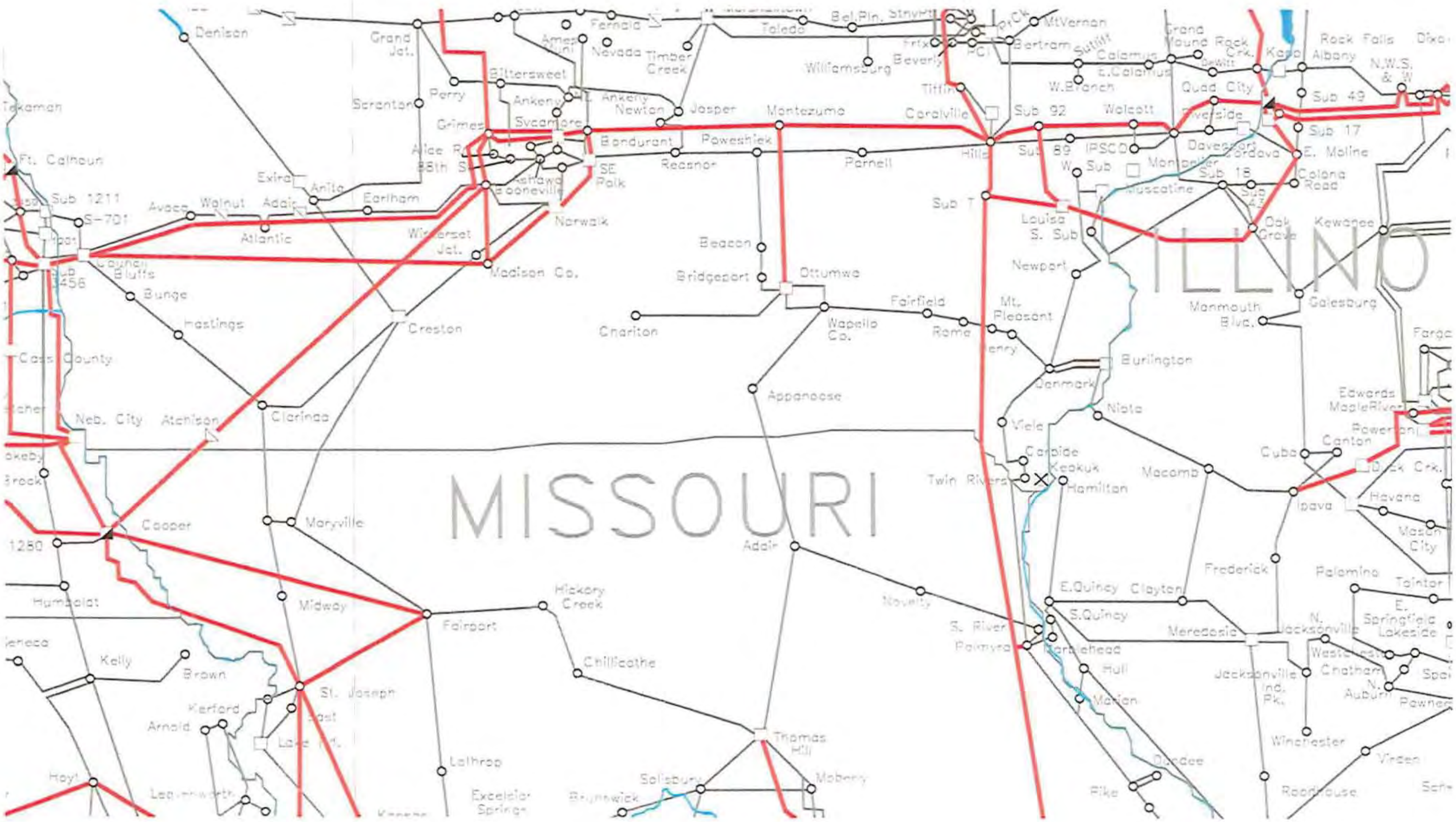
Company Name: Midcontinent Independent System Operator, Inc.

Case Description: Ameren Transmission Co. of Illinois Application for Certificate of Convenience and Necessity
No. EA-2015-0146 (Missouri P.S.C.)

Response to Request by Neighbors United

Date of Response: October 16, 2015

ATTACHMENT 1



MISSOURI
ILLINO
Denison
Grand Jct.
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Perry
Bittersweet
Ankeny
Ames
Nevada
Fernald
Timber Creek
Jasper
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Toledo
Bel.Pln.
Williamsburg
Beverly
MtVernon
Bertram
Calamus
E.Calamus
W.Branch
Grand Mound
Rock Crk.
DeWitt
Rock Falls
Albany
N.W.S. & W
Sub 49
Sub 17
E. Moline
Colona Road
Quad City
Riverside
Davenport
Cordova
Wolcott
Sub 92
Sub 89
IPSCO
Coralville
Tiffin
PCI
Hills
Sub T
Montezuma
Poweshiek
Parnell
Reasnor
Bondurant
Sycamore
Grimes
SE Polk
Norwalk
Madison Co.
Winterset Jct.
Earlham
Anita
Exira
Adair
Walnut
Avoca
Atlantic
Sub 1211
S-701
Ft. Calhoun
Tekamah
Council Bluffs
Sub 3456
Bunge
Hastings
Cass County
Neb. City
Atchison
Clarinda
Creston
Beacon
Bridgeport
Ottumwa
Chariton
Wapello Co.
Fairfield
Rome
Mt. Pleasant
Appanoose
Louisa S. Sub
Newport
Muscatine
Montpelier
Sub 18
Oak Grove
Kewanee
Galesburg
Monmouth Blvd.
Burlington
Denmark
Niota
Viele
Carbide
Keokuk
Hamilton
Twin Rivers
Macomb
Cuba
Canton
Ipava
Havana
Mason City
Edwards
MapleRiver
Powerton
Duck Crk.
Frederick
Palomino
Tainter
E. Springfield
Lakeside
N. Jacksonville
Meredosia
Jacksonville
Ind. Pk.
Chatham
N. Auburn
Pawnee
Winchester
Virden
Roadhouse
Clayton
E.Quincy
S.Quincy
S. River
Palmyra
Hull
Marion
Dundee
Pike
Novelty
Adair
Thomas Hill
Moberly
Salisbury
Brunswick
Chillicothe
Hickory Creek
Fairport
Lathrop
Excelsior Springs
Maryville
Midway
Cooper
1280
Humboldt
Kelly
Brown
St. Joseph
East
Lake Rd.
Kerford
Arnold
Hoyt
Leavenworth
Farga

SA 2697 AMEREN-AECI INTERCHANGE AGREEMENT VERSION 31.0.0

EFFECTIVE 9/13/2014

ORIGINAL SERVICE AGREEMENT NO. 2697

PUBLIC VERSION

INTERCHANGE AGREEMENT

entered into by the

UNION ELECTRIC COMPANY

(dba Ameren Missouri)

and

ASSOCIATED ELECTRIC COOPERATIVE, INCORPORATED

Coordinating Committee is unable to agree on any matter falling under its jurisdiction, such matter shall be referred to the Senior Vice President – Transmission of UE and the General Manager of AECI for decision. All decisions and agreements made by the Coordinating Committee or the Senior Vice President – Transmission of UE and the General Manager of AECI, shall be evidenced in writing.

Section 3.2 - Parallel Operation. The systems of UE and AECI shall normally be operated in parallel, with circuits closed at the connections set forth under the Appendices except during switching operations or as hereinafter provided.

It is recognized that, with the systems of UE and AECI connected as set forth herein, the flow of power through the connections is not subject to precise control, but is determined by the physical and electrical characteristics of the systems. It is also recognized that to fully realize the benefits attainable under this Agreement, it is desirable that the systems of the Parties operate in parallel at all times to permit the transfer of power and energy as needed. However, if at any time, the energy flow over the system of either Party, or the flow to any third Party because of such parallel operation, should jeopardize or give rise to conditions which could be expected, if not corrected, to jeopardize customer service or system operation of either Party, then the Party which in its sole judgment suffers or anticipates suffering such injury shall have the right to open, or have the other Party open, any or all of the connections between the Parties to relieve its system of the burden imposed upon it by such flow or anticipated flow of power. However, prior notice shall be given to the other Party when practicable, so that any feasible corrective measures may be put into effect before opening the connections.

Each Party shall establish schedules for the exchange of energy with the dispatcher of the other before intentionally taking any energy from the system of the other. To the extent it can be controlled, neither Party shall impose any unusual burden upon the facilities of the other Party in excess of their safe and proper capacity as determined by the owning Party. If emergency conditions arise which overload the connecting facilities between the systems of the Parties, then both Patties shall cooperate in taking immediate steps to eliminate such

overload conditions, but the Party whose system causes the emergency situation shall have the primary responsibility for such corrective action, even though this may involve dropping load on its system.

Section 3.3 - Reactive Power and Voltage Regulation. Each Party shall supply the reactive kVA required on its own system; and except as otherwise arranged from time to time, neither Party shall be obligated to supply reactive kVA to the other Party. A sufficient proportion of the reactive kVA supply be each Party shall be capable of being switched so as to minimize leading power factor problems during light load conditions.

The Coordinating Committee shall from time to time, but not less than annually, review reactive kVA flows over the connections and the power factor of the Parties' loads.

If, at any time, the flow of reactive kVA over any connection is, or can reasonably be expected to be, unduly detrimental to customer service or system operation of either Party, then the Party which in its sole judgment so suffers or reasonably expects to suffer such injury shall have the right in its sole discretion and judgment to open, or have the other Party open, the connection between the Parties to relieve its system of the burden imposed upon it by such flow or potential flow of reactive kVA. However, prior notice shall be given to the other Party when practicable, so that any feasible corrective measures may be put into effect before opening the connection.

Section 3.4 - Disturbances. Each Party shall, insofar as practicable, so protect, operate, and maintain its system and facilities as to avoid disturbances which might cause impairment of service in the system of the other Party.

Section 3.5 - Spinning Reserve. UE and AECI shall each carry, or provide to be carried, appropriate spinning reserve.

Section 3.6 - Regulation of Connections. The Parties agree that it is the responsibility of each Party to operate its power supply facilities so as to supply its own system load, except

INTERCONNECTION NO. 5 – ADAIR

Point of Interconnection: The point at which the conductors of AECI's 161 kV line from AECI's South River Substation near Palmyra make contact with the strain insulators at UE's Adair Substation.

Facilities Provided by UE: UE will continue to provide, or be responsible for, all substation facilities required at Adair Substation for the termination of AECI's 161 kV, single circuit, three phase transmission line from AECI's South River Substation. These facilities include disconnects, protective, control, synchronizing, recording and area load control telemetering equipment installed in the Adair Substation. Metering by UE at Adair Substation is at 161 kV on the line to ITC Midwest's Appanoose 161 kV substation.

Facilities Provided by AECI: AECI will continue to provide, operate and maintain a 161 kV, single circuit, three phase transmission line extending from its South River Substation to UE's Adair Substation.

Metering: At its Novelty substation, AECI will continue to provide, operate and maintain 161 kV metering on the 161 kV line to Adair. The 161 kV metering at Novelty will be adjusted for losses on the Adair to Novelty 161 kV line back to the Point of Interconnection at Adair.

Condition: UE will, at its own expense, continue to own, operate, and maintain a 161 kV, single circuit transmission line with necessary metering from UE's Adair Substation to a point on the Iowa-Missouri border within the first mile west of the east boundary of Appanoose County, Iowa, where it interconnects with a 161 kV transmission line owned by ITC Midwest from its Appanoose Substation south to the point of interconnection, known as the Appanoose-Adair Line. AECI shall have the right to schedule up to 50,000 kW with ITC Midwest over the Appanoose-Adair Line. Transactions involving more than 50,000 kW are subject to the approval of UE.

AECI will also continue to have available, operate, and maintain a 161 kV, single circuit, three phase transmission line with necessary metering from its Thomas Hill Substation to a point of interconnection with the system of Kansas City Power and Light Greater Missouri Operations (KCPL-GMO) near Maryville, Missouri. UE shall have the right to schedule up to 50,000 kW with KCPL-GMO for transmission to and from UE's system over the Thomas Hill-Maryville 161 kV line. Transactions involving more than 50,000 kW are subject to approval of AECI.

Jurisdictional and Functional Control: UE will have functional and AECI will have jurisdictional control over the Adair terminal for the 161 kV line to Novelty. AECI will have functional and UE will have jurisdictional control over the Adair terminal for the 161 kV line to Thomas Hill.

Ameren Transmission Company of Illinois's
Response to Neighbors United Data Request

In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line from Palmyra, Missouri, to the Iowa Border and an Associated Substation Near Kirksville, Missouri.
Data Request

Data Request No.: NU-A1 - Jennifer Hernandez

For the three 161 kV line segments with projected voltage violations under NERC Category C contingency conditions, answer the following questions:

What are the MVA ratings of line segments?

RESPONSE

Prepared By: Dennis Kramer
Title: Sr. Director – Transmission Policy, Planning and Stakeholder Relations
Date: October 10, 2015

The low voltage conditions that could result in the loss of both Ameren Missouri and Cooperative customer load in the northeastern Missouri area occur when two of the three existing 161 kV lines that supply that area are out of service during peak load conditions. This event could result in loss of customer load and would be a NERC Category C contingency condition.

During the development of the MVP portfolio, MISO (at that time named the Midwest ISO) performed a system analysis to identify facility overloads and resultant NERC contingency conditions that would be created by connecting additional wind generation resources to the existing 161 kV system in northeastern Missouri. MISO's analysis indicated that the Mark Twain Project was the best solution to address the overload conditions.

What are the MVA ratings of line segments?
The below ratings are summer emergency ratings from the Eastern Interconnection System Model 2010 series for 2021 Summer or other sources where indicated. The models are periodically updated by the transmission line owners.

1. Thomas Hill to Adair owned by Ameren Missouri = 315 MVA

2. Appanoose to Adair with Missouri portion owned by Ameren Missouri and Iowa portion owned by ITC Midwest = 223 MVA
3. Adair to Novelty and continuing to Palmyra owned by Associated Electric = 285 MVA. Rating based upon information provided by Associated Electric.

Ameren Transmission Company of Illinois's
Response to Neighbors United Data Request

In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line from Palmyra, Missouri, to the Iowa Border and an Associated Substation Near Kirksville, Missouri.
Data Request

Data Request No.: NU-A2 - Jennifer Hernandez

For the three 161 kV line segments with projected voltage violations under NERC Category C contingency conditions, answer the following questions:

What are the ages of the poles and conductors (for each line segment)?

RESPONSE

Prepared By: Dennis Kramer
Title: Sr. Director – Transmission Policy, Planning and Stakeholder Relations
Date: October 10, 2015

The low voltage conditions that could result in the loss of both Ameren Missouri and Cooperative customer load in the northeastern Missouri area occur when two of the three existing 161 kV lines that supply that area are out of service during peak load conditions. This event could result in loss of customer load and would be a NERC Category C contingency condition.

During the development of the MVP portfolio, MISO (at that time named the Midwest ISO) performed a system analysis to identify facility overloads and resultant NERC contingency conditions that would be created by connecting additional wind generation resources to the existing 161 kV system in northeastern Missouri. MISO's analysis indicated that the Mark Twain Project was the best solution to address the overload conditions.

What are the ages of the poles and conductors (for each line segment)?

1. Thomas Hill to Adair: Miscellaneous replacements have occurred over time, but most of the poles were installed in 1969. The conductor was installed in 1969.
2. Appanoose to Adair (Ameren Missouri portion): Miscellaneous replacements have occurred over time, but most of the poles were installed in 1970. The conductor was installed in 1970.

3. Adair to Novelty and continuing to Palmyra: This line is owned and maintained by Associated Electric, and ATXI is unaware of the ages of the poles and conductors.

Ameren Transmission Company of Illinois's
Response to Neighbors United Data Request

In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line from Palmyra, Missouri, to the Iowa Border and an Associated Substation Near Kirksville, Missouri.
Data Request

Data Request No.: NU-A3 - Jennifer Hernandez

For the three 161 kV line segments with projected voltage violations under NERC Category C contingency conditions, answer the following questions:

What is the material used in the existing conductors for each line segment?

RESPONSE

Prepared By: Dennis Kramer
Title: Sr. Director – Transmission Policy, Planning and Stakeholder Relations
Date: October 10, 2015

The low voltage conditions that could result in the loss of both Ameren Missouri and Cooperative customer load in the northeastern Missouri area occur when two of the three existing 161 kV lines that supply that area are out of service during peak load conditions. This event could result in loss of customer load and would be a NERC Category C contingency condition.

During the development of the MVP portfolio, MISO (at that time named the Midwest ISO) performed a system analysis to identify facility overloads and resultant NERC contingency conditions that would be created by connecting additional wind generation resources to the existing 161 kV system in northeastern Missouri. MISO's analysis indicated that the Mark Twain Project was the best solution to address the overload conditions.

What is the material used in the existing conductors for each line segment?

1. Thomas Hill to Adair is 954 KCMIL ACSR 45/7 RAIL conductor).
2. Appanoose to Adair (Ameren Missouri portion) is 795 KCMIL ACSR 45/7 TERN conductor.
3. Adair to Novelty and continuing to Palmyra is owned and maintained by Associated Electric, and ATXI is unaware of the existing conductor material.

Ameren Transmission Company of Illinois's
Response to Neighbors United Data Request

In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line from Palmyra, Missouri, to the Iowa Border and an Associated Substation Near Kirksville, Missouri.
Data Request

Data Request No.: NU-A10 - Jennifer Hernandez

For the three 161 kV line segments with projected voltage violations under NERC Category C contingency conditions, answer the following questions:

Provide the length (in miles) of the three 161 kV line segments that experience NERC reliability violations under Category C contingency conditions.

RESPONSE

Prepared By: Dennis Kramer
Title: Sr. Director – Transmission Policy, Planning and Stakeholder Relations
Date: October 10, 2015

The low voltage conditions that could result in the loss of both Ameren Missouri and Cooperative customer load in the northeastern Missouri area occur when two of the three existing 161 kV lines that supply that area are out of service during peak load conditions. This event could result in loss of customer load and would be a NERC Category C contingency condition.

During the development of the MVP portfolio, MISO (at that time named the Midwest ISO) performed a system analysis to identify facility overloads and resultant NERC contingency conditions that would be created by connecting additional wind generation resources to the existing 161 kV system in northeastern Missouri. MISO's analysis indicated that the Mark Twain Project was the best solution to address the overload conditions.

Provide the length (in miles) of the three 161 kV line segments that experience NERC reliability violations under Category C contingency conditions.

1. Thomas Hill to Adair: Approximately 44 miles.
2. Appanoose to Adair (Ameren Missouri portion): Approximately 41 miles.

Adair to Novelty and continuing to Palmyra: This line is owned and maintained by Associated Electric, and ATXI does not know the exact line length.

Ameren Transmission Company of Illinois's
Response to Neighbors United Data Request

In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line from Palmyra, Missouri, to the Iowa Border and an Associated Substation Near Kirksville, Missouri.
Data Request

Data Request No.: NU-A11 - Jennifer Hernandez

For the three 161 kV line segments with projected voltage violations under NERC Category C contingency conditions, answer the following questions:

Describe the location and assumed output (in MW) of wind power generation facilities that contribute to the Category C violations on the three 161 kV lines.

RESPONSE

Prepared By: Dennis Kramer
Title: Sr. Director – Transmission Policy, Planning and Stakeholder Relations
Date: October 10, 2015

The low voltage conditions that could result in the loss of both Ameren Missouri and Cooperative customer load in the northeastern Missouri area occur when two of the three existing 161 kV lines that supply that area are out of service during peak load conditions. This event could result in loss of customer load and would be a NERC Category C contingency condition.

During the development of the MVP portfolio, MISO (at that time named the Midwest ISO) performed a system analysis to identify facility overloads and resultant NERC contingency conditions that would be created by connecting additional wind generation resources to the existing 161 kV system in northeastern Missouri. MISO's analysis indicated that the Mark Twain Project was the best solution to address the overload conditions.

Describe the location and assumed output (in MW) of wind power generation facilities that contribute to the Category C violations on the three 161 kV lines.

A NERC Category C contingency condition occurs when two of the existing 161 kV lines that supply the northeastern Missouri area are out of service during peak load conditions.

The location and assumed output of wind power generation facilities do not contribute to the low voltage condition.

The MISO analysis of the impact of connecting additional wind generation resources to the existing 161 kV system in northeastern Missouri identified facility overloads. The assumptions used by MISO in its analysis are contained in publically available MISO materials.

Ameren Transmission Company of Illinois's
Response to Neighbors United Data Request

In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line from Palmyra, Missouri, to the Iowa Border and an Associated Substation Near Kirksville, Missouri.
Data Request

Data Request No.: NU-C7 - Jennifer Hernandez

Identify the 2021 wind power capital cost assumption and annual capacity factor assumption used as inputs in the MTEP14 Triennial Review cost-benefit calculations.

RESPONSE

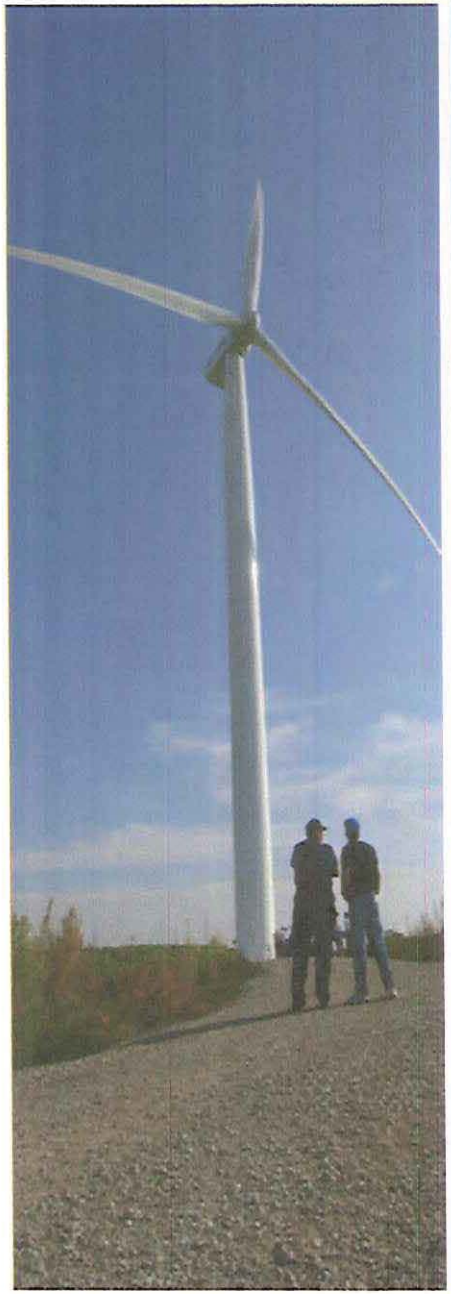
Prepared By: Dennis Kramer
Title: Sr. Director – Transmission Policy, Planning and Stakeholder Relations
Date: October 10, 2015

Identify the 2021 wind power capital cost assumption and annual capacity factor assumption used as inputs in the MTEP14 Triennial Review cost-benefit calculations.

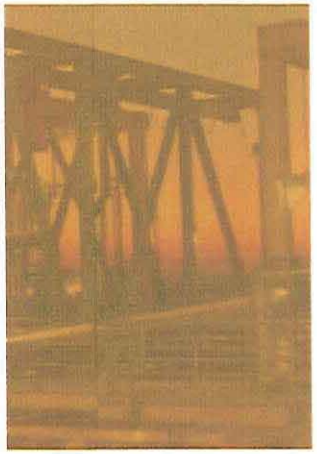
ATXI possesses only the publicly available information provided by MISO regarding the assumptions used by MISO in its analysis.

Page 40 of the MISO MTEP14 Triennial Review Report states, "The incremental wind benefits were monetized by applying a value of $2 to $2.8 million/MW, based on the U.S. Energy Information Administration's estimates of the capital costs to build onshore wind."

Page 23 of the MTEP14 Triennial Review Report states, "A MISO-wide per-unit capacity factor was averaged from the 2028 incremental wind zone capacities to 31.4 percent."



Associated Electric Cooperative Overview

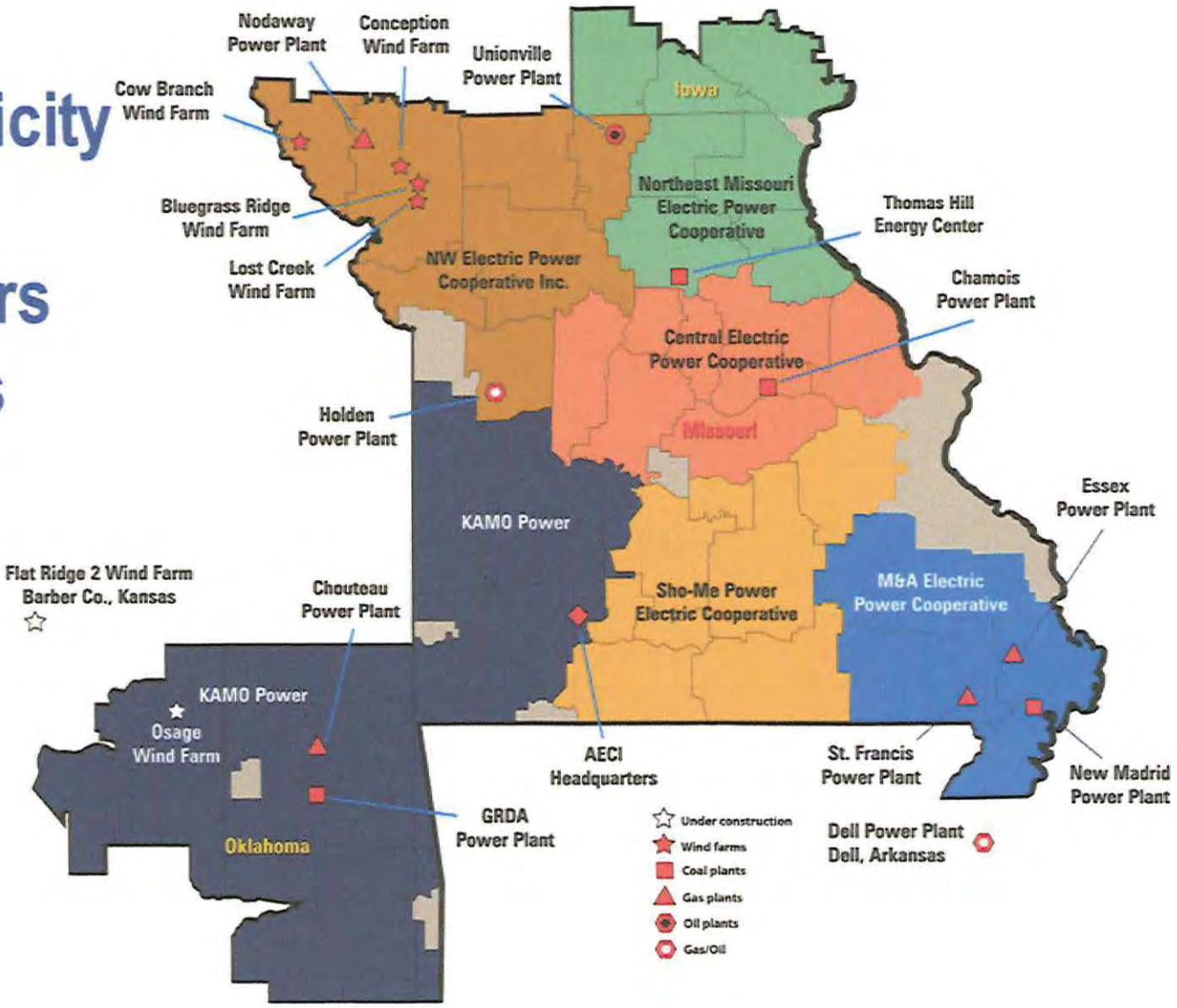


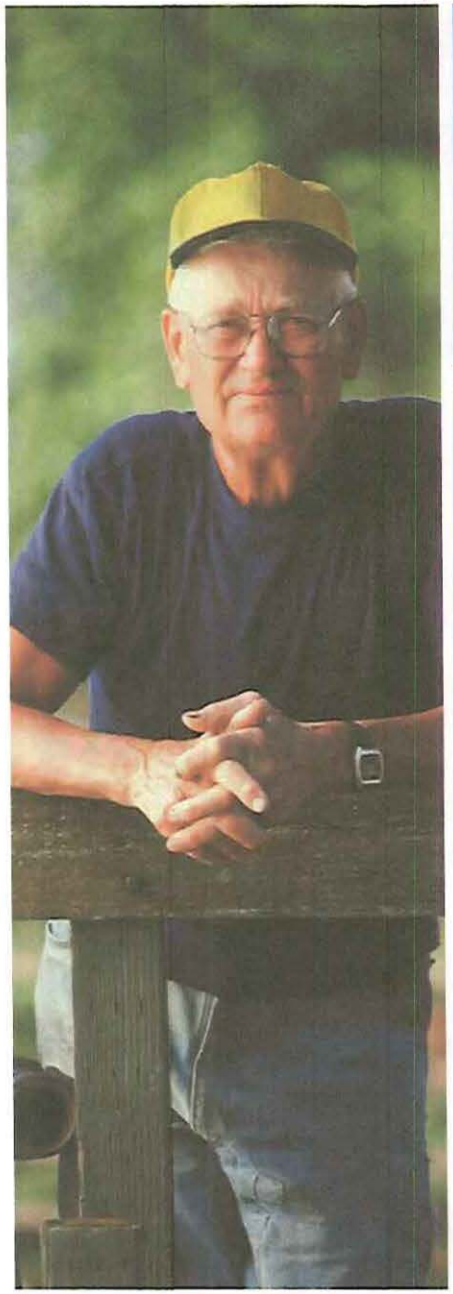
Jim Jura

CEO & General Manager

Associated Electric Cooperative

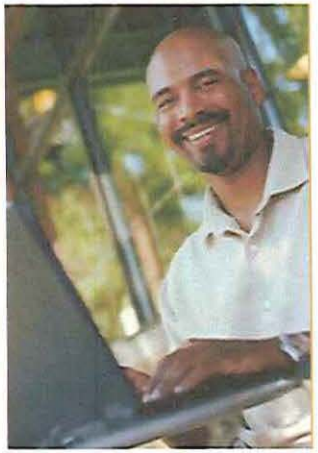
3-tier system supplies electricity for 875,000 member–owners across 3 states

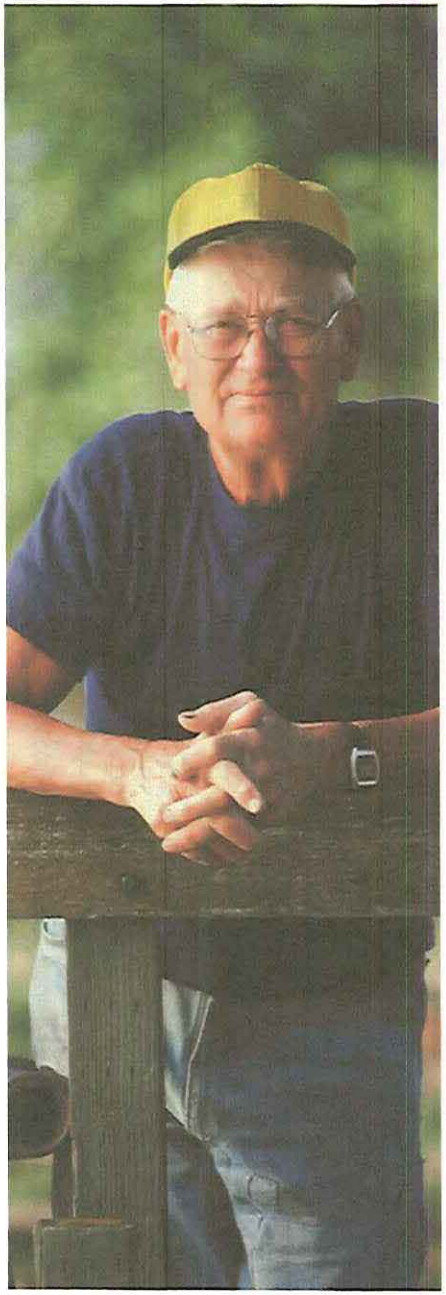




Our Mission Statement

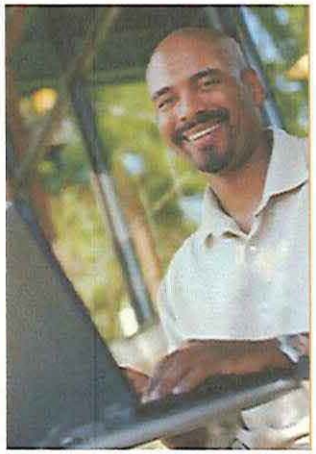
Associated Electric Cooperative's mission is to provide an economical and reliable power supply and support services to its members



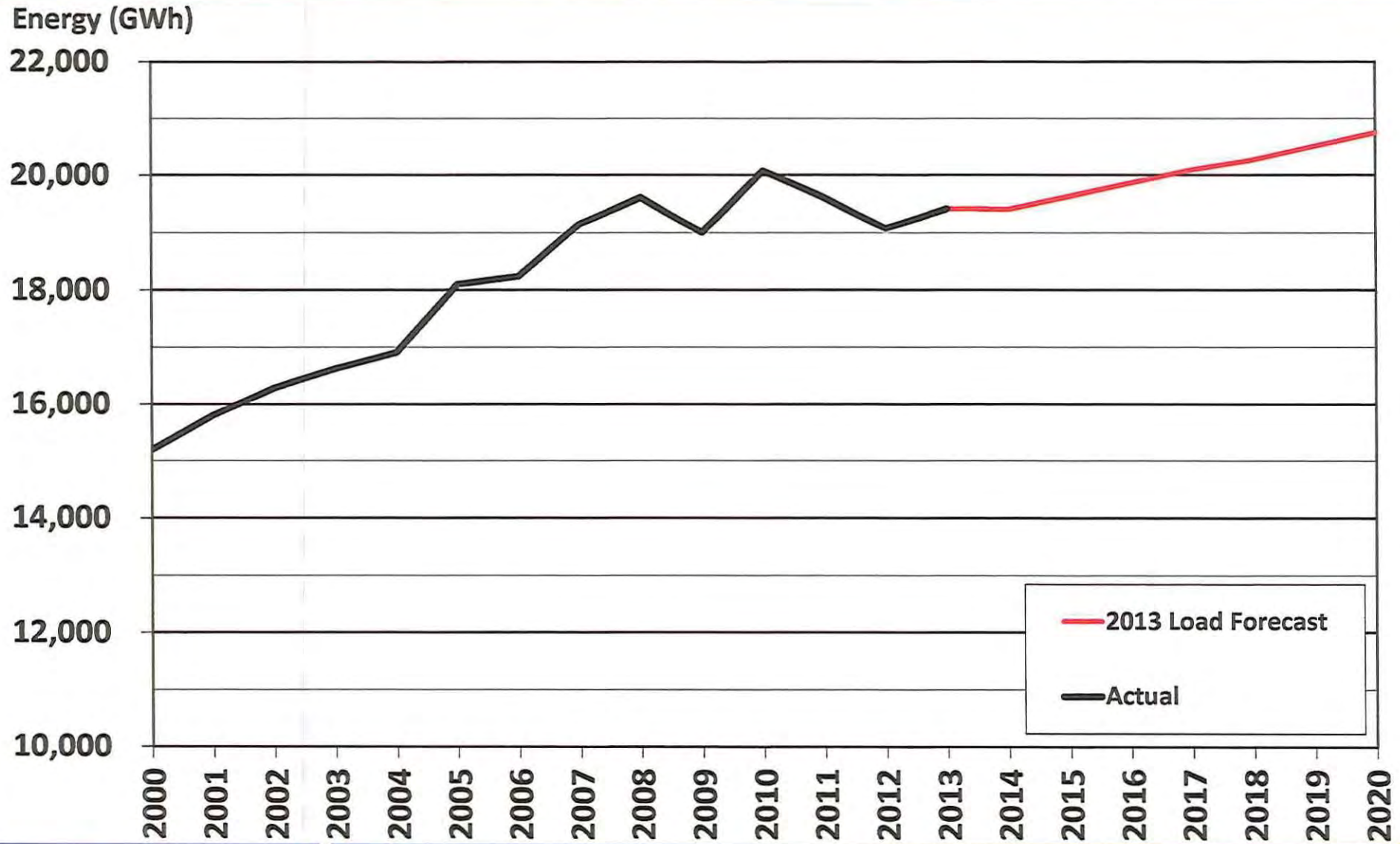


Our Vision Statement

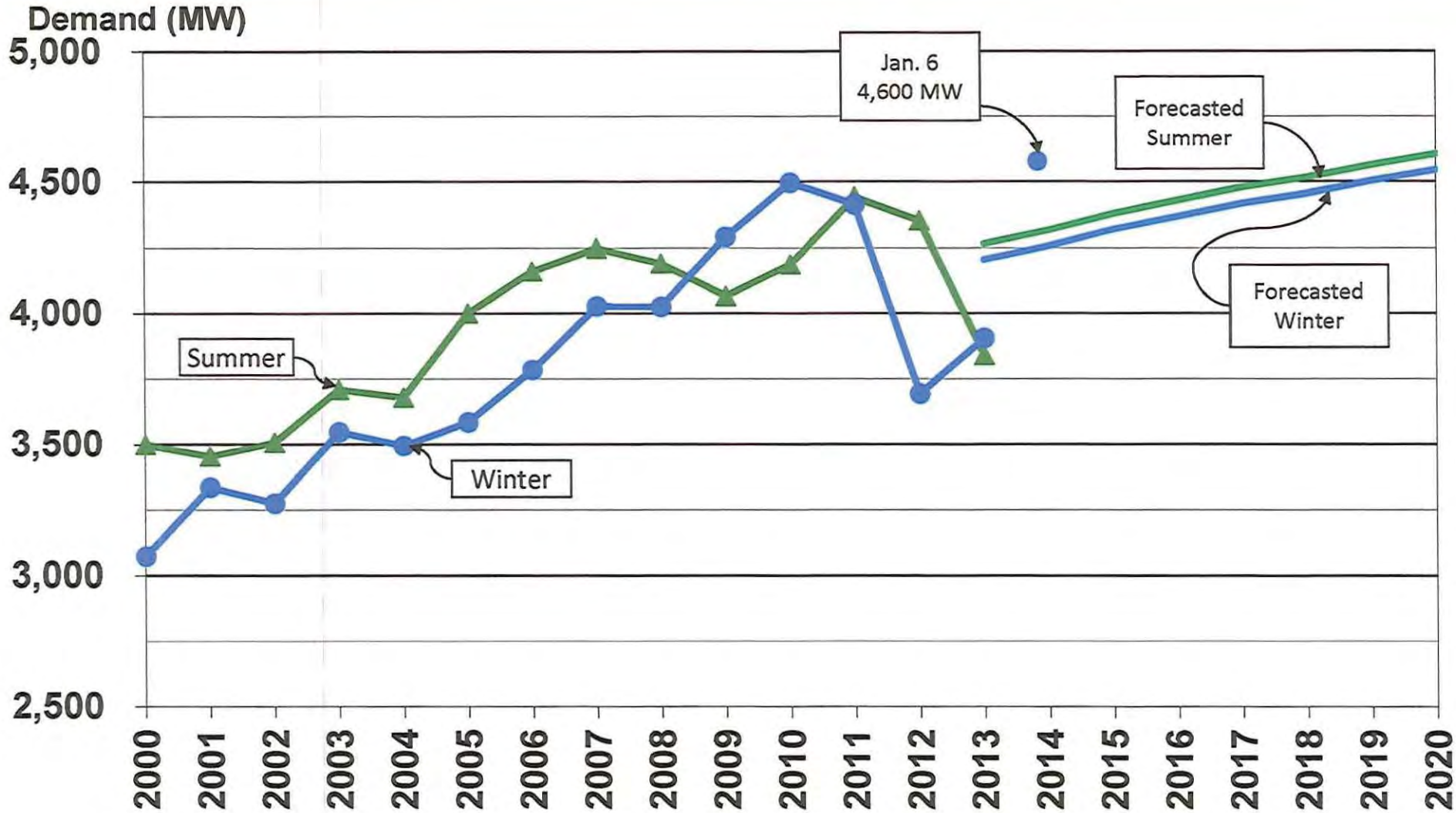
Associated Electric Cooperative will be the lowest-cost wholesale power supplier



Historical / Forecasted Loads



Historical / Forecasted Demand



Rulemaking No.:	12-03-014
Exhibit No.:	SCE-1
Witnesses:	Garry Chinn Colin Cushnie Mark Nelson Jonathan Rumble Carl Silsbee

SOUTHERN CALIFORNIA EDISON®

An *EDISON INTERNATIONAL®* Company

(U 338-E)

TRACK 4 TESTIMONY OF SOUTHERN CALIFORNIA EDISON COMPANY

Before the
Public Utilities Commission of the State of California

Rosemead, California
August 26, 2013

sections and breakers) violates system performance requirements specified by the NERC Reliability Standards.[16]

The United States Congress created an electric reliability organization (ERO) through the Energy Policy Act of 2005. The Federal Energy Regulatory Commission (FERC) certified NERC as the ERO on July 20, 2006. NERC develops, implements, and enforces mandatory reliability standards for the bulk power system. NERC performs its duties in accordance with Section 215 of the Federal Power Act. The statute requires users, owners and operators of the bulk power system in the United States to be subject to FERC approved NERC Reliability Standards.

These 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 in SCE's studies. 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.

Attachment 1 is Table 1 from NERC Reliability Standard TPL-001-3 which provides a complete description of Category A through D contingencies and the associated system performance requirements. Table 1 is common to transmission planning standards TPL-001-3, TPL-002-2b, TPL-003-2b, and TPL-004-2a. These NERC Transmission Planning (TPL) Reliability Standards require the system to be stable and both thermal and voltage limits to be within facility

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[16] NERC transmission planning Reliability Standards include TPL-001-3 (Category A), TPL-002-2b (Category B), TPL-003-2b (Category C), and TPL-004-2a (Category D).

ratings for Categories A through C. NERC TPL Reliability Standards generally do not permit loss of demand, such as load shedding, for Categories A and B. However, if planned and controlled, NERC TPL Reliability Standards permit loss of demand for Category C. Category D contingencies are extreme events with no specific performance requirements other than an evaluation for risks and consequences. SCE's power flow studies examined Category A through D conditions for facilities in SCE and SDGE's service areas.

b) SCE's Studies Look For Thermal Overloading and Voltage Violations During These Contingencies

SCE's studies identify both thermal overload and voltage violations for Category A through D conditions. The studies look for power flows in excess of normal (Category A) and emergency (Categories B through D) thermal ratings of transmission facilities. SCE establishes the thermal ratings of transmission facilities as the owner of these facilities to prevent damage to equipment and assure safe clearances are maintained in accordance with General Order No. 95. The studies also look for voltages at substations outside of specific bandwidths and percentage deviations in excess of thresholds established by the CAISO as provided in Table III-2 below[17]. Maintaining voltages at substations prevents voltage collapse events in which voltages in a portion of the electric system decrease catastrophically causing a blackout. The CAISO established these voltage limits via an open stakeholder process in 2011. Based on the identified thermal overloads and voltage violations, SCE develops mitigation options to improve system performance.

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[17] "California ISO Planning Standards", June 23, 2011, Section II.3., page 4

Table III-2
CAISO VOLTAGE REQUIREMENTS

(Voltages are relative to the nominal voltage of the system studied)

Voltage level	Normal Conditions (TPL-001)		Contingency Conditions (TPL-002 & TPL-003)		Voltage Deviation	
	Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu)	TPL-002	TPL-003
≤ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 500 kV	1.0	1.05	0.90	1.1	≤5%	≤10%

c) **SCE Then Adds New Generation At Key Locations To Mitigate Violations**

SCE's studies first use generation as mitigation to establish a base line to address violations. SCE located the generation at several existing substations including: Alamitos, Huntington Beach, Johanna, Santiago, and San Onofre. SCE selected Alamitos, San Onofre, and Huntington Beach substations because they are existing OTC sites and are favorably located to relieve identified violations. Coastal southern California is both densely populated and well regulated. So, locating sufficient land for new generation development is challenging. Developing new generation at existing OTC sites may be possible. However, not all existing OTC sites were favorably located to relieve identified violations. Johanna and Santiago are not existing OTC sites, but proved beneficial locations to minimize the total generation needed to address violations in specific scenarios.

The generation modeled at these substations is a proxy for any generation in the vicinity that is electrically equivalent. SCE adds the minimum amount of generation required to mitigate all identified thermal and voltage violations. After establishing a minimum generation solution, SCE then tests transmission projects and Preferred Resources to determine the incremental reduction in the amount of generation required for each alternative.

Document name	**WECC Board of Directors Request Regarding Performance Category Upgrade Request**
Category	( ) Regional reliability standard ( ) Regional criteria ( ) Policy ( ) Guideline (X) Report or other ( ) Charter
Document date	
Adopted/approved by	
Date adopted/approved	
Custodian (entity responsible for maintenance and upkeep)	
Stored/filed	Physical location: Web URL:
Previous name/number	(if any)
Status	( ) in effect ( ) usable, minor formatting/editing required ( ) modification needed ( ) superseded by _____ ( ) other _____ ( ) obsolete/archived)

Attachment 2

Performance Level Adjustment Record (PLAR) **Comments**

Facility Outage	Specified Category	Adjusted Category	>300 Yr MTBF	Cascading Allowed	Date BOD Approved	
Hassayampa-Pinal West and Hassayampa-Jojoba 500-kV lines	C	D	No	No	6/27/2012	
Hassayampa-Pinal West and Jojoba-Kyrene 500-kV line	C	D	No	No	6/27/2012	
Hassayampa-North Gila existing and 2nd Future 500-kV lines	C	D	No	No	12/8/2010	
Palo Verde-Westwing Line 2 and Palo Verde-Rudd 500-kV lines	C	D	Yes	No	12/8/2010	
Imperial Valley-Miguel and Imperial Valley-Central 500-kV lines	C	D	No	No	4/16/2008	
Both Palo Verde-Westwing 500-kV lines	C	D	Yes	No	Aug-03	
Raver-Echo Lake and Shultz-Echo Lake 500-kV lines	C	D	Yes	Yes	Aug-02	
From Prior Exceptions List						
Laramie River-Ault and Laramie River-Beaver Creek 345-kV lines	D	D	NA		Aug-01	Separate rights-of-way, Separate substation bays
Navajo-McCullough and Navajo-Moenkopi 500-kV lines	D	D	NA		Aug-01	Separate rights-of-way, Separate substation bays
Navajo-Westwing and Navajo-Moenkopi 500-kV lines	C	D	No		Aug-01	Same right-of-way, no 2 line outages have occurred
Palo Verde-Devers and Palo Verde North Gila 500-kV lines	D	D	NA		Aug-01	Separate rights-of-way, Separate substation bays
Lugo-Eldorado and Lugo-Mohave 500-kV lines	C	D	No		Aug-01	Same right-of-way for only 33% of length
Navajo-McCullough and Moenkopi-Eldorado 500-kV lines	D	D	NA		Aug-01	Separate rights-of-way, Separate substations

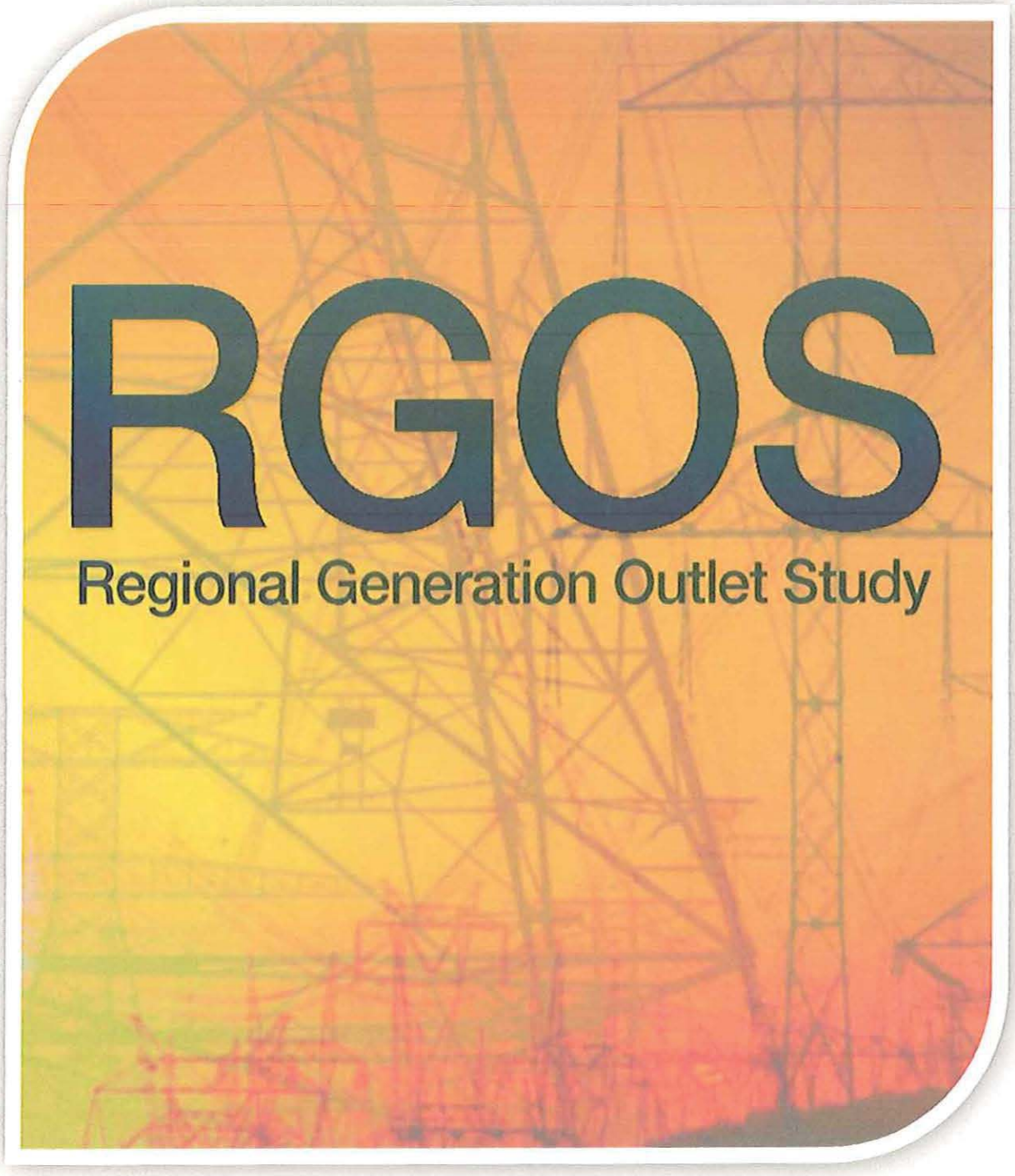
(other exceptions were RAS failures - omitted because handled differently)

NA - No Probabilistic-based Reliability Criteria adjustment is needed because the facilities are on different rights-of-way with different terminations

Updated June 29, 2012

MidwestISO
Energizing the Heartland

Midwest ISO



November 19, 2010

Table 3.2-1 below summarizes the results of the RGOS survey, identifying total and net renewable energy requirements, existing and planned renewable energy, and the net renewable capacity for 2027. Table 3.2-1 also identifies the amount (in percent) of each states RPS expected to be served by wind energy. The 'Total Energy Required' column is the net requirement after applying the "% of RPS by Wind" percentages. As can be seen in Table 3.2-1, some states have more existing renewable energy than required by their respective mandates or goals. Existing renewables were only counted towards the requirements of the respective state in which these renewables originate; thus, an excess of existing wind in one state was not counted towards the requirements in another state. In Iowa, for example, it was not fully known where an excess of that state's existing renewable energy is being supplied. Confining source to state also reduced the risk of double counting if an LSE is fulfilling part of its requirements by deriving some of its renewable energy from another state.

Table 2.2-1: RGOS Survey Results

State	% of RPS by Wind	Total Energy Required (GWh)	Existing & Planned (GWh)	Net Needs (GWh)	Wind Zone Capacity (MW)
IA	100%	348	10,272	-	4,650
IL	75%	17,905	5,608	12,297	2,200
IN	-	-	2,263	-	1,000
MI	92%	7,884	365	7,519	3,150
MN	95%	22,786	6,929	15,857	3,875
MO	90%	6,591	439	6,152	1,000
MT	-	-	-	-	400
OH	100%	26,244	3	26,241	5,075
WI	63%	14,630	1,959	12,671	2,325
ND	-	1,453	4,752	-	2,325
SD	-	1,294	626	668	2,325
Total	-	**99,135**	**33,215**	**81,406**	**28,325**
RTO					
Midwest ISO	-	78,707	32,165	62,028	21,582
PJM	-	20,428	1,050	19,378	6,743

Note the following:

- "Existing & Planned" refers to wind farms or other qualifying renewable energy source currently in operation or holding a signed Generator Interconnection Agreement.
- The Wisconsin RPS is 10% of energy served from renewable; however, it has been adjusted to 25% per direction from the State of Wisconsin.
- Several sources were considered in order to determine the most up-to-date levels of Existing and Planned renewable energy within the study footprint. Those sources included LSE surveys, Midwest ISO Operations data, and data compiled from the SMARTransmission[2] study.

[2] SMARTransmission

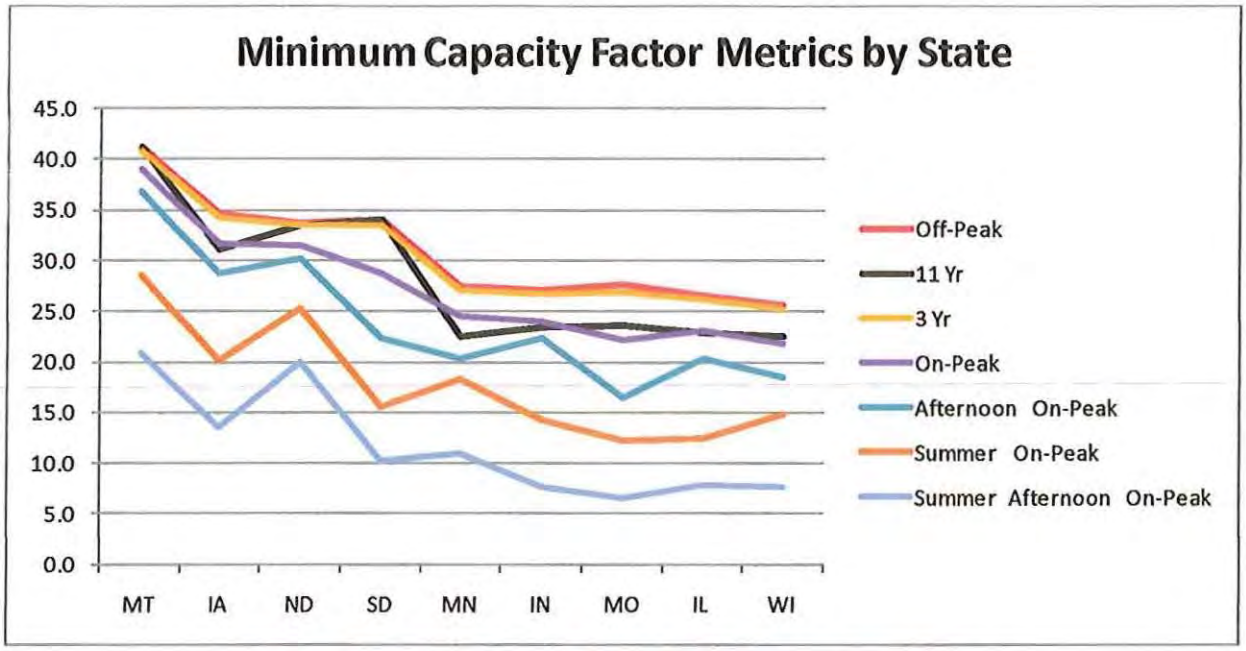


Figure A1.3-3 Minimum Capacity Factor Metrics by State

Some other metrics developed for analysis include correlation of wind to load, ramp, and correlation of wind sites to distance from each other. The following figures demonstrate some of the results from this work.

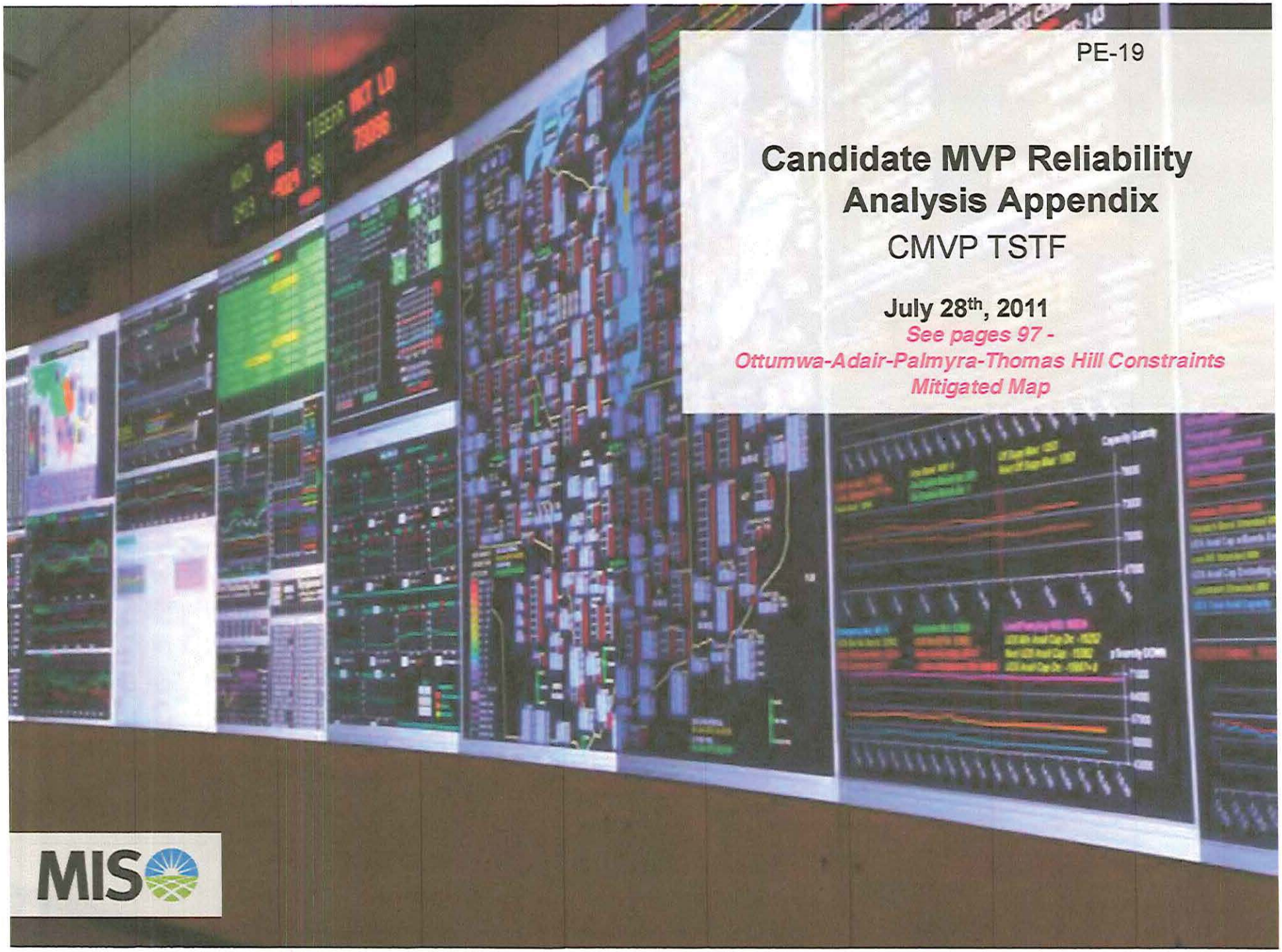
PE-19

Candidate MVP Reliability Analysis Appendix

CMVP TSTF

July 28th, 2011

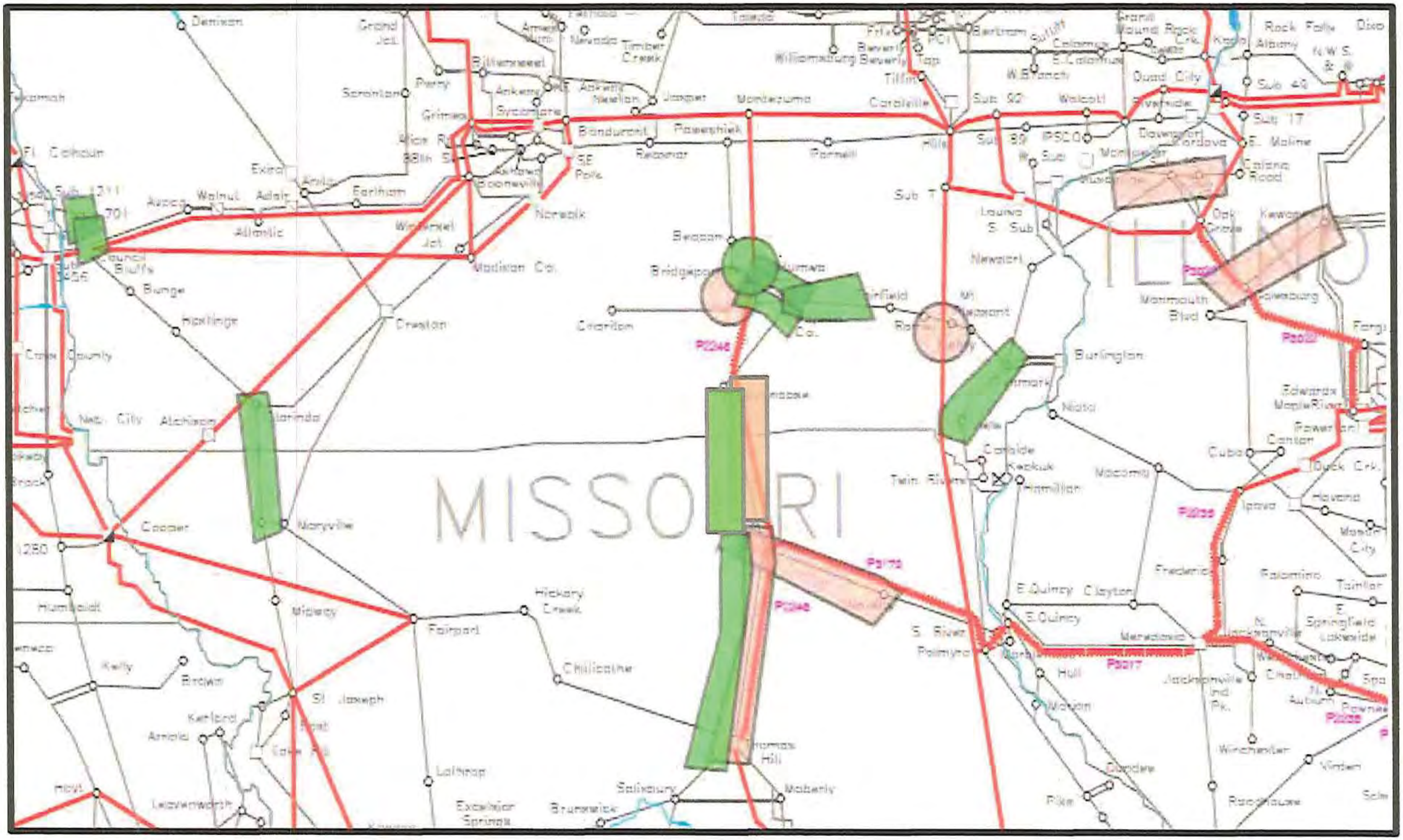
See pages 97 -
Ottumwa-Adair-Palmyra-Thomas Hill Constraints Mitigated Map



Appendix

- **Reliability Analysis Justification of Brookings MVP in Shoulder and Summer Cases**
- **Reliability Analysis Justification of all other MVPs in Shoulder Case**
- **Wind Curtailment Calculations**

Ottumwa-Adair-Palmyra-Thomas Hill Constraints Mitigated Map



Ottumwa – Adair – Palmyra – Thomas Hill CMVP

- Project adds 345kV line between MEC's Ottumwa Substation south to Ameren's Adair Substation, east to Palmyra and further south from Adair to Thomas Hill.
- This path provides an outlet for wind generation connected into Adair (500MW max, 450MW dispatched in shoulder case)
- Without this path, the connected wind 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
- Any 161 kV bus outages could result in the wind generation at Adair being disconnected from the transmission system
- At 2026 wind levels, the overloads increase in severity along the main outlet from Adair, along with constraints beginning to show up in western Missouri along a parallel path of Ottumwa to Adair

BES Transmission Issues Mitigated by Ottumwa to Adair to Palmyra to Thomas Hill CMVP (Shoulder Peak) – NERC Cat B

Element	Rating	Maximum Loading %	Minimum Loading %	# of Contingencies
Novelty to Adair 161 kV Line*	167	154.6	93.9	13149
Kewanee South Tap to East Galesburg 138 kV	143	98.8	98.8	1
*Novelty to Adair is a base case overload without the MVP, with the wind connected to the 161kV Bus at Adair				

MISO

BES Transmission Issues Mitigated by Ottumwa to Adair to Palmyra to Thomas Hill CMVP (Shoulder Peak) – NERC Cat C

Element	Rating	Maximum Loading %	Minimum Loading %	# of Contingencies
Adair to Apanoose 161kV Line	223	121.0	121.0	1
Thomas Hill to Adair 161kV Line	315	101.2	101.2	1
Sub 18 to Sub 85 161kV Line	248	99.3	99.3	1
Lucas 161/69kV Transformer	96	97.8	97.8	1
Henry 161/69kV Transformer	56	95.8	81.7	1
NOTE: For a 161kV bus fault or any of the three 161 kV breaker faults at Adair station, the outlet for 450MW of wind generation is lost without the MVP				

MISO

Non-BES Transmission Issues Mitigated by Ottumwa to Adair to Palmyra to Thomas Hill CMVP (Shoulder Peak) NERC Cat B and C

Category B				
Element	Rating	Maximum Loading	Minimum Loading	# of Contingencies
Jeff to Fairfield NW Tap 69 kV Line	48	120.6	106.1	2
Mark to Apanose County 69 kV Line	48	118.9	83.7	7
Wooster to Jefferson 69 kV Line	41	96.3	96.1	2

Category C				
Element	Rating	Maximum Loading	Minimum Loading	# of Contingencies
North Centerville to Iowa Steel and Wire 69kV Line	51	101.4	101.4	1
Wooster to Jefferson 69kV Line	41	99.8	99.8	1

New Transmission Issues Resulting From Ottumwa to Adair to Palmyra to Thomas Hill CMVP – Shoulder Peak Model

Category B			
Element	Rating	Maximum Loading %	Minimum Loading %
None			

Category C			
Element	Rating	Maximum Loading %	Minimum Loading %
Palmyra 345/161 kV Transformer	370	109.44	109.44
Ottumwa to Montezuma 345 kV Line	478	106.88	106.88
Note: There is a project that would fix the Ottumwa to Montezuma 345kV Line overload that would be implemented with the MVP			

MISO

BES Transmission Issues Mitigated by Ottumwa to Adair to Palmyra to Thomas Hill CMVP (Shoulder Peak) – NERC Cat B 2026 Wind Levels

Element	Rating	Maximum Loading %	Minimum Loading %	# of Contingencies
Viele to Denmark 161kV Line	167	100.4	98.1	3
Wapello to Ottumwa 161kV Line #2	335	99.0	97.0	2
Wapello to Ottumwa 161kV Line #1	335	95.7	95.7	1

MISO

BES Transmission Issues Mitigated by Ottumwa to Adair to Palmyra & to Thomas Hill CMVP (Shoulder Peak) – NERC Cat C 2026 Wind Levels

Element	Rating	Maximum Loading %	Minimum Loading %	# of Contingencies
Adair to Apanoose 161kV Line	223	122	122	1
Thomas Hill to Adair 161kV Line	315	102.1	102.1	1
Sub 702 to Manawa 161kV Line	335	100.2	100.2	1
Ottumwa 345/161kV Transformer	400	98.6	98.6	1
Viele to Denmark 161kV Line	167	98.1	98.1	1
Council Bluffs to Indian Creek 161kV line	371	97.4	97.4	1
Wapello County to Jefferson 161kV Line	223	97.0	95.8	2
Maryville to Clarinda 161kV Line	153	95.5	95.5	1

MISO

Non-BES Transmission Issues Mitigated by Ottumwa to Adair to Palmyra to Thomas Hill CMVP (Shoulder Peak) NERC Cat B and C 2026 Wind Levels

Category B				
Element	Rating	Maximum Loading	Minimum Loading	# of Contingencies
Jefferson to Fairfield NW 69kV Line	48	132.5	114.6	2
Mark to Apanoose County 69kV Line	48	125.8	94.9	48
Wooster to Jefferson 69kV Line	41	105.8	103.9	3
Arlington to Green Isle 69kV Line	34.25	103.2	103.2	1
Henry County 161/69kV Transformer	56	99.3	99.3	1
Wapello to Eldon 69kV Line	69	96.9	96.9	1

Category C				
Element	Rating	Maximum Loading	Minimum Loading	# of Contingencies
Venice 138/69kV Transformer	143	103.0	103.0	1
North Centeville to Iowa Steel and Wire 69kV Line	51	111.4	111.4	1
Wooster to Jefferson 69kV Line	41	108.0	108.0	1
Henry County 161/69kV Transformer	56	100.7	100.7	1
Wapello County to Eldon 69kV Line	69	97.5	97.5	1
Lucas County 161/69kV Transformer	96	97.1	97.1	1

New Transmission Issues Resulting From Ottumwa to Adair to Palmyra to Thomas Hill CMVP – Shoulder Peak Model 2026 Wind Levels

Category B			
Element	**Rating**	**Maximum Loading %**	**Minimum Loading %**
Ottumwa to Montezuma 345kV Line	478	110.5	80.3
Jasper 161/69kV Transformer	84	106.4	106.4
Note: There is a project to fix the Ottumwa to Montezuma 345kV line overload that would be implemented with the MVP			

Category C			
Element	**Rating**	**Maximum Loading %**	**Minimum Loading %**
Ottumwa to Montezuma 345kV Line	478	130.7	80.2
Palmyra 345/161kV Transformer	370	120	83
Dahlberg to Stinson 115kV Line	98	103.6	103.6
Grimes to Sycamore 345kV Line	956	99.7	82.8
Granger Tap to 100th and 54th 161kV Line	373	99.2	99.2
Note: There is a project that would fix the Ottumwa to Montezuma 345kV Line overload that would be implemented with the MVP			

MISO

Alternative

- Given that existing 500 MW Adair wind zone is connected to three 161 kV lines without adequate capacity to reliably connect wind in base case (without contingent loss of any one of the three outlets) and that existing outlets out of Ottumwa 345 kV station are thermally constrained, it is reasonable to expect new 345 kV connection from Ottumwa and into Adair. This will alleviate base case constraint but not alleviate n-1 contingent loss of the 345 kV connection. Additional outlet from Adair to Palmyra 345 kV provides for reliable n-1 delivery of wind.
- A third 345 kV connection from Adair to Thomas Hill (AECI station) helps improve reliability without improving distribution of benefits into MISO.
- It is therefore recommended that the MVP be limited to Ottumwa to Adair to Palmyra

MISO

Bill Powers

From: CTC Global Corporation <info@ctcglobal.com>
Sent: Wednesday, October 14, 2015 7:38 AM
To: Bill Powers
Cc: Matt Hutchison; Jeffrey Townsend
Subject: RE: examples/cost of 161 kV line retrofits with ACCC conductor
Attachments: ACCC Engineering Manual.pdf

Hi Bill,

Thanks for connecting. We would be very happy to help. The AEP project you mentioned was about 12 miles in length and used about 38 miles of conductor. AEP is currently completing their 9th ACCC installation (also in Texas). This project is about 240 miles long and using over 1,440 miles of conductor. To date we have completed nearly 375 project in more than 30 countries with about 20,000 miles of conductor. I have attached a copy of our Engineering Manual. You may also be interested in our Conductor Comparison Program software. You can download a copy at:
http://www.ctcglobal.com/ftp/CCP4_0.msi
The password is 202620011054 It is an excel program that uses macros. You must enable the macros. This might 'scare' your computer but the program is totally safe. Please let us know how we can be of further assistance.

Thanks,

Dave Bryant
Director Technology
CTC Global
2026 McGaw Avenue
Irvine, CA 92614
www.ctcglobal.com
Phone: 949.428.8500
Fax: 949.428.8515
Cell: 949.677.8560

From: Bill Powers [mailto:powers.engineering@att.net]
Sent: Tuesday, October 13, 2015 6:41 PM
To: CTC Global Corporation <info@ctcglobal.com>
Subject: examples/cost of 161 kV line retrofits with ACCC conductor

CTC Global:

I have been asked to compile examples of 161 kV line retrofits using ACCC conductor. Attached are a couple of photos of the 161 kV lines in question. There is a need to substantially increase the capacity of three 161 kV line segments in the Midwest, ranging in length from 30 -60 miles, to accommodate wind power development in the immediate vicinity. Attached are a couple of photos of the 161 kV lines in question.

I am particularly interested in the CTC Cable Corporation (CTC Cable) projects done about a decade ago for American Electric Power (AEP), as they are very similar to the proposed projects. One of these AEP projects, an existing 161 KV line that runs from Chamber Springs to Tontitown, Arkansas, is 38 miles long. The quoted cost of ACCC conductor and related hardware was $1.5 million: http://www.prnewswire.com/news-releases/composite-technology-receives-third-order-from-general-cable-for-accc-conductor-for-american-electric-power-57180992.html.

Bill Powers

From: CTC Global Corporation <info@ctcglobal.com>
Sent: Wednesday, October 14, 2015 7:49 AM
To: Bill Powers
Cc: Jeffrey Townsend; Matt Hutchison
Subject: RE: examples/cost of 161 kV line retrofits with ACCC conductor

Bill,

I noticed your office is located in San Diego. CTC is only about a one hour drive north in Irvine, CA. If you have the opportunity, please visit us some time. In the meantime, here is a list of 161 kV projects we completed in the US:

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

This only represents about 100 km of wire, but we have done similar installations at a wide range of voltages. If you have a minute, you might be interested in watching Jim Lehan of NV Energy share his experience using ACCC conductor on their H-Frame structures. The video was taken at an IEEE conference about 4 years ago. I believe NV Energy has completed four additional projects since then.

https://www.youtube.com/watch?v=9QBhU49PVzo

Thanks,

Dave Bryant
Director Technology
CTC Global
2026 McGaw Avenue
Irvine, CA 92614
www.ctcglobal.com
Phone: 949.428.8500
Fax: 949.428.8515
Cell: 949.677.8560

Bill Powers

From: Dave Bryant <dbryant@ctcglobal.com>
Sent: Wednesday, October 14, 2015 1:10 PM
To: Bill Powers
Cc: Matt Hutchison
Subject: Re: two questions RE: examples/cost of 161 kV line retrofits with ACCC conductor

Thanks Bill, generally you can assume ACCC of the same diameter and weight will double the amps. The conductor is about 2.5 x ACSR. I will try to get you more regarding installation cost

Sent from my Verizon Wireless 4G LTE DROID
On Oct 14, 2015 1:05 PM, Bill Powers <powers.engineering@att.net> wrote:
Hello Matt and Dave,

Thank you for the quick turnaround on the response. The 2006 press release for the 12-mile 161 kV Arkansas reconductoring project indicated a CTC equipment sale price of $1.5 million.

Two questions: 1) Does CTC have a rule-of-thumb equipment/installed price estimate for reconductoring a single three-phase 161 kV line segment, in cost per mile?

2) Is there is an expected range of amperage increase, for example 50 – 100 percent compared to ACSR conductor (depending on site-specific situation). My interest is in the minimum expected increase in amperage when replacing ACSR conductor with ACCC conductor of the same conductor size.

I need to confirm whether the 161 kV line segments in question are Drake or Cardinal ACSR conductor size.

Regards,

Bill Powers
619-917-2941

From: Matt Hutchison [mailto:mhutchison@ctcglobal.com]
Sent: Wednesday, October 14, 2015 7:49 AM
To: Dave Bryant
Cc: Bill Powers
Subject: Re: examples/cost of 161 kV line retrofits with ACCC conductor

Bill,
If you need any thing else just let us know I would like to send you our latest cable comparison program and design manual . I will need your contact information and mailing address.

Kind Regards
Matthew Hutchison
VP North America
949-232-4014

On Oct 14, 2015, at 7:38 AM, CTC Global Corporation <info@ctcglobal.com> wrote:

> Hi Bill,
>
> Thanks for connecting. We would be very happy to help. The AEP project you mentioned was about 12 miles in length and used about 38 miles of conductor. AEP is currently completing their 9th ACCC installation (also in Texas). This project is about 240 miles long and using over 1,440 miles of conductor.

To date we have completed nearly 375 project in [redacted] than 30 countries with about 20,000 miles of conductor. I have attached a copy of our Engineering Manual. You may also be interested in our Conductor Comparison Program software. You can download a copy at:
http://www.ctcglobal.com/ftp/CCP4_0.msi
The password is 202620011054 It is an excel program that uses macros. You must enable the macros. This might 'scare' your computer but the program is totally safe. Please let us know how we can be of further assistance.

Thanks,

Dave Bryant
Director Technology
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2026 McGaw Avenue
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www.ctcglobal.com
Phone: 949.428.8500
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Cell: 949.677.8560

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http://www.prnewswire.com/news-releases/composite-technology-receives-third-order-from-general-cable-for-accc-conductor-for-american-electric-power-57180992.html.

Regards,

Bill Powers, P.E.
Powers Engineering
4452 Park Blvd., Suite 209
San Diego, CA 92116

619-295-2072 (o)
619-917-2941 (c)

<ACCC Engineering Manual.pdf>

IRVINE, Calif., Sept. 27 /PRNewswire-FirstCall/ -- Composite Technology Corporation (CTC) (OTC Bulletin Board: CPTC) is pleased to announce that its subsidiary, CTC Cable Corporation (CTC Cable) has received its third order from General Cable Corporation (General Cable) to provide for the delivery of ACCC conductor to American Electric Power (AEP). This third reconductoring project will use 38 linear miles of ACCC conductor to upgrade an existing 161 KV line that runs from Chamber Springs to Tontitown, Arkansas. The General Cable order has a value of nearly $1.5 million, which includes conductor, hardware, product warranty, and CTC Cable technical support.

This is the third order of ACCC conductor destined for AEP and underscores their confidence in CTC Cable's technology and the benefit of using ACCC conductors to increase capacity on constrained transmission lines. As in previous orders, AEP has chosen a General Cable TransPower ACCC Drake 1020 kcmil conductor, which uses CTC Cable's proprietary composite core. Installation is slated for the first quarter of 2007. The ACCC light weight, high strength composite core allows for more conductive aluminum in the same diameter conductor with the same overall weight as a conventional steel core conductor, which allows ACCC conductors to carry more electricity more efficiently. The AEP line can take advantage of the reduced sag characteristics of ACCC conductors and the ability to operate at much higher temperatures than traditional conductors, thereby providing reserve capacity for crisis situations and future growth.

"A third order from American Electric Power, one of the leading power companies in our home market, is a great statement of confidence in ACCC conductors and we are very excited about the growing adoption of ACCC conductors both in the US and around the world," noted Benton Wilcoxon, CTC's Chairman and CEO.

About CTC:

Composite Technology Corporation, based in Irvine, California, USA develops, manufactures and sells high performance electrical transmission and renewable energy generation products through its two principal subsidiaries:

* CTC Cable Corporation produces composite rod for use in its proprietary ACCC aluminum conductor composite core. ACCC conductors virtually eliminate the sag in power lines caused by high current and high line temperatures. ACCC conductors also reduce electricity line losses, and have demonstrated significant savings in capital and operating expenses when substituted for other conductors. ACCC conductors enable grid operators to eliminate blackouts and brownouts, providing a 'reserve electrical capacity' by operating at higher temperatures. ACCC conductors are an innovative solution for reconductoring power lines, constructing new lines and crossing large spans. ACCC composite rod is delivered to qualified conductor manufacturers worldwide for local ACCC conductor production and resale into local markets.

* EU Energy Inc., and EU Energy Ltd., produce, sell, and license the

DeWind series of wind energy turbines including the 50Hz D6 rated at 1.25 megawatts (MW) and the 50Hz D8 rated at 2MW, both noted for their reliability. In 2007, the new 2MW D8.2 is planned to be delivered to North American customers from assembly operations in Lubeck, Germany. The D8.2 utilizes the advanced WinDrive(R) hydrodynamic torque converter developed by Voith AG with a synchronous AC generator that is able to connect directly to the grid without the use of power conversion electronics. The DeWind 8.2 will be available in both a 60Hz and 50Hz version.

For further information visit our websites: www.compositetechcorp.com & www.eunrg.com

For Investor Relations Contact: James Carswell, +1-949-428-8500

This press release may contain forward-looking statements, as defined in the Securities Reform Act of 1995 (the "Reform Act"). The safe harbor for forward-looking statements provided to companies by the Reform Act does not apply to Composite Technology Corporation (Company). However, actual events or results may differ from the Company's expectations on a negative or positive basis and are subject to a number of known and unknown risks and uncertainties including, but not limited to, competition with larger companies, development of and demand for a new technology, risks associated with a startup company, risks associated with international transactions, general economic conditions, availability of funds for capital expenditure by customers, availability of timely financing, cash flow, timely delivery by suppliers, successful integration of the EU Energy acquisition, ability to produce the turbines and its components, ability to maintain quality control, collection-related risks from international transactions, or the Company's ability to manage growth. Other risk factors attributable to the Company's business may affect the actual results achieved by the Company including those that are found in the Company's Annual Report filed with the SEC on Form 10-K for fiscal year ended September 30, 2005 and subsequent Quarterly Reports on Form 10-Q and subsequent Current Reports filed on Form 8-K and including those pertaining to EU Energy that will be included with or prior to the filing of the Company's next Quarterly or Annual Report.

SOURCE Composite Technology Corporation

Midwest ISO

Technical Report

Feasibility Study for Generation Interconnection
Queue #38706-01

Feasibility Study Report

June 7, 2006

Keywords
Feasibility Study

Midwest ISO

Postal address

Midwest ISO
701 City Center Dr
Carmel, Indiana 46032

Internet
http://www.midwestiso.org/

1. SUMMARY

This report contains the Feasibility Study (FS) results for the Midwest ISO (MISO) Generation Interconnection Project #38706-01. The purpose of this study is to identify steady state thermal and voltage violations caused by the proposed generation interconnection. The requested in-service date is October 1, 2007.

Project #38706-01 proposes the addition of 300 MW of wind generation to connect to the ADAIR substation, in Adair County, Missouri, at 161 kV. 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 1. The final interconnection will depend on the thermal, voltage, and stability analysis performed in the Interconnection System Impact Study (ISIS), in addition to operational issues and Facility Study analysis, which will include an evaluation of physical space requirements for the new equipment to support the interconnection.

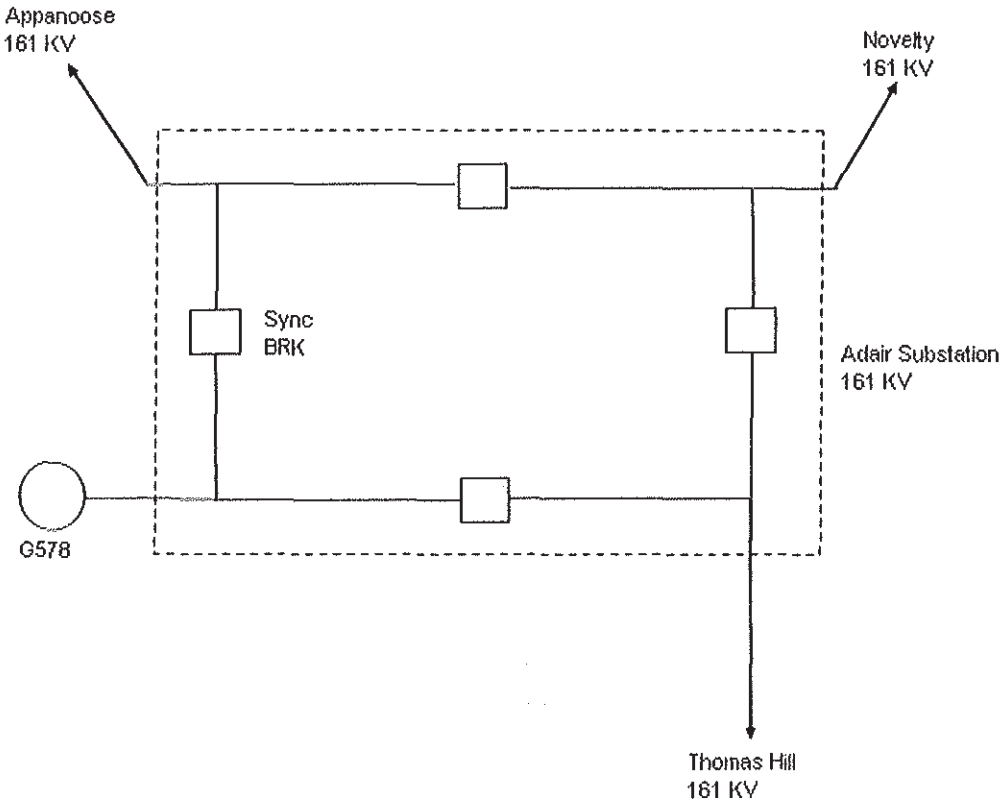


Figure 1: ADAIR Substation and Project 38706-01

An injection analysis study was performed by sourcing 300 MW from project 38706-01 and delivering the power to the MISO footprint. The study identified a handful of branch overload constraints, shown in Table 1 below.

Table 1: Summary of Constraints

Branch	Contingency	Rating	Pre Transfer	Post Transfer	Impact	DF %	FCITC
34189 OTTUMWA5 161 – 34188 OTTUMWA3 345 CKT 1* (ALTW)	OPEN 34190 BRDGPRT5 161 - 34174 EICTAP 5 161 CKT 1 OPEN 34172 EIC 5 161 - 34174 EICTAP 5 161 CKT 1 OPEN 34174 EICTAP 5 161 - 64096 BEACON 5 161 CKT 1	335	315.9	354.4	38.5	12.8	148.8
	OPEN 34174 EICTAP 5 161 - 64096 BEACON 5 161 CKT 1	335	315.9	354.4	38.5	12.8	148.8
	OPEN 64096 BEACON 5 161 - 34174 EICTAP 5 161 CKT 1 DISCONNECT BUS 64627 BEAC MD8 69.0	335	315.7	354.2	38.5	12.8	150.4
	OPEN 64096 BEACON 5 161 - 34174 EICTAP 5 161 CKT 1 OPEN 64096 BEACON 5 161 - 64628 BEACMID8 CKT 2	335	315.3	353.8	38.5	12.8	153.5
	OPEN 34189 OTTUMWA5 161 - 34190 BRDGPRT5 161 CKT 1 OPEN 34190 BRDGPRT5 161 - 34174 EICTAP 5 161 CKT 1 OPEN 34174 EICTAP 5 161 - 64096 BEACON 5 161 CKT 1	335	317.5	355.8	38.3	12.8	137.1
34174 EICTAP 5 161 – 64096 BEACON 5 161 CKT 1* (ALTW / MEC)	OPEN 64050 SE POLK3 345 - 64192 GDMEC 345 CKT 1 OPEN 64064 BONDRNT3 345 - 64080 SYCAMOR3 345 CKT 1 OPEN 64050 SE POLK3 345 - 64634 SE MID 5 161 CKT 1	335	347.5	363	15.5	5.2	0.0

* Local generation adjusted to maximize flows on the constraint.

The proposed project creates new constraints and impacts existing constraints, wherein operation of this plant may be restricted. None of the constraints are classified as injection; therefore the customer is not required to mitigate the constraints in order to gain Energy Resource (ER) status. The study did not identify any voltage limit violations or need for reactive power capability enhancement specifically due to the addition of project 38706-01.

Further Study

The next step in the Generator Interconnection Request process is for the Generator customer to proceed with an ISIS. The ISIS will determine the system upgrades required to resolve all injection limits and will include a detailed analysis verifying these study results along with short circuit, transient and dynamic stability, and deliverability studies, as applicable. Limits identified in the ISIS will also need to be resolved to obtain interconnection service. The ISIS will also determine what upgrades, if any, are necessary for the generation to become a Network Resource (NR), as well the final interconnection configuration at the Adair substation.

The study process included the modelling all of earlier-queued generation projects in the area. The addition of the Norborne generation facility may have removed constraints in the study region. However, because the Norborne plant will not be in service for a few years after the proposed in-service date of the study generation, more constraints may be introduced in the study area. This will be studied further in the ISIS.

Required Interconnection Facilities

To be determined in the ISIS.

Network Upgrades

To be determined in the ISIS.

Special Facility Requirements

To be determined in the ISIS.

Operation Restrictions

To be determined in the ISIS.

2. CRITERIA, METHODOLOGY AND ASSUMPTIONS

2.1 Study Criteria

All relevant MISO-adopted NERC Reliability Criteria are to be met for both the thermal and voltage analysis.

2.2 Study Methodology

The results of this study are subject to change. The results of the Study are based on data provided by the Generator and other MISO system information that was available at the time the study was performed, and the injection study does not guarantee deliverability to the MISO energy market. If there are any significant changes in the generator and controls data, in earlier-queued Generator Interconnection Requests, or in related Transmission Service Requests then the results of this study may also change significantly. Therefore, this request is subject to restudy. The Generator is responsible for communicating any significant generation facility data changes in a timely fashion to MISO prior to commercial operation.

2.2.1 Competing Generation Requests

The Midwest ISO determined in its sole judgment that there were fifteen Generator Interconnection Requests with an earlier queue position that could impact the 38706-01 study results. MISO projects 38049-01, 38267-01, 38518-01, 38548-01, 38601-01, 38602-01, 38612-01, 38667-01, and 38705-01 were included in the model, along with the Ameren-coordinated project 38107-01. Non-MISO generation projects included in the model were Norborne, Gentry, Atchison (all three AECI), 38621-02 (PJM), and Iatan (2nd unit, SPP).

Public information related to the MISO Generator Interconnection Request queue can be found via the MISO web site at **http://oasis.midwestiso.org/documents/ATC/queue.html**

2.2.2 Linear Transfer Analysis and A.C. Power Flow Analysis Methods

Thermal overloads were identified using linear transfer analysis and then verified with AC power flow solutions. The linear transfer analysis was used to evaluate the intact system, N-1 contingency, and certain MISO-defined multi-terminal contingency conditions. The linear transfer analysis utilized adjusted MW ratings for facilities to account for reactive power flows and a 5% transmission reserve margin ("TRM"). All AC power flow solutions utilized actual facility ratings in MVA (i.e. 0% TRM) along with real and reactive power flows. However, the 5% TRM was factored in the computation of required MVA rating for the limiting elements.

The linear transfer analysis was performed using the Linear Transfer Analysis modules of the Managing and Utilizing System Transmission 6.04 (MUST, Version 6.04) program from Power Technologies, Inc (PTI). All AC solutions were performed using the Power Flow module of the

Power System Simulation/Engineering 29 (PSS/E, Version 29) program from Power Technologies, Inc (PTI). These programs are accepted industry-wide for power flow analysis.

2.2.3 Base Cases

2.2.3.1 Power flow analysis

The base case used in the thermal and voltage analysis for this study was developed based on the NERC MMWG 2004 series MISO Central Illinois Group Study (CIGS) model built for the summer of 2009. Two models were taken from this base case; one had the new generation online and the other did not.

The MISO system was modified by updating all loads to the expected coincident peak value and including all earlier-queued generation projects in the area.

2.2.3.2 Deliverability analysis

Deliverability analysis, required for project 38706-01 to attain NR status, was not performed for this study. This will be performed in the ISIS.

2.3 Assumptions

The 38706-01 study generation was modeled at 300 MW of real power output connected to the ADAIR 161 kV substation. The power factor was held between 0.9 and 0.95 leading lag.

3. ANALYSIS RESULTS

3.1 Power Flow Analysis Results

3.1.1 Voltage Analysis & Reactive Capability

Voltage analysis determined that the voltage magnitude of all system buses whose magnitude decreases at least 0.01 p.u. after adding project 38706-01 remain above 0.95 p.u. for the intact system, and remain above 0.9 p.u. for the single contingency condition. Hence, the study did not identify any voltage limit violations or need for reactive power capability enhancement specifically due to the addition of 38706-01. Local planning criteria will be applied during the ISIS in order to determine any reactive support requirements from the generator.

3.1.2 Results of Single Contingencies (N-1)

Study of the 300 MW injection from project 38706-01 identified zero steady-state thermal violations for NERC Category A events (Intact System). Six transmission element violations for NERC Category B events (N-1) were identified.

The proposed project impacts existing constraints, wherein operation of this plant may be restricted. None of the constraints are classified as injection; therefore the customer is not required to mitigate the constraints in order to gain ER status. To obtain NR status, an ISIS must be preformed.

CAPITAL COSTS FOR TRANSMISSION AND SUBSTATIONS

Recommendations for WECC Transmission Expansion Planning

B&V PROJECT NO. 176322

PREPARED FOR

Western Electricity Coordinating Council

OCTOBER 2012

Principal Investigators:

Tim Mason, Project Manager

Trevor Curry

Dan Wilson

BLACK & VEATCH
Building a world of difference.®

capability. Transformers can vary in cost substantially based on variables such as copper commodity prices, as well as cost of freight; however, the costs considered and vetted by the WECC stakeholders are typical in the industry. The costs considered include foundation and oil containment for the transformer.

Table 3-3 below identifies the capital costs associated with each voltage class in a cost per mega-volt ampere (MVA), which is dependent on the amount of current carrying capability necessary to deliver from the high voltage side to the low voltage side of the transformer.

Table 3-3 Transformer Capital Costs

TRANSFORMER COST ($/MVA)	230 KV SUBSTATION	345 KV SUBSTATION	500 KV SUBSTATION
115/230 kV XFMR	$7,000	-	-
115/345 kV XFMR	-	$10,000	-
115/500 kV XFMR	-	-	$10,000
138/230 kV XFMR	$7,000	-	-
138/345 kV XFMR	-	$10,000	-
138/500 kV XFMR	-	-	$10,000
230/345 kV XFMR		$10,000	-
230/500 kV XFMR	$11,000	-	$11,000
345/500 kV XFMR	-	$13,000	$13,000

3.4 REACTIVE COMPONENTS

An ideal transmission system does not require any reactive support; however, this is rarely the case. Many transmission networks are integrated in a manner that supports voltage dips across the network; however, some weaker systems may require additional reactive power support to maintain grid reliability. The amount of reactive support, and the speed with which the support needs to be transferred to the grid, will determine what type of reactive component is required at the substation.

Black & Veatch identified three key reactive components commonly used for transmission level grid support. Each piece of equipment has its own level of complexity, size, and cost.

- Shunt Reactor
- Series Capacitor
- Static VAr Compensator (SVC)

Shunt reactors are commonly used to reduce voltages due to high line charging on lightly loaded transmission networks. Series capacitors do the exact opposite – they increase voltages by providing additional reactive charging to the transmission network to maintain system voltages.

Black & Veatch worked with stakeholders to assume a "turnkey" installation, which includes with engineering, design, and construction support for a site that "has been rough-graded and has access to a source of medium voltage auxiliary power"[7]. Table 3-4 identifies the typical costs for shunt reactors and series capacitors.

Table 3-4 Shunt Reactor and Series Capacitor Capital Costs

EQUIPMENT	230 KV SUBSTATION	345 KV SUBSTATION	500 KV SUBSTATION
Shunt Reactor ($/MVAR)	$20,000	$20,000	$20,000
Series Capacitor ($/MVAR)	$30,000	$10,000	$10,000

Static VAr Compensators (SVCs) combine both technologies, while adding speed of support. SVCs are constantly connected to the grid, whereas capacitors and reactors typically have to be switched. SVCs are more expensive than their static counterparts; however, they offer more flexibility in resources. The costs for SVCs vary based on size and the assumptions made about the ease of installation. Table 3-5 below shows SVC costs identified by HydroOne, Arizona Public Service Company (APS), and the Peer Review Group adopted costs. Like Shunt Reactor and Series Capacitor capital costs, SVC costs assume a "turnkey" installation.

Table 3-5 SVC Capital Costs

VOLTAGE CLASS	HYDRO ONE[8]	APS[9]	WECC
500 kV	-	-	$85,000
345 kV	-	-	$85,000
230 kV	$94,500	$75,000	$85,000
115 kV	$141,000	-	-
Medium Voltage	$142,000	-	-
Low Voltage	$250,000	-	-

[7] Stakeholder comment from Eric John of ABB, regarding turnkey SC turnkey installation.

[8] http://www.appro.org/docs/HONIconnectionsJan2009/Naren_Pattani_%20-_Tx_presentation_at_%20APPrO-CanWEA-OWA_workshop,_Jan_22_2009.pdf

[9] http://www.wecc.biz/committees/BOD/TEPPC/020209/Lists/Agendas/1/Reactors%20%20Capacitors%20%20SVC%20%20PSS.pdf

7. Demand-Side Resources

Highlights

- *Ameren Missouri has conducted a DSM Market Potential Study with primary data from its service territory to assess the potential for energy and demand savings*
- *A total of 425 demand side measures have been evaluated*
- *Ameren Missouri plans to spend nearly $60 million over 3 years on energy efficiency programs to obtain nearly 253 GWh of energy savings and over 54 MW of peak demand savings.*
- *Business Custom Program incentive levels increased by over 50% from prior implementation plan levels.*
- *The budget for the Residential HVAC program has increased more than 25% from the Cycle 1 budget to position it as one of the premier program offerings.*
- *The innovative Multi-family Income Qualified program will continue and may be expanded depending on how Ameren Missouri and stakeholders determine how best to serve hard-to-reach customer segments.*

Ameren Missouri has undertaken significant steps to improve and expand its consideration and evaluation of demand side resources. Chief among these is the development of a DSM Market Potential Study, which relies on primary market research within Ameren Missouri's franchise service territory. Using the results of this study, Ameren Missouri has developed a range of potential DSM portfolios for evaluation in the integration and risk portions of the IRP analysis.

7.1 Implementation Plan Summary

7.1.1 Introduction

The implementation plan covers a three year period beginning on January 1, 2012 and extending through December 31, 2014. The following table summarizes the estimated energy and demand savings and costs estimated for this period.

Table 7. 1: Estimated Incremental Savings and Costs for the Implementation Period - LOW RISK Portfolio

	2012	2013	2014
Estimated energy savings (MWh)	100,378	80,393	73,064
Estimated demand reduction (MW)	18	17	19
Estimated costs (Program costs in millions)*	$ 20.50	$ 18.76	$ 20.17

Table 7. 3: Ameren Missouri Portfolio Summary for Cycle 2 (2012-2014)

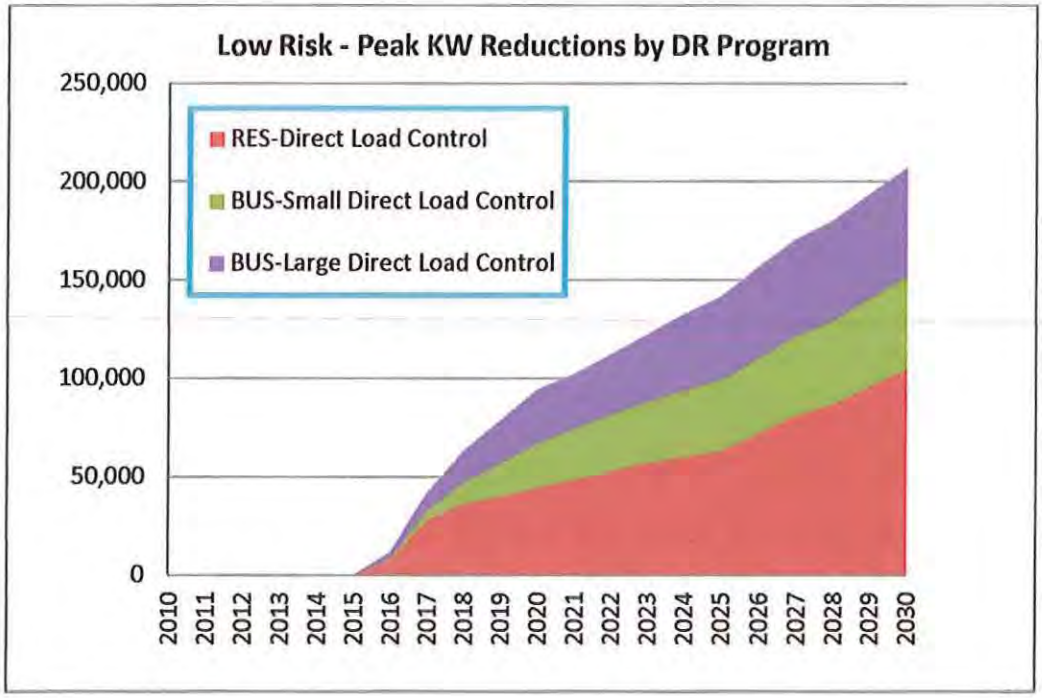
LOW RISK	Incremental GWh			Incremental MW			Budget (millions of $)		
	2012	2013	2014	2012	2013	2014	2012	2013	2014
Lighting	44.3	30.5	17.1	1.3	0.9	0.5	$3.78	$2.70	$1.53
HVAC	9.2	10.8	14	4.4	5.1	6.5	$3.11	$3.74	$4.95
Appliance Recycling	7.0	3.9	3.4	1.0	0.6	0.5	$1.65	$0.95	$0.89
Low Income	3.3	2.8	2.2	0.2	0.2	0.2	$2.78	$2.96	$3.12
EE Residential Total	**63.9**	**48.1**	**36.8**	**6.9**	**6.8**	**7.7**	**$11.32**	**$10.34**	**$10.49**
Standard	9.8	11.5	13.7	3.9	4.6	5.5	$2.90	$3.35	$3.94
Custom	23.6	17.7	19.2	6.3	4.8	5.3	$5.57	$4.26	$4.75
RCx	1.0	0.8	0.8	0.2	0.2	0.2	$0.11	$0.09	$0.08
New Construction	1.2	1.4	1.7	0.4	0.5	0.6	$0.43	$0.54	$0.71
Multifamily Common	0.9	0.9	0.9	0.2	0.2	0.2	$0.17	$0.19	$0.21
EE Business Total	**36.5**	**32.3**	**36.3**	**10.9**	**10.2**	**11.7**	**$9.18**	**$8.42**	**$9.69**
EE PORTFOLIO TOTAL	**100.4**	**80.4**	**73.1**	**17.8**	**17.0**	**19.4**	**$20.50**	**$18.76**	**$20.17**

	Total System Energy (GWh)			Total System Peak (MW)			Total Revenue Requirements (million $)		
	2012	2013	2014	2012	2013	2014	2012	2013	2014
Ameren Missouri Baseline Forecasts	41,035	41,291	41,601	8,318	8,380	8,425	$3,034	$3,251	$3,474
DSM as %	0.24%	0.19%	0.18%	0.22%	0.20%	0.23%	0.68%	0.58%	0.58%

The graphs on the following pages summarize portfolio cumulative energy savings, cumulative peak demand savings, and annual program costs for the planning horizon.

It should be noted that 2010 and 2011 reflect plans from the previous 3-year implementation plan (Cycle 1) that are already in motion. Also, no demand response (-DR") programs are part of the upcoming implementation plan (Cycle 2), but are planned to begin in 2016. A more detailed description of the energy savings and demand reduction calculations for each program can be found in the Electronic Work Papers -BatchTool_(desired program name).xlsx".

Figure 7. 14: Low Risk Demand Response Potential



7.2.7 Rate Design

The Company considered alternative rate designs in the development of its demand response programs. The following matrix illustrates the demand response technologies and rate designs considered:

Table 7. 18: Demand Response Program Matrix

Demand Response Program	Residential [1M]	Small C&I [2M]	Medium C&I [3M]	Large C&I [4M, 11M]
Direct Load Control				
Residential Direct Load Control	X			
Small C&I Direct Load Control		X		
Dynamic Pricing Programs				
Residential Dynamic Pricing	X			
C&I Dynamic Pricing		X	X	X
Other C&I Programs				
Demand Bidding			X	X
Curtailable				X
DR Aggregator Contracts		X	X	X

8. Demand-Side Resources

Highlights

- *Ameren Missouri completed its most comprehensive Demand Side Management (DSM) Potential Study and Market Assessment in 2013. Key components were:*
  - *Energy efficiency potential for the planning period 2016-2034*
  - *Demand response potential*
  - *Distributed generation potential*
  - *Combined heat and power potential*
  - *Demand-side rate potential*
- *Although Demand Response (DR) programs are not cost effective for 2016-2018, Ameren Missouri is considering an innovative pilot DR program to better understand the tolerance customers have for various frequencies and durations of DR events.*
- *Ameren Missouri plans to spend $148 million from 2016-2018 to achieve 426 GWH of energy savings and 114 MW of peak demand savings*

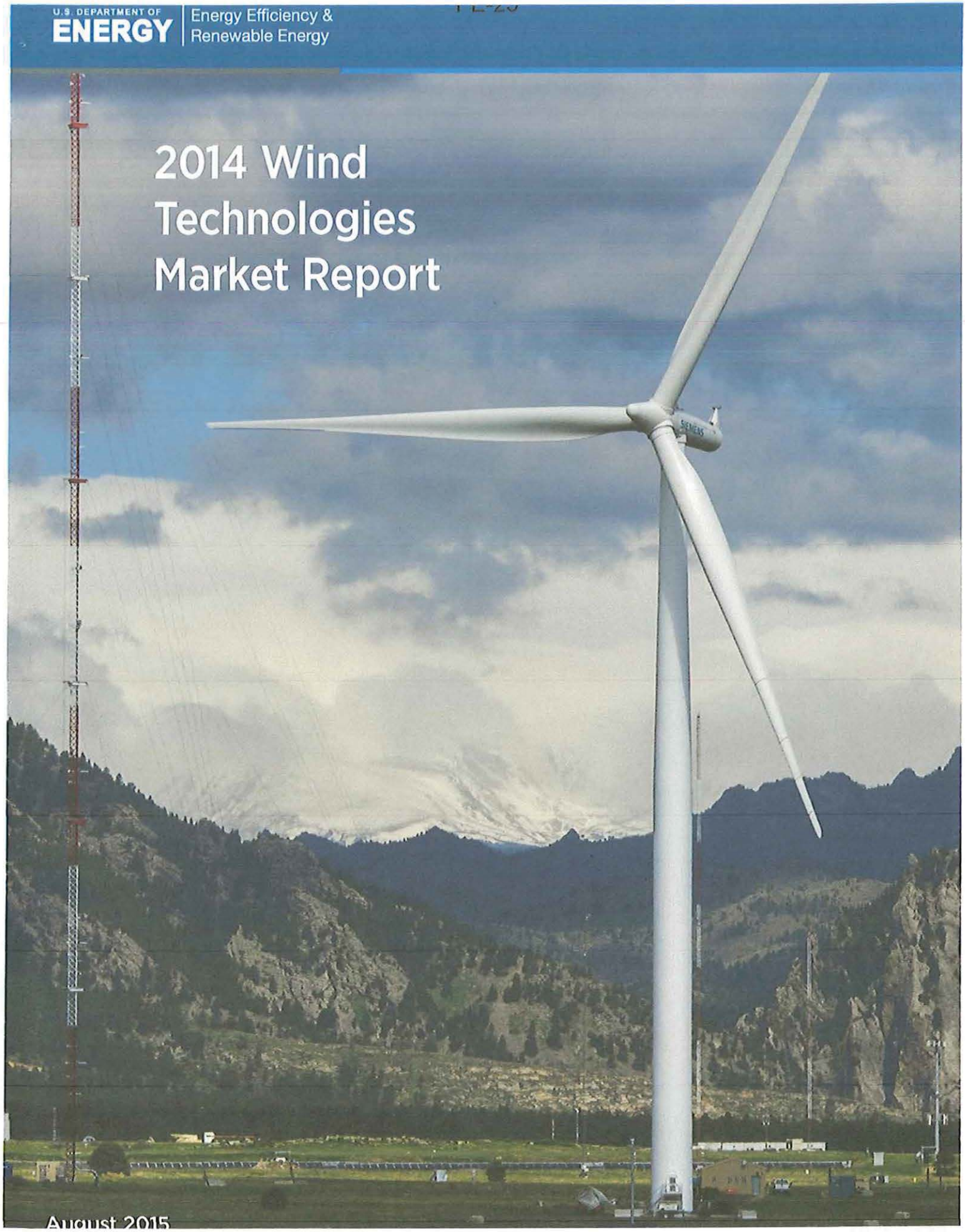
Ameren Missouri continues to build on its DSM planning, implementation and evaluation performance leadership from MEEIA Cycle 2013 - 2015. Examples of performance leadership include:

- The addition of formal project management processes and procedures
- The addition of a state-of-the art DSM data collection and tracking system
- The addition of a Marketing Manager
- The development of market segmentation strategies to tailor specific DSM messages to specific market segments[1]
- The addition of a state-of-the art web-based Technical Reference Manual
- The execution of national best practice EM&V processes and procedures

[1] 4 CSR 240-22.050(1)(A)1 through 3; 4 CSR 240-22.050(3)(B) The market segmentation is discussed further on page 2-4 thru 2-7 in Volume 3 of the Potential Study

U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy

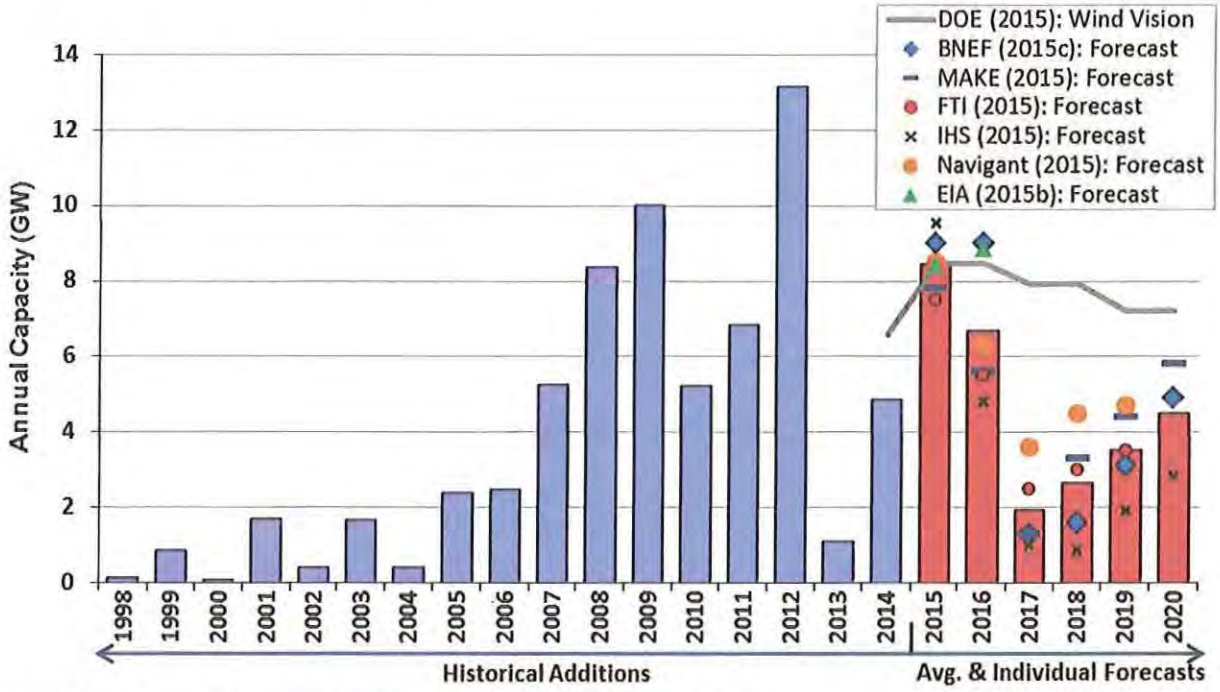
2014 Wind Technologies Market Report



August 2015

9. Future Outlook

Because federal tax incentives are available for wind projects that *initiated* construction by the end of 2014, a further resurgence in new builds is anticipated in both 2015 and 2016 as those projects are commissioned. Near-term wind additions will also be driven by the recent improvements in the cost and performance of wind power technologies, which have resulted in the lowest power sales prices ever seen in the U.S. wind sector. Growing corporate demand for wind energy and state-level policies play important roles as well. Among the forecasts for the domestic market presented in Figure 53, expected capacity additions range from 7,500 to 9,500 MW in 2015 and from 4,800 to 9,000 in 2016. With AWEA (2015b) reporting that more than 13,600 MW of wind power was under construction at the end of the first quarter of 2015, the industry appears to be on track to meet these expectations. Still, the upper end of the forecast range for 2015 and for 2016 does not approach the record build level achieved in 2012.



Source: AWEA (historical additions), individual forecasts, DOE 2015 (Wind Vision)

Figure 53. Wind additions: historical installations, projected growth, DOE *Wind Vision* report

Projections for 2017 show a steep downturn in additions in that year, and then a steady rebound through 2020. Forecasts for this period are uncertain. The PTC has expired, and its renewal remains in question. The "base-case" forecasts presented in Figure 53 generally assume no further PTC extensions in the near term. Expectations for continued low natural gas prices, modest electricity demand growth, and limited near-term renewable energy demand from state RPS policies also put a damper on growth expectations, as do inadequate transmission infrastructure and growing competition from solar energy in certain regions of the country. Industry hopes for a federal renewable or clean energy standard, or climate legislation, have also dimmed in the near term. At the same time, recent declines in the price of wind energy have been substantial, helping to improve the economic position of wind even in the face of relatively low natural gas prices and boosting the prospects for future growth even if state and federal

Actual Average Annual Capacity Factors, Missouri Wind Farms, 2013 and 2014

Project	Capacity, MW	2013 Form 923 production data (Page 1, Generator and Fuel Data)			2014 Form 923 production data (Page 1, Generator and Fuel Data)		
		spreadsheet line	MWh total, 2013	capacity factor	spreadsheet line	MWh total, 2014	capacity factor
Lost Creek	150	6406	446,019	0.339	6595	448,888	0.342
Farmers City	146	6404	332,329	0.260	6597	283,023	0.221
Conception	50.4	6397	124,668	0.282	6588	127,169	0.288
Cow Branch	50.4	6396	120,611	0.273	6587	128,913	0.292
Bluegrass Ridge	56.7	6399	133,752	0.269	6590	132,924	0.268
Average capacity factor			2013:	**0.285**		2014:	**0.282**

Mean capacity factor, Missouri wind farms, 2013 and 2014: (0.285 + 0.282)/2 = 0.2835

Capacity factor calculation: (total annual production, MWh)/[(MW capacity)(8,760 hours per year)] = capacity factor

Source of production data, EIA Form 923, 2013 and 2014, Page 1 Generator and Fuel Data:
http://www.eia.gov/electricity/data/eia923/

Independent Statistics & Analysis
U.S. Energy Information Administration

Assumptions to the Annual Energy Outlook 2015

September 2015

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

- Capital costs for wind technologies are assumed to increase in response to: (1) declining natural resource quality as the best sites are utilized, such as terrain slope, terrain roughness, terrain accessibility, wind turbulence, wind variability, or other natural resource factors , (2) increasing costs of upgrading existing local and network distribution and transmission lines to accommodate growing quantities of remote wind power, and (3) market conditions, such as the increasing costs of alternative land uses, including aesthetic or environmental reasons. Capital costs are left unchanged for some initial share, then increased by 10%, 25%, 50%, and finally 100%, to represent the aggregation of these factors.
- Proportions of total wind resources in each category vary by EMM region. For all EMM regions combined, about 1% of windy land (107 GW of 11,600 GW in total resource) is available with no cost increase, 3.4% (390 GW) is available with a 10% cost increase, 2% (240 GW) is available with a 25% cost increase, and over 90% is available with a 50% or 100% cost increase.
- Depending on the EMM region, the cost of competing fuels, and other factors, wind plants can be built to meet system capacity requirements or as a "fuel saver" to displace generation from existing capacity. For wind to penetrate as a fuel saver, its total capital and fixed operations and maintenance costs minus applicable subsidies must be less than the variable operating costs, including fuel, of the existing (non-wind) capacity. When competing in the new capacity market, wind is assigned a capacity credit that declines based on its estimated contribution to regional reliability requirements.
- Because of downwind turbulence and other aerodynamic effects, the model assumes an average spacing between turbine rows of 5 rotor diameters and a lateral spacing between turbines of 10 rotor diameters. This spacing requirement determines the amount of power that can be generated from wind resources, about 6.5 megawatts per square kilometer of windy land, and is factored into requests for generating capacity by the EMM.
- Capacity factors for each wind class are calculated as a function of overall wind market growth. The capacity factors are assumed to be limited to about 50% for a typical Class 6 site. As better wind resources are depleted, capacity factors are assumed to go down, corresponding with the use of less-desirable sites. By 2040, the typical wind plant build will have a somewhat lower capacity factor than those found in the best wind resource areas. Capacity factors in the Reference case increase to about 40% in the best wind class resulting from taller towers, more reliable equipment, and advanced technologies, although, as noted, these may not represent the best available sites because of other site-specific factors.
- AEO2015 allows plants under construction by 2015 to claim the federal Production Tax Credit (PTC), a 2.3-cent-per-kilowatthour tax incentive for wind that was initially set to expire for wind only on December 31, 2014. Wind plants are assumed to depreciate capital expenses using the Modified Accelerated Cost Recovery System with a 5-year tax life and 5-year double declining balance depreciation.

SunShot
U.S. Department of Energy

Photovoltaic System Pricing Trends

Historical, Recent, and Near-Term Projections
2014 Edition

David Feldman[1], Galen Barbose[2], Robert Margolis[1], Ted James[1], Samantha Weaver[2], Naïm Darghouth[2], Ran Fu[1], Carolyn Davidson[1], Sam Booth[1], and Ryan Wiser[2]

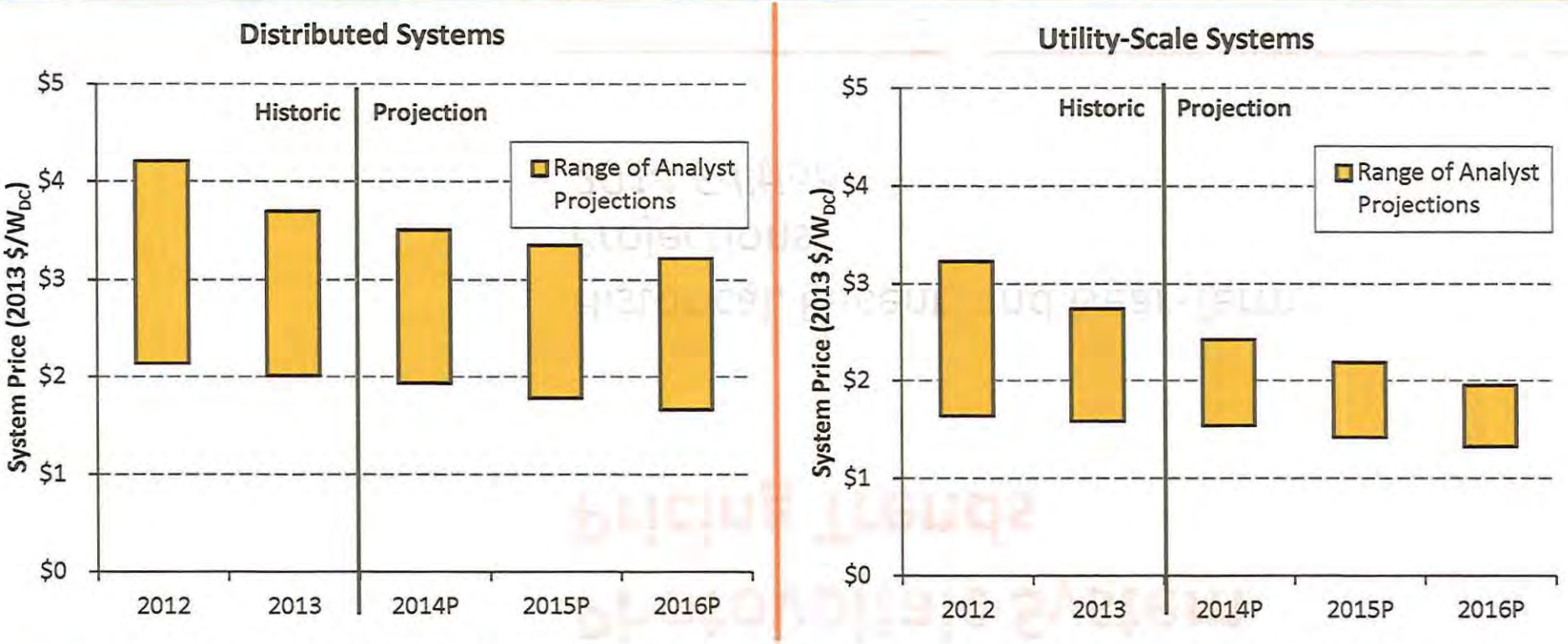
[1]National Renewable Energy Laboratory
[2]Lawrence Berkeley National Laboratory

energy.gov/sunshot

September 22, 2014

NREL/PR-6A20-62558

Analyst Estimates (2012-13) and Projections (2014–2016) of Global Average System Price



- Analysts expect the system prices of both utility-scale and distributed systems to continue to fall in the near future
  - Distributed systems are expected to reach between $1.50/W - $3.00/W by 2016
  - Utility-scale systems are expected to reach between $1.30 - $1.95/W by 2016.

Note: P = projection. Data represent the max. and min. figures from: Bloomberg New Energy Finance (05/15/14); Cowen & Company (04/24/14); Deutsche Bank (04/23/14, 05/06/14, 05/08/14); Stifel Nicolaus (03/20/14). Inflation adjusted 2013-14: EIA, AEO, Table 20, Gross Domestic Product, August 2012.

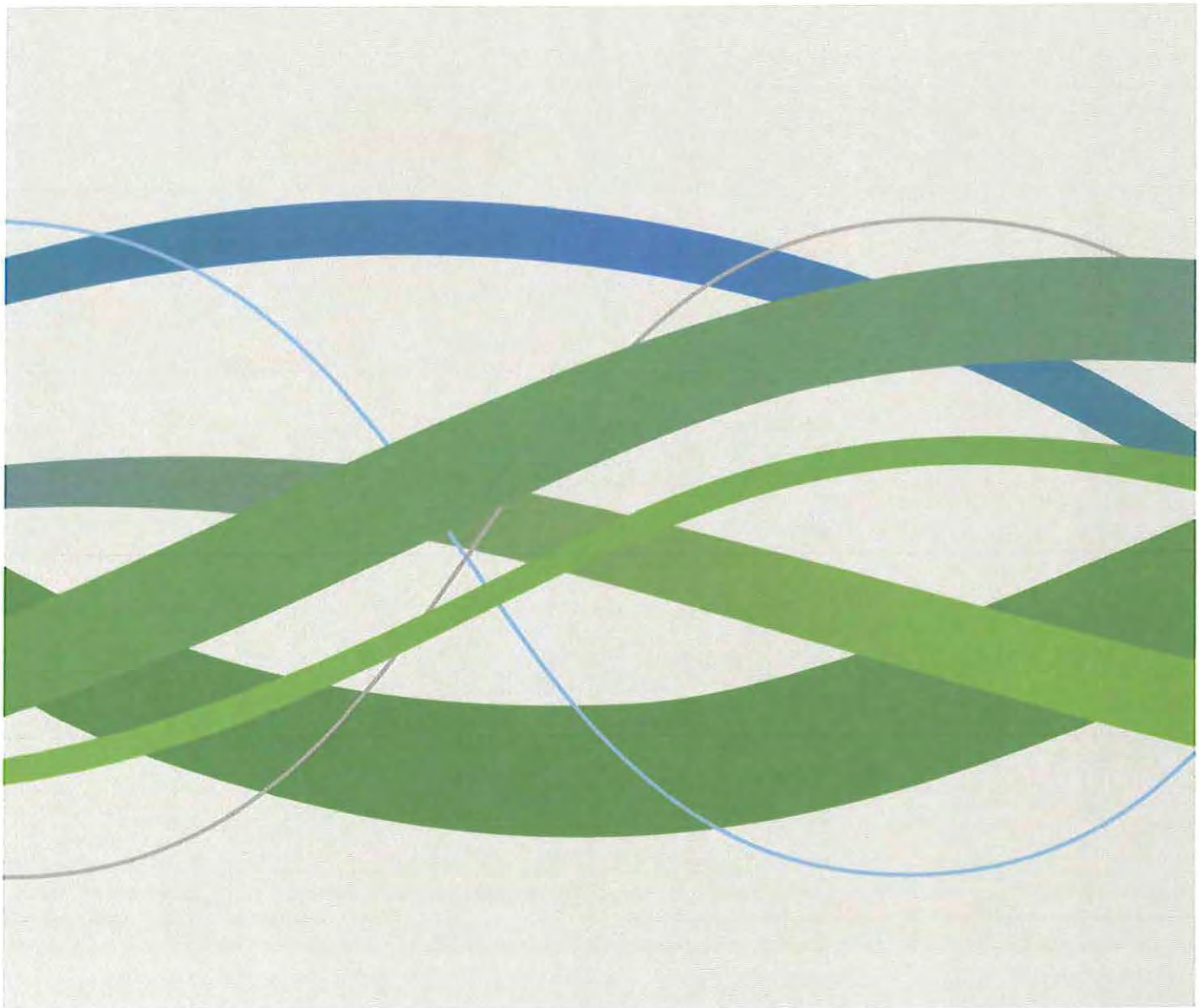
Austin Energy

Review of Strategic Plan for Local Solar in Austin

Prepared by DNV KEMA Energy & Sustainability

November 22, 2013

FINAL REVISED REPORT



Category	Assumption	DNV KEMA Response	Comments
Installed Cost	$3.90/Wdc with 6-7% Annual Decline	Reasonable	Ryan Wiser et al, in their July 2013 report titled "Tracking The Sun VI," indicate residential PV costs of $3.90/W in Texas in 2012.[5] The declining price trend of 6-7% per year is reasonable and consistent with both an industry growth rate of 25% and a commonly anticipated technology "progress ratio," (price-volume learning curve term) of 0.82.[6] [7]
Production Factor	1,300 kWh/kWac	Conservative	A production factor of just 1,300 kWh/kWac would be viewed as conservative by DNV KEMA. In the Austin climate, a typical but sub-optimal residential system could reasonably be expected to receive 5.2 peak sun hours per day per NREL's 30-year average. At a typical modern performance ratio of 0.75 for a modestly shaded and intermittently dusty residential system, this would amount to a production factor, or specific yield, of 1,423 kWh/kWp. Converting this to an ac-based capacity under warmer real field operational conditions would likely amount to a derating factor of about 0.85, not 0.95, making the expected production factor about 1,674 kWh/kW-ac. (A modern residential inverter might have an efficiency of 95%, but when coupled with the inevitable temperature, wire, and mismatch losses, the dc-to-ac conversion is about 85%.) The projected yield of 1,674 kWh/kW-ac is 29% higher than the LSAC production forecast anticipates, and would represent that much more of an energy contribution at no additional rebate cost. The higher production would increase the cost of a PBI-based incentive program, though such incentives are not common among residential installations.
Policy Impact	Did not address the impact from potential federal ITC changes in 2016	Optimistic	Based on PV cost and installed capacity trends over the past five years, and on the generally declining incentive structures in numerous states, it seems likely that the industry won't need to lobby heavily for a Federal 30% tax credit extension. While not wholly unpopular even among non-industry sectors, the political backlash of continued Federal generosity in the wake of the Solyndra case and similar loan failures may not be practical to expect. A Federal tax credit of 10% would seem to be more in line with past support. If so, there would be a drop-off of several percent in residential PV market capacity unless that discontinuity were matched by an equal boost at the state or local level, neither of which would seem likely for Austin Energy. On that basis, the residential forecast per LSAC would seem unexpectedly optimistic for growth between 2016-17, as the LSAC trend shows an 18% increase that year, with just 2-5% program increases in the three prior years.

Table 7: Evaluation of Residential Assumptions

While the LSAC report's estimated current and future installed PV costs are defensible, the report acknowledged that it did not model the expected decrease in the federal tax credit. The

[5] Wiser, Ryan et al. "Tracking the Sun VI". June, 2013

[6] Margolis, Robert. "Photovoltaic Technology Experience Curves and Markets". March, 2013

[7] Bowden, Stuart et al. Moore's Law of Photovoltaics. May, 2010

3.1.2 Commercial Solar

LSAC's plan calls for a goal of 55 MW of commercial solar by 2020. Many of the assumptions made by the committee for commercial solar are similar to those made for residential. This section will review the rigor of the major assumptions, most of which are embedded in the Table 9, below.

Commercial									
	2012	2013	2014	2015	2016*	2017	2018	2019	2020
MWac (Annual)		1	4	4.5	7	4.4	6.1	14.3	12.8
MWac (cumulative)	1.4	2.4	6.4	10.9	17.9	22.4	28.4	42.7	55.5
Installed costs ($/Wdc)	$3.30	$3.05	$2.80	$2.60	$2.40	$2.20	$2.00	$1.85	$1.60
Installed Cost Annual Decrease		8%	8%	7%	8%	8%	9%	8%	14%
Installed costs Post ITC ($/Wdc)	$2.31	$2.14	$1.96	$1.82	$2.40	$2.20	$2.00	$1.85	$1.60
Annual PBI Budget ($M)	$0.14	$0.14	$0.13	$0.11	$0.10	$0.08	$0.06	$0.04	$0.01
Amt.: net projects ($M)		$0.21	$0.75	$0.75	$1.00	$0.50	$0.50	$0.75	$0.25
Assumes 10 year PBI contracts									
Production factor is assumed to be 1,276 kWh/kWdc, per PVWatts v.1 modeled at 5% tilt, due south orientation in Austin. Conversion from kWh/kWdc to kWh/kWac assumes a DC-AC conversion factor of 0.85.									
Annual PBI commitment costs peak at $5M/yr in 2020 and 2021 and taper to $0/yr in 2030.									
Total Incentives (2013-2020): $24.00M After 2020: $25.71									
Total (through 2030): $49.71									
NPV 5% of Incentives (2013-2020): $18.29M NPV 5% of Incentives (through 2030): $33.02M									
* The current federal investment tax credit (ITC) is scheduled to decrease from 30 percent to 10 percent in 2016. Modeling does not assume the effect of this expiration on nominal and after-tax costs.									

Table 9: Commercial Summary Table Adapted from LSAC Strategic Report

A summary of DNV KEMA's review of LSAC's assumptions is presented in the table below.

Category	Assumption	DNV KEMA Response	Comments
Installed Cost	$3.30/Wdc and 7%-14% annual decline	Slightly Optimistic	Wiser's 2013 Lawrence Berkeley report, the same source used to verify the exact price cited in the LSAC report for Texas residential PV cost in 2012, also lists a 2012 medium-size commercial PV cost of $4.50/Wp in Texas, so the LSAC cost figures seem considerably more optimistic than that one trusted source would suggest.[8] However, for commercial PV greater than 100 kW, for which no Texas system data were reported due to an insufficient sample size, there were states that reported costs in the $3.30/W range. For example, Colorado commercial systems averaged $3.20/W, so the LSAC quote is not implausibly optimistic.
Production Factor	1,276 kWh/kWac	Conservative	The specific yield for a commercial rooftop system in Austin, even for a popular very low-slope type, would likely be well in excess of 1,276 kWh/kWac. Depending on the value used to convert kWac to kWp, a yield of 1,276 would translate to less than 1,100 kWh/kWp, an implausibly poor result for this climate. DNV KEMA would expect a typical low-slope yield to be more in line with the product of a solar resource of 5 peak hours per day x 365 days/yr x 0.80 performance ratio for modern, maintained and unshaded commercial systems, for a dc yield of 1,460 kWh/kWp. This is the more common nomenclature used in the industry, but if that value were converted to an ac basis using a conversion factor of 0.85, the corresponding ac-based yield would be 1,718 kWh/kW-ac. This is 35% above the LSAC projection and is worthy of further study and clarification. In PVWatts, users are tasked to apply a derate factor that accounts for all losses other than temperature. The default derate factor is 0.77, which was appropriate for older systems but is widely viewed as too conservative for contemporary systems. Modern PV features true-to-nameplate module output, whereas manufacturers formerly routinely overstated actual output by 5%. Modern inverters operate in the 95-97% efficiency range, while the older PVWATTS guideline assumed efficiencies of about 90-92%. These two changes alone mean most modern PV systems should achieve annual performance ratios of 75-80%, when older systems typically hovered around 70%. PVWatts is a fine tool, but its inputs must be user-adjusted to reflect current practices and expectations, and generally, these expectations are now several percent better than when the program was introduced over 15 years ago.
Policy Impact	Did not address the impact from potential federal ITC changes in 2016	Optimistic	See Residential Section

Table 10: Evaluation of Commercial Assumptions

[8] Wiser, Ryan et al. June, 2013

The table below details the assumptions made in the LSAC report and DNV KEMA's evaluation of them.

Category	Assumption	DNV KEMA Response	Comments
Solar Contract Cost	$0.08/kWh to $0.06/kWh	Reasonable (see ITC comment)	The reduced PPA of 8 cents/kWh would only look attractive if the investor were able to realize the 30% tax credit (or its equivalent Federal 1603 Grant), and if the cost were $2/W, and the location was a sunnier spot such as El Paso, and if the PPA term were 30 years. Under those terms, a favorable B/C ratio of 1.09 may be realized. At 20 years, this doesn't seem to pencil out favorably - B/C ratio dips slightly below 1.0. At $2.50/W, the B/C ratio dips to 0.91 and is far too low to justify the investment. The financing terms of 20% equity, 80% debt, 8% loan and 9% discount rate as applied above were used for this analysis as well.
Production Factor	2,250 kWh/kWac	Conservative	The production factor of 2,250 is consistent with DNV KEMA estimates for tracking system output in El Paso on a dc basis, that is, 2,250 kWh/kWp is a reasonable estimate. On an ac basis, the stated value is viewed by DNV KEMA as conservative, since a value of over 2,600 would be expected on an ac basis for this optimal southwest tracker example. Throughout, it appears there may be a mismatch of labeling on the production factor units, as 2,250 kWh/kWp is a common high-end yield that has been proven in the field, and, as noted above, yields are most commonly expressed in units of kWh/kWp.
DC-AC Conversion Factor	DC-AC Conversion factor of 0.90	Reasonable	In general, the more generous assumption of a 0.90 conversion is probably justified for best-case contemporary utility scale systems. Most should be able to achieve the 0.90 dc to ac conversion because they feature very high efficiency inverter/transformer combinations of around 0.96. Depending on what other loss factors are considered in the conversion, this leaves plenty of calculation allowance for small but cumulative effects such as clipping, wire resistance, imperfect maximum-power-point tracking, and mismatch, which collectively would lessen the conversion factor from 0.96 but still enable it to surpass 0.90. The one large unknown in this discussion is temperature. If temperature is intended to be included in this dc to ac conversion, then 0.90 is not likely to be attained. Temperature losses alone would be in the 8% range in most southwest locations. That consideration alone would drop the overall dc to ac conversion factor back into the mid-80 percentile range. The reasonableness of this and other conversion and conventions is entirely dependent on the terms that lumped within the conversion.
Installed Costs	$2.50/W	Slightly Conservative	Although a reasonable cost assumption, as noted above, at $2.50/W, the investment does not look attractive, even in an optimal southwest location such as El Paso. At this cost, a higher PPA would be needed: at least 10 cents/kWh for 20 years.

Table 15: Evaluation of Other Utility Scale Assumptions

Although not addressed in the LSAC report, Austin Energy may also wish to consider the cost impacts from ERCOT settlement of non-local generation. Such an analysis is beyond the scope of this assessment and will depend on the nodal location of the procured other utility scale solar.

NREL

1-AXIS
TRACKING

Annual production = 173,832 kWh
Array size (ac) = 90 kW

(173,832 kWh)/[(90 kW)(8,760 hr/yr)] = 0.220 (22 percent capacity factor)

Month	Solar Radiation (kWh / m² / day)	AC Energy (kWh)	Energy Value ($)
January	4.24	11,565	1,121
February	5.60	13,366	1,295
March	6.01	15,307	1,483
April	6.89	16,526	1,601
May	6.74	16,229	1,573
June	7.36	16,906	1,638
July	7.24	16,790	1,627
August	7.35	16,985	1,646
September	6.55	15,189	1,472
October	6.06	15,005	1,454
November	4.08	10,205	989
December	3.63	9,759	946
Annual	**5.98**	**173,832**	**$ 16,845**

Location and Station Identification	
Requested Location	Kirksville missouri
Weather Data Source	(TMY2) COLUMBIA, MO 97 mi
Latitude	38.82° N
Longitude	92.22° W

PV System Specifications *(Residential)*	
DC System Size	100 kW
Module Type	Standard
Array Type	1-Axis Tracking
Array Tilt	40.2°
Array Azimuth	180°
System Losses	14%
Inverter Efficiency	96%
DC to AC Size Ratio	1.1
Ground Coverage Ratio	0.4

Initial Economic Comparison	
Average Cost of Electricity Purchased from Utility	0.10 $/kWh
Initial Cost	3.30 $/Wdc
Cost of Electricity Generated by System	0.15 $/kWh

These values can be compared to get an idea of the cost-effectiveness of this system. However, system costs, system financing options (including 3rd party ownership) and complex utility rates can significantly change the relative value of the PV system.

NREL

FIXED ARRAY

Annual production = 141,644 kWh
Array size (ac) = 90 kW

(141,644 kWh)/[(90 kW)(8,760 hr/yr)] = 0.180 (18 percent capacity factor)

Month	Solar Radiation (kWh / m^2 / day)	AC Energy (kWh)	Energy Value ($)
January	3.12	8,421	816
February	4.18	9,981	967
March	4.83	12,290	1,191
April	5.82	13,898	1,347
May	5.99	14,324	1,388
June	6.64	15,107	1,464
July	6.46	14,863	1,440
August	6.25	14,349	1,390
September	5.32	12,290	1,191
October	4.59	11,332	1,098
November	3.07	7,636	740
December	2.68	7,153	693
Annual	4.91	141,644	$ 13,725

Location and Station Identification	
Requested Location	kirksville missouri
Weather Data Source	(TMY2) COLUMBIA, MO 97 mi
Latitude	38.82° N
Longitude	92.22° W

PV System Specifications *(Residential)*	
DC System Size	100 kW
Module Type	Standard
Array Type	Fixed (open rack)
Array Tilt	20°
Array Azimuth	180°
System Losses	14%
Inverter Efficiency	96%
DC to AC Size Ratio	1.1

Initial Economic Comparison	
Average Cost of Electricity Purchased from Utility	0.10 $/kWh
Initial Cost	3.30 $/Wdc
Cost of Electricity Generated by System	0.19 $/kWh

These values can be compared to get an idea of the cost-effectiveness of this system. However, system costs, system financing options (including 3rd party ownership) and complex utility rates can significantly change the relative value of the PV system.

WATER | ENERGY | LIFE

RIVERSIDE PUBLIC UTILITIES

Board Memorandum

BOARD OF PUBLIC UTILITIES **DATE:** JUNE 19, 2015

ITEM NO: 7

SUBJECT: POWER SALES AGREEMENTS BETWEEN SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY AND THE CITY OF RIVERSIDE – SPOWER'S ANTELOPE DSR SOLAR PHOTOVOLTAIC PROJECT

ISSUE:

The issue for Board of Public Utilities (**Board**) consideration is the approval of the Power Sales Agreement **(PSA)** between the Southern California Public Power Authority **(SCPPA)** and the City of Riverside (**City**) for sPower's Antelope DSR Solar Photovoltaic (**PV**) project.

RECOMMENDATIONS:

That the Board recommend that the City Council:

1. Approve the 20-year PSA between SCPPA and the City to provide renewable solar PV energy and Renewable Energy Credits from sPower's Antelope DSR Solar PV Project;
2. Authorize the City Manager or his designee to execute the PSA, as well as future extensions and purchase and/or storage options associated with the PSAs under terms and conditions substantially similar or superior to this PSA;
3. Authorize the City Manager or his designee to execute any documents necessary to administer the PSA; and
4. Authorize the City Manager or his designee to terminate the PSA for circumstances provided in the PSA.

BACKGROUND:

In 2012 California Senate Bill **(SB)** X1-2 mandated that all electric utilities, including Riverside Public Utilities (**RPU**), procure increasing amounts of renewable power primarily from in-state resources to serve its retail needs during specific compliance periods. RPU's current Renewable Portfolio Standard (**RPS**) requires that it supply 20%, 25% and 33% of retail energy needs using renewable resources by 2010, 2015 and 2020, respectively.

On April 29, 2015 the Governor of California issued Executive Order B-30-15 establishing a Greenhouse Gas (**GHG**) reduction target of 40% below 1990 levels by 2030, including among other things, increasing the RPS targets to 50% by 2030. Several bills are being considered by the state legislature to codify the increased RPS mandate.

The City has been very supportive of the existing renewable targets set by the State and is committed to serving its retail energy requirement using more renewable energy. In order to satisfy the current RPS targets, while anticipating more stringent RPS requirements in the future, RPU continues to explore additional cost-effective, renewable energy procurement opportunities.

Since 2012 the Board and City Council have approved 218 Megawatts (**MW**) of renewable resource contracts/extensions. The RE Columbia II Solar and Cabazon Wind project (combined 50 MW), achieved Commercial Operation Dates (**COD**) by 2014. Tequesquite, AP Northlake and Kingbird projects (combined 41 MW) are expected to come online in 2015, and the Salton Sea expansion (first phase) and Silverado (subsequently acquired by sPower) projects (combined 40 MW) have expected CODs in 2016. These projects qualify as Portfolio Content Category 1 renewable energy resources under California SB X1-2 RPS legislation.

However, one SCPPA project (20 MW RE Clearwater solar PV) faced unanticipated permitting challenges, will not be constructed and is being unwound. To date, the developer has paid approximately $1.8 million in non-refundable liquidated damages (RPU's share is $1.3 million). Staff is looking to replace this project (using SCPPA's ongoing renewable RFP process) with sPower Solar Holding LLC (sPower), and has been negotiating for the City's participation in the 50 MW solar PV Antelope DSR (Project) located in the City of Lancaster. The sPower solar PV price is the lowest RPU has seen in recent years and is about 20% lower than the failed RE Clearwater solar project pricing, resulting in an approximate net present value savings of $8.8 million. The competitive price offered by sPower is due to several factors:

1. The continued decline in the equipment and labor costs of solar PV projects;

2. The Project is part of a much larger transmission interconnection position with the California Independent System Operator (**CAISO**), with an executed interconnection agreement (with known cost exposures), and certain shared interconnection upgrades;

3. Economies of scale due to sPower's extensive holdings of more than 800 MW of solar development assets in the general Antelope Valley area; and

4. Solar developers' increased efforts to find off-takers to insure a 2016 COD, prior to expiration of the federal Investment Tax Credit (**ITC**).

The sPower is in the final project development stage and requires a power purchase commitment no later than fall 2015 to meet its 2016 deadline. The Antelope DSR Project will aid RPU in achieving current and future RPS goals by replacing the failed RE Clearwater project; moreover this project has the following desirable characteristics and favorable terms:

Economy of Scale of Joint SCPPA Project: A 50 MW solar PV project will be shared jointly by Riverside (25 MW) and Vernon (25 MW), through SCPPA. SCPPA will enter into a Power Purchase Agreement (PPA) with sPower, and subsequently SCPPA will enter into individual PSAs with the participating SCPPA members under the same terms and conditions of the SCPPA-Antelope DSR PPA.

Familiar Developer: sPower is formerly known as Silverado. SCPPA/RPU already have two PSAs for solar PV projects (Summer Solar and Antelope Big Sky Ranch), originally approved by the Board and City Council on December 7, 2012 and January 8, 2013, respectively, with an expected 2016 COD. sPower and its parent company, FTP Power, have a substantial solar footprint in the Antelope Valley area and as of December 2014, the companies have $500 million in equity and $60 million in cash to support its development and operation activities.

Project Site and Interconnection: sPower has either lease or purchase options over multiple parcels in the City of Lancaster, with sufficient acreage to develop the Project. All necessary interconnection studies have been completed and the interconnection agreement has been executed. The Project will be interconnected to Southern California Edison's Antelope 230kV Substation.

Term of the PSA: Twenty-year PSA commencing on the COD anticipated at the end of 2016, but absolutely no later than June 30, 2017.

Pricing: The all-in price for the energy, capacity (local) and environmental attributes is $53.75 per megawatt/hour (**MWh**), fixed over the term of the contract.

Performance Security: sPower will post a letter of credit (**LOC**) or cash in the amount of $2.25 million as Development Security. After COD, sPower will replace the Development Security with a Delivery Term Security in the amount of $6.91 million during the first 10 years and $5.41 million in the last 10 years, using a combination of cash, a LOC and a performance bond.

Mitigation of Development Risks: The PPA includes enforceable development milestone dates with significant financial penalties, ranging from $5,000 to $10,000 per day if dates are missed, or in the more severe cases, SCPPA can unilaterally terminate the PPA.

Scheduling Coordinator Fee: sPower will compensate SCPPA $91,000 each year to perform Scheduling Coordinator services for the Project. RPU intends to offer Scheduling Coordinator services to SCPPA for the Project and receive the revenues for performing such service.

Right of First Offer and Right of First Refusal: sPower must first offer to sell the Project to SCPPA before it can offer it to third parties.

Purchase Option: SCPPA has the option to purchase the Project in years 10, 15 and 20 (after COD) at the then fair market value. A Purchase Option Agreement will be an appendix to the PPA and will be executed concurrently with the PPA.

Storage Option: SCPPA has the option in the first 15 years of the contract to install up to 12 MW of energy storage at the project site. This provides the opportunity to integrate energy storage with the solar facility to: 1) shape the output of the solar production if needed, and 2) help meet any potential future storage mandates. sPower will reserve sufficient area on site to accommodate the storage installation. In addition, sPower will fund up to $182,000 for permitting and interconnection modifications. A Storage Option Agreement will be an appendix to the PPA and will be executed concurrently with the PPA.

Step-Up Provisions for Tax Exempt Debts: In case SCPPA exercises the purchase option or the storage option and issue tax exempt bonds to finance these options on behalf of the project participants, then project participants will be required to guarantee the payment of such bonds. In the event of a payment default by a project participant, then SCPPA would issue a Step-Up Invoice to the other non-defaulting participant, who would pay such invoice to cover the non-payment on behalf of the defaulting participant. The non-defaulting participant would then be reimbursed by means of a) receiving a repayment by the defaulting participant, b) taking delivery of defaulting participant's share of the facility output, or c) collecting proceeds from the sale of defaulting participant's share of the facility output to a third party. Such step-up provisions are typical provisions in SCPPA jointly financed projects including Palo Verde Nuclear Generating Station, Hoover Uprating Project, Mead-Adelanto Transmission Project, Mead-Phoenix Transmission Project and Southern Transmission Project which RPU is party to.

Contribution toward RPU's RPS Goal: RPU's share of the Project will generate approximately 71,000 MWh of renewable energy, or 3% of the City's RPS requirements in 2017, and is contemplated in the recently completed Integrated Resource Plan presented to the Board on February 20, 2015. This also assists the City's GHG reduction efforts and the strategic replacement of other expiring contracts. The project qualifies as an in-state renewable resource under SB X1-2 rules.

FISCAL IMPACT:

The annual cost of power under the PSA is estimated to be approximately $1.9 million in Fiscal Year 2016/17 and $3.8 million each Fiscal Year thereafter. This cost is fixed with no annual escalation for 20 years. Staff will incorporate the costs of the PSA in future power supply budgets.

Prepared by:	Reiko A. Kerr, Public Utilities Assistant General Manager/Resources
Approved by:	Girish Balachandran, Public Utilities General Manager
Approved by:	John A. Russo, City Manager
Approved as to form:	Gary G. Geuss, City Attorney
Certifies availability of funds:	Laura Chavez-Nomura, Public Utilities Assistant General Manager/Finance
Attachment:	Power Sales Agreement between SCPPA and Riverside

Execution Version

POWER PURCHASE AND SALE AGREEMENT

BETWEEN

CITY OF LANCASTER, A CALIFORNIA MUNICIPAL CORPORATION AND CHARTER CITY, D/B/A LANCASTER CHOICE ENERGY

AND

WESTERN ANTELOPE DRY RANCH LLC

EXHIBIT C

CONTRACT PRICE

The Contract Price of the Product shall be:

Contract Year	Contract Price
1 – 20	$54.99

CITY OF RIVERSIDE

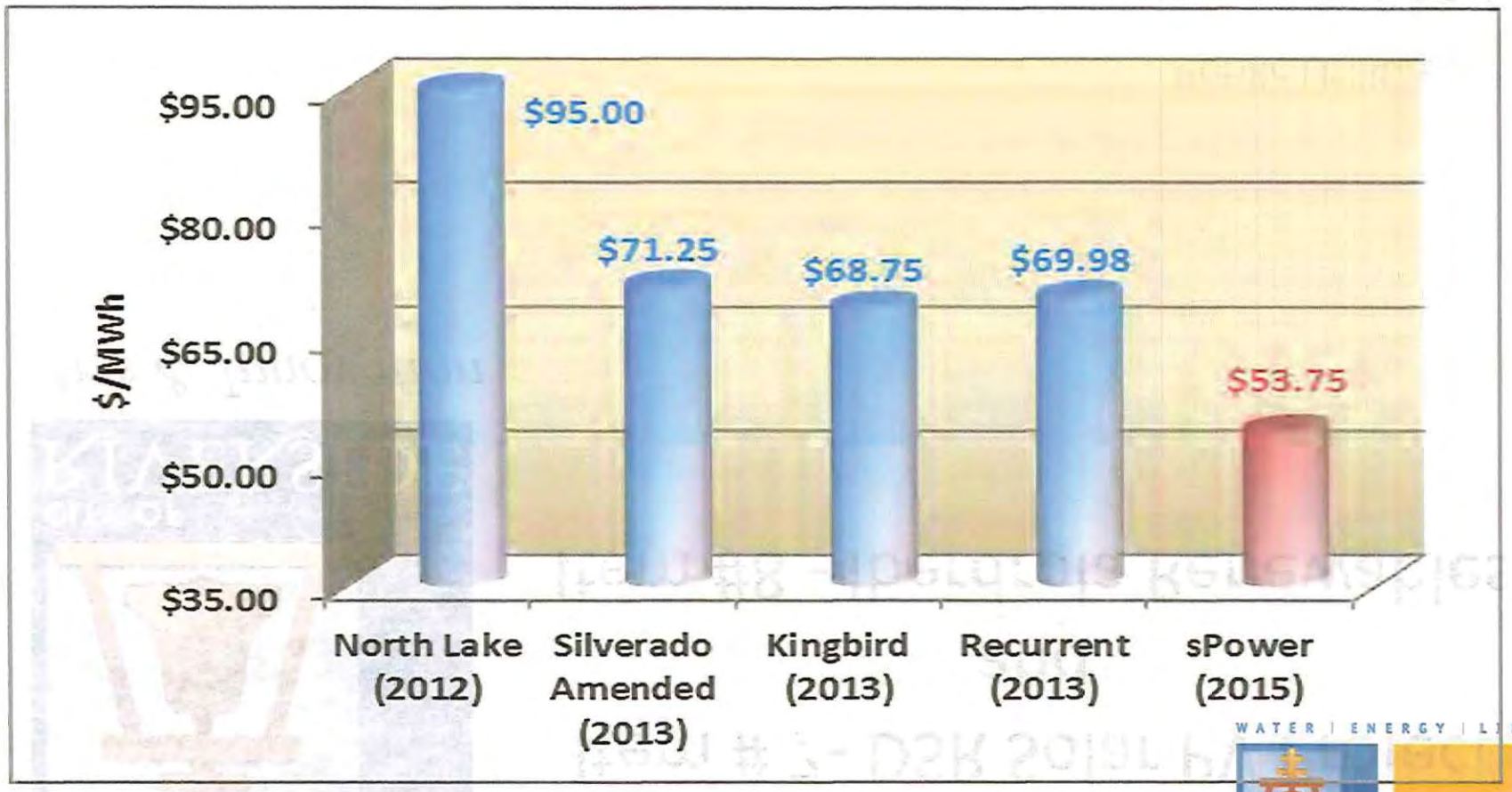
Arts & Innovation

Item # 7- DSR Solar PV Project and Item #8 - Iberdrola Renewables

Public Utilities Board

June 19, 2015

Project Price Comparison



GREENTECH MEDIA

SOLAR PROJECTS

Cheapest Solar Ever? Austin Energy Buys PV From SunEdison at 5 Cents per Kilowatt-Hour

An unprecedentedly low price for a large solar project

by Eric Wesoff
March 10, 2014

An unprecedentedly low price for a large solar project

Texas utility Austin Energy is going to be paying 5 cents per kilowatt-hour for solar power, and it could mean lower customer rates.

City-owned Austin Energy is about to sign a 25-year PPA with Sun Edison for 150 megawatts of solar power at "just below" 5 cents per kilowatt-hour. The power will come from two West Texas solar facilities, according to reports in the *Austin American-Statesman*. According to reports, around 30 proposals were at prices near SunEdison's. Austin Energy has suggested that the PV deal will slightly lower rates for customers.

This is one of the lowest, if not the lowest, reported prices for contracted solar that we have seen. Last year, First Solar (FSLR) entered a 25-year PPA in New Mexico for 50 megawatts of solar power at 5.79 cents

per kilowatt-hour. That number included a significant PTC from the state. The Macho Springs project, the Austin project and most solar projects of this nature rely on the 30 percent federal Investment Tax Credit.

Austin Energy's net sub-five cent price does not include any state PTC, according to Monty Humble of energy development firm Brightman Energy LLC. He said that the utility was "to be commended" for this solicitation. Humble added, "Based on our analysis, it can be done. There's not a whole lot of profit in it, but it's not a loss leader. It's a legitimate bid."

GTM Solar Analyst Cory Honeyman points out that "new PPAs signed in North Carolina fetched prices for less than 7 cents per kilowatt-hour" citing a report by the *Charlotte Observer*.Like Macho Springs, those projects could also take advantage of an in-state tax credit to make the economics work. Honeyman said that none of the projects in Georgia or North Carolina were larger than 20 megawatts, so 5 cents does seem like "an unprecedented low for large-scale projects."

Bret Kadison, COO of Austin-based Brazos Resources, an energy investment firm, said this was "a highly competitive solicitation." Although historically, "Texas hasn't been a hotbed of solar, you're starting to see that change. ERCOT needs the generation."

He expects to see more solar activity "not just as a green source of energy, but as an affordable source of energy. Texas is seeing economic growth, but the power grid has not kept pace." Kadison added, "When you think about the volatility of natural gas, a 25-year PPA starts to look pretty attractive."

Kadison notes, "This is below the all-in cost of natural gas generation, even with low fuel prices and before factoring in commodity volatility and cost overruns." He also points out that the original RFP was for 50 megawatts, but the utility ended up buying 150 megawatts "in a red state where hydrocarbons dominate the political landscape." Kadison suggests that "one of the biggest cost reduction drivers that allowed solar to reach this parity came from the massive reduction in financing costs."

The 5-cent price falls below Austin Energy's estimates for natural gas at 7 cents, coal at 10 cents and nuclear at 13 cents. The utility points out that it approved a 16.5-cent price for the Webberville solar plant in 2009.

Austin Energy has a 35 percent renewable energy resource goal by 2016 and a solar goal of 200 megawatts by 2020. The utility is currently at about 25 percent, much of it made up by its 850 megawatts of wind.

Humble of Brightman Energy said, "I expect that this will force a lot of players to reexamine their approach and get far more aggressive. Because of the size of the ERCOT market and the size of the state, Texas is potentially the largest solar market in the country." According to GTM Research's 2013 U.S. SMI report, Texas ranked 8th in the nation with 75 megawatts installed in 2013.

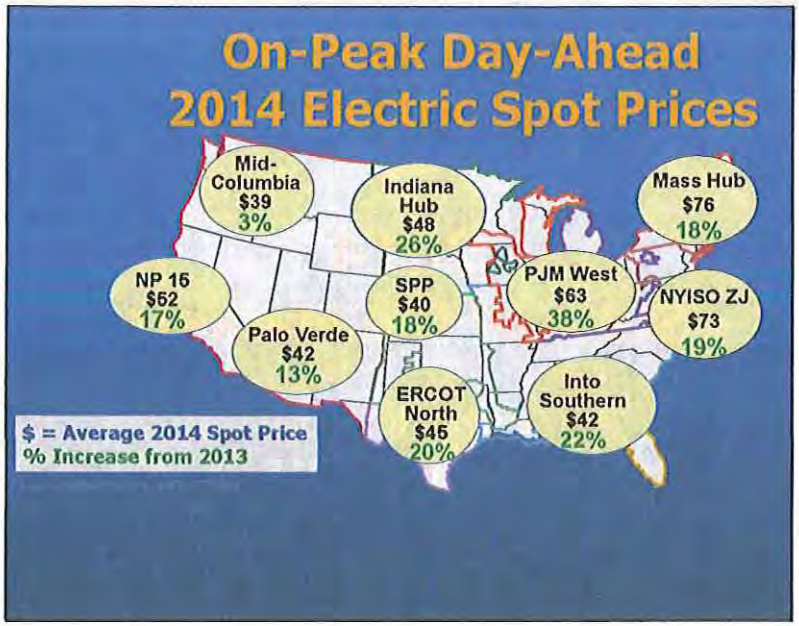
GTM's Honeyman notes, "This is the second major announcement in which a utility has stated plans to procure more than 100 megawatts of solar PV based on its cost-competitiveness with natural gas, as opposed to RPS-driven demand."

If developers continue to bid in at these prices -- it won't be the last.

Good morning Chairman and Commissioners.

The Office of Enforcement's Division of Energy Market Oversight is pleased to present the 2014 State of the Markets Report. This report is staff's annual opportunity to share our assessment on natural gas, electric, and other energy markets developments during the past year to better inform the Commission's understanding of current and future trends.

Slide 11



Electricity average spot prices rose across the country in 2014, primarily driven by high prices in the first quarter.

Natural gas remained a major driver of electricity prices, with regional prices reflecting, in part, variations in natural gas prices. The largest increases were in PJM, where average on-peak day-ahead prices at the Western Hub rose 38 percent due to price spikes in the first quarter.

Prices in the Pacific Northwest, where increased hydro generation kept prices down, were the lowest in the country. CAISO had some of the lowest price increases in the country with average on-peak day-ahead prices rising by 17 percent. Prices remained modest in the Southeast throughout the year, averaging $42/MWh at the Into Southern pricing point.

Greentech Media

http://www.greentechmedia.com/articles/read/cheapest-solar-ever-austin-energy-gets-1.2-gigawatts-of-solar-bids-for-less

PROJECTS

Cheapest Solar Ever: Austin Energy Gets 1.2 Gigawatts of Solar Bids for Less Than 4 Cents

"We expect to see prices out in the future that are possibly below $20 a megawatt-hour."

by Stephen Lacey, June 30, 2015

Correction: Khalil Shalabi said was that 1,295 megawatts were priced below the Recurrent solar deal from last year, which was under 5 cents per kilowatt-hour not under 4 cents per kilowatt-hour.

A lot more cheap solar is coming for Austin, Texas.

The city's utility, Austin Energy, just released new data on developer bids for PV projects as part of a 600-megawatt procurement. The numbers show how far solar prices have come down over the last year -- and will continue to drop.

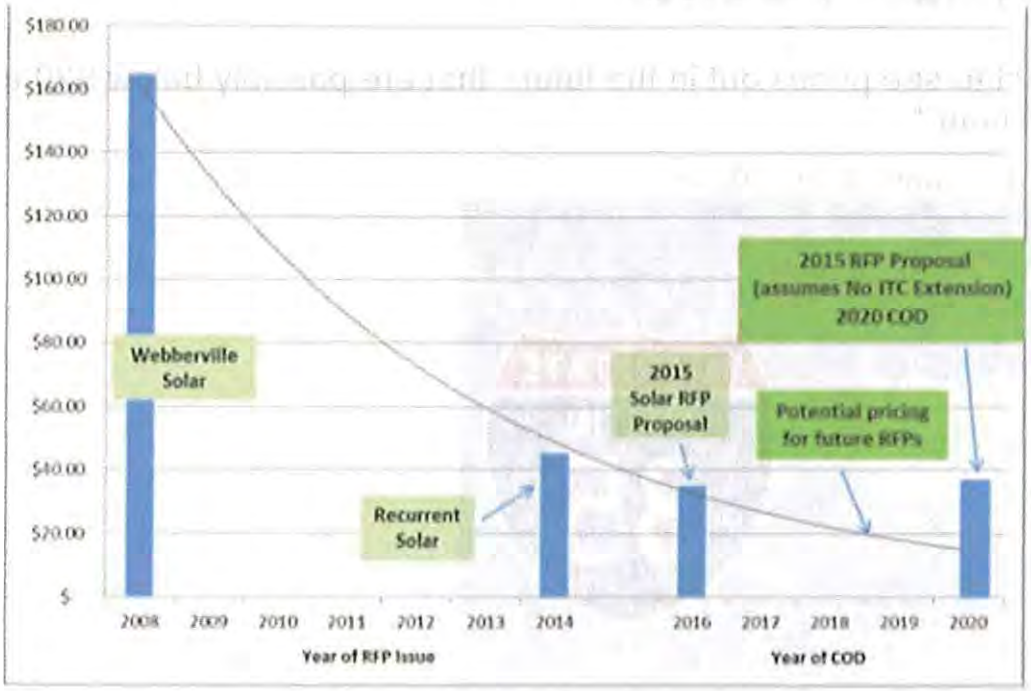
According to Khalil Shalabi, Austin Energy's vice president of resource planning, the utility received offers for 7,976 megawatts of projects after

issuing a request for bids in April. Out of those bids, 1,295 megawatts of projects were priced below 4 cents per kilowatt-hour.

"The technology is getting better and the prices are decreasing with time," said Shalabi during a presentation in front of the Austin city council last week.

Shalabi displayed the chart below showing an "exponentially declining curve" for PV projects in Texas.

"If you continue the curve, you can see that if the cost points continue along this sort of exponentially declining curve. We expect to see prices out in the future that are possibly below $20 a megawatt-hour," he said.



Source: Austin Energy

As part of a resource plan approved by city officials in 2014, Austin Energy must procure 55 percent of its electricity from renewable resources by 2025. The utility plans to build 600 megawatts of utility-scale solar projects in the next few years in order to meet the target.

In March of last year, Recurrent Energy signed a 25-year deal with Austin Energy to deliver electricity from a 150-megawatt solar plant for just under 5 cents per kilowatt-hour. It was a landmark contract. But today, more than a thousand megawatts of projects are coming in for 20 percent cheaper.

"These bids are without question the cheapest bids ever seen in a utility solar solicitation," said Cory Honeyman, a senior analyst with GTM Research.

This price trend is a mixed blessing for developers and the utility. It shows that Austin Energy will be able to meet its 600-megawatt target with competitive PV resources. But Shalabi also said the company has "a little bit of buyer's remorse" when bids came down 20 percent after signing the 150-megawatt contract with Recurrent.

Yes, solar prices are coming down so quickly that a 5-cent contract can induce buyer's remorse.

This could cause delays for developers if Austin Energy cuts its procurement in 2015 in the hopes that solar prices keep dropping.

According to Austin Energy's projections, contract prices will likely rise for 18 months if the federal Investment Tax Credit (ITC) expires at the end of 2016. But then prices will drop back down to today's levels -- or lower. With that scenario in mind, the utility may only sign one-third of expected contracts as it plans through 2020.

"The prices of equipment and installations are going down so fast that if you were to issue another RFP post-2016, you would wipe out that difference, which is very, very small -- in the order of single digits," said Shalabi. "In other words, the ITC is not a driver for us making a decision today. We don't have to gobble up all 600 megawatts because of the ITC."

Nationwide, an ITC expiration is expected to slow utility-scale project development for at least a year. According to GTM Research, large installations will drop from 7.2 gigawatts in 2016 to around 1 gigawatt in 2017.

ST. LOUIS POST-DISPATCH

Ameren seeks to build massive solar array along I-70

JULY 01, 2015 5:15 PM • BY JACOB BARKER

St. Louisans driving to Columbia or Kansas City can look forward to some new scenery starting this fall.

By October, Ameren Missouri hopes to break ground on a large new solar array along the north side of Interstate 70 in Montgomery County. The 70-acre project between New Florence and High Hill will be visible from the highway for more than half a mile.

"Going between here and Columbia and here and Kansas City, you will not miss it in either direction," said Bill Barbieri, the St. Louis utility's renewable energy chief.

The solar array in Montgomery County would be Ameren's second major solar project. It filed this week an application seeking approval from state regulators.

The utility's plans call for a 15-megawatt solar plant that would produce an estimated 20,655 megawatt-hours per year, enough to power roughly 1,500 households annually. Construction is expected to take until the end of 2016.

Once completed, the new solar array would contain almost 48,000 panels and be nearly three times the size of Ameren's first utility-scale solar array in O'Fallon, Mo. The O'Fallon array went into service in December.

Ameren first mentioned a new solar project when it released its long-range energy plan in October. The plan calls for phasing out two of its coal power plants by 2033. The roughly 1,800 megawatts of coal power would be offset by an additional 400 megawatts of wind and a new 600-megawatt combined cycle natural gas plant.

Ameren's renewable energy projects are largely driven by Missouri's renewable energy standard, passed by voters in 2008. It requires a certain amount of power to come from low carbon sources such as wind and hydroelectric, and it mandates a certain allocation for solar power.

Also, a federal tax credit for renewable energy investment is expected to drop to 10 percent from 30 percent at the end of 2016, and Barbieri said Ameren wants to take advantage of the larger credit while it's available.

The state's renewable energy standard also created a rebate program that allowed customers to offset the cost of installing their own solar panels on roofs. Those credits expired last year after Ameren paid some $90 million to customers.

Efforts to revive the program haven't gained momentum, and meanwhile Ameren has started building utility-owned solar arrays, which it says is more efficient and cheaper for customers than a rebate program.

Ameren did not reveal the cost of the proposed solar array in Montgomery County because it's still negotiating with contractors, Barbieri said.

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Missouri Ecological Services Field Office
101 Park DeVille Drive, Suite A
Columbia, Missouri 65203-0057
Phone: (573) 234-2132 Fax: (573) 234-2181

December 5, 2014

Mr. Kenny Lynn
Ameren Transmission
1901 Chouteau Ave
PO Box 66149
St. Louis, Missouri 63166-6149

Dear Mr. Lynn:

This letter is in response to the revised route alternatives for the Ameren Mark Twain Transmission Project received in our office on October 6, 2014. The U.S. Fish and Wildlife Service (Service) is providing this response under the authority of the Fish and Wildlife Coordination Act (16 U.S.C. 661 et seq.), National Environmental Policy Act of 1969 (42 U.S.C. 4321-4327), Migratory Bird Treaty Act (16 U.S.C. 703-712), and Endangered Species Act of 1973, as amended (16 U.S.C. 1531-1543).

Federally Listed and Proposed Bat Species

The Mark Twain Transmission Project consists of two major segments, Maywood to Zachary and Zachary to State Line. For each major segment, Ameren has reduced the potential alternatives within each segment to two alternative routes per segment. The two routes for Maywood to Zachary run through Marion, Shelby, Lewis, Knox, and Adair counties. The two routes for Zachary to State Line run through Adair and Schuyler counties. Every county intersected by the proposed alignment is known to be occupied by maternity colonies of the endangered Indiana bat (*Myotis sodalis*). Furthermore, based on past surveys, the routes pass through five known maternity colony home ranges. Many areas along the proposed alignment have suitable habitat but likely have not been surveyed for federally listed bats. These areas of suitable habitat in the aforementioned counties have a high likelihood of occupancy by Indiana bats. The proposed endangered northern long-eared bat (*Myotis septentrionalis*) also occurs in northeast Missouri and has been documented in Lewis County.

Removal of trees during the hibernation season of bats (November 1 to April 1) prevents the direct take of tree-roosting bats. However, there is still potential for indirect take through habitat loss and degradation. In a June 23, 2014 email, Shauna Marquardt of my staff relayed to you the

need to conduct surveys for federally listed bats along the proposed alignment in order to determine where the species might occur and to identify roost trees or roosting areas. These data are necessary to identify areas that should be avoided and to help develop minimization measures where necessary. Guidelines for conducting summer surveys for Indiana bats are available here: http://www.fws.gov/midwest/Endangered/mammals/inba/inbasummersurveyguidance.html.

Migratory Birds

Restricting woody vegetation clearing to winter months also serves to prevent injury to or mortality of most nesting migratory birds. Raptors and owls, however, breed during late winter and early spring. Because these species are protected under the Migratory Bird Treaty Act, we recommend implementing measures to avoid or minimize impacts to active nests.

While direct take may be avoided by clearing woody vegetation during the winter, the Service is concerned about the effects of permanent loss of habitat from clearing the ROW. According to the proposed alignments you provided, the project will consist of approximately 100 miles of new transmission line and associated ROW through the forest-limited landscape of northeast Missouri. ROW construction for each alternative route will require tree and woody vegetation removal. Should the final alignment require substantial removal of forested habitat, we would like to discuss with you options to replace this habitat elsewhere or to protect other areas containing comparable habitat. We have worked with other companies involving the removal of mature forested habitat associated with ROWs and would be happy to provide examples of mitigation measures which have been implemented to benefit migratory birds.

Finally, when selecting the final alignment, Ameren should minimize overall forest degradation and loss and should avoid fragmentation of existing forest patches to the extent practical to reduce impacts to federally listed bats and migratory birds. At this time, the Service cannot recommend specific routes because each of the four alternatives intersects with known Indiana bat maternity colony home ranges. The Service requests a meeting with Ameren and the Missouri Department of Conservation to coordinate efforts on the Mark Twain Transmission Project before the final alignment is selected. Should proposed route alternatives change, or if you have questions concerning this response, please contact Shauna Marquardt at (573) 234-2132, extension 174.

Sincerely,

Amy Salveter
Field Supervisor

Cc: MDC, Jefferson City, MO (Attn: Jennifer Campbell-Allison, Policy Coordination)

Marquardt, Shauna <shauna_marquardt@fws.gov>

Mark Twain 345kV Transmission Line Project

Marquardt, Shauna <shauna_marquardt@fws.gov> Mon, Jun 23, 2014 at 3:28 PM
To: "Lynn, Kenneth W" <KLynn@ameren.com>
Cc: Shauna Marquardt <shauna_marquardt@fws.gov>

Kenny,

I am going to be taking the lead on the Mark Twain 345kV Line project. To obtain your official list of species that could be present in your project area, you can use our new project review website, IPaC. I have attached instructions on how to obtain a species list that serves as official correspondence from us. Based on this species list you will be able to further evaluate potential impacts to species that could be present.

Based on the information you submitted, I do have a few initial thoughts for you consider. Both Indiana and northern long-eared bats will show-up on your species list. This project is basically going right through the part of the state we consider to have the most maternity colonies of Indiana bat. We know a little less about northern long-eared bats here, but we do know they occur and will be concentrated in larger forested blocks.

Although you have not yet selected your alignment, I can tell you that if there will be more than 5 acres of mature forest removed to complete this project, bat surveys will be necessary. It could be prudent to skip the time and expense of a highly detailed habitat assessement and use a more general assessment to guide the level of effort and locations of bat surveys. What is the timeline of this project? Seems like we are a little ways out? I am happy to visit with you about alignment alternatives when you get to that point.

Please feel free to call or email with questions as you move into the next stages of this project.

Shauna

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Shauna Marquardt
Fish and Wildlife Biologist
U.S. Fish and Wildlife Service
Missouri Ecological Services Field Office
101 Park De Ville Drive, Suite A
Columbia, MO 65203
573/234-2132 ext. 174 (office)
573/234-2181 (fax)

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IPaC Instructions.pdf
148K

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Missouri Ecological Services Field Office
101 Park DeVille Drive, Suite A
Columbia, Missouri 65203-0057
Phone: (573) 234-2132 Fax: (573) 234-2181

Information for Planning and Conservation (IPaC) is a project planning tool which streamles the U.S. Fish and Wildlife Service environmental review process. Through IPaC, you can obtain an Official Species List, but IPac will not provide you with a concurrence or non-concurrence with "may affect" determinations. You should use the species list to make a determination for your project. If your determination is "no effect," document your decision for your file; no further consultation with our office is necessary. If your project may affect species noted in the Official Species List, contact our office to initiate consultation.

How to use IPaC to obtain an Official Species List:

1. Go to http://ecos.fws.gov/ipac/
2. Click "GET STARTED."
3. Click "ENTER PROJECT LOCATION" and search for the nearest town in the "Find a place" search bar.
4. Define your project area using the "Sketch," "Polygon," or "Line" tool. You can also upload a shapefile if you have one.
5. Click "Continue" to confirm the project area.
6. **Please note the resulting webpage is NOT an Official Species List.** To request an Official Species List, click "Request an Official Species List" under "Tasks."
7. Fill out the information requested on the next page and click "SUBMIT OFFICIAL SPECIES LIST REQUEST."
8. A message from "fwhq_ecos_support" should be delivered to the email address you provided; click the link in the email to verify your email address.
9. Shortly after you verify your email address, you should receive an email with an Official Species List attached.
10. If you have any questions, please contact the Missouri Ecological Services Field Office at 573-234-2132.

MISSOURI DEPARTMENT OF CONSERVATION

Headquarters

2901 West Truman Boulevard, P.O. Box 180, Jefferson City, Missouri 65102-0180

Telephone: 573-751-4115 ▲ www.MissouriConservation.org

ROBERT L. ZIEHMER, Director

October 16, 2014

Mark Twain Transmission Project
C/O Burns and McDonnell
Attention: Jennifer Berry
9400 Ward Parkway
Kansas City, MO 64114

RE: MARK TWAIN TRANSMISSION PROJECT - ENVIRONMENTAL COMMENTS

Ms. Berry:

The Missouri Department of Conservation (Department) is in receipt of your request for environmental concerns related to the Mark Twain Transmission Project.

The Department is the state agency responsible for forest, fish and wildlife resources in Missouri. As such, the Department participates in project review when a project might affect those resources. Department comments are for your consideration to avoid, minimize and mitigate project impacts in Missouri.

PROJECT DESCRIPTION

The proposed transmission line would total approximately 100 miles from Palmyra to Kirksville to the Iowa border. Version 10 of the route network (provided by Ameren UE staff) includes the counties of Schuyler, Adair, Knox, Lewis, Shelby and Marion. Transmission line support towers would have dimensions of up to 130 feet in height with a cleared right-of-way of approximately 150 feet.

LISTED AND PROTECTED SPECIES

Enclosed find a Natural Heritage Review Report for the proposed Mark Twain Transmission Line based on Alignment Version 10 provided by Ameren UE to the Department by email on August 15, 2014.

Multiple natural heritage records for Indiana bat (*Myotis sodalis*) exist adjacent to the proposed routes. You or your client may be required to consult with the U.S. Fish and Wildlife Service pursuant to the Endangered Species Act. The U.S. Fish and Wildlife Service may be contacted by phone at 573-234-2132 or by mail at U.S. Fish and Wildlife Service, Ecological Services, 101 Park Deville Drive, Suite A, Columbia, Missouri 65203-0007.

Bald eagles (*Haliaeetus leucocephalus*), a federally protected species under the Bald and Golden Eagle Protection Act, are known to nest near streams and rivers within the range of this project. Work managers should be alert for nesting areas within 1500 meters of project activities and follow federal guidelines at: http://www.fws.gov/midwest/MidwestBird/EaglePermits/baeatakepermit.html. In addition, you may wish to request assistance from the U.S. Fish and Wildlife Service as described above.

SPAWNING STREAM SEASONAL CONSTRUCTION RESTRICTIONS

The following waterways have seasonal restrictions that could impact construction timing, if work would occur below the ordinary high water mark: South Fabius River and Troublesome Creek (Marion County). The affected locations are described in the enclosed Natural Heritage Review Report and shown in the enclosed map. Any work conducted below the ordinary high water mark in these stream segments should be avoided between March 15 and June 15. Management recommendations for construction projects affecting Missouri streams and rivers are also enclosed for reference.

The South Fabius River watershed supports a diverse aquatic community. Surveys conducted from 1941 to 1999 in the watershed revealed the presence of 58 fish species, four crayfish species, and 19 freshwater mussel species. Three species have been collected in the watershed that are part of the Communities of Conservation Concern Checklist, namely American eel, ghost shiner, and Mississippi silvery minnow. Special designation has been given to the watershed because of these robust aquatic communities. A portion of the watershed was designated an Aquatic Conservation Opportunity Area in 2006, and a Priority Watershed in 2011. Sampling in 2008 showed robust aquatic communities in the South Fabius Aquatic Conservation Opportunity Area near the potential project sites. Many of the aquatic species found in the watershed rely on clean, cool and high-quality habitat. Forested riparian corridors are critical to maintaining these high-quality aquatic systems. Degradation of these high-quality habitats could result in losses of biological diversity.

EXISTING CONSERVATION EASEMENTS

The Department holds interest in two conservation easements that precede proposed route segments A1 and A2.

Proposed segment A2 crosses the Bringer Stream Stewardship Trust Fund Easement (Marion County, T59N, R07W, Section 15 and 16) as seen in Figure 1. This easement is part of an In-lieu-Fee Mitigation (ILF) instrument originally purchased by the Missouri Conservation Heritage Foundation in 2006. This perpetual easement compensated landowners to maintain the existing condition of a wooded riparian corridor along the

watercourse for the purpose of sustaining fish, wildlife, forest and riparian values, as described in the enclosed Stream Stewardship Trust Fund Conservation Easement. A change of condition, such as removal of riparian vegetation, would violate the terms of the Bringer Conservation Easement and the In-lieu-Fee instrument. At a minimum, a change of condition of this parcel would require an amendment to the agreement and repayment of the purchase price plus interest to the Missouri Conservation Heritage Foundation for the affected portion of the easement parcel.

The proposed route A2 would impact two portions of the Bringer easement for an estimated total of 3.95 acres. The proposed route A2 would bisect the easement into two unconnected portions. Short term impacts of the proposed route segment A2 at the Bringer easement would likely include conversion of riparian corridor to shrubs and grasses, and possibly soil compaction. Long term impacts of this conversion would likely result in a diminished riparian function offered by existing trees along the watercourse. Shrubs and grasses provide a lesser level of stream bank protection from erosion than trees because their root networks are more shallow than those of trees. Unlike trees, shrubs and grasses provide no shade for the stream channel. Riparian trees offer stream shading which maintains lower water temperatures and increased dissolved oxygen levels during the warm seasons. Many aquatic wildlife have an upper thermal tolerance for survival, growth and reproduction that is better served by stream shading. In addition, aquatic wildlife require a minimum dissolved oxygen content in river water which cannot be sustained diurnally during the warm season without stream shading.

Pages 12 and 13 of the enclosed ILF mitigation instrument between the U.S. Army Corps of Engineers, Kansas City District and the Missouri Conservation Heritage Foundation Stream Stewardship Trust Fund describe allowed and restricted activities on the parcels for which the perpetual easement applies.

Proposed segment A1 crosses the Bevill Stream Stewardship Agreement Easement (Marion County, T59N, R08W, Section 25), as seen in Figure 2. This perpetual easement was purchased by the Department in 1996 as part of a Stream Stewardship Agreement. The agreement compensated landowners to maintain the existing condition of a wooded riparian corridor along the watercourse for the purpose of sustaining fish, wildlife, forest and riparian values, as described in the enclosed Stream Stewardship Agreement Easement. A change of condition, such as removal of riparian vegetation, would violate the restrictions contained in the easement. At a minimum, a change of condition of this parcel would require repayment of the purchase price plus interest for the affected portion of the easement parcel.

An estimated 0.80 acres of the Bevill easement would be impacted by proposed route segment A1. The proposed route A1 would bisect the easement into two unconnected

portions. Short term impacts could include vegetation conversion from riparian corridor to shrubs and grasses, as well as soil compaction. Similar to the impacts on the Bringer Easement, long term impacts of this conversion on the Bevill easement would likely result in a diminished riparian function.

CONCLUSION

In consideration of the Department's responsibility to manage fish, wildlife, and forest resources held in the public trust, the least environmentally damaging route segment would be a modified form of route A2 that would completely avoid the Bringer Stream Stewardship Trust Fund Conservation Easement.

Thank you for the opportunity to provide comments. Note that this response does not preclude other comments the Department may provide under the Clean Water Act permitting process or the National Environmental Policy Act, if applicable. If you have any questions about these comments, please contact me at (573) 522-4115, Extension 3159 or by email at jennifer.campbell-allison@mdc.mo.gov.

Sincerely,

JENNIFER CAMPBELL-ALLISON
POLICY COORDINATOR

JCA/ak

Enclosures

c: Chris Wood, Burns & McDonnell
Peggy Ladd, Ameren UE
Kenny Lynn, Ameren UE
Brian Holderness, Ameren UE
Shauna Marquart, U.S. Fish and Wildlife Service
Marvin and Loretta Bringer, Bringer Stream Stewardship Trust Fund landowner
Edward and Betty Bevill, Bevill Stream Stewardship Agreement landowner
Chris Vitello, Missouri Conservation Heritage Foundation

MISSOURI DEPARTMENT OF CONSERVATION

Headquarters

2901 West Truman Boulevard, P.O. Box 180, Jefferson City, Missouri 65102-0180

Telephone: 573-751-4115 ▲ www.MissouriConservation.org

ROBERT L. ZIEHMER, Director

November 21, 2014

Mark Twain Transmission Project
C/O Burns and McDonnell
Attention: Jennifer Berry
9400 Ward Parkway
Kansas City, MO 64114

RE: MARK TWAIN TRANSMISSION PROJECT - ENVIRONMENTAL COMMENTS

Ms. Berry:

This letter provides a supplemental response to Ameren's request for environmental concerns related to the Mark Twain Transmission Project and is a part of the Department of Conservation (Department) response provided in a letter to you dated October 16, 2014.

As indicated previously, the Department is the state agency responsible for forest, fish and wildlife resources in Missouri. As such, the Department participates in project review when a project might affect those resources. Department comments are for your consideration to avoid, minimize and mitigate project impacts in Missouri.

PROJECT DESCRIPTION

The proposed transmission line would total approximately 100 miles from Palmyra to Kirksville to the Iowa border. Version 10 of the route network (provided by Ameren UE staff) includes the counties of Schuyler, Adair, Knox, Lewis, Shelby and Marion. Transmission line support towers would have dimensions of up to 130 feet in height with a cleared right-of-way of approximately 150 feet.

CONTIGUOUS FOREST BLOCKS

A number of the alignments proposed as of the October 2014 Open House will result in fragmentation of woodland habitat, including forest blocks greater than 150 acres. The northerly route from Maywood to Zachary (comprised of segments A2, A6, A9, A14) fragments the fewest forest blocks.

Large forest blocks provide important habitat for wildlife. These habitat types are rare in present day northern Missouri and are utilized by neotropical migrant birds, currently in decline, as well as both game and non-game wildlife. Some neotropical migrant bird species are forest interior species and fragmentation of timber blocks leaves them vulnerable to brood parasitism from the brown-headed cowbird and predation. While edge habitat benefits habitat generalist species of birds, specialized species that require forest/woodland interiors are vulnerable to fragmentation caused by forest/woodland disturbances and would likely decline from a transmission line transecting the forest/woodland block.

Large forest blocks are associated with diverse wildlife species. For example, Henry Sever Lake Conservation Area is approximately 300 acres of forest and woodland habitat that supports 29 neotropical migrant bird species. Large timber blocks on the proposed routes range from 173 to 1,222 acres and likely include the same bird species, as well as additional species.

Forest blocks that would be impacted by the remaining proposed route segments on the Maywood to Zachary route are as follows:

- A2 would fragment a forest block approximately 300 acres in size at T60N, R8W Section 36 and T60N, R7W, Sections 31 and 32.
  - Two *Myotis sodalis* (Indiana bat) records are located within six (6) miles of where the A2 route segment and the subject forest block intersect.
- A3 would fragment the following forest blocks:
  - Approximately 1,222 acres: T59N, R9W, Sections 9, 10, 11, 14, 15, 22, and 23;
    - One (1) *Myotis sodalis* record within five (5) miles.
  - Approximately 181 acres: T60N, R12W, Sections 23-24;
  - Approximately 206 acres: T59N, R11W, Section 13 and T59N, R10W, Section 18;
  - Approximately 440 acres: T60N, R13W, Sections 1 and 2; and T61N, R13W, Section 36; and T61N, R12W, Section 31.
- The eastern portion of A7 includes a large forest block. According to Department records, this area includes a known Blue Heron rookery. The landowner reports that this rookery is still active.
- A13 would fragment the following forest blocks:
  - Approximately 293 acres: T61N, R14W, Sections 22 and 23;
  - Approximately 223 acres: T61N, R14W, Section 24.

Forest blocks that would be impacted by the remaining proposed route segments on the Zachary to State Line route are as follows:

- B9 would fragment a forest block (approximately 652 acres) at T65N, 15W, Section 12 and T65N, 14W, Sections 7,8 and 18.
  - Eight (8) *Myotis sodalis and* one (1) *Lasionycteris noctivagans (*silver-haired bat) records are known within four (4) miles of this forest block.

- B13 would fragment a forest block (approximately 270 acres) at T66N, R15W, Sections 31 and 32.
  - Five (5) *Myotis sodalis* and one (1) *Lasionycteris noctivagans* (silver-haired bat) records are known within 3 miles of this forest block.
  - Two known roosting sites are located 1.4 miles from this forest block, and are located within 0.17 miles of the proposed B13 route segment.
  - This block is adjacent to another 204 acre block at T66N, 15W, Section 31, separated by a farm road. These two blocks effectively form a 474 acre block, and it is located within four (4) miles of several other large timber blocks.

You or your client may need to consult with the U.S. Fish and Wildlife Service (573-234-2132) regarding Endangered Species Act and Migratory Bird Treaty Act compliance.

EXISTING EASEMENTS

Please refer to the earlier letter to you, dated October 16, 2014, regarding impacts to the Bringer and Bevill easements that would be impacted by route segments A2 and A1, respectively.

The South Fabius River is an important river in the northeastern portion of Missouri. Its ecological integrity and diverse aquatic community are reflective of the relatively wide and contiguous riparian woodlands and stable stream channels found in the watershed. As currently proposed, segment A2 would impact 3.95 acres of the Bringer easement, or segment A1 would impact 0.8 acres of the Bevill easement. Impacts of the proposed transmission line route segments on these easements will include riparian woodland fragmentation and an increased risk of stream channel instability.

An alternative to crossing one of these easements should include avoidance of the easement by routing around the parcel. Shapefiles of these easements were provided to Chris Wood by email on October 22, 2014.

If it is not possible to avoid the subject easement, impacts should be minimized by crossing perpendicular to the stream to reduce the area of land disturbed by right-of-way clearing.

As previously stated, a modified form of route segment A2 would appear to be the least environmentally damaging to forest, fish and wildlife resources and the Department's interest in these existing stream easements.

CONCLUSION

As presented in October 2014, the routes from Maywood to Zachary and the routes from Zachary to State Line appear to create potential impacts to forest, fish and wildlife resources in Missouri. The northerly route from Maywood to Zachary comprised of segments A2, A6, A9, A14 appears to create the fewest impacts to these resources. Alternatives and modifications to the remaining proposed route segments could focus on

first avoiding, then minimizing, and finally mitigating impacts to forest, fish and wildlife resources.

Avoidance measures could include upgrade of existing transmission lines rather than clearing a new right of way.

Minimization measures could include paralleling the new line to existing transmission lines to avoid new fragmentation events and minimize the total number of cleared acres for the project. Another minimization measure could consider routing around forest and woodland blocks of greater than 150 acres, rather than bisecting these forest blocks.

Avoidance and minimization of impacts to the Bringer or Bevill easements are strongly encouraged. Avoidance could include routing around the easement. If avoidance were not possible, minimization could include crossing at a different location within the easement or crossing perpendicular to the waterway.

If it would be helpful, the Department would be willing to meet with Ameren, its consultant, and the U.S. Fish and Wildlife Service to discuss Department comments provided for this project.

Thank you for the opportunity to provide comments. Note that this response does not preclude other comments the Department may provide under the Clean Water Act permitting process or the National Environmental Policy Act, if applicable. If you have any questions about these comments, please contact me at (573) 522-4115, Extension 3159 or by email at jennifer.campbell-allison@mdc.mo.gov.

Sincerely,

Jennifer Campbell-Allison

JENNIFER CAMPBELL-ALLISON
POLICY COORDINATOR

JCA/pb

Enclosures

c: Chris Wood, Burns & McDonnell
Peggy Ladd, Ameren UE
Kenny Lynn, Ameren UE
Brian Holderness, Ameren UE
Shauna Marquart, U.S. Fish and Wildlife Service

Missouri Department of Conservation

Natural Heritage Review Report

September 4, 2014 -- Page 1 of 5

Resource Science Division
P. O. Box 180
Jefferson City, MO 65102
Prepared by: Emily Clancy
Emily.Clancy@mdc.mo.gov
(573) 522 – 4115 ext. 3182

Brian F Holderness
Ameren
BHolderness@ameren.com

Project type:	Transmission Line
Location/Scope:	Map insert
County:	Adair, Knox, Lewis, Marion, Schuyler, and Shelby
Query reference:	Mark Twain Transmission Line Route
Query received:	August 29, 2014

This NATURAL HERITAGE REVIEW is not a site clearance letter. Rather, it identifies public lands and sensitive resources known to have been located close to and/or potentially affected by the proposed project. *On-site verification is the responsibility of the project. Natural Heritage records were identified at some date and location. This report considers records near but not necessarily at the project site. Animals move and, over time, so do plant communities. To say "there is a record" does not mean the species/habitat is still there. To say that "there is no record" does not mean a protected species will not be encountered. These records only provide one reference and other information (e.g. wetland or soils maps, on-site inspections or surveys) should be considered. Look for additional information about the biological and habitat needs of records listed in order to avoid or minimize impacts. More information may be found at http://mdc.mo.gov/discover-nature/places-go/natural-areas and mdc4.mdc.mo.gov/applications/mofwis/mofwis_search1.aspx. Contact information for the department's Natural History Biologist is online at http://mdc.mo.gov/contact-us.*

Records of federal-listed and/or state-listed (endangered) species or critical habitats within one mile of the transmission line:

The following Indiana bat records are within 2 miles:

Scientific Name	Common Name	Federal Status	State Status	County	Township & Range	Section
Myotis sodalis	Indiana bat	Endangered	Endangered	Knox	T61N R11W	36
Myotis sodalis	Indiana bat	Endangered	Endangered	Adair	T63N R15W	33
Myotis sodalis	Indiana bat	Endangered	Endangered	Lewis	T60N R08W	17
Myotis sodalis	Indiana bat	Endangered	Endangered	Lewis	T60N R08W	28
Myotis sodalis	Indiana bat	Endangered	Endangered	Schuyer	T65N R15W	23
Myotis sodalis	Indiana bat	Endangered	Endangered	Schuyer	T65N R15W	16
Myotis sodalis	Indiana bat	Endangered	Endangered	Schuyer	T65N R15W	23
Myotis sodalis	Indiana bat	Endangered	Endangered	Schuyer	T65N R15W	23
Myotis sodalis	Indiana bat	Endangered	Endangered	Schuyer	T65N R15W	17
Myotis sodalis	Indiana bat	Endangered	Endangered	Schuyer	T65N R15W	9
Myotis sodalis	Indiana bat	Endangered	Endangered	Schuyer	T65N R15W	9
Myotis sodalis	Indiana bat	Endangered	Endangered	Schuyer	T65N R15W	17
Myotis sodalis	Indiana bat	Endangered	Endangered	Schuyer	T65N R14W	33

Indiana bats *(Myotis sodalis*, federally and state listed endangered) hibernate during winter months in caves and mines. During the summer months, they roost and raise young under the bark of trees in riparian forests and upland forests near perennial streams. During project activities, avoid degrading stream quality and where possible leave snags standing and preserve mature forest canopy. Do not enter caves known to harbor Indiana bats, especially from September to April. **Further coordination with the U.S. Fish and Wildlife Service (Ecological Services, 101 Park Deville Drive, Suite A, Columbia, Missouri 65203-0007; Phone 573-234-2132) is recommended.**

Cross-country lines affect both plants and wildlife, as do activities necessary to their construction, maintenance and repair. Stream and drainage crossings are primary concerns, and every effort should be made to avoid erosion, silt introduction, petroleum or chemical pollution, and disruption or realignment of stream banks and beds. See insert pertaining to recommendations to follow when projects may impact streams and rivers.

Revegetation is an important part of managing utility corridors, and it can have significant resource impacts – for better or worse. Revegetation of disturbed areas is recommended to minimize erosion, as is restoration with native plant species compatible with the local landscape and wildlife needs. Annuals like ryegrass may be combined with native perennials for quicker green-up. Avoid aggressive exotic perennials such as crown vetch and sericea lespedeza.

Maintenance of ground cover in utility corridors can have significant implications for sensitive resources. Native plant species typically require low maintenance over the long term, and provide more benefits to native wildlife. Utility corridors can provide wildlife travel corridors, food sources and types of low-growing plant diversity sometimes rare in adjoining land. Mowing and maintenance schedules should consider nesting seasons, and diversity in plant composition.

Natural Heritage records were identified at some date and at a more or less precise location. This report includes information about records near but not necessarily on the project site. Animals move and, over time, so do plant communities. To say "there is a record" does not mean the species/habitat is still there. To say that "there is no record" does not mean the project will not encounter something not recorded. On-site verification is the responsibility of the project. Incorporating information from Natural Heritage records into plans can help reduce adverse impacts to sensitive natural resources. However, these records only provide one reference and other information (e.g. wetland or soils maps, on-site inspections or surveys) should be considered. Compare biological and habitat needs of records listed to planned project activities to avoid or minimize impacts. More information may be found at www.mdc.mo.gov/nathis/endangered/ and mdc4.mdc.mo.gov/applications/mofwis/mofwis_search1.aspx. Find contact information on the department's nearest Natural History Biologist at http://www.mdc.mo.gov/nathis/contacts/.

Records of state-ranked (but not state-listed) species and natural communities of conservation concern. The Department tracks these species and natural communities due to population declines or apparent vulnerability.

The following Natural Heritage records are located within 2 miles:

Scientific Name	Common Name	State Rank	County	Township & Range	Section
Hybognathus hankinsoni	Brassy Minnow	S3	Adair	T62N R15W	27
Mustela nivalis	Least weasel	S3	Adair	T61N R14W	6

Ambystoma tigrinum	Eastern Tiger Salamander	SU	Schuyler	T65N R15W	3
Taxidea taxus	American Badger	SU	Adair	T62N R15W	2
Central Plains - Warmwater - Small river	South Fabius River	S?	Marion	T59N R06W	30
Central Plains - Warmwater - Small river	Troublesome Creek	S?	Marion	T59N R07W	15
Central Plains - Warmwater - Creek	Tiger Fork	S?	Shelby	T59N R09W	28

*Each record represents a separate occurrence.

Definitions of each state-rank

- S3: Vulnerable in the state means this species is rare and uncommon, or found only in a restricted range (even if abundant in some locations), or because of other factors making it vulnerable to extirpation. Typically 21 to 100 occurrences or between 3,000 and 10,000 individuals.
- SU: Currently unrankable due to lack of information or due to substantially conflicting information about status or trends.
- State-rank S? is defined as unranked – aquatic community is not yet ranked in the state.

The Department encourages stewardship for all state-ranked species to minimize the risk of further decline that could lead to listing.

See http://mdc.mo.gov/sites/default/files/resources/2010/04/2013_species_concern.pdf for a complete list of species and communities of conservation concern.

Recommendations related to this project or site (not specific Natural Heritage records):

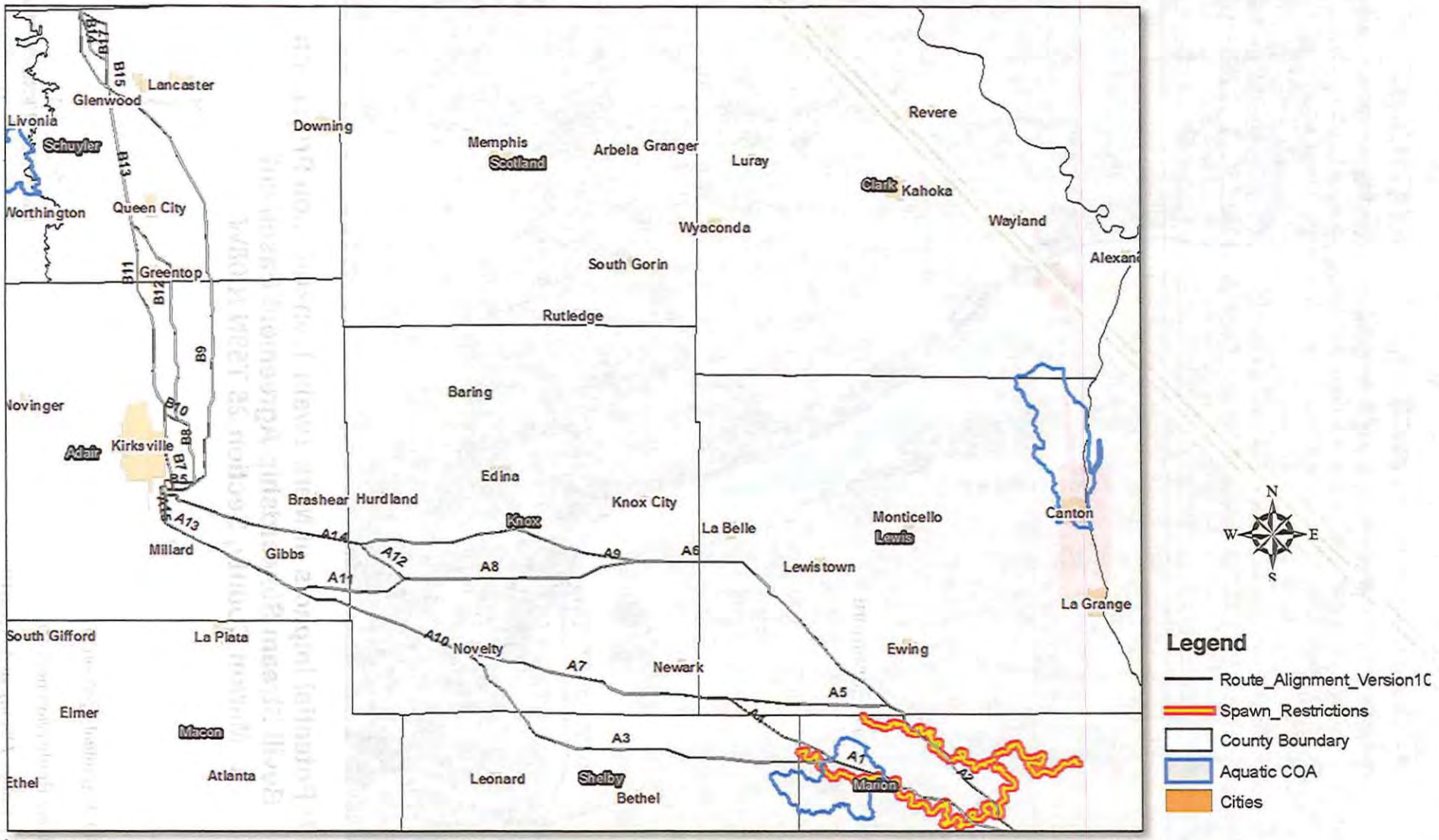
- Knox, Shelby, and Marion Counties have known karst geologic features (e.g. caves, springs, and sinkholes, all characterized by subterranean water movement). Few karst features are recorded in Natural Heritage records, and ones not noted here may be encountered at the project site or affected by the project. Cave fauna (many of which are species of conservation concern) are influenced by changes to water quality, so check your project site for any karst features and make every effort to protect groundwater in the project area.
- The project is within South Fabius River Aquatic Conservation Opportunity Area (see map insert). COAs have been identified based on the diversity and rarity of species and habitats present, and the comparative likelihood/importance of projects to maintain

them in the area over time. COAs have no regulatory role, but do reflect interest from multiple government agencies and citizen groups to work for conservation in the area. There may be ways your project or agency can contribute to or benefit from this COA. More information about it is available on line at http://www.mdc.mo.gov/nathis/cws/coa/.

- Invasive exotic species are a significant issue for fish, wildlife and agriculture in Missouri. Seeds, eggs, and larvae may be moved to new sites on boats or construction equipment, so inspect and clean equipment thoroughly before moving between project sites.
  - Remove any mud, soil, trash, plants or animals from equipment before leaving any water body or work area.
  - Drain water from boats and machinery that has operated in water, checking motor cavities, live-well, bilge and transom wells, tracks, buckets, and any other water reservoirs.
  - When possible, wash and rinse equipment thoroughly with hard spray or HOT water (≧104° F, typically available at do-it-yourself carwash sites), and dry in the hot sun before using again.

Spawning streams: The project site is near two of the 138 state-designated spawning stream segments. Activities that alter or destabilize stream bottoms or banks should be avoided from March 15 to June 15 in order not to disrupt spawning (laying and fertilizing fish eggs). At all times, avoid habitat destruction or introducing heavy sediment loads, chemical or organic pollutants. Spawning stream segments were designated because they are important to maintaining, restoring, or avoiding future listing of species of conservation concern.

Stream	From Location	To Location	Criteria	Avoidance Dates
South Fabius River	Hwy 61 Bridge	Shelby County Line	specific species management by MDC	March 15th – June 15th
Troublesome Creek	South Fabius River	Lewis County Line	specific species management by MDC	March 15th – June 15th



*Map created using shapefile provided in August 2014.

These recommendations are ones project managers might prudently consider based on a general understanding of species needs and landscape conditions. Natural Heritage records largely reflect only sites visited by specialists in the last 30 years. This means that many privately owned tracts could host unknown remnants of species once but no longer common.

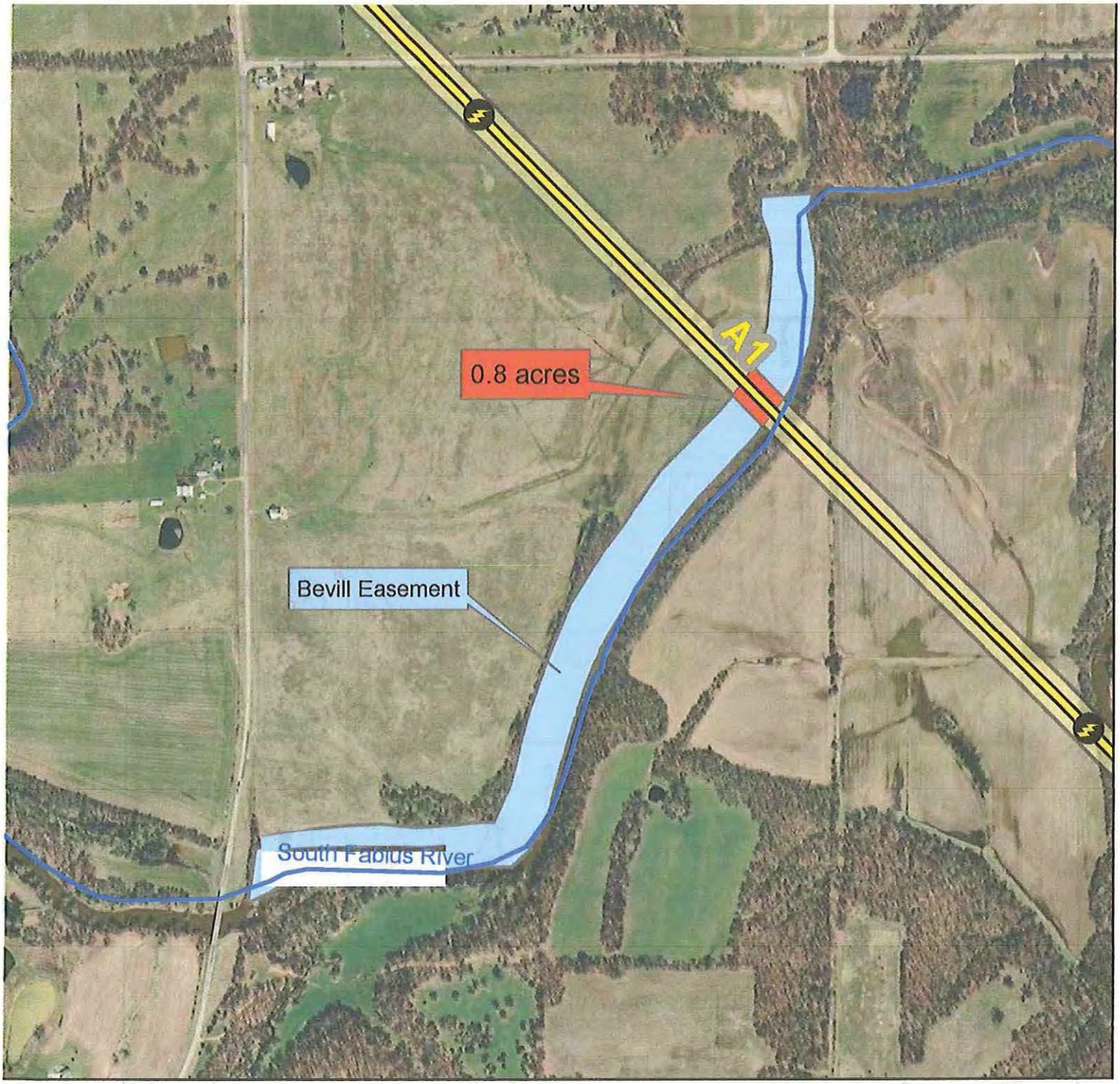


Figure 2: Potential Impacts of Mark Twain Transmission Project on Bevill Stream Stewardship Agreement Easement Marion County, Section 25 T59N R 08W

Legend

MARK TWAIN Route_Alignment_Version10

Intersection of SSA and Route Alignment 10

ROW clearing buffer_Route_Alignment_Version10

N

0 250 500 1,000 Feet

Map Date: 10/16/2014

STREAMS FOR THE FUTURE
STREAM STEWARDSHIP AGREEMENT
for a perpetual
CONSERVATION EASEMENT

THIS EASEMENT, made on the 14th day of December, 1996, by and between Edward J. and Loretta J. Bevill of Marion County, Missouri, hereinafter referred to as the "Landowner" and the MISSOURI DEPARTMENT OF CONSERVATION, and agency of the State of Missouri, hereinafter referred to as the "Department".

WITNESSETH:

WHEREAS, the Landowner is the owner in fee simple of a tract of land fronting the South Fabius River in Marion County, said area fully described below and hereinafter referred to as the "area"; and

WHEREAS, the Department in accordance with its constitutional authority over the fisheries, forestry, and wildlife resources of the State of Missouri, desires to conserve the riparian habitat on the area; and

WHEREAS, both parties wish to assure the preservation and wise use of the watercourse associated with the riparian area of said tract of land in perpetuity;

NOW, THEREFORE, in consideration of the mutual promises and covenants herein contained, to be performed by both parties,

THE LANDOWNER AGREES, in consideration of the sum of $10,035.00, an amount to be paid by the Department at a rate of $45.00 per acre per year on 22.3 acres for a 10-year period, and other valuable consideration, the receipt and adequacy of which is hereby acknowledged, to hereby GRANT, BARGAIN, SELL, CONVEY AND CONFIRM unto the Commission an easement in perpetuity for the conservation of the area. The area, which may vary slightly over time as the stream channel meanders, is more particularly described below:

A tract of land extending 200 feet landward from, and parallel to, top of bank along an approximately 4,864-foot reach of the South Fabius River as it flows along the southern and most of the eastern boundaries of the following described tract of land: All that part of the Northwest Quarter of the Northeast Quarter of Section 25 lying North and West of the South Fabius River; and all the Southeast Quarter of the Northwest Quarter of Section 25; and all that part of the Southwest Quarter of the Northeast Quarter of Section 25 lying North and West of the South Fabius River; and all that part of the Northeast Quarter of the Southwest Quarter of Section 25 that lies North and West of the South Fabius River; and all that part of the Northwest Quarter of the Southeast Quarter of Section 25 that lies North and West of the South Fabius River. All above said land lies in Township 59 North, Range 8 West.

TERMS AND CONDITIONS:

THE LANDOWNER AGREES:

1. To refrain from constructing or placing any buildings, billboards, or other temporary or permanent structures on the area.
2. To refrain from farming (grazing, cropping, or cutting hay) on the area, except as expressly permitted in the Stream Stewardship Agreement Plan (SSA Plan) or with written permission from the Department.
3. To refrain from filling, excavating or dredging, removing topsoil, sand, gravel, rock or other materials, or building any roads or making any change in the topography of the area in any manner, except as expressly permitted in the SSA Plan or with written permission from the Department.
4. To refrain from cutting or removing trees or plants, spraying herbicides and/or pesticides or using the area to provide livestock with access to the stream, except as expressly permitted in the SSA Plan or with written permission of the Department.
5. To refrain from dumping ashes, trash, garbage or other unsightly or offensive material on the area.
6. To refrain from altering the natural course of the stream or the character of its associated wetlands, and from engaging in activities detrimental to water quality on the area.
7. To refrain from operating or allowing others to operate, any motor driven land or amphibious conveyance, including, but not limited to, dune buggies, motorcycles and all terrain vehicles, except as expressly permitted in the SSA Plan or with written permission of the Department.
8. To permit the Department to enter on the area to inspect and enforce the provisions of this agreement.

THE DEPARTMENT AGREES:

1. To grant the Landowner the rights to any agricultural products, timber, or firewood which might be removed from the area. Such removals, however, may only take place under the conditions outlined in the SSA Plan or with written permission from the Department.
2. To make payments in lieu of taxes on the area to the appropriate county taxing body beginning the 11th year of the easement and continuing as long as the easement remains in force.

IT IS MUTUALLY AGREED:

1. The easement shall commence upon the date of execution by both parties.
2. The covenants agreed to and the terms, conditions, restrictions, and purposes imposed with this grant shall not only be binding upon the Landowner, but also his agents, personal representatives, heirs and assigns, and all other successors to him in interest and shall continue as a servitude running with the land in perpetuity.

3. If any provision of this easement or the application thereof to any person or circumstance is found to be invalid, the remainder of the provisions of this easement and the application of such provisions to persons or circumstances other than those as to which it is found to be invalid, shall not be affected thereby.

4. If the Landowner fails to carry out any of the terms and conditions of this agreement, and fails to correct the infraction within 60 days of a written notice, the Department may terminate this agreement (for cause). If this agreement is terminated by the Department, the Landowner will:

(a) forfeit all rights to payments under this contract; and
(b) refund all payments previously issued in addition to interest; and
(c) pay liquidated damages in accordance with the following item 5.

5. In the event the agreement is breached by the Landowner, the Department will suffer substantial damages which may not be possible to quantify with certainty. The Landowner, therefore, agrees to pay an amount equal to the sum obtained by multiplying: (1) 25 percent of the annual per-acre payment by, (2) the number of acres that are the subject of the agreement, as liquidated damages and not as a penalty.

6. Payments under this agreement are subject to appropriations by the Missouri General Assembly. In the event payment is not made within 60 days of the date due, this agreement may be terminated by mutual agreement and the Landowner will not be subject to the penalties listed in items 4 and 5 above.

7. That, given the dynamic nature of streams and the resulting changes in the adjacent land, both parties will mutually agree to develop, amend or change and implement a Stream Stewardship Agreement Plan in writing whenever necessary to achieve the stated purposes of this Easement.

8. No right of access by the general public to any portion of the real property is conveyed by this Easement.

IN WITNESS WHEREOF, the party hereto has executed this Easement the date and year above written:

DEPARTMENT:

JERRY J. PRESLEY
Jerry M. Conley
DIRECTOR

LANDOWNER:

Edward J. Bevill
EDWARD J. BEVILL

Loretta J. Bevill
LORETTA J. BEVILL

ACKNOWLEDGMENT

STATE OF MISSOURI)
) ss.
COUNTY OF MARION)

On this 6th day of January, 1997, before me, Carolyn Auckley, a Notary Public, personally appeared ~~Jerry D. Presley~~ Jerry M. Conley, to me personally known who, being by me duly sworn, did say that he is Director of THE CONSERVATION COMMISSION OF THE STATE OF MISSOURI, and that this foregoing instrument was signed in behalf of The Conservation Commission by authority vested in him by such Commission and the said ~~Jerry D. Presley~~ Jerry M. Conley acknowledged said instrument to be the free act and deed of the Commission.

IN TESTIMONY WHEREOF, I have hereunto set my hand and affixed my official seal at my office in Jefferson City, Mo, the day and year first above written.

Carolyn Auckley
Notary Public

My Commission Expires May 22, 2000

CAROLYN AUCKLEY
NOTARY PUBLIC
NOTARY SEAL
STATE OF MISSOURI

CAROLYN AUCKLEY
Notary Public - State of Missouri
County of Cole
My Commission Expires May 22, 2000

ACKNOWLEDGMENT

STATE OF MISSOURI)
) ss.
COUNTY OF MARION)

On this 14th day of December, 1996, before me, Ruth A. Hathaway, a Notary Public, personally appeared Edward J. & Loretta J. Bevill, to me personally known to be the person described in and who executed the foregoing instrument, and acknowledges that they executed the same as their free act and deed.

IN TESTIMONY WHEREOF, I have hereunto set my hand and affixed my official seal at my office in Philadelphia, MO the day and year last above written.

Ruth A. Hathaway
Notary Public

RUTH A. HATHAWAY
NOTARY PUBLIC, MARION CO., MISSOURI
MY COMM. EXPIRES 12-8-97

My Commission Expires 12-8, 1997.

STREAM STEWARDSHIP AGREEMENT PLAN

Edward J. and Loretta J. Bevill property, Marion County,
as described in the Stream Stewardship Agreement (SSA) Conservation Easement

The purpose of this SSA Plan is to document permitted activities within the SSA Conservation Easement boundaries of the Edward J. and Loretta J. Bevill property in Marion County. This document was mutually developed and is agreed upon as described in the Terms and Conditions section of the SSA Conservation Easement. This plan becomes effective on the date of signing of the Easement.

Only the items described in the SSA Plan Conditions section shall apply and do not supersede any other restricted uses contained in the Terms and Conditions section as described in the SSA Conservation Easement. The Landowner may request a change in these conditions by writing to the Fisheries District Supervisor (2500 South Halliburton, Kirksville, MO 63501). The Fisheries District Supervisor will review the request and will provide a letter to the Landowner within 30 days. This letter will represent an addendum to the SSA Plan and becomes a binding agreement within the SSA Conservation Easement.

SSA Plan Conditions

1. The Landowner may cut live trees for fuelwood according to written guidelines of a Missouri Department of Conservation Resource Forester at P.O. Box 428, Hannibal, MO 63401 (314/248-2530). Dead trees and drifted woody debris may be taken at Landowner discretion.

2. The Landowner may selectively harvest trees for sale according to written guidelines of a Resource Forester at the above location.

3. The Landowner may construct a fence to exclude livestock at the SSA Conservation Easement boundary, but in so doing may not cut live trees or expose soil within the SSA Conservation Easement zone.

4. The Landowner may manage the landward half (100 feet wide) of the SSA Conservation Easement zone as warm-season grass hayland or allow it to regenerate as forest. The streamward half (also 100 feet wide) of the SSA Conservation Easement zone must remain forested or be allowed to regenerate as forest.

5. For purposes of haying the landward half of the SSA Conservation Easement zone and gaining access to the South Fabius River for fishing, hunting, camping and other compatible forms of recreation, the Landowner may traverse the SSA Conservation Easement zone by motor-driven land conveyance, provided that such activity does not create areas devoid of vegetative cover which are vulnerable to sheet erosion during out-of-bank flows within the SSA Conservation Easement zone.

David J. Neuswanger — 12/12/96
Fisheries District Supervisor — Date

Edward J. Bevill — 12-14-96
Landowner — Date

Loretta J. Bevill — 12-14-96
Landowner — Date

DocH 909
Pages: 5
Date : 03-19-1997
Time : 11:26:11 A.M.
Filed & Recorded in
Official Records
of MARION County, MO.
JOHN E. YANCEY
RECORDER OF DEEDS
Rec. $ 30.00

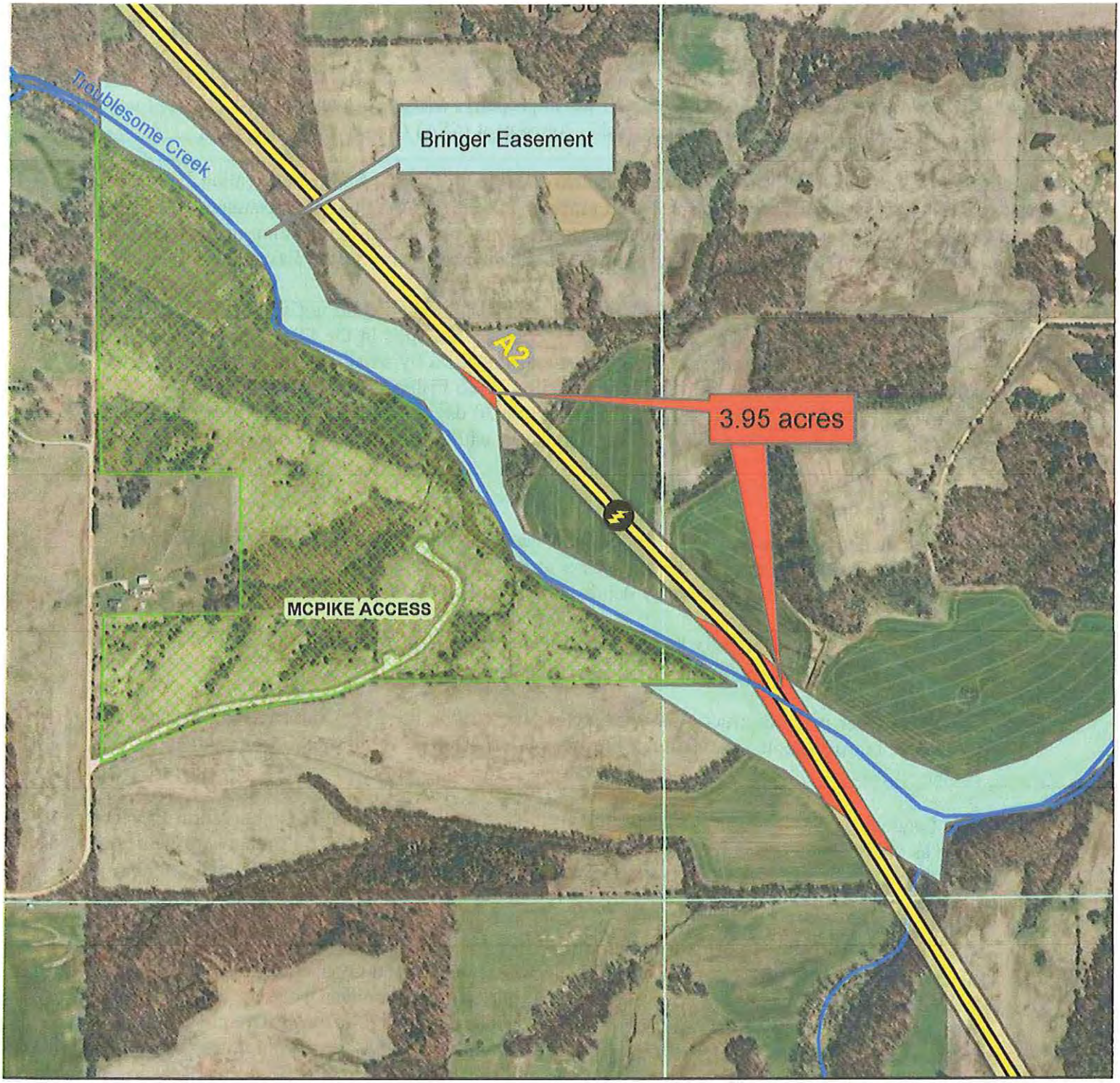


Figure 1: Potential Impacts of Mark Twain Transmission Project on Bringer Stream Stewardship Trust Fund Easement Marion County, Section 15 and 16 of T59N R 07W

Legend

- MARK TWAIN Route_Alignment_Version10
- Intersection of SSTF and Route Alignment 10
- ROW clearing buffer_Route_Alignment_Version10
- SSTF_Easement

N

0 250 500 1,000 Feet

Map Date: 10/16/2014

STREAM STEWARDSHIP TRUST FUND
CONSERVATION EASEMENT

THIS EASEMENT, made on the 26 day of December, 2006, by and between MARVIN W. BRINGER and LORETTA L. BRINGER, husband and wife, hereinafter referred to as "Landowners", and the CONSERVATION COMMISSION OF MISSOURI, an agency of the State of Missouri, hereinafter referred to as "Commission" with a mailing address of 2901 W. Truman Blvd., P.O. Box 180, Jefferson City, Missouri, 65102-0180.

WITNESSETH:

WHEREAS, Landowners are the owner in fee simple, with clear and marketable title, not subject to limiting liens or claims that would preclude conveyance, of a tract of land fronting Troublesome Creek in Marion County, Missouri, said land being fully described in Exhibit A attached hereto and incorporated herein by this reference, and being hereinafter referred to as the "area"; and

WHEREAS, the Commission, in accordance with its Article IV, Sections 40-46 constitutional authority over the fisheries, forestry and wildlife resources of the State of Missouri, desires to ensure the management, preservation and protection of said resources of the area and to promote the wise use of these resources; and

WHEREAS, both parties desire to ensure the preservation of the area in a condition that will sustain the fish, wildlife, forest and riparian values and assure the protection and maintenance of the watercourse associated with said tract of land in perpetuity;

NOW, THEREFORE, in consideration of the mutual promises and covenants herein contained, the parties hereto agree as follows:

In consideration of the sum of $1.00 and other good and valuable consideration for the easement, the receipt and adequacy of which is hereby acknowledged, MARVIN W. BRINGER and LORETTA L. BRINGER, husband and wife, ("Landowners"), do hereby grant, bargain and sell, convey, and confirm unto the CONSERVATION COMMISSION OF MISSOURI, an agency of the State of Missouri ("Commission"), its successors and assigns,

a perpetual conservation easement to the land described in Exhibit A attached hereto and incorporated herein by this reference, to ensure the proper conservation management, protection and preservation of the area more particularly described as:

TERMS AND CONDITIONS:

THE LANDOWNERS AGREE:

1. That no permanent or temporary buildings, billboards, or other permanent or temporary structures will be placed on the area described herein, except that deer stands may be placed within the easement boundary.

2. Not to farm, graze, or crop the area, except that hay may be cut as needed from the landward portion of the easement, defined as being more than 100' from the top of the stream bank.

3. To refrain from filling, excavating or dredging, removing topsoil, sand, gravel, rock or other materials or building any roads or making any change in the topography of the easement area in any manner, except that sand and gravel may be harvested from gravel bars for personal use as long as state sand and gravel guidelines are followed.

4. To refrain from removing, damaging, or cutting of trees or plants except under the direction of a forest stewardship plan provided by a Missouri Department of Conservation resource forester or their designate and that only A-grade logs may be removed from the first 20 feet from top of streambank.

5. To refrain from using the area to water livestock and to maintain the easement boundary fence in such a manner as to exclude livestock.

6. To refrain from spraying herbicides and/or pesticides except to control noxious plants or pests, and then only approved herbicides or pesticides may be used in accordance with label directions.

7. To refrain from dumping of ashes, trash, household wastes, tires, vehicles or farm equipment, hazardous waste, toxic chemicals or materials, garbage or other unsightly, foreign or offensive material on the area.

8. To refrain from changing, manipulating or altering natural water courses, backwaters, marshes or other water bodies adjacent to the easement zone, or engaging in activities or uses detrimental to water quality of the area, except that Landowners may maintain the existing low water crossing.

9. To refrain from operating, allowing, or giving permission to others to operate, any motor driven land or amphibious conveyance except for equipment used in agricultural practices or in the pursuit of fishing, hunting, camping, or other compatible forms of recreation, provided

that such activity does not create areas devoid of vegetative cover which are vulnerable to erosion within the conservation easement area.

10. To manage all properties currently enrolled in the Conservation Reserve Program (CRP) and within the conservation easement boundary, fully in accordance with the terms of this agreement and the current CRP contract, and fully in accordance with this agreement once the current CRP contract expires.

11. To permit the Commission and the Missouri Department of Conservation, their agents, representatives, or licensees to enter on the area to inspect and enforce the provisions of this agreement.

12. To allow the Missouri Department of Conservation and the Missouri Conservation Heritage Foundation, or either of them, to conduct limited tours of the easement area for educational purposes relative to stream and riparian management demonstrations.

13. To place of record any release or subordination agreement from any lienholder (other than road and utility easement holders) necessary to give this easement priority over any and all existing mortgages, deeds of trust or liens on or affecting the property conveyed hereunder.

THE CONSERVATION COMMISSION OF MISSOURI AGREES:

1. To grant the Landowners the rights to any agricultural products, timber, or firewood which might be removed from the area. Such removals, however, may only take place under the conditions outlined in a forest stewardship plan approved by, or with, written permission from the Missouri Department of Conservation.

2. To recognize existing utility easements and their holder's responsibility to maintain such easement properties; and such holders will be encouraged to maintain ground cover on these properties.

3. To provide the Landowners with verbal or written notice at least one week prior to:

(a) the Commission and the Missouri Department of Conservation, their agents, representatives, or licensees entering upon and inspecting the area; and

(b) the Missouri Department of Conservation and the Missouri Conservation Heritage Foundation, or either of them, conducting any limited tour of the easement area for educational purposes relative to stream and riparian management demonstrations.

IT IS MUTUALLY AGREED BY THE PARTIES HERETO:

1. The easement shall commence upon the date of execution by both parties.

2. The covenants agreed to and the terms, conditions, restrictions, and purposes imposed with this grant shall not only be binding upon the Landowners, but shall be deemed to run with the land and therefore bind also their agents, personal representatives, heirs and assigns, and all other successors to them in interest and shall continue as a servitude running with the land in perpetuity.

3. If any provision of this easement or the application thereof to any person or circumstance is found to be invalid, the remainder of the provisions of this easement and the application of such provisions to persons or circumstances other than those as to which it is found to be invalid, shall survive and not be affected thereby.

4. The Conservation Commission of Missouri and the Missouri Department of Conservation, or either of them, may enforce the terms of this easement by inspection, viewing, letter, claim, demand, or suit at law or in equity, subject to the notice provisions of this agreement, and shall have standing for such suit or suits and may bring same in the Circuit Court of Cole County, Missouri, the parties agreeing that venue shall be proper in that county and circuit.

5. If the Landowners fail to abide by any of the terms and conditions of this agreement (and fail to correct the infraction within 60 days of a written notice), the Conservation Commission of Missouri and its successor or assign may at its sole election either enforce the terms of the agreement as above, or terminate this agreement for cause. If this agreement is terminated by the Commission, the Landowners will:

(a) forfeit all rights to payments under this contract; and

(b) refund all payments previously issued in addition to interest within 60 days and at the then-existing prime rate plus 3% interest.

6. Payments under this agreement are subject to reimbursement to Missouri Conservation Heritage Foundation's policies and procedures.

7. That, given the dynamic nature of streams and the resulting changes in the adjacent land, both parties will mutually agree to develop, amend or change and implement a Stream Stewardship Trust Fund (SSTF) Plan in writing whenever necessary to achieve the stated purposes of this Easement.

8. No right of access by the general public to any portion of the real property described herein is conveyed by this Easement.

9. Nothing herein shall be deemed to place upon the Conservation Commission of Missouri or the Department of Conservation any obligation or duty to supervise or manage the subject property, but this shall not limit their ability to electively monitor, subject to the notice provisions of this contract, and enforce this easement as provided herein.

IN WITNESS WHEREOF, each party hereto has executed this Easement the date and year above written:

LANDOWNERS:

Marvin W. Bringer — Date: 12-26-06

Loretta L. Bringer — Date: 12-26-06

CONSERVATION COMMISSION
OF THE STATE OF MISSOURI

by: John Hoskins — Date: 12-26-06
John Hoskins, Director

Approved as to Form:

Deputy Counsel

State of ~~Missouri~~ Illinois)
) ss.
County of Adams)

On this 26 day of December, 2006, before me personally appeared Marvin W. Bringer and Loretta L. Bringer, his wife, to me known to be the persons described in and who executed the foregoing instrument, and acknowledged that they executed the same as their free act and deed.

IN TESTIMONY WHEREOF, I have hereunto set my hand and affixed my official seal the day and year first above written.

John P. Johannes
Notary Public

My Commission Expires: 10-18-08

"OFFICIAL SEAL"
JOHN P. JOHANNES
NOTARY PUBLIC—STATE OF ILLINOIS
MY COMMISSION EXPIRES OCT. 18, 2008

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

On this 27th day of December, 2006, before me appeared John Hoskins, to me personally known who, being by me duly sworn, did say that he is Director of the Missouri Department of Conservation, and that the foregoing instrument was signed in behalf of the Conservation Commission of the State of Missouri by authority vested in him by such Commission and the said John Hoskins acknowledged said instrument to be the free act and deed of the Commission.

IN TESTIMONY WHEREOF, I have hereunto set my hand and affixed my official seal at my office in Jefferson City, the day and year first above written.

Joe Weidinger
Notary Public

My Commission Expires:

"NOTARY SEAL"
Joe Weidinger, Notary Public
Maries County, State of Missouri
My Commission Expires 6/2/2010
Commission Number 06433639

EXHIBIT A

TRACT 1:

A parcel of land lying in the East half of Section 16 and the West half of Section 15, Township 59 North, Range 7 West of the 5th P.M., Marion County Missouri, being part of land conveyed to Marvin and Loretta Bringer in Book 539, Page 1620A and book 541, Page 1427 described as follows:

Commencing at the South Quarter corner of said Section 16; thence North 01° 28' 33" East the West line of the East half of said Section 16, a distance of 3570.94 feet to the centerline of Troublesome Creek and the Southerly boundary line of Marvin and Loretta Bringer as recorded in Book 539, Page 1620A, at Station 20+00, being the Point of Beginning; thence South 66 44' 41" East along said line, 109.78 feet to Station 21+09.78, thence South 54° 39' 34" East along said line, 282.74 feet to Station 23+92.52; thence South 50° 56' 25" East along said line, 228.69 feet to Station 26+21.21; thence South 49° 12' 43" East along said line, 349.67 feet to Station 29+70.88; thence South 29° 02' 04" East along said line, 157.27 feet to Station 31+28.15; thence South 07° 54' 01" West along said line, 177.32 feet to Station 33+05.47; thence South 34° 53' 48" East along said line, 129.23 feet to Station 34+34.70; thence South 50° 14' 53" East along said line, 249.29 feet to Station 36+83.99; thence South 55° 42' 36" East along said line, 175.81 feet to P.C. Station 38+59.80; thence along a tangent curve to the left having a radius of 118.36 feet, through a central angle of 80° 55' 14", an arc distance of 167.16 feet (chord bearing North 83° 49' 34" East, 153.61 feet) to P.R.C. Station 40+26.96; thence along a tangent curve to the right having a radius of 13.86 feet through a central angle of 71° 36' 18", an arc distance of 17.33 feet (chord bearing North 79° 10' 37" East, 16.22 feet) to P.T. Station 40+44.29; thence South 65° 01' 48" East along said line, 46.42 feet to Station 40+90.71; thence South 46° 36' 58" East along said line, 131.39 feet to Station 42+22.10; thence South 36° 56 20" East along said line, 117.74 feet to Station 43+39.84; thence South 23° 52' 26" West along said line, 64.94 feet to Station 44+04.78; thence South 28° 30' 43" West along said line, 73.83 feet to P.C. Station 44+78.61; thence along a tangent curve to the left having a radius of 27.50 feet through a central angel of 72° 03' 10", an arc length of 34.58 feet; (chord bearing South 07° 33' 18" East, 32.32 feet) to P.T. Station 45+13.19; thence South 43° 32' 28" East along said line, 76.10 feet to Station 45+89.29; thence South 54° 21' 25" East along said line, 66.57 feet to Station 46+55.86; thence South 18° 00' 51" East along said line, 143.15 feet to Station 47+99.01; thence South 29° 36' 08" East along said line, 143.06 feet to Station 49+42.07; thence South 54° 58' 09" East along said line, 278.52 feet to Station 52+20.59; thence South 59° 33' 04" East along said line, 424.04 feet to Station 56+44.63; thence South 63° 08' 39" East along said line, 349.22 feet to Station 59+93.85; thence South 59° 14' 09" East along said line, 388.45 feet to Station

63+82.30; thence South 54° 17' 17" East along said line, 421.13 feet to Station 68+03.43; thence South 60° 18' 20" East along said line, 186.46 feet to Station 69+89.89; thence South 46° 34' 24" East along said line, 172.00 feet to Station 71+61.89; thence South 42° 54' 11" East along said line, 193.28 feet to Station 73+55.17; thence South 58° 42' 56" East along said line, 116.45 feet to Station 74+71.62; thence North 83° 05' 45" East along said line, 153.14 feet to Station 76+24.76; thence North 75° 27' 56" East along said line, 182.68 feet to Station 78+07.44; thence North 84° 56' 14" East along said line, 173.36 feet to Station 79+80.80; thence North 62° 38' 08" East along said line, 133.82 feet to Station 81+14.62; thence North 49° 41' 12" East along said line, 226.75 feet to Station 83+41.37; thence North 47° 08' 36" East along said line, 181.71 feet to Station 85+23.08; thence North 52° 24' 44" East along said line, 291.45 feet to Station 88+14.53; thence North 62° 31' 55" East along said line, 325.43 feet to the East line of the Southwest Quarter of said Section 15, also being the East property line of Marvin and Loretta Bringer as recorded in Book 541, Page 1427 at Station 90+68.43; thence North 01° 29' 00" East along said East line, 147.76 feet to the Northerly line of the flowage easement at Station 91+39.96, 129.29 feet left; thence South 64° 46' 25" West along said line, 400.28 feet to Station 87+66.62, 155.79 feet left; thence South 47° 14' 17" West along said line, 294.76 feet to Station 84+85.13, 133.26 feet left; thence South 61° 18' 44" West along said line, 373.75 feet to Station 80+64.91, 209.00 feet left; thence South 71° 33' 41" West along said line, 409.43 feet to Station 75+83.67, 162.03 feet left; thence North 59° 52' 03" West along said line, 240.26 feet to Station 71+72.18, 147.52 feet left; thence North 52° 04' 42" West along said line, 223.32 feet to Station 69+89.89, 128.82 feet left; thence North 55° 54' 34" West along said line, 247.86 feet to Station 67+27.61, 140.64 feet left; thence North 57° 34' 04" West along said line, 242.08 feet to Station 64+85.92, 126.79 feet left; thence North 55° 12' 52" West along said line, 239.78 feet to Station 62+57.27, 134.20 feet left; thence North 57° 00' 23" West along said line, 326.76 feet to Station 59+40.92, 150.87 feet left; thence North 67° 04' 29" West along said line, 215.34 feet to Station 57+26.09, 136.11 feet left; thence North 61° 31' 32" West along said line, 387.05 feet to Station 53+30.58, 127.61 feet left; thence North 46° 35' 26" West along said line, 243.65 feet to Station 50+78.99, 171.50 feet left; thence North 29° 50' 52" West, 182.77 feet to Station 47+66.58, 210.61 feet left; thence North 02° 26' 41" West along said line, 431.22 feet to Station 43+87.11 (back, Station) 296.46 feet left; thence North 53° 19' 13" West along said line, 399.93 feet to Station 41+08.94 (back, Station) 223.51 feet left; thence North 50° 00' 50" West along said line, 179.93 feet to Station 38+71.08, 361.17 feet left; thence North 86° 47' 00" West along said line, 209.58 feet to Station 36+33.31, 248.20 feet left; thence North 50° 31' 30" West along said line, 139.39 feet to Station 32+21.30, 268.73 feet left; thence North 20° 10' 00" West along said line, 143.69 feet to Station 32+22.10 (back, Station) 180.98 feet left; thence North 24° 28' 27" West along said line, 167.44 feet to Station 30+55.19, 194.29 feet left; thence North 29° 44' 32' West along said line, 155.02 feet to Station 29+70.88, 204.96 feet left; thence North 43° 06' 39" West along said line, 261.12 feet to Station 27+11.24, 232.71 feet left; thence North 57° 58' 33" West along said line, 169.64 feet to Station 25+49.85, 209.11 feet left; thence North 25° 51' 10" West along said line, 83.17 feet to Station 24+74.53, 244.37 feet left; thence North 44° 57' 10" West along said line, 197.12 feet to Station 22+95.91, 271.77 feet left; thence North 64° 51' 16"

West along said line, 218.66 feet to Station 21+30.15 (back, Station) 233.99 feet left; thence North 58° 56' 58" West along said line, 238.79 feet to the West line of the East half of said Section 16, also being the West line of Marvin and Loretta Bringer property as recorded in Book 539, Page 1620A at Station 18+17.96, 215.00 feet left; thence South 01° 28' 33" West along said West line, 286.86 feet to the Point of Beginning containing 30.78 Acres.

TRACT 2:

A parcel of land in the Southwest Quarter of Section 15, Township 59 North, Range 7 West of the 5th P.M., Marion County Missouri, being part of land conveyed to Marvin and Loretta Bringer in Book 539, Page 1620A described as follows:

Commencing at a stone marking the West Quarter corner of said Section 15; thence South 01° 30' 37" West along the West line of the Southwest Quarter of said Section 15, a distance of 1678.49 feet to the South property line of the Missouri Conservation Commission recorded in Book 554, Page 5245; thence South 87° 06' 14" East along said South line, 74.50 feet to the Southerly flowage easement line at Station 60+79.90, 159.90 feet right, being the Point of Beginning; thence continuing South 87° 06' 14" East along said South property line, 342.08 feet to the centerline of Troublesome Creek at Station 63+82.30; thence South 54° 17' 17" East along said line, 421.13 feet to Station 68+03.43; thence South 60° 18' 20" East along said line, 186.46 feet to Station 69+89.89; thence South 46° 34' 24" East along said line, 172.00 feet to Station 71+61.89; thence South 42° 54' 11" East along said line, 193.28 feet to Station 73+55.17; thence South 58° 42' 56" East along said line, 116.45 feet to Station 74+71.62; thence North 83° 05' 45" East along said line, 35.66 feet to the East property line of Marvin and Loretta Bringer recorded in Book 539, Page 1620A; thence South 01° 29' 48" West along said East line, 208.76 feet to the Southerly flowage easement line at Station 74+76.78, 206.52 feet right; thence South 83° 05' 45" West along said line, 121.15 feet to Station 75+08.13 (back, Station), 234.03 feet right; thence North 54° 11' 58" West along said line, 275.22 feet to Station 72+96.21, 237.41 feet right; thence North 52° 57' 15" West along said line, 812.19 feet to Station 64+32.16, 243.89 feet right; thence North 44° 26' 58" West along said line, 342.38 feet to the Point of Beginning, containing 7.50 Acres.

TRACT 3:

A parcel of land in the East half of Section 15, and the West half of Section 14, Township 59 North, Range 7 West of the 5th P.M., being a part of land conveyed to Marvin and Loretta Bringer recorded in Book 532, Page 943, described as follows:

Commencing at an aluminum monument marking the Southeast corner of said Section 15; thence North 88° 34' 55" West along the South line of the Southeast Quarter of said Section 15, a distance of 1328.78 feet to the Southwest corner of the Southeast Quarter of the Southeast Quarter of said Section 15; thence North 01° 30' 20" East along the West line of the Southeast Quarter of the Southeast Quarter of said Section 15, a

distance of 988.54 feet to the Southerly line of the flowage easement at Station 106+27.55, 241.20 feet right being the Point of Beginning; thence continuing North 01° 30' 20" East along said West line, 333.03 feet to the Southerly property line of Marvin and Loretta Bringer as recorded in book 532, Page 943 at Station 105+14.93, 76.12 feet left; thence North 69° 52' 28" West along said Southerly line, 323.26 feet to the West line of said property at Station 101+78.96, 61.78 feet left; thence North 01° 28' 57" East along said line, 205.40 feet to the Northerly line of the flowage easement at Station 100+90.19, 243.90 feet left; thence South 61° 33' 45" East along said line, 221.91 feet to Station 103+48.74, 241.87 feet left; thence South 72° 15' 11" East along said line, 237.81 feet to Station 105+86.49, 247.19 feet left; thence South 67° 48' 30" East along said line, 246.38 feet to Station 108+20.27, 244.34 feet left; thence South 49° 08' 58" East along said line, 170.02 feet to Station 109+70.88, 196.37 feet left; thence North 12° 11' 44" West along said line, 617.49 feet to Station 122+03.62, 205.95 feet left; thence North 27° 54' 12" West along said line, 473.47 feet to Station 127+33.93; 237.33 feet left; thence North 31° 58' 00' West along said line, 291.62 feet to the Easterly property line of Bennie and Virginia Deverger as recorded in Book 536, Page 2499 at Station 130+12.72, 236.44 feet left; thence North 17° 31' 02" East along said Westerly line, 123.95 feet to the Northerly line of Marvin and Loretta Bringer recorded in book 532, Page 943, property also being the North line of the Southeast Quarter of said Section 15 at Station 130+97.37, 145.90 feet left; thence South 88° 34' 49" East along said North line, 169.91 feet to the centerline of Troublesome Creek, also being the said Northerly property line at Station 130+10.29; thence North 29° 24' 45" West along said line, 90.75 feet to Station 131+01.04; thence North 40° 22' 56" West along said line, 181.49 feet to Station 132+82.53; thence North 02° 00' 36" West along said line, 218.17 feet to Station 135+00.70; thence North 41° 48' 36" East along said line, 254.80 feet to Station 137+55.50; thence North 72° 40' 32" East along said line, 311.56 feet to Station 140+67.06; thence North 89° 02' 36" East along said line, 293.45 feet to Station 143+60.51; thence North 86° 37' 53" East along said line, 292.15 feet to Station 146+52.66; thence South 89° 43' 54" East along said line, 165.54 feet to Station 148+18.20; thence South 75° 10' 48" East along said line, 237.79 feet to Station 150+55.99; thence South 65° 33' 54" East along said line, 94.40 feet to Station 151+50.39; thence South 48° 05' 52" East along said line, 299.20 feet to Station 154+49.59; thence South 20° 48' 21" East along said line, 196.86 feet to Station 156+46.45; thence South 23° 09' 36" East along said line, 320.35 feet to Station 159+66.80 to the North line of the Southwest Quarter of said Section 14, also being the Northerly property line of Marvin and Loretta Bringer as recorded in Book 532, Page 943; thence South 89° 04' 54" East along said North line, 218.29 feet to the flowage easement line at Station 160+55.86, 199.30 feet left; thence South 15° 08' 39" East along said line, 279.61 feet to Station 162+97.51, 208.43 feet left; thence South 02° 10' 58" West along said line, 137.62 feet to Station 164+30.78 (back, Station) 174.14 feet left; thence South 06° 52' 16" West along said line, 200.27 feet to Station 165+29.52, 218.30 feet left; thence South 26° 17' 27" West along said line, 305.53 feet to Station 168+10.83, 189.89 feet left; thence South 05° 19' 02" West along said line, 115.41 feet to Station 169+19.22, 229.54 feet left; thence South 13° 58' 49" West along said line, 97.53 feet to the Northerly right-of-way line of the County Road No. 118 at Station 170+14.82, 248.87 feet left; thence along said Northerly line along a non-tangent curve

to the left having a radius of 1077.28 feet through a central angle of 22° 26' 11", an arc length of 421.85 (chord bearing North 71° 13' 28" West, 419.16 feet) to Station 170+50.92, 168.27 feet right; thence continuing along said line along a tangent curve to the left having a radius of 654.50 feet, through a central angle of 08° 04' 39", an arc length of 92.27 feet (chord bearing North 86° 28' 53" West, 92.19 feet) to the Southerly line of the flowage easement at Station 170+78.92, 256.11 feet right; thence North 28° 33' 21" East along said line, 387.86 feet to Station 166+83.36, 229.05 feet right; thence North 08° 04' 07" East along said line, 394.87 feet to Station 161+51.56, 217.14 feet right; thence North 12° 52' 06" West along said line, 436.25 feet to Station 156+79.62, 151.98 feet right; thence North 22° 38' 07" West along said line, 190.42 feet to Station 154+18.61, 160.20 feet right; thence North 40° 36' 18" West along said line, 207.39 feet to Station 152+12.99, 133.16 feet right; thence North 72° 19' 04" West along said line, 346.72 feet to Station 147+61.93, 135.73 feet right; thence South 84° 40' 03" West along said line, 268.91 feet to Station 144+84.35, 151.60 feet right; thence South 88° 22' 19" West along said line, 308.88 feet to Station 141+81.76, 149.87 feet right; thence South 80° 07' 48" West along said line, 320.28 feet to Station 137+39.51, 147.21 feet right; thence South 49° 42' 01" West along said line, 152.53 feet to Station 134+76.56, 151.85 feet right; thence South 18° 22' 58" East along said line, 290.74 feet to Station 130+96.21, 133.95 feet right; thence South 85° 42' 15" East along said line, 111.72 feet to Station 130+34.21, 226.89 feet right; thence South 33° 17' 14" East along said line, 375.62 feet to Station 126+46.22, 234.32 feet right; thence South 23° 33' 13" East along said line, 530.53 feet to Station 121+69.56, 242.13 feet right; thence South 12° 45' 22" East along said line, 396.96 feet to Station 117+91.73, 227.48 feet right; thence South 05° 34' 02" East along said line, 443.79 feet to the North right-of-way line of the County Road at Station 113+96.11, 207.15 feet right; thence South 31° 23' 50" West along said Northerly line, 4.48 feet to Station 113+92.32, 204.75 feet right; thence continuing South 34° 37' 18" West along said line, 185.95 feet to Station 113+04.14, 129.10 feet right; thence continuing along said line along a tangent curve to the left having a radius of 1073.39 feet, through a central angle of 13° 38' 02", an arc length of 255.42 feet (chord bearing South 27° 48' 17" West, 254.82 feet) to Station 112+20.28, 247.36 feet right; thence South 20° 59' 17" West along said line, 19.67 feet to Southerly flowage easement line at Station 112+17.14, 263.71 feet right; thence North 75° 57' 50" West along said line, 158.91 feet to Station 111+70.95, 226.74 feet right; thence North 71° 53' 02" West along said line, 219.82 feet to Station 109+96.69, 240.98 feet right; thence North 66° 49' 04" West along said line 356.19 feet to the Point of Beginning, containing 46.80 Acres.

TRACT 4:

A parcel of land in the West half of Section 14, the Southeast Quarter of Section 15, and the Northwest Quarter of Section 23, Township 59 North, Range 7 West of the 5th P.M., Marion County, Missouri, being part of land conveyed to Marvin and Loretta Bringer in Book 532, Page 943 described as follows:

Commencing at an aluminum monument marking the Southwest corner of said Section 14; thence South 89° 06' 00" East along the South line of the Southwest Quarter of said

Section 14 a distance of 643.40 feet to the Southerly line of the flowage easement at Station 188+31.82, 210.48 feet right being the Point of Beginning; thence North 51° 14' 45" West along said line, 305.58 feet to Station 185+56.61, 167.60 feet right; thence North 47° 32' 35" West along said line, 533.80 feet to Station 181+86.56 (back, Station), 185.44 feet right; thence North 06° 51' 13" West along said line, 319.65 feet to Station 179+43.90, 233.18 feet right; thence North 39° 38' 29" East along said line, 179.74 feet to Station 177+77.95, 164.11 feet right; thence North 28° 05' 46" East along said line, 141.60 feet to Station 176+38.99, 136.96 feet right; thence North 24° 06' 38" East along said line, 557.88 feet to the Southerly right-of-way line of County Road No. 118 at Station 170+84.75, 137.07 feet right; thence along said Southerly line along a non-tangent curve to the right having a radius of 1037.28 feet, through a central angle of 15° 40' 06", an arc length of 283.66 feet (chord bearing South 73° 22' 28" East, 282.77 feet) to the Northerly flowage easement line at Station 170+62.18, 144.80 feet left; thence South 26° 22' 05" West along said line, 265.31 feet to Station 173+34.19, 105.92 feet left; thence South 21° 54' 45" West along said line, 288.21 feet to Station 175+86.12, 140.11 feet left; thence South 02° 17' 14" West along said line, 349.36 feet to Station 179+70.10, 235.97 feet left; thence South 45° 41' 08" East along said line, 188.94 feet to Station 184+44.70, 226.15 feet left; thence South 59° 17' 15" East along said line, 311.86 feet to Station 187+93.25, 237.98 feet left; thence South 64° 04' 33" East along said line, 167.02 feet to Station 189+60.19, 242.99 feet left; thence South 65° 33' 10" East along said line, 312.28 feet to Station 192+40.30, 253.32 feet left; thence South 64° 03' 03" East along said line, 385.62 feet to Station 197+16.90, 240.27 feet left; thence South 78° 59' 20" East along said line, 281.98 feet to Station 200+38.41, 231.48 feet left; thence South 89° 25' 03" East, 204.47 feet to Station 202+41.81, 252.31 feet left; thence South 66° 58' 48" East along said line, 120.46 feet to Station 203+57.26 (back, Station), 217.92 feet left; thence South 88° 27' 33" East along said line, 374.90 feet to Station 208+79.89, 270.94 feet left; thence South 80° 11' 50" East, 81.15 feet to the East line of the Northwest Quarter of said Section 23, also being the East property line of Marvin and Loretta Bringer as recorded in Book 532, Page 943 at Station 209+48.46, 227.54 feet left; thence South 01° 19' 35" West along said East line, 248.80 feet to the centerline of Troublesome Creek, also being the Southerly property line of Marvin and Loretta Bringer as recorded in Book 532, Page 943 at Station 208+47.84; thence South 67° 28' 17" West along said line, 53.58 feet to Station 207+94.26; thence South 81° 58' 26" West along said line, 96.30 feet to Station 206+97.96; thence North 77° 29' 16" West along said line, 201.15 feet to Station 204+96.81; thence North 72° 34' 42" West along said line, 164.61 feet to Station 203+32.20; thence North 83° 34' 13" West along said line, 511.11 feet to Station 198+21.09; thence North 74° 13' 09" West along said line, 218.75 feet to Station 196+02.34; thence North 79°20'04" West along said line 104.40 feet to the East line of the Northwest Quarter of the Northwest Quarter, Section 23 at Station 194+97.95; thence North 01°21'03" East along said East line 125.92 feet to the South line of Section 14, also being the South property line of Marvin and Loretta Bringer as recorded in Book 532, Page 943 at Station 193+30.24, 110.99 feet left; thence North 89°06'00" West along said South line 680.00 feet to the Point of Beginning, containing 26.18 Acres.

California Public Utilities Commission
505 Van Ness Ave., San Francisco

FOR IMMEDIATE RELEASE
Media Contact: Terrie Prosper, 415.703.1366, news@cpuc.ca.gov

PRESS RELEASE
Docket #: A.08-03-015

CPUC APPROVES EDISON SOLAR ROOF PROGRAM

SAN FRANCISCO, June 18, 2009 - The California Public Utilities Commission (CPUC), in its ongoing commitment to innovative programs and policies to advance the delivery of renewable energy, today approved a solar photovoltaic program for Southern California Edison.

The program will result in the deployment of 500 megawatts (MW) of solar photovoltaic (PV) on existing commercial rooftops in Edison's service territory. Edison will own, install, operate, and maintain 250 MW of solar PV projects, which will primarily consist of one to two MW rooftop systems. The remaining 250 MW will be installed, owned, and operated by independent, non-utility solar providers selected through a competitive process.

Prior to today's decision, utility solar programs in the one to two MW range had limited participation in the California Solar Initiative or Renewables Portfolio Standard (RPS) program. Edison's program creates a new avenue for developing such smaller sized solar projects.

"This program represents a valuable complement to the existing renewable procurement efforts we have underway, given the significant permitting challenges large scale renewables face, both in terms of transmission and the generating facilities themselves," said CPUC President Michael R. Peevey. "It represents an important hedging strategy by allowing for the deployment of distributed resources that, while somewhat more expensive than the large scale renewable projects that are the primary focus of the RPS program, offer a much higher level of certainty in terms of when they will come online."

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 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."

"This decision is good for California because it makes good use of all that sun and warehouse roofs in Southern California to produce clean energy right where we need it, both by Edison and independent generators," commented Commissioner Rachelle Chong. "I commend Edison for its foresight in bringing a focus on commercial solar PV projects that are 1-2 megawatts in size."

Commissioner Timothy Alan Simon said, "I support this decision because it strikes a balance between promoting utility-owned generation and competitive procurement for independent energy producers, as well as distributed generation and central station solar systems. Finally, it will bring much needed economic stimulus to the Inland Empire."

Because this is the first significant foray by a utility into ownership of renewable generation, the CPUC will carefully monitor the program's progress, examine ways in which the program can be improved, and fine tune the program when and where appropriate.

The energy generated from the project will be used to serve Edison's retail customers and the output from these facilities will be counted towards Edison's RPS goals. The output and capacity of the projects will not count towards the California Solar Initiative program goals.

The RPS program is one of the most ambitious renewable energy standards in the country. It requires investor-owned utilities to procure 20 percent of their electricity sales from renewable sources by 2010. Governor Schwarzenegger subsequently established an RPS target of 33 percent by 2020 for all retail sellers of electricity. The California Solar Initiative has a goal to install 3,000 MW of new customer solar projects by 2016, moving the state toward a cleaner energy future and helping lower the cost of solar systems for consumers.

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line from Palmyra, Missouri, to the Iowa Border and Associated Substation near Kirksville, Missouri.	)))))))	**File No. EA-2015-0146**

AFFIDAVIT OF WILLIAM E. POWERS, P.E.

STATE OF CALIFORNIA)
) ss
COUNTY OF SAN DIEGO)

William E. Powers, being first duly sworn on his oath states:

1. My name is William E. Powers and I am the principal of Powers Engineering, 4452 Park Blvd., Suite 209, San Diego, California, 92116.

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony on behalf of Neighbors United Against Ameren's Power Line consisting of 44 pages and Schedules 1 TO 39 (REBUTTAL TESTIMONY IS "1") prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear that my answers to the questions contained in the attached rebuttal testimony are true and correct to the best of my knowledge, information and belief.

William E. Powers, P.E.
William E. Powers, P.E.

Subscribed and sworn to before me this 21 day of October, 2015

OFFICIAL SEAL
ELYCE MARIE MARTINEZ
NOTARY PUBLIC-CALIFORNIA
COMM. NO. 1995401
SAN DIEGO COUNTY
MY COMM. EXP. OCT. 26, 2016

Elyce Marie Martinez
Notary Public