS targets in MISO and PJM will be met with remote wind power. MISO determined in its 2010 "*Regional Generation Outlet Study*" that wind power will provide approximately 90 percent on average of the renewable power used to meet RPS targets for states in MISO and PJM.[59]

Q. Does MISO consider any other possibility in the MTEP11 or MTEP14 reports?

A. No. The most recent report, the MTEP14 Triennial Review Report, does not consider that other forms of renewable energy, specifically solar energy, could displace wind power as a more cost-efficient alternative to wind power to meet RPS requirements.

Q. What are the prospects for the development of wind projects in the Adair Wind Zone that would tie in directly to the ATXI 345 kV transmission line?

A. Poor. Missouri utilities have shown no interest in developing wind projects in the Adair Wind Zone.

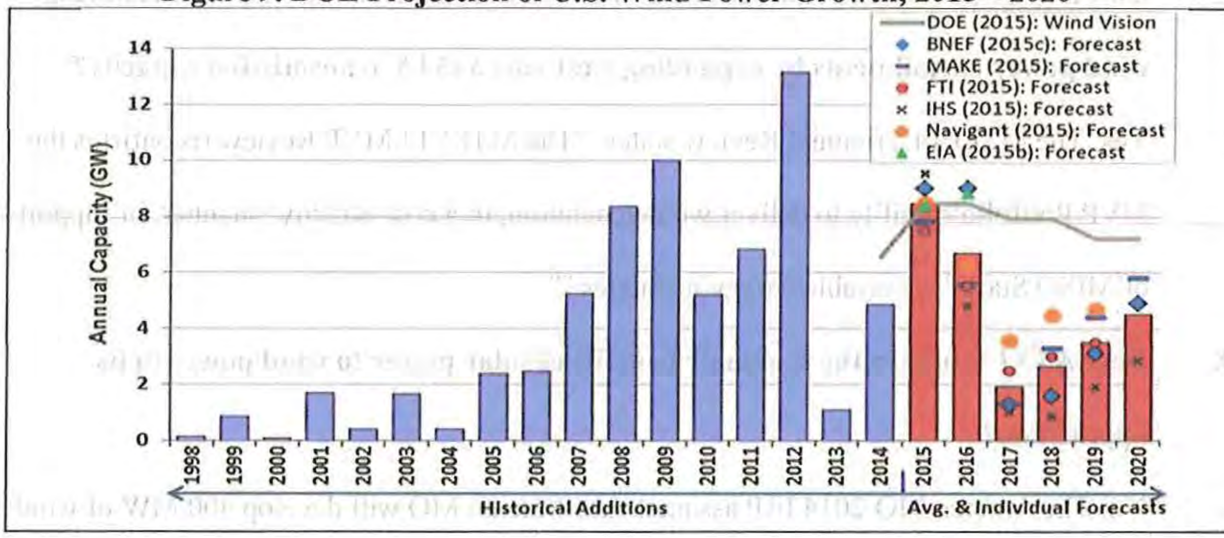
Q. What are the growth prospects for the U.S. wind industry beyond 2016?

A. Not good. The August 2015 DOE projection for wind power growth is shown in Figure 9. DOE projects a major decline in wind power growth in the U.S. after 2016. One of the

[59] **Exhibit PE-18**, p. Table 2.2-1, p. 17.

factors that DOE cites as leading to uncertainty and lower growth in wind power post-2016 is growing competition from solar energy in certain regions of the country.[60]

Figure 9. DOE Projection of U.S. Wind Power Growth, 2015 – 2020[61]



Q. What is the current MISO assumption about the capital cost of wind power?

A. The MISO MTEP14 Triennial Review Report identifies a mean capital cost of wind power of $2,400/kW.[62]

Q. What was the average annual capacity factor of operating wind projects in Missouri in 2013 and 2014?

A. About 28 percent.[63]

Q. Is the capital cost of wind power expected to increase or decrease over time?

A. Increase. The U.S. Energy Information Administration, in its *Assumptions to the Annual Energy Outlook 2015* (September 2015), states "Capital costs for wind technologies are assumed to increase."[64]

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[60] **Exhibit PE-25**, DOE, *2014 Wind Technologies Market Report*, August 2015, p. 72.
[61] Ibid, Figure 53, p. 72.
[62] MTEP14 Triennial Review, p. 40. "*$2 to $2.8 million/MW*" is equivalent to a mean of $2.4 million/MW ($2,400/kW).
[63] **Exhibit PE-26**, EIA Form 923, 2013 and 2014, Page 1 Generator and Fuel Data, electricity production in MWh per year for five Missouri wind farms: 150 MW Lost Creek, 146 MW Farmers City, 50.4 MW Conception, 50.4 MW Cow Branch, and 56.7 MW Bluegrass Ridge.

Q. What is the typical current wind power cost-of-production?

A. In the range of \$50/MWh to \$60/MWh.[65]

Q. Isn't a large part of the value proposition of MTEP based on the value of reducing wind power curtailments by expanding west-east 345 kV transmission capacity?

A. Yes. The MTEP14 Triennial Review states: "The MTEP14 MVP Review reconfirms the MVP Portfolio's ability to deliver wind generation, in a cost-effective manner, in support of MISO States' renewable energy mandates."[66]

Q. Does ATXI compare the economic benefits of solar power to wind power in its application?

A. No. The Ameren MO 2014 IRP assumes that Ameren MO will develop 400 MW of wind power and 45 MW of solar power by 2021 to meet the 15 percent RPS requirement. This is the same ratio of wind power to other renewables, 90/10, assumed by MISO in 2010 as the renewable energy justification for the MVP projects.[67]

Q. What is the current cost of solar power?

A. DOE identifies the 2016 best-in-class to mid-range capital cost for utility-scale solar 5 MW and larger of \$1,300/kW_{dc} to \$1,625/kW_{dc}.[68] The adjusted solar capital cost, based on alternating current (ac) output and assuming a dc-to-ac conversion efficiency of 90 percent,[69] would be \$1,444/kW_{ac} to 1,806/kW_{ac}. This is a mean capital cost of about \$1,600/kW_{ac}, two-thirds the capital cost of wind power that is assumed by MISO.

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[64] **Exhibit PE-27**, U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2015*, September 2015, p. 192.
[65] **Exhibit PE-04**, p. 2.
[66] MISO, MTEP14 Triennial Review, p. 3.
[67] **Exhibit PE-18**, p. Table 2.3-2, p. 19.
[68] **Exhibit PE-28**, NREL, *Photovoltaic System Pricing Trends Historical, Recent, and Near-Term Projections 2014 Edition*, September 22, 2014, p. 22.
[69] **Exhibit PE-29**, DNV KEMA Energy & Sustainability, *Austin Energy Review of Strategic Plan for Local Solar in Austin*, prepared for Austin Energy, November 22, 2013, p. 8, p. 10, and p. 16. For utility-scale solar, the dc-to-ac conversion is assumed to be 90 percent. For rooftop systems, the dc-to-ac conversion is assumed to be 85 percent.

Table 3. DOE Projected Capital Costs for Rooftop and Utility-Scale (≥ 5 MW) Solar PV Projects[70]

Type of solar PV	2014 modeled capital cost ($\$/kW_{dc}$)	2016 forecast best-case & mid-point capital cost ($\$/kW_{dc}$)	2016 forecast in $\$/kW_{ac}$ with DC-to-AC conversion
Residential rooftop	3,290	1,500 – 2,250	1,765 – 2,647
Commercial rooftop	2,540	1,500 – 2,250	1,765 – 2,647
Utility-scale, ≥ 5 MW	2,030	1,300 – 1,625	1,444 – 1,806

Q. What is the capacity factor of solar power in Northeast Missouri?

A. 18 to 22 percent, depending on whether the solar power is fixed (18 percent) or single-axis tracking (22 percent) for a representative site in Columbia, Missouri.[71]

Q. Is the cost of production of wind power and solar power in Northeast Missouri essentially the same in late 2015?

A. Yes. Wind power has about a 50 percent higher capital cost at about \$2,400/kW than solar at \$1,600/kW. This higher capital cost is offset by a 27 to 56 percent higher wind capacity factor, 28 percent for wind power versus a mean solar capacity factor of 18 to 22 percent.

Q. So the gross cost-of-production from Missouri wind and solar projects is about the same in late 2015?

A. Yes.

Q. Does solar power have other grid-related attributes that enhance its value relative to wind power?

A. Yes. Unlike wind power, solar output is well matched to diurnal and summer peak load profile of Ameren MO. This attribute contributes to the higher "grid value" of solar

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[70] **Exhibit PE-28**, p. 4, p. 22.

[71] **Exhibit PE-30**, NREL PV Watts, 100 kW (dc), 1-axis tracking and fixed array, Columbia, MO site location: http://pvwatts.nrel.gov/.

power, in the form of firm solar capacity available at summer peak demand when power prices are highest, compared to wind power. Solar arrays can also be economically connected at the distribution level of the transmission and distribution system, which reduces load and congestion on the transmission system.

Q. **Does the $0/MWh production cost that the MTEP14 Triennial Review Report attributes to wind power (p. 5) apply equally to solar power?**

A. Yes.

Q. **Does the fuel savings benefit the MTEP14 Triennial Review Report attributes to wind power (p. 5), as a result of its lower production cost relative to natural gas-fired generation, apply equally to solar power?**

A. Yes.

Q. **What is the price decline trend for solar power?**

A. The price decline trend is steep. An example is provided in Figure 10 of the solar price decline trend of a California public utility over the last three years. These are mid-sized utility-scale projects. The most recent project in Figure 10, sPower 2015, is 50 MW.[72] The City of Lancaster (California) signed a 20-year fixed power purchase agreement for a single 10 MW solar array on the outskirts of the city at a fixed price of $54.99/MWh.[73]

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[72] **Exhibit PE-31**, City of Riverside PPA, 50 MW Antelope Valley Solar, $53.75/MWh.
[73] **Exhibit PE-32**, Lancaster Clean Energy PPA, 10 MW, $54.99/MWh.

Figure 10. Riverside Public Utilities Solar Project Price Decline Trend, 2012 - 2015[74]

Q. Could a 10 MW solar array be interconnected to the transmission and distribution system at the 12 kV distribution level, and thereby reduce load on the transmission system?

A. Yes. A 10 MW solar would occupy in the range of 50 acres, a size range that could be located at or near a substation like the Adair Substation. The output of the array, at 10 MW, would be sufficiently limited that the project's output could be interconnected at the substation distribution voltage to serve local load. This form of interconnection would have the same effect on the transmission system as point-of-use rooftop solar. It would reduce the need for power imported over the transmission system to serve the load in the Kirksville area.

Q. How do the prices of these recent solar PPA contracts compare to the 2014 on-peak MISO wholesale energy price?

A. The lowest reported contract prices for solar arrays in the 10 to 50 MW range are competitive with the average 2014 MISO on-peak wholesale electricity price. Austin

[74] **Exhibit PE-33**, City of Riverside PowerPoint, June 19, 2015, solar PPA contract price trend, p. 20.

Energy (Texas) signed solar PPAs in 2014 for less than \$50/MWh.[75] The average on-peak wholesale electricity price in MISO in 2014 was \$48/MWh.[76]

Q. Are solar contract prices continuing to drop at a rapid pace?

A. Yes.

Q. What contract prices did Austin Energy receive for its recent April 2015 RFP for 600 MW of solar capacity?

A. About 15 percent of the bids received were priced at less than \$40/MWh.[77] The solar bid price trend over the last years documented by Austin Energy is shown in Figure 11. The \$40/MWh bid prices for 2016 projects are one-quarter the \$160/MWh PPA price for Austin's first solar project (Webberville Solar) in 2008. 2008 is also the year MISO began planning the MVP transmission build-out assuming remote wind power would be the predominant form of renewable energy relied on to meet RPS targets in MISO and PJM.[78]

Figure 11. Solar Price Decline Trend in Solar Bids Received by Austin Energy, 2008-2016[79]

[75] **Exhibit PE-34**, GreenTech Media, Cheapest solar ever? Austin Energy buys at 5 cents per kWh, March 10, 2014.
[76] **Exhibit PE-35**, 2014, FERC, PowerPoint, MISO on-peak wholesale electricity prices, p. 11.
[77] **Exhibit PE-36**, GreenTech Media, Austin Energy solar RFP, June 30, 2015.
[78] MTEP11 Report, p. 44.
[79] **Exhibit PE-36**, GreenTech Media, Austin Energy RFP bids, June 30, 2015.

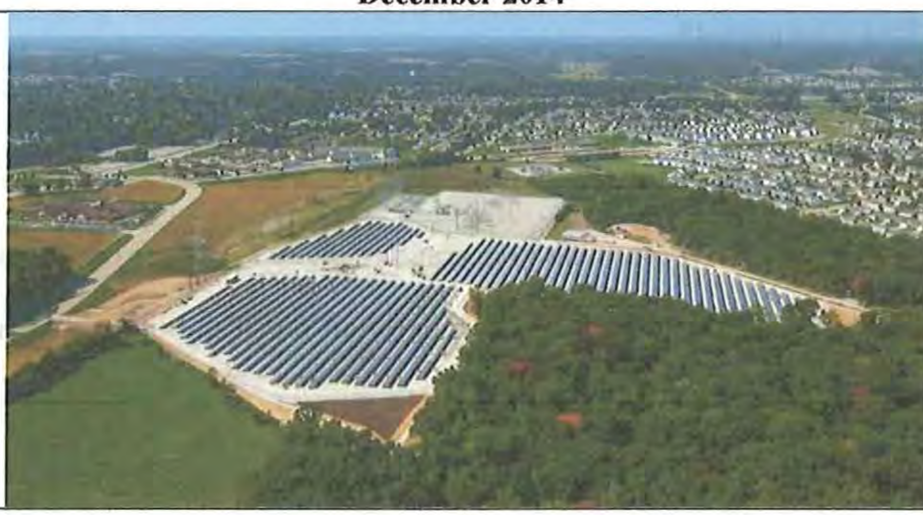
Q. Does Austin Energy predict that solar PPA prices will continue to drop?

A. Yes. Austin Energy predicts that solar PPA prices will drop below $20/MWh in 2020 if the solar investment tax credit is extended, and that PPA prices will remain under $40/MWh in 2020 if it is not. See Figure 11 above.

Q. Is distributed solar already in operation in Ameren MO service territory?

A. Yes. Ameren MO began operation of its 5.7 MW O'Fallon Renewable Energy Center in December 2014.[80] This solar project is located on the adjacent to Ameren MO Belleau substation and is shown in Figure 12. Ameren MO is also in the process of constructing a 15 MW solar array along I-70 in Montgomery County on 70 acres.[81]

Figure 12. Ameren MO 5.7 MW O'Fallon Renewable Energy Center, Operational in December 2014[82]



Q. Could the remaining 30 MW of Ameren MO's planned 45 MW solar portfolio in 2021 be located at or near the Adair Substation to minimize load on the substation during modeled summer peak contingency events?

A. Yes.

[80] Ameren MO O'Fallon Renewable Energy Center webpage: https://www.ameren.com/missouri/solar/ofallon-rec.
[81] **Exhibit PE-37**, St. Louis Post-Dispatch, July 1, 2015.
[82] Ameren MO O'Fallon Renewable Energy Center webpage: https://www.ameren.com/missouri/solar/ofallon-rec.

Q. Does Missouri also have a net-metered rooftop solar program?

A. Yes. The 2008 Proposition C Missouri Solar Rebate established incentive funding for net metered solar rooftop installations. Total program funding is $91.9 million, with installation in the 2014 to 2016 timeframe.[83] The incentive funding is fully subscribed. The initial funding level was $2 per watt. The final funding level was $1 per watt. Ultimately somewhere between 46 and 92 MW of net-metered rooftop solar will be installed in part due to this incentive program. At the lower incentive rate of $1 per watt, 1 MW of rooftop solar capacity is installed per each $1million of incentive funding.

Q. What will the average annual customer-installed solar installation rate be over the 2014-2016 time period?

A. About 20 MW per year, assuming the average incentive payment for program participants is $1.50 per watt.[84]

Q. Assuming Ameren MO continues to average about 20 MW per year of customer installed solar over the 2017-2021 timeframe, how much additional solar will be installed?

A. About 100 MW.

Q. Has Ameren MO accounted for an additional 100 MW of customer generated solar power in its RPS calculations?

A. No.

Q. Could an additional 100 MW of solar by 2021 displace a comparable amount of wind power in Ameren MO's RPS portfolio?

A. Yes.

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[83] Ameren MO webpage: https://www.ameren.com/missouri/solar/customerownedgeneration

[84] $91.9 million ÷ $1.5 million per MW = 61 MW (or about 20 MW per year over three years).

IX. There Are Viable and Cost-Effective Alternatives that Would Eliminate the Environmental Impacts of the Proposed ATXI 345 kV Line

Q. ATXI must assess potential impacts and develop mitigation strategies to address numerous environmental concerns along the pathway of the proposed 345 kV transmission line, including: the endangered Indiana bat and proposed endangered northern long-eared bat, raptor nesting areas, fragmentation of woodland habitat, degradation of spawning streams, and degradation of conservation easements.[85] How would the use of the alternatives described in your rebuttal testimony compare to the proposed 345 kV transmission line regarding such impacts?

A. Reconductoring the Adair-to-Novelty 161 kV line with composite conductor, adding voltage regulation at the Adair Substation, installing automatic demand response on central air conditioner systems used by Ameren MO customers served by the Adair Substation, and selectively focusing energy efficiency measures on Ameren MO customers served by the Adair Substation would have no environmental impacts. Solar on rooftops and parking lots in the Kirksville area would have no significant air, water, or land impacts. The environmental advantages of rooftop solar relative to remote utility-scale renewable energy, and associated transmission lines, were recognized by the California Public Utilities Commission at the time of its approval of a 500 MW urban warehouse rooftop PV project:[86]

> Added Commissioner John A. Bohn, author of the decision, "This decision is a major step forward in diversifying the mix of renewable resources in California and spurring the development of a new market

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[85] **Exhibit PE-38**, documents describing environmental issues associated with transmission line pathway.
[86] **Exhibit PE-39**, CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009.

niche for large scale rooftop solar applications. Unlike other generation resources, these projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts. By authorizing both utility-owned and private development of these projects we hope to get the best from both types of ownership structures, promoting competition as well as fostering the rapid development of this nascent market."

X. Conclusion

Q. Does this conclude your rebuttal testimony?

A. Yes.

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Master of Public Health – Environmental Sciences, University of North Carolina
Bachelor of Science – Mechanical Engineering, Duke University

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
American Society of Mechanical Engineers
Air & Waste Management Association

TECHNICAL SPECIALTIES

Thirty years of experience in:

- Power plant air emission control system and cooling system assessments
- Petroleum refinery air engineering and testing
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Latin America environmental project experience

POWER PLANT EMISSION CONTROL AND COOLING SYSTEM CONVERSION ASSESSMENTS

LMS100 Gas Turbine Power Plant Air Emissions Control Assessment. Lead engineer to assess Best Available Control Technology (BACT) for four proposed LMS100 gas turbines to be owned and operated by El Paso Electric Company. El Paso Electric proposed NOx and CO emission rates of 2.5 ppm and 6.0 ppm respectively, use of wet cooling tower(s) for intercooler heat rejection, and up to 5,000 hours per year of operation. I identified BACT as equivalent to combined cycle plant levels, 2.0 ppm NO_x and 2.0 ppm CO, due to high operating hour limit., and air cooling with mist augmentation at high ambient temperatures as BACT for PM. The TCEQ Office of Public Interest Council agreed that BACT for the LMS100s should be 2.0 ppm NO_x and 2.0 ppm CO, and that air cooling with mist augmentation should be BACT for PM.

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NOx and oxidation catalyst for CO, in settlement agreement with local landowners.

PE-02

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 °F and 13 °F were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 °F and 13 °F. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 °F. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Kentucky Coal-Fired Power Plant – Pulverized Coal vs IGCC. Expert witness in Sierra Club lawsuit against Peabody Coal Company's plan to construct a 1,500 MW pulverized-coal fired power plant in Kentucky. Presented case that Integrated Gasification Combined Cycle (IGCC) is a superior method for producing power from coal, from environmental and energy efficiency perspective, than the proposed pulverized-coal plant. Presented evidence that IGCC is technically feasible and cost competitive with pulverized coal.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Utility Boiler – Best Available NO_x Control System for 525 MW Coal-Fired Circulating Fluidized Bed Boiler Plant. Expert witness in dispute over whether 50 percent NO_x control using selective non-catalytic reduction (SNCR) constituted BACT for a proposed 525 MW circulating fluidized bed (CFB) boiler plant. Presented testimony that SNCR was capable of continuous NO_x reduction of greater than 70 percent on a CFB unit and that tail-end selective catalytic reduction (SCR) was technically feasible and could achieve greater than 90 percent NO_x reduction.

Utility Boilers – Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units.
Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.
Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

BP Whiting Refinery Expansion Air Permit. Served as lead engineer on review of netting analysis that resulted in the BP Whiting Refinery Expansion receiving a minor source air permit from the Indiana Department of Environmental Management. Determined that BP Whiting omitted several major sources of emissions, underestimated others, and incorrectly calculated contemporaneous increases and decreases in air emissions. These sources included refinery heaters, flares, coking units, sulfur recovery, and fugitive emissions. These errors and omissions were sufficient in number and magnitude to exceed NSR significance thresholds.

Hyperion Refinery Air Permit. Served as lead engineer on review of BACT determinations in the PSD air permit for the proposed Hyperion Refinery in South Dakota.. BACT review included controls for refinery heaters, cooling systems, fugitive emissions, and greenhouse gases. BACT was identified as SCR for all refinery heaters, use of enclosed ground flare for periodic flare gas emissions from gasification process, and use of leakless fugitive emission components.

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 °F and 20 °F were evaluated. The annualized cost of the fin-fin air-cooler with a 20 °F approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla, located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range.

Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the wide availability of urea on the island. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.
Microturbines – Ronald Reagan Library, Ventura County, California.
Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District.
Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines will be equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea will be used as the SCR reagent to avoid trigger hazardous material storage requirements. A separate permit will be obtained for the NO_x and CO continuous emissions monitoring systems. The ATCs is pending.

Industrial Boilers – NO_x BACT Evaluation for San Diego County Boilers.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for three industrial boilers to be located in San Diego County. The BACT included the review of low NO_x burners, FGR, SCR, and low temperature oxidation (LTO). State-of-the-art ultra low NO_x burners with a 9 ppm emissions guarantee were selected as NO_x BACT for these units.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County.
Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion ($SCONO_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District.
Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling.
Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was

two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM.
Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to receive approval for the alternate CO RATA standard. The time-share CEM passed the subsequent annual RATA without problems as a result of changes to some of the CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "$/kwh" and "$/ton" cost of these control systems was developed in the evaluation.

Gas Turbines – Evaluation of Proposed NO_x Control System to Achieve 3 ppm Limit.
Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol.
Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 °F) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide ± 1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

DISTRIBUTED SOLAR PV SITING AND REGIONAL RENEWABLE ENERGY PLANNING

Bay Area Smart Energy 2020 Plan . Author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan for the nine-county region surrounding San Francisco Bay. This plan uses the zero net energy building targets in the *California Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage, and a 50 percent reduction in peak demand for grid electricity, by 2020. The 2020 targets in the plan include: 25 percent of detached homes and 20 percent of commercial buildings achieving zero net energy, adding 200 MW of community-scale microgrid battery storage and 400 MW of utility-scale battery storage, reduction in air conditioner loads by 50 percent through air conditioner cycling and targeted incentive funds to assure highest efficiency replacement units, and cooling system modifications to increase power output from The Geysers geothermal production zone in Sonoma County. Report is available online at: http://pacificenvironment.org/-1-87.

Solar PV technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Rooftop PV alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The preliminary decision issued by the presiding CEC commissioner in the case recommended denial of the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines. No final decision has yet been issued in the proceeding (as of May 2009).

San Diego Smart Energy 2020 Plan. Author of October 2007 "San Diego Smart Energy 2020," an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy whether, and for grid reliability support. Report at: http://www.etechinternational.org/new_pdfs/smartenergy/52008_SmE2020_2nd.pdf

Development of San Diego Regional Energy Strategy 2030. Participant in the 18-month process in the 2002-2003 timeframe that led to the development of the San Diego Regional Energy Strategy 2030. This document was adopted by the SANDAG Board of Directors in July 2003 and defines strategic energy objectives for the San Diego region, including: 1) in-region power generation increase from 65% of peak demand in 2010 to 75% of peak demand in 2020, 2) 40% renewable power by 2030 with at least half of this power generated in-county, 3) reinforcement of transmission capacity as needed to achieve these objectives. The SANDAG Board of Directors voted unanimously on Nov. 17, 2006 to take no position on the Sunrise Powerlink proposal primarily because it conflicts the Regional Energy Strategy 2030 objective of increased in-region power generation. The Regional Energy Strategy 2030 is online at: http://www.energycenter.org/uploads/Regional_Energy_Strategy_Final_07_16_03.pdf

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.

Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application "templates" for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

BACT Evaluation of Wool Fiberglass Insulation Production Line. Project manager and lead engineer for BACT evaluation of a wool fiberglass insulation production facility. The BACT evaluation was performed as a component of a PSD permit application. The BACT evaluation included a detailed analysis of the available control options for forming, curing and cooling sections of the production line. Binder formulations, wet electrostatic precipitators, wet scrubbers, and thermal oxidizers were evaluated as potential PM_{10} and VOC control options. Low NO_x burner options and combustion control modifications were examined as potential NO_x control techniques for the curing oven burners. Recommendations included use of a proprietary binder formulation to achieve PM_{10} and VOC BACT, and use of low-NO_x burners in the curing ovens to achieve NO_x BACT. The PSD application is currently undergoing review by EPA Region 9.

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions. The cost of these potential PM_{10} RACT controls exceeded regulatory guidelines for cost effectiveness, though testing of modified shield configurations and dense-phase conveying is being conducted under a separate regulatory compliance order.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications. The coater line was equipped with an afterburner for VOC and CO destruction prior to the initiation of the RACT study. It was determined that the afterburner meets or exceeds RACT requirements for the coater line. Significant sources of PM_{10} emissions included the remelt furnaces and the 80-inch hot rolling mill. Chlorine fluxing in the melting and holding furnaces was identified as the principal source of PM_{10} emissions from the remelt furnaces. The facility is in the process of minimizing/eliminating fluxing in the melting furnaces, and exhaust gases generated in holding furnaces during fluxing will be ducted to a baghouse for PM_{10} control. These modifications are being performed under a separate compliance order, and were determined to exceed RACT requirements. A water-based emulsion coolant and inertial separators are currently in use on the 80-inch hot mill for PM_{10} control. Current practices were determined to meet/exceed PM_{10} RACT for the hot mill. Tray tower absorption/recovery systems were also evaluated to control PM_{10} emissions from the hot mill, though it was determined that the technical/cost feasibility of using this approach on an emulsion-based coolant had not yet been adequately demonstrated.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops. Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide ± 1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's <u>Performance Specification Test - 2 (NO_x and SO_2)</u> alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Preliminary Design of Ambient Air Quality Monitoring Network – Lima, Peru. Project leader for project to prepare specifications for a fourteen station ambient air quality monitoring network for the municipality of Lima, Peru. Network includes four complete gaseous pollutant, particulate, and meteorological parameter monitoring stations, as well as eight PM_{10} and TSP monitoring stations.

Evaluation of Proposed Ambient Air Quality Network Modernization Project – Venezuela. Analyzed a plan to modernize and expand the ambient air monitoring network in Venezuela. Project was performed for the U.S. Trade and Development Agency. Direct interaction with policy makers at the Ministerio del Ambiente y de los Recursos Naturales Renovables (MARNR) in Caracas was a major component of this project.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters.

Renewable Energy Resource Assessment Proposal – Panama. Translated and managed winning bid to evaluate wind energy potential in Panama. Direct interaction with the director of development at the national utility monopoly (IRHE) was a key component of this project.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at turbocharger/air cooler assembly plant in Mexicali, Mexico. Source specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish for review by the Mexican federal environmental agency (SEMARNAP).

Air Pollution Control Equipment Retrofit Evaluation – Mexico. Project manager and lead engineer for comprehensive evaluation of air pollution control equipment and industrial ventilation systems in use at assembly plant consisting of four major facilities. Equipment evaluated included fabric filters controlling blast booth emissions, electrostatic precipitator controlling welding fumes, and industrial ventilation systems controlling welding fumes, chemical cleaning tank emissions, and hot combustion gas emissions. Recommendations included modifications to fabric filter cleaning cycle, preventative maintenance program for the electrostatic precipitator, and redesign of the industrial ventilation system exhaust hoods to improve capture efficiency.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at automotive components assembly plant in Acuña, Mexico. Source-specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

PUBLICATIONS

Bill Powers, "*More Distributed Solar Means Fewer New Combustion Turbines*," Natural Gas & Electricity Journal, Vol. 29, Number 2, September 2012, pp. 17-20.

Bill Powers, "*Bay Area Smart Energy 2020,*" March 2012. See: http://pacificenvironment.org/-1-87

Bill Powers, "*Federal Government Betting on Wrong Solar Horse*," Natural Gas & Electricity Journal, Vol. 27, Number 5, December 2010,

Bill Powers, "*Today's California Renewable Energy Strategy—Maximize Complexity and Expense*," Natural Gas & Electricity Journal, Vol. 27, Number 2, September 2010, pp. 19-26.

Bill Powers, "*Environmental Problem Solving Itself Rapidly Through Lower Gas Costs*," Natural Gas & Electricity Journal, Vol. 26, Number 4, November 2009, pp. 9-14.

Bill Powers, "*PV Pulling Ahead, but Why Pay Transmission Costs?*" Natural Gas & Electricity Journal, Vol. 26, Number 3, October 2009, pp. 19-22.

Bill Powers, "*Unused Turbines, Ample Gas Supply, and PV to Solve RPS Issues*," Natural Gas & Electricity Journal, Vol. 26, Number 2, September 2009, pp. 1-7.

Bill Powers, "*CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost-Effective,*" Natural Gas & Electricity Journal, Vol. 26, Number 1, August 2009, pp. 8-13.

Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications. The coater line was equipped with an afterburner for VOC and CO destruction prior to the initiation of the RACT study. It was determined that the afterburner meets or exceeds RACT requirements for the coater line. Significant sources of PM_{10} emissions included the remelt furnaces and the 80-inch hot rolling mill. Chlorine fluxing in the melting and holding furnaces was identified as the principal source of PM_{10} emissions from the remelt furnaces. The facility is in the process of minimizing/eliminating fluxing in the melting furnaces, and exhaust gases generated in holding furnaces during fluxing will be ducted to a baghouse for PM_{10} control. These modifications are being performed under a separate compliance order, and were determined to exceed RACT requirements. A water-based emulsion coolant and inertial separators are currently in use on the 80-inch hot mill for PM_{10} control. Current practices were determined to meet/exceed PM_{10} RACT for the hot mill. Tray tower absorption/recovery systems were also evaluated to control PM_{10} emissions from the hot mill, though it was determined that the technical/cost feasibility of using this approach on an emulsion-based coolant had not yet been adequately demonstrated.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops. Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's <u>Performance Specification Test - 2 (NO_x and SO_2)</u> alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Preliminary Design of Ambient Air Quality Monitoring Network – Lima, Peru. Project leader for project to prepare specifications for a fourteen station ambient air quality monitoring network for the municipality of Lima, Peru. Network includes four complete gaseous pollutant, particulate, and meteorological parameter monitoring stations, as well as eight PM_{10} and TSP monitoring stations.

Evaluation of Proposed Ambient Air Quality Network Modernization Project – Venezuela. Analyzed a plan to modernize and expand the ambient air monitoring network in Venezuela. Project was performed for the U.S. Trade and Development Agency. Direct interaction with policy makers at the Ministerio del Ambiente y de los Recursos Naturales Renovables (MARNR) in Caracas was a major component of this project.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters.

Bill Powers, "*San Diego Smart Energy 2020 – The 21st Century Alternative*," San Diego, October 2007.

Bill Powers, "*Energy, the Environment, and the California – Baja California Border Region*," Electricity Journal, Vol. 18, Issue 6, July 2005, pp. 77-84.

W.E. Powers, "*Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler*," presented at California Energy Commission/Electric Power Research Institute Advanced Cooling Technologies Symposium, Sacramento, California, June 2005.

W.E. Powers, R. Wydrum, P. Morris, "*Design and Performance of Optimized Air-Cooled Condenser at Crockett Cogeneration Plant*," presented at EPA Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures, Washington, DC, May 2003.

P. Pai, D. Niemi, W.E. Powers, "*A North American Anthropogenic Inventory of Mercury Emissions*," presented at Air & Waste Management Association Annual Conference in Salt Lake City, UT, June 2000.

P.J. Blau and W.E. Powers, "*Control of Hazardous Air Emissions from Secondary Aluminum Casting Furnace Operations Through a Combination of: Upstream Pollution Prevention Measures, Process Modifications and End-of-Pipe Controls*," presented at 1997 AWMA/EPA Emerging Solutions to VOC & Air Toxics Control Conference, San Diego, CA, February 1997.

W.E. Powers, et. al., "*Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico* ," presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, "*Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines*," presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

W. E. Powers, et. al., "*Retrofit Control Options for Particulate Emissions from Magnesium Sulfite Recovery Boilers*," presented at 1992 TAPPI Envr. Conference, April 1992. Published in *TAPPI Journal*, July 1992.

S. S. Parmar, M. Short, W. E. Powers, "*Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique*," presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, "*Air Toxics Emissions from Gas-Fired Internal Combustion Engines*," presented at AIChE Summer Meeting, August 1990.

W. E. Powers, "*Air Pollution Control of Plating Shop Processes*," presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, "*Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator*," presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo
Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme
Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094

Integrated Resource Plan

We are committed to accomplishing a transition to cleaner energy in a way that is cost-effective and environmentally responsible while maintaining the reliability our customers expect.

2014 Integrated Resource Plan

Ameren Missouri's Integrated Resource Plan (IRP) was filed Oct. 1 with the Missouri Public Service Commission (PSC). It is a 20-year plan that supports cleaner energy in Missouri, including major expansions of solar and wind power. The IRP, which is filed every three years with the PSC, examines electric customers' projected long-term energy needs and describes our preferred approach to meeting those needs in a cost-effective fashion that maintains system reliability as it moves to cleaner and more diverse sources of energy generation.

Specifics of our plan include:

- Significantly expanding renewable generation by adding 400 megawatts (MW) of wind power, 45 MW of solar, 28 MW of hydroelectric and 5 MW of landfill gas.
- Continuing to offer energy efficiency programs to customers through our ActOnEnergy program and adding demand response programs when they are cost-effective.
- Retiring approximately one-third (about 1,800 MW) of Ameren Missouri's current coal-fired generating capacity. This includes converting two units at Meramec Energy Center to natural gas in 2016, and retiring the remaining units at Meramec by the end of 2022 and the Sioux Energy Center by the end of 2033.
- Reducing emissions of Ameren Missouri's existing coal fleet by continuing to make investments in pollution-control equipment.
- Adding 600 MW of efficient combined-cycle and clean-burning natural gas generation in 2034.
- Constructing a second solar energy center in 2016 that would be the largest in Missouri. Earlier this year, we broke ground on our first solar energy center in O'Fallon, Mo., which is scheduled for completion later this year.

Ameren Missouri is focused on adding nearly 500 MW of renewable power generation, which, together with other planned changes to generation resources, would allow us to achieve a 30% reduction in carbon dioxide emissions by 2035, based on 2005 levels. Our planned CO_2 emissions reductions by 2035 position the company to address the CO_2 reductions proposed in June by the federal Environmental Protection Agency (EPA). The EPA's Clean Power Plan targets a 30% reduction in CO_2 emissions from the power sector by 2030. Our IRP allows us to achieve significant reductions in CO_2 emissions over a slightly longer time frame but would save our customers an estimated $4 billion.

We are committed to accomplishing this transition to cleaner energy in a way that is cost-effective and environmentally responsible while maintaining the reliability our customers expect.

Investing in Missouri / 2014 Integrated Resource Plan

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October 1, 2015

Advice 4713-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: Submission of Data Necessary to Calculate the Market Price Benchmark for 2016 in Compliance With Resolution E-4475

Purpose

In compliance with Ordering Paragraph (OP) 4, of California Public Utilities Commission's (Commission or CPUC) Resolution E-4475, Pacific Gas and Electric Company (PG&E) is submitting data necessary to calculate the market price benchmark (MPB) for 2016, in accordance with that resolution. In addition, the value of the capacity PG&E plans to include in the benchmark calculation is discussed below.

Background

Resolution E-4475, OP 4, requires that by October 1 of each year, PG&E, San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE), shall file Tier 1 advice letters to update the data specified in OP 4 of Decision (D.)11-12-018 so that the applicable percentage weightings (32% for Department of Energy (DOE) data and 68% for utility data) are updated in subsequent years.

OP 4 of D.11-12-018 requires PG&E, SDG&E, and SCE to identify the data necessary to revise the Power Charge Indifference Amount (PCIA), Ongoing Competition Transition Charge (CTC), and Transitional Bundled Service (TBS) tariffs. Specifically, the information to be provided includes:

a. most recent 12-month figures derived from US Department of Energy survey of Western US renewable energy premiums in calculating a weighted proxy for the Market Price Benchmark compiled by the National Renewable Energy Laboratory; and

b. all Renewable Portfolio Standard (RPS)-compliant resources that are used to serve Investor Owned-Utility (IOU) customers during the current year (i.e., most recent 12 months) and those projected to serve customers during the next year, including both contracts and IOU-owned resources, including the projected costs together with the net qualifying capacity of energy produced by each of these resources (providing relevant costs in dollars and volumes in MWh and qualifying capacity in kW).

From this information, the Commission will then adopt an RPS adder to be used to determine a MPB. The RPS adder proxy value will be based on a 32% weighting of the DOE data in relation to a 68% weighting of the IOU cost data and will reflect renewable resources in the calculation of the PCIA and Ongoing CTC.

The average cost of power from the IOU RPS resources will be determined by summing up all the costs from all three IOUs, subtracting the product of the net qualifying capacity of those resources times the IOU's current resource adequacy capacity adder used in the MPB, and dividing by the sum of all the MWhs from all three IOUs.

Appendix A provides the most recent data from the DOE survey of Western US renewable energy premiums. Confidential Appendix B provides all RPS-compliant resources that began serving customers in 2015 or are forecast to begin serving customers in 2016. Energy Division will combine this data with SDG&E's and SCE's data and will provide a renewable adder for 2015. This adder will be used to update the 2016 forecast PCIA and Ongoing CTC in PG&E's November Update of the 2016 ERRA Forecast.

Resource Adequacy Capacity Value

D.11-12-018 agreed that it is reasonable to provide a means for updating the Resource Adequacy (RA) capacity value included in the MPB and adopted SCE's proposal to update the RA capacity adder using the Net Qualifying Capacity of the utility electric supply portfolio and the most recent California Energy Commission (CEC) estimate of the going forward costs of a combustion turbine.[1] Based on the CEC's most recent estimate, the RA capacity value to be included in the MPB would be $58.27/kW-yr. This estimate is based on data from Table E-4 of the CEC's Final Staff Report of the Estimated Cost of New Renewable and Fossil Generation in California, and is the summation of three components: (1) Insurance ($9.29), (2) Ad Valorem ($13.47) and (3) Fixed Operations & Maintenance (O&M) ($35.51).[2]

1 D.11-12-018 at p. 115.

2 See: California Energy Commission, Estimated Cost of New Renewable and Fossil Generation in California Final Staff Report, Appendix E, Table E-4

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than October 21, which is 20 days after the date of this filing. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-7226
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

Effective Date

PG&E requests that this Tier 1 advice filing become effective October 1, 2015, which is the date of filing.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service lists for R.07-05-025 and A.15-06-001. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Erik Jacobson
Director, Regulatory Relations

Attachments

Public Attachments:
Appendix A: Department of Energy Renewable Data
Appendix B: Renewable Resources Online in 2015 and 2016 (Public)
Appendix C: Confidentiality Declaration and Matrix

Confidential Attachment:
Appendix B: Renewable Resources Online in 2015 and 2016

cc: Service List R.07-05-025
Service List A.15-06-001

Appendix A

Department of Energy Renewable Data

Pacific Gas And Electric
Advice 4713-E pursuant to D.11-01-016
October 1, 2015

Appendix A
Western States
Utility Green Pricing Programs

State-Specific Utility Green Pricing Programs (http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=1) Western US Only
Western US Only

State-Specific Utility Green Pricing Programs (verified January 2015)						
State	Utility Information	Enrollment Information	Type	Start Date	Premium	Premium (cents/kWh)
AZ	Arizona Public Service	Green Choice	wind, biomass, landfill gas, geothermal, and	2007	1.02¢/kWh	1.02
AZ	Salt River Project	EarthWise Energy	PV for non-profits	1998/2001	Contribution	
AZ	Tri-State Generation & Transmission: Columbus Electric Cooperative, Inc.	Renewable Resource Power Rider	wind, hydro	2001	1.25¢/kWh	1.25
AZ	Tucson Electric	Bright Tucson Community Solar Program	local PV	2010	2.0¢/kWh	2.00
AZ	UniSource Energy Services	Bright Arizona Community Solar Program	local PV	2004	2.0¢/kWh	2.00
CA	Alameda Municipal Power	Alameda Green	wind, solar	2012	1.5¢/kWh	1.50
CA	Anaheim Public Utilities	Green Power for the Grid	various renewables	2002	2.0¢/kWh	2.00
CA	Anaheim Public Utilities	Sun Power for the Schools	PV	2002	Contribution	
CA	Los Angeles Department of Water and Power	Green Power for a Green LA	wind, hydro and PV	1999	3.0¢/kWh	3.00
CA	Marin Clean Energy: City of Belvedere, Town of Fairfax, County of Marin, City of Mill Valley, Town of San Anselmo	Local Sol	100% local solar	2014	6.0¢/kWh	6.00
CA	Marin Clean Energy: City of Belvedere, Town of Fairfax, County of Marin, City of Mill Valley, Town of San Anselmo	Deep Green	100% renewable	2010	1.0¢/kWh	1.00
CA	Marin Clean Energy: City of Belvedere, Town of Fairfax, County of Marin, City of Mill Valley, Town of San Anselmo	Light Green	50% renewable	2008	0.0¢/kWh	0.00
CA	PacifiCorp: Pacific Power	Blue Sky Block	wind	2000	1.95¢/kWh	1.95
CA	Pasadena Water & Power	Green Power	wind	2003	2.5¢/kWh	2.50
CA	Roseville Electric	Green Roseville	wind, PV	2005	0.5¢/kWh	0.50
CA	Sacramento Municipal Utility District	Greenergy	100% wind, PV, landfill gas, hydro, geother	1997	$6/month	1.00
CA	Sacramento Municipal Utility District	SolarShares	PV	2007	$10.75/mo	1.79
CA	Silicon Valley Power / 3Degrees	Santa Clara Green Power	wind, PV	2004	1.5¢/kWh	1.50
CA	Sonoma Clean Power	Clean Start	36% biomass, geothermal, wind	2014	0.0¢/kWh	0.00
CA	Sonoma Clean Power	Evergreen	100% geothermal	2014	3.5¢/kWh	3.50
CO	Colorado Springs Utilities	Renewable Energy Certificates Program	wind and geothermal	2008	0.34¢/kWh	0.34
CO	Colorado Springs Utilities	Green Power	wind	1999	3.0¢/kWh	3.00
CO	Holy Cross Energy	Wind Power Pioneers	wind	1998	0.5¢/kWh-1.25¢/kWh	0.88
CO	Holy Cross Energy	Local Renewable Energy Pool	small hydro	2002	2.33¢/kWh	2.33
CO	Platte River Power Authority: Estes Park, Fort Collins Utilities, Longmont Power & Communications, Loveland Wat	Nature's Energy	wind	1999	1.3¢/kWh-2.96¢/kWh	2.13
CO	Tri-State Generation & Transmission : Delta-Montrose Electric Association, Empire Electric Association, Inc., Gunn	Green Power Program	wind, solar, and hydro	1998	1.25¢/kWh	1.25
CO	Xcel Energy	WindSource	wind	1997	2.16¢/kWh	2.16
CO	Yampa Valley Electric Association	Green Power Options	wind and solar	1999	0.6¢/kWh	0.60
ID	Avista Utilities	Buck-A-Block	wind, solar and biomass	2002	0.35¢/kWh	0.35
ID	Idaho Power	Green Power Program	wind	2001	Contribution	
ID	PacifiCorp: Rocky Mountain Power	Blue Sky	wind	2003	1.95¢/kWh	1.95
ID	Vigilante Electric Cooperative	Alternative Renewable Energy Program	wind	2003	1.1¢/kWh	1.10
MT	Basin Electric Power Cooperative: Flathead Electric Coop, Lower Yellowstone, Powder River Energy	Prairie Winds	wind	2000	varies by utility	
MT	Northwestern Energy	E+ Green	wind, PV	2003	2.0¢/kWh	2.00
MT	Park Electric Cooperative	Green Power Program	various renewables	2002	0.09¢/kWh	0.09
MT	Tri-State Generation & Transmission: Big Horn Rural Electric Company	Renewable Resource Power Service	wind, hydro	2001	1.25¢/kWh	1.25
MT	Vigilante Electric Cooperative	Alternative Renewable Energy Program	wind	2003	1.1¢/kWh	1.10
NV	Deseret Power: Mt. Wheeler Power Cooperative	GreenWay	various	2005	1.95¢/kWh	1.95
NV	NV Energy	Desert Research Institute's GreenPower Pro	PV on schools	Unknown	Contribution	
NV	NV Energy	NV Green Energy Rate	50% or 100% renewables	2013	varies quarterly	
NM	El Paso Electric Company	Renewable Energy Tariff	solar, wind, geothermal, hydro and biomass	2003	5.84¢/kWh	5.84
NM	Los Alamos Department of Public Utilities	LA Green	wind, solar and hydro	2013	0.5¢/kWh	0.50
NM	Public Service of New Mexico	PNM Sky Blue	solar and wind	2003	1.7¢/kWh	1.70
NM	Tri-State Generation & Transmission: Central New Mexico Electric Cooperative, Inc., Columbus Electric Cooperati	Renewable Resource Power Service	wind, hydro	2001	varies by utility	
NM	Xcel Energy	WindSource	wind	1999	4.12¢/kWh	4.12
OR	City of Ashland / Bonneville Environmental Foundation	Renewable Pioneers	PV, wind	2003	2.0¢/kWh	2.00
OR	Columbia River PUD	Choice Energy	wind	2005	1.5¢/kWh	1.50
OR	Emerald People's Utility District	GREEN for Homes	wind and landfill gas	2011	0.8¢/kWh	0.80
OR	Eugene Water & Electric Board	EWEB Greenpower	various renewables	2007	1.0¢/kWh-1.5¢/kWh	1.25
OR	Idaho Power	Green Power Program	wind	2001	Contribution	
OR	Midstate Electric Cooperative	Environmentally-Preferred Power	wind	1999	2.5¢/kWh	2.50
OR	Oregon Trail Electric Cooperative	Green Power	wind	2002	1.5¢/kWh	1.50
OR	Pacific Northwest Generating Cooperative: Blachly-Lane Electric Cooperative, Central Electric Cooperative, Clearw	Green Power	landfill gas	1998	1.8¢/kWh-2.0¢/kWh	1.90
OR	PacifiCorp: Pacific Power	Blue Sky Block	wind	2000	1.95¢/kWh	1.95
OR	PacifiCorp: Pacific Power	Blue Sky QS (Commercial Only)	wind	2004	Sliding scale depending on size	
OR	Portland General Electric /	Clean Wind for Medium to Large Commercia	wind	2002	0.3¢/kWh	0.30
OR	Portland General Electric /	Clean Wind	wind	2002	1.25¢/kWh	1.25
OR	Portland General Electric /	Green Source	wind, landfill gas, low-impact hydro	2002	0.8¢/kWh	0.80
OR	Springfield Utility Board	ECOchoice	various	2007	1.0¢/kWh	1.00
UT	City of St. George	Clean Green Power	wind, small hydro	2005	2.95¢/kWh	2.95
UT	Deseret Power: Bridger Valley Electric, Dixie Escalante Rural Electric, Flowell Electric, Garkane Energy, Moon Lak	GreenWay	various	2004	1.95¢/kWh	1.95
UT	PacifiCorp: Rocky Mountain Power	Blue Sky	wind	2003	1.95¢/kWh	1.95
UT	PacifiCorp: Utah Power	Blue Sky	wind	2000	1.95¢/kWh	1.95
UT	Tri-State Generation & Transmission: Empire Electric Association, Inc.	Renewable Resource Power Service	wind, hydro	2001	1.25¢/kWh	1.25
WA	Avista Utilities	Buck-A-Block	wind, solar and biomass	2002	0.35¢/kWh	0.35
WA	Benton County Public Utility District	Green Power Program	landfill gas, wind, hydro	1999	Contribution	
WA	Chelan County PUD	Sustainable Natural Alternative Power (SNAP	PV, wind, micro hydro	2001	Contribution	
WA	Clallam County PUD	Watts Green	landfill gas	2001	1.7¢/kWh	1.70
WA	Clark Public Utilities	Green Lights	PV, wind	2002	1.5¢/kWh	1.50
WA	Cowlitz PUD/Bonneville Environmental Foundation	Renewable Resource Energy	wind, PV	2002	0.8¢/kWh	0.80
WA	Lewis County PUD	Green Power Energy Rate	wind	2003	2.0¢/kWh	2.00
WA	Mason County PUD No. 3	Mason Evergreen Power	wind	2003	1.0¢/kWh	1.00
WA	Northen Wasco County PUD	Pure Power	wind	2007	2.5¢/kWh	2.50
WA	Orcas Power & Light	Go Green	wind, hydro	1999	4.0¢/kWh	4.00
WA	Pacific County PUD	Green Power	landfill gas	2002	1.05¢/kWh	1.05
WA	PacifiCorp: Pacific Power	Blue Sky Block	wind	2000	1.95¢/kWh	1.95
WA	Peninsula Light	Renewable Option Program	wind	2002	1.5¢/kWh	1.50
WA	Puget Sound Energy	Green Power Program	wind, hydro, biogas, solar	2002	1.25¢/kWh	1.25
WA	Seattle City Light	Green Up	geothermal, biomass, wind, hydro	2005	1.5¢/kWh	1.50
WA	Seattle City Light	Seattle Green Power	PV, biogas	2002	Contribution	
WA	Snohomish County Public Utility District	Planet Power	wind	2002	Contribution	
WA	Tacoma Power	EverGreen Options	wind	2000	1.2¢/kWh	1.20
WY	Basin Electric Power Cooperative: Powder River Energy	Prairie Winds	wind	2000	varies by utility	
WY	Cheyenne Light, Fuel and Power Company/Bonneville Environmental Foundation	Renewable Premium Program	99% new wind, 1% new solar	2006	1.24¢/kWh	1.24
WY	Lower Valley Energy	Green Power	wind	2003	1.2¢/kWh	1.20
WY	PacifiCorp: Pacific Power	Blue Sky	wind	2000	1.95¢/kWh	1.95
WY	Tri-State Generation & Transmission: Carbon Power & Light, Inc.	Renewable Resource Power Service	wind, hydro	2001	1.25¢/kWh	1.25
WY	Yampa Valley Electric Association	Green Power Options	wind and solar	1999	0.6¢/kWh	0.60
					Average Cents / kWh	1.66
					Average $ / MWh	16.55

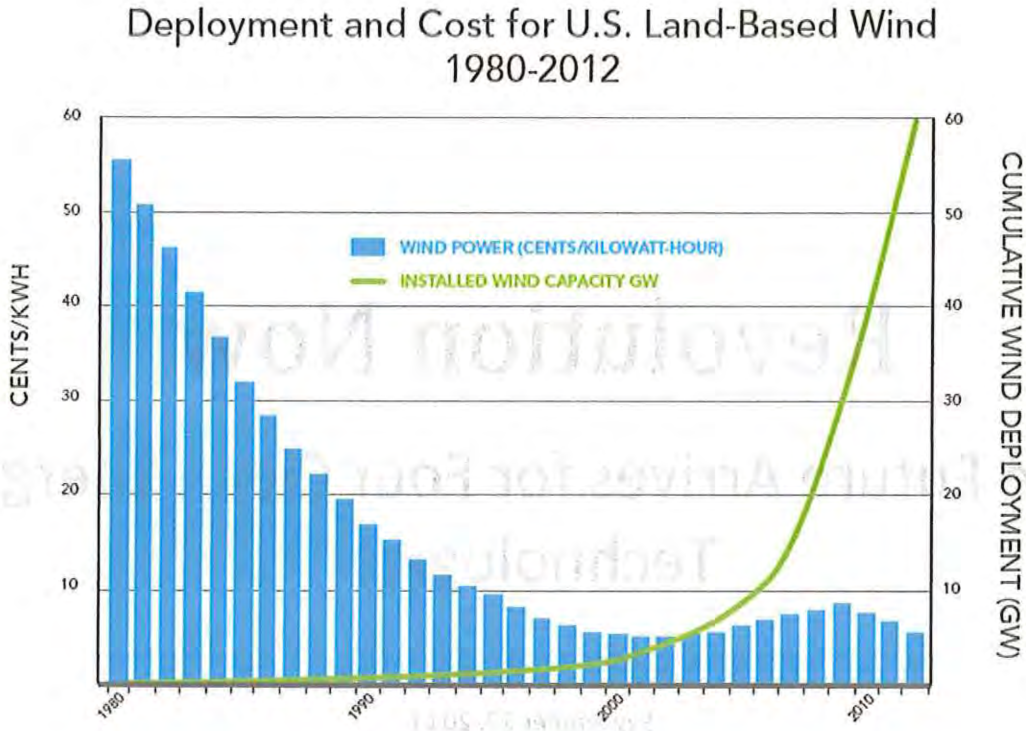
U.S. DEPARTMENT OF ENERGY

Revolution Now

The Future Arrives for Four Clean Energy Technologies

September 17, 2013

Land-Based Wind Power



Wind deployments on a steep upward climb[3]

Today, deployed wind power in the United States has the equivalent generation capacity of about 60 large nuclear reactors.[4] Wind is the first non-hydro renewable energy source to begin to approach the same scale as conventional energy forms like coal, gas and nuclear.

This success has been decades in the making – with both government and private-sector R&D dollars propelling its progress. From a technology standpoint three elements have been key to wind power's success. The first is increasing size: wind turbines have gotten progressively larger in terms of generation capacity over the past 30 years and this has helped to drive down costs. In fact, since 1999 the average amount of electricity generated by a single turbine has increased by about 260%. The second is the scale of production. As with many industries, increases in scale tend to drive down costs. Finally, wind farm

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[3] Bolinger, Mark; Wiser, Ryan. *MEMORANDUM - Documentation of a Historical LCOE Curve for Wind in Good to Excellent Wind Resource Sites*; Lawrence Berkeley National Laboratory, June 11, 2012. Bloomberg New Energy Finance power plant database (1980-1994) and American Wind Energy Association wind industry database (1994-2012).

[4] This number refers to "nameplate capacity" which represents the peak generation capacity of a wind turbine, solar panel, etc. In practice, electricity generation from renewable resources is variable – which means that they do not always produce at nameplate capacity. See the Energy Information Administration's Annual Energy Outlook 2013 for a deeper discussion regarding these issues: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

Ameren MISSOURI FOCUSED ENERGY. For life.

Outage Center - Details by County: Missouri

Updated: Oct 15, 2015 04:10 PM

http://apps.ameren.com/outage/OutageTrend.aspx?state=MO

The "Now" column shows the number of customers currently without power in each county. The "Past Outages" columns identify the number of customers without power at the same time of day as shown below over the past 8 days. Excluding major weather events, the "Past Outages" numbers are typically different customer(s) that have experienced outages over the last 8 days in that county and not the same customer(s) out for the entire duration.

	Now			+ Past Outages
County TOTAL:	Outages 136	% Out < 1%	# Served 1,190,821	
ADAIR	-	-	10,308	
AUDRAIN	-	-	7,158	
BOONE	-	-	3,992	
CALDWELL	-	-	2,728	
CALLAWAY	-	-	4,697	
CAMDEN	-	-	23,128	
CAPE GIRARDEAU	-	-	24,852	
CHARITON	-	-	1	
CLARK	-	-	865	
CLAY	-	-	6,485	
CLINTON	-	-	2,326	
COLE	-	-	29,196	
COOPER	-	-	5,920	
DAVIESS	-	-	295	
DEKALB	-	-	1,205	
DENT	-	-	2	
DUNKLIN	-	-	1,054	
FRANKLIN	-	-	44,960	
GASCONADE	-	-	3,797	
GENTRY	-	-	74	
HOWARD	-	-	787	
IRON	-	-	4,852	
JEFFERSON	2	< 1%	87,463	
KNOX	-	-	1,321	
LEWIS	-	-	2,583	

LINCOLN	-	-	11,910
LINN	-	-	3,161
LIVINGSTON	-	-	376
MACON	-	-	7
MADISON	-	-	340
MARIES	-	-	1,518
MARION	-	-	68
MILLER	-	-	7,653
MISSISSIPPI	-	-	5,129
MONITEAU	-	-	1,931
MONROE	-	-	637
MONTGOMERY	2	< 1%	4,843
MORGAN	-	-	6,994
NEW MADRID	-	-	4,774
OSAGE	-	-	2,724
PEMISCOT	-	-	7,398
PERRY	-	-	3
PETTIS	-	-	357
PIKE	-	-	7,465
RALLS	-	-	1,042
RANDOLPH	-	-	10,066
RAY	-	-	1,606
REYNOLDS	-	-	46
SAINT CHARLES	1	< 1%	131,639
SAINT FRANCOIS	11	< 1%	25,851
SAINT LOUIS CITY	1	< 1%	166,088
SAINT LOUIS COUNTY	117	< 1%	479,531
SAINTE GENEVIEVE	-	-	77
SALINE	-	-	93
SCHUYLER	-	-	619
SCOTLAND	-	-	182
SCOTT	2	< 1%	8,868
STODDARD	-	-	7,535
SULLIVAN	-	-	630
WARREN	-	-	9,314
WASHINGTON	-	-	10,297
County TOTAL:	Outages 136	% Out < 1%	# Served 1,190,821

	Now

The "Now" column shows the number of customers currently without power in each county. The "Past Outages" columns identify the number of customers without power at the same time of day as shown below over the past 8 days. Excluding major weather events, the "Past Outages" numbers are typically different customer(s) that have experienced outages over the last 8 days in that county and not the same customer(s) out for the entire duration.

3. Load Analysis and Forecasting

Highlights

- *Ameren Missouri expects energy consumption to grow 12% and peak demand to grow 8% over the next 20 years.*
- *The commercial class is expected to provide the most growth while federal efficiency standards continue to slow residential growth compared to historical trends.*
- *Key forecast uncertainties include growth in miscellaneous plug load, the future mix of customers and the impact that has on energy intensity of the local economy, and the impact of rising prices.*

Ameren Missouri has developed a range of load forecasts consistent with the scenarios outlined in Chapter 2. These load forecasts provide the basis for estimating Ameren Missouri's future resource needs and provide hourly load information used in the modeling and analysis discussed in Chapter 9. In addition, the Statistically Adjusted End-use forecasting tools and methods used to the develop the forecasts provide a solid analytical basis for testing and refining the assumptions used in the development of the potential demand-side resource portfolios discussed in Chapter 7.[1] The energy intensity of the future economy and the inherent energy efficiency of the stock of energy using goods are explored throughout the analysis to arrive at reasonable estimates of high, base, and low load growth.

3.1 Energy Forecast

This chapter describes the forecast of Ameren Missouri's energy, peak demand, and customers that underlies the analysis of resources undertaken in this IRP. In order to account for a number of combinations of possible economic and policy outcomes, fifteen different forecasts were prepared. Based on the subjective probabilities of these scenarios identified by Ameren Missouri, a sixteenth case was developed to represent the planning case for the study. The planning case forecast projects Ameren Missouri's retail sales to grow by 0.59% annually between 2014 and 2034, and retail peak demand to grow by 0.40% per year.

[1] 4 CSR 240-22.030(1)(A)

Figure 3.12: Ameren Missouri Actual Historical Energy Sales and Past IRP Energy Forecasts

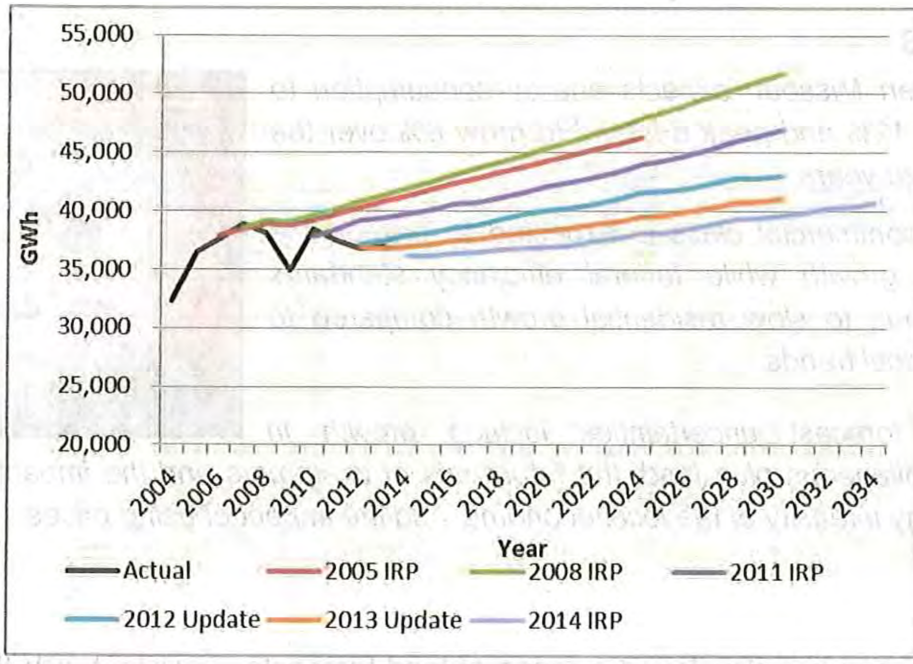


Figure 3.13: Ameren Missouri Actual Historical Peak Demand and Past IRP Peak Demand Forecasts

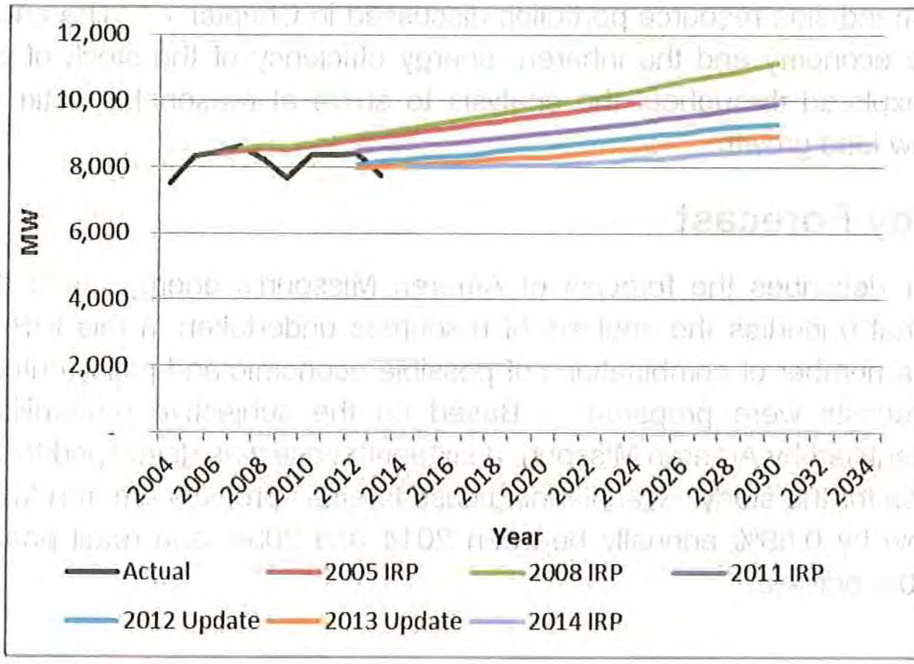
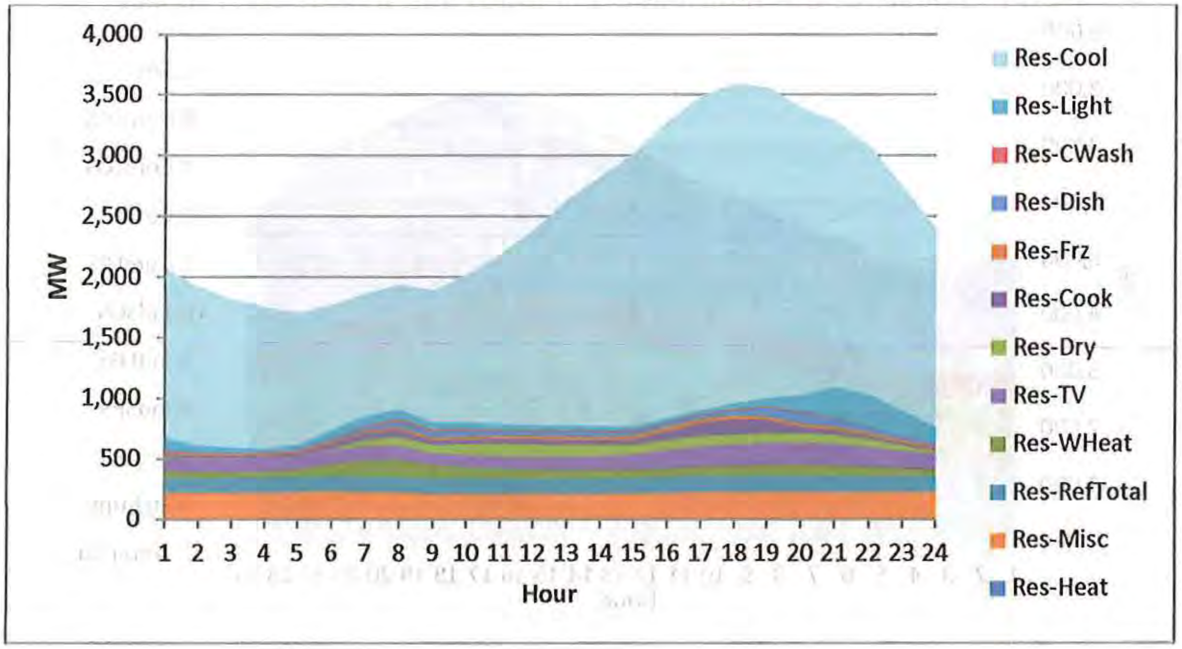


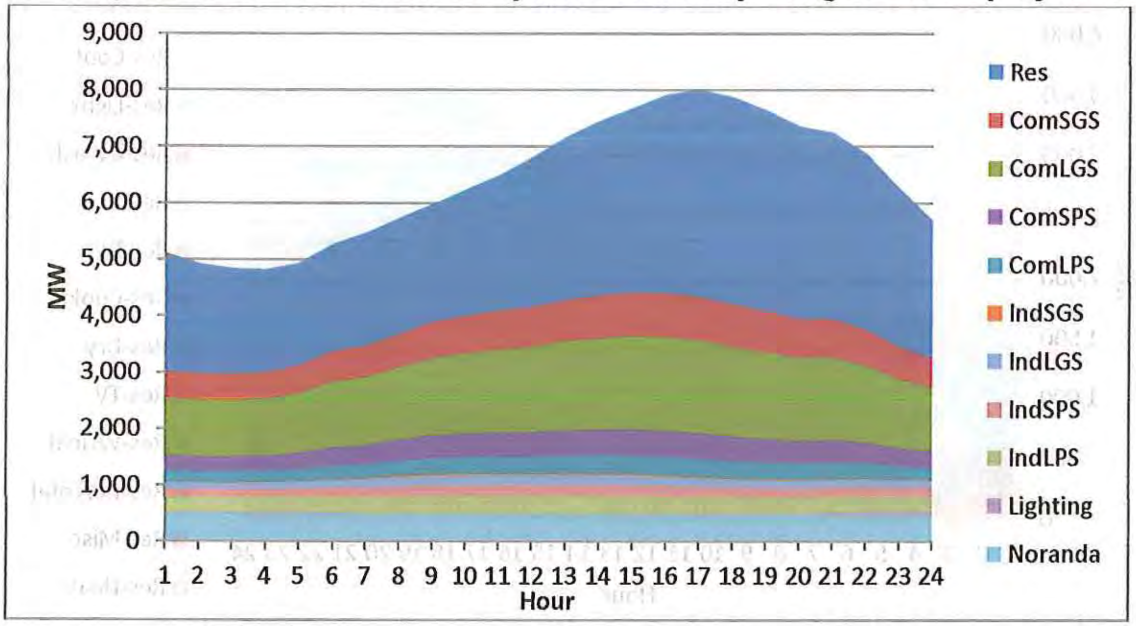
Figure 3.24: Residential Summer Day Usage Built-Up by End Use



Once each class load has been constructed on an hourly basis (either through direct application of the class profile to the class energy forecast or through the aggregation of the end-use scaled load shapes), transmission and distribution losses are applied. The transmission and distribution losses are based on the Ameren Missouri 2011 loss study performed by its distribution engineers. For purposes of calculating the load for the peak forecast, demand loss rates are utilized. Demand loss rates are the loss rates determined by the study to apply to loads at times of peak demand. Typically this loss rate is higher than average or energy loss rates due to the properties of the system that cause losses to increase both under high load conditions and high temperatures.

The demand loss rates are applied to the profiled loads based on the planning calendar. This is done because the planning calendar was created specifically to develop a consistent peak forecast across time and the demand loss rates are designed specifically for application to peak periods. Each class has the applicable loss rate applied to it based on the voltage level at which its customers are served. When each class' hourly load has been grossed up to represent the amount of energy that must be generated to serve them inclusive of applicable losses, the class loads are summed for each hour. This results in a forecast of the hourly load from which the maximum value for each month can be isolated as the forecasted peak load for that month. Similar to the build-up of the residential class from end-use data, a graphical representation of the build-up of the system load by class can be seen in Figure 3.25.

Figure 3.25: 2014 Summer System Peak Day Usages Built-Up by Class



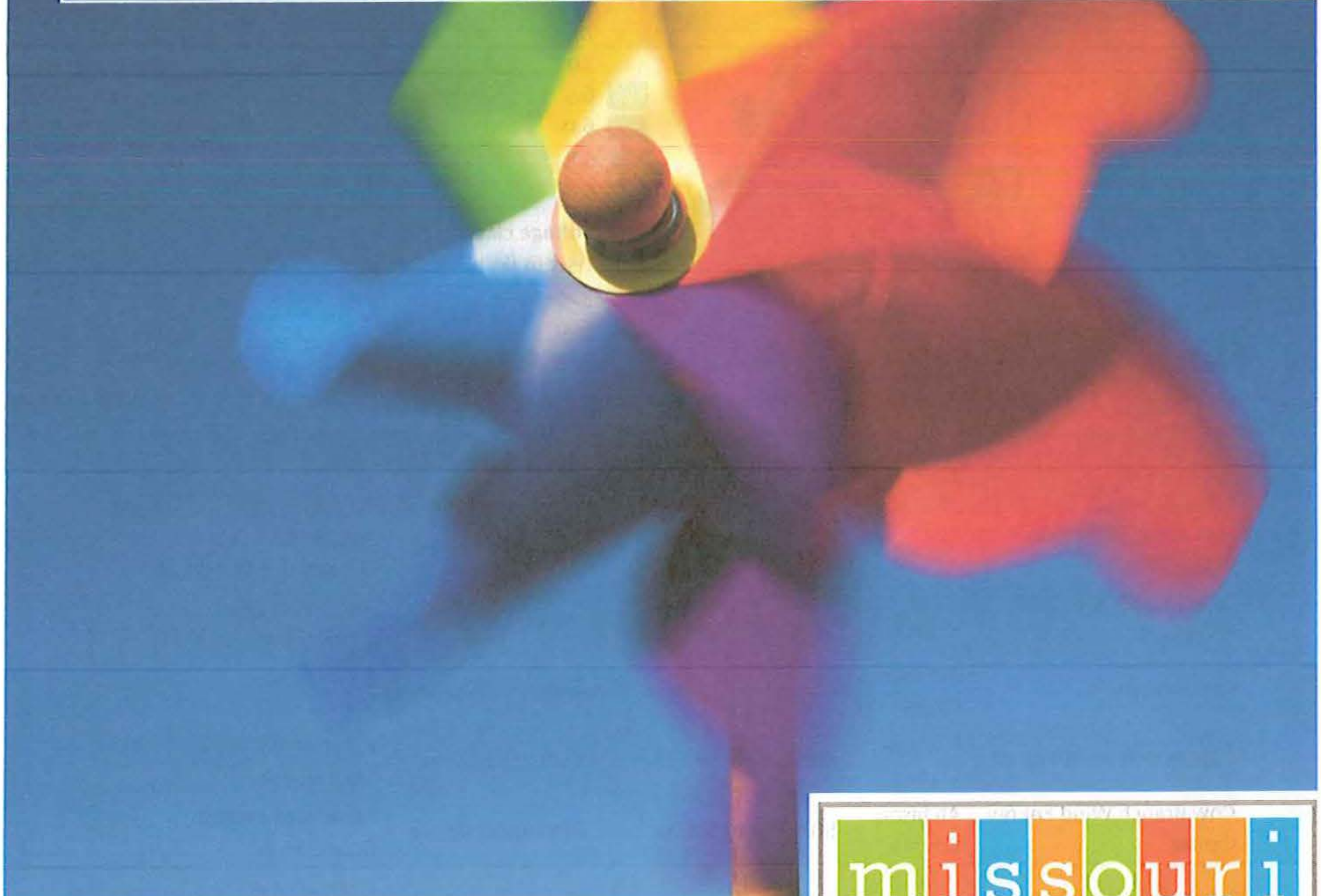
Back Testing and Calibration of Peaks

In order to ensure that the bottom-up forecast is producing a peak load estimate that is reliable, Ameren Missouri used the same methodology to backcast historical peaks for the period from 2007 through 2012. Historical calendar month actual sales were disaggregated into end uses where necessary by application of information from the Statistically Adjusted End Use models. The end use and class level profiles were updated with actual historical weather and calendar information to produce historical shapes to represent actual conditions. The historical sales were shaped using the profiles, grossed up for line losses, and aggregated. The peak values from those historical calculations for each year were compared to the actual peak loads observed in those years. The results are shown in the Table 3.7.

Table 3.7: Actual vs. Model Peak

Year	Modeled Peak (MW)	Actual Peak (MW)	Difference	% Diff
2007	8,458	8,784	326	3.7%
2008	8,254	8,367	113	1.3%
2009	7,750	7,761	11	0.1%
2010	8,248	8,444	196	2.3%
2011	8,037	8,413	376	4.5%
2012	8,744	8,439	-305	-3.6%
Avg.	8,249	8,368	120	1.4%

Missouri's Advantages for Wind Energy



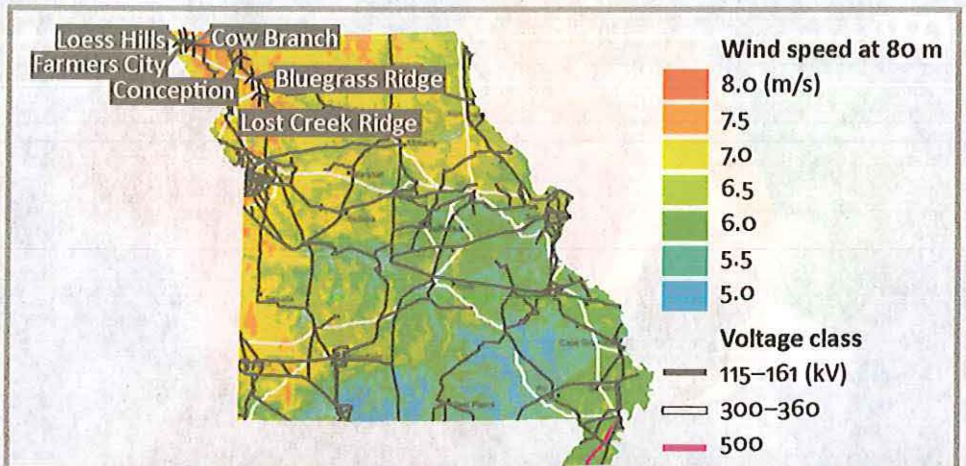
missouri
we get business.™

Currents. It's how we describe the flow of air moving around us...and the flow of electricity powering our homes and businesses. In Missouri, we're working to blur the line between the two by making our wind resources a big part of our energy picture.

Located on the eastern edge of the U.S. wind corridor, Missouri contributes to the Midwest's significant wind resources. An advanced supply chain, a highly-ranked transportation network, and a business-friendly environment further the state's ability to compete for wind energy projects.

With each new turbine that's built, with each new component that rolls off the line, Missouri is putting into motion that which is already stirring in the air.

Missouri's wind farms



Click to open a larger version

Name	Location	Power Capacity (MW)	Units	Turbine Mfr.	Developer & Owner	Power Purchaser	Year Online
Lost Creek Ridge Wind Farm (2011)	DeKalb	1.5	1	GE Energy	Wind Capital Group	Associated Electric Cooperative Inc. (AECI)	2011
Lost Creek Ridge Wind Farm (2010)	DeKalb	148.5	99	GE Energy	Wind Capital Group	Associated Electric Cooperative Inc. (AECI)	2010
Farmers City	Atchison County	146.0	73	Gamesa	Iberdrola Renewables		2009
Conception Wind Project	Nodaway County	50.4	24	Suzlon	Wind Capital Group	Associated Electric Cooperative	2008
Cow Branch Wind Energy Center	Atchison County	50.4	24	Suzlon	Wind Capital Group	Associated Electric Cooperative	2008
Loess Hills Wind Energy Center	Rock Port	5.0	4	Suzlon	Wind Capital Group	Missouri Joint Municipal Electric Utility Commission	2008
Bluegrass Ridge Wind Energy Project	Gentry county	56.7	27	Suzlon	Wind Capital Group	Associated Electric Cooperative	2007

Utility Scale Wind-Powered Electric Generation

As part of our diversified generation portfolio, we purchase 102 MW of wind power from Phase II of Horizon Wind Energy's Pioneer Prairie Wind Farm in Iowa. This is enough energy to power 26,000 average households. This wind power ties into the Midwest Independent System Operator (MISO) transmission grid, of which we are a member. Ameren Missouri began using wind power in June 2009 as part of an agreement with Pioneer Prairie.

Fun fact

The St. Louis Gateway Arch is 630 feet tall. A Suzion 2.1 MW wind turbine is 404 feet in total height. The turbine tower itself (without turbine blades) is 262 feet tall.

Additional wind power links

- American Wind Energy Association (AWEA)
- Wind Technologies Program (DOE)
- Wind Resource Information (NREL)

Midwest ISO
We manage power.

Interconnection System Impact Study Report

Midwest ISO Project: G578
Queue #: 38706-01

Shuteye Creek Wind Project
Adair County, MO
300 MW

Connecting to Ameren Facilities
in the Associated Electric Cooperative Inc. Control Area

FINAL REPORT

08/07/2007

Midwest ISO
701 City Center Drive
Carmel
Indiana - 46032
http://www.midwestiso.org

CONTENTS

1 Executive Summary

1.1 *Steady State Analysis*

The Steady State Analysis identified one injection related constraint. The Thomas Hill – Moberly Tap 161 kV line is overloaded for multiple contingencies. This constraint must be mitigated prior to interconnection; a solution is provided by AECI at an estimated cost of $10.9M.

1.2 *Transient Stability Analysis*

The Transient Stability Analysis identified no constraints. However, the current Low Voltage Ride Through (LVRT) capability of the turbines is insufficient to stay online during various faults.

1.3 *Short Circuit Analysis*

The Short Circuit Analysis identified no constraints.

1.4 *Local Planning Criteria Analysis*

The Ameren Local Planning Criteria identified no constraints.

1.5 *Deliverability Analysis*

The Deliverability Analysis found the G578 study generator to be 0 (zero) MW deliverable. This constraint occurs when monitoring Thomas Hill - Moberly Tap 161 kV for the loss of Thomas Hill - McCredie 345 kV. To fix this constraint and make G578 fully deliverable, a solution is provided by AECI at an estimated cost of $10.9M.

1.6 *Study Assumptions*

The results of this study are subject to change depending on the assumptions made in the study and status or outcome of higher queued generation interconnection requests which were included in the study. If these assumptions change, or if higher queued projects drop out of the queue, additional analysis may be required to determine if there are impacts on the study results.

2 Introduction

This report contains the System Impact Study (SIS) results for the Midwest ISO (MISO) Generation Interconnection Project G578 (Queue # 38706-01). Project G578 proposes the addition of 300 MW of wind generation to connect to the Adair Substation, in Adair County, Missouri, at 161 kV. The Adair Substation is owned by Ameren (AMRN) and located within the Associated Electric Cooperative Inc. (AECI) Control Area. The requested in-service date is October 1, 2007. The generation will be built in the southwest corner of Adair County, with a ten mile line going east to the Adair Substation, as shown in Figure 2.1 on the following page.

AMRN owns the 69 kV and 161 kV facilities at the Adair Substation as well as the 161 kV lines from Adair to Appanoose and from Adair to Thomas Hill. AECI owns the 161 kV line from Adair to Novelty. The 161 kV facilities at Adair and the lines to Novelty and Thomas Hill are located in the AECI Control Area. The line to Appanoose is located in the Alliant (ALTW) Control Area, while the 69 kV facilities at Adair are located in the AMRN Control Area.

The purpose of the study is to evaluate the impacts of the interconnection of the study generator when operating at 100% of their requested output on the transmission system. The generator is required to mitigate all injection, stability, and short circuit constraints for the Energy Resource Interconnection Service (ERIS). ERIS allows the generator to deliver its output using existing firm or non-firm capacity of the transmission system on an as-available basis. Additionally, all constraints identified in the Local Planning Criteria and Deliverability Analyses need to be mitigated for the Network Resource Interconnection Service (NRIS).

An Ad Hoc Study Group was formed from the representatives of the affected Transmission Owners and Transmission Providers in the area: AECI, ALTW, AMRN, and MEC. The group reviewed and approved the models, assumptions, and results.

KTVO.com

http://ktvo.com/news/local/economic-hopes-blow-away-as-wind-farm-falls-through?id=738789#.T39K29XNkS9

Economic hopes blow away as wind farm falls through

By John Garlock Thursday, April 5th 2012

Fri, 06 Apr 2012 01:12:59 GMT — A multi-million dollar renewable energy project proposed for northeast Missouri is gone with the wind.

TradeWind Energy out of Lenexa, Kansas confirms it is terminating its Shuteye Creek Wind Project that would have put up numerous wind turbines in parts of Adair, Putnam and Sullivan counties.

TradeWind CEO Rob Freeman explained the reason behind the decision in a lengthy statement. Part of that statement stated, "Unfortunately it has become increasingly evident that the wind energy market in Missouri will simply not develop in the foreseeable future given the lack of interest in wind energy in the state.â??

The company recently mailed project termination notifications to all landowners associated with the project.

State Representative Zachary Wyatt of Novinger told KTVO he was not glad to hear the news that TradeWind was pulling out.

"One of the things I like to talk about when I go around the state and talk about renewable energy is that this is one of the last hopes for rural economic development, and if we shut the door on this, what else do we have in small towns throughout the northern part of missouri?"

Wyatt said he's disappointed in TradeWind's decision because of the loss of tax revenue that the Shuteye Creek Wind Project would have generated in Adair, Sullivan and Putnam counties.

The wind farm would have provided millions of dollars in revenue to school districts in those counties.

Below is the full e-mail KTVO received from Rob Freeman:

To confirm your inquiry, TradeWind Energy has provided project termination notifications to all landowners associated with the Shuteye Creek Wind Project.

In 2005, TradeWind began developing the Shuteye Creek Wind Project located in parts of Sullivan, Adair, and Putnam counties with the expectation of an emerging Missouri wind energy market. At that time we were very optimistic about the future for wind power in Missouri based on the fact that the northern part of the state in particular has a robust wind resource that is comparable to surrounding states that are actively and successfully developing wind energy.

TradeWind has invested millions of dollars to lease and develop the Shuteye project area, including funding transmission interconnection studies, collecting wind data, conducting environmental studies, and developing engineering plans. Unfortunately it has become increasingly evident that the wind energy market in Missouri will simply not develop in the foreseeable future given the lack of interest in wind energy in the state. Base on this TradeWind has made the difficult decision to significantly reduce its presence in the state of Missouri and to more heavily focus its resources in other states where there is a clear commitment to development of this great energy resource.

The communities associated with the Shuteye project have been extremely helpful and supportive along the way over the last 7 years, and for that we are very grateful. Really it is for them that we are most disappointed as this project would have represented a rare opportunity for significant economic development in the area of clean energy technology for these communities.

Since 2008, Tradewind Energy has constructed over 800 megawatts of wind energy in Midwestern statesâ?|.enough to power 250,000 homes. These projects have represented approximately $1.3 billion in capital investment. To these states these projects have brought economic development, jobs, and a component of energy technology diversification and energy security, conservation of natural resources, and protection against price volatility associated with burning fossil fuels to generate electricity.

It is our sincere hope that eventually we will see the state of Missouri enjoy the same benefits that surrounding states are seeing with development of wind energy.

Sincerely,

Rob Freeman, CEO

TradeWind Energy, LLC