ORIGINAL

0000166638

BEFORE THE
ARIZONA POWER PLANT AND TRANSMISSION LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION OF SUNZIA TRANSMISSION LLC, IN CONFORMANCE WITH THE REQUIREMENTS OF ARIZONA REVISED STATUTES 40-360, ET SEQ., FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AUTHORIZING THE SUNZIA SOUTHWEST TRANSMISSION PROJECT, WHICH INCLUDES THE CONSTRUCTION OF TWO NEW 500 KV TRANSMISSION LINES AND ASSOCIATED FACILITIES ORIGINATING AT A NEW SUBSTATION (SUNZIA EAST) IN LINCOLN COUNTY, NEW MEXICO, AND TERMINATING AT THE PINAL CENTRAL SUBSTATION IN PINAL COUNTY, ARIZONA. THE ARIZONA PORTION OF THE PROJECT IS LOCATED WITHIN GRAHAM, GREENLEE, COCHISE, PINAL, AND PIMA COUNTIES.	DOCKET NO. L-00000YY-15-0318-00171 Case No. 171 NOTICE OF FILING EXHIBITS OF INTERVENOR, PETER T. ELSE

Arizona Corporation Commission
DOCKETED
OCT 23 2015
DOCKETED BY

Peter T. Else, a Party in this case, is herein filing a copy of his Exhibits. These Exhibits are contained in an attached 3-ring binder, and are submitted pursuant to Paragraph 15 of the Procedural Order issued by Chairman Chenal on September 11, 2015, requiring the filing a single copy of the Exhibits with Docket Control.

Respectfully submitted on October 23, 2015,

P. T. Else

Peter T. Else
PO Box 576
Mammoth, Arizona 85618
(520) 487-1903
bigbackyardfar@gmail.com

ONE (1) ORIGINAL of the
foregoing hand-delivered on
this 23rd day of October 2015 to:

Arizona Corporation Commission
Docket Control
1200 W. Washington Street
Phoenix, AZ 85007-2996

COPY of the attached Exhibits
were hand delivered on October 19, 2015
to the Applicant and all members of the
Arizona Power Plant and Transmission
Line Siting Committee and the Reporter.

Substantive copies of the attached exhibits were emailed
On October 13, 2015 to the Chairman,
all parties, potential parties, and others on the
following distribution list:

Thomas Chenal Thomas.chenal@azag.gov
J. Alward jalward@azcc.gov
T. Broderick tbroderick@azcc.gov
D. Nodes dnodes@azcc.gov
[Reporter] mh@coashandcoash.com
Samuel Lofland SLofland@rcalaw.com
Lawrence Robertson tubaclawyer@aol.com
Albert Acken aacken@rcalaw.com
Cedric Hay cedric.hay@pinalcountyaz.gov
Charles Hains chains@azcc.gov
Lat Celmins lcelmins@mclawfirm.com
Norm Meader nmeader@cox.net
Peter Gerstman peter.gerstman@robson.com
Jay Shapiro jay@shapslawaz.com
Christina McVie christina.mcvie@gmail.com
Chris Keller chris.keller@pinalcountyaz.gov
Pearl Mast cpearlmast@gmail.com
Elna Otter elna.otter@gmail.com
Matt Clark mclark@tucsonaudubon.org
Dorothy Hallock halgros@hallockgross.com
Karen Fogas kfogas@tucsonaudubon.org
Linda Pollock Linda.pollock@azag.gov
Matt Clark mclark@tucsonaudubon.org
Peter Steere peter.steere@tonation-nsn.gov
Rob Peters rpeters@defenders.org
Sandy Bahr sandy.bahr@sierraclub.org
Tim Hogan thogan@aclpi.org
Rob Peters rpeters@defenders.org
Bill Dunn dunnranches@yahoo.com

List of Exhibits, for the testimony of Peter T. Else

Exhibit PTE-01: High Plains Express Transmission Project Feasibility Study (2008)

Exhibit PTE-02: Benefit-Cost Analysis of Frontier Line Possibilities (2007)

Exhibit PTE-03: Energy Development Forecast Analysis, SunZia final EIS, 2013.
Source link: http://www.sunzia.net/documents_pdfs/10_sunzia_feis_chapter_4.pdf

Exhibit PTE-04: Average retail price of electricity 2002-2014 USEIA.
Source link:
http://www.eia.gov/electricity/data/browser/#/topic/7?agg=2,0,1&geo=g&freq=M

Exhibit PTE-05: Average price of coal and gas in Arizona for electricity production, 1990-2013, USEIA.
Source link: http://www.eia.gov/electricity/state/arizona/index.cfm

Exhibit PTE-06: Heartland Line Burial Cost
Source link for Alberta's Heartland Project Line Burial Report:
http://www.aeso.ca/downloads/CCI_Feasibility_Study_for_500_kV_AC_Underground_Cables.pdf

Exhibit PTE-07: Albuquerque (ABQ) Journal article of 6-19-15
Source link:
http://www.abqjournal.com/601392/abqnewsseeker/sunzia-may-move-north-of-white-sands.html

Exhibit PTE-08: Interstate Transmission Projects, from 8th ACC BTA, ACC Docket No. E-00000D-13-0002.
Source link:
http://www.azcc.gov/Divisions/Utilities/Electric/Biennial/2014%20BTA/Workshop%20Announcements%20&%20Agendas/Final%20-%208th%20Biennial%20Transmission%20Assessment%20-%2010-29-2014%20-%20Complete.pdf

Exhibit PTE-09: Schematic diagram of some proposed "clean" transmission lines in AZ and NM

Exhibit PTE-10: Description of Lucky Corridor.
Source link: http://www.luckycorridor.com/index-2.html

Exhibit PTE-11: Description of Western Spirit Clean Line.
Source link: http://www.westernspiritcleanline.com/site/page/project-description

Exhibit PTE-12: BLM Notice to prepare SunZia EIS, Federal Register 2009.
Source link: https://www.federalregister.gov/articles/2009/05/29/E9-12512/notice-of-intent-to-prepare-an-environmental-impact-statement-and-possible-resource-management-plan

Exhibit PTE-13: SunZia Map from BLM Record of Decision, 2015.
Source link: http://www.sunzia.net/documents_pdfs/book_1_sunzia_rod_final_print_quality.pdf

Exhibit PTE-14: Underground Transmission, Infeasibility, SunZia final EIS, 2013.
Source link: http://www.sunzia.net/documents_pdfs/08_sunzia_feis_chapter_2.pdf

Exhibit PTE-15: Underground Transmission, Feasibility, SunZia TWG Report, 2013.
Source link: http://www.nextgov.com/media/gbc/docs/pdfs_edit/081413bb1.pdf

Exhibit PTE-16: SunZia Project Need and Benefits, CEC Application, 2015.
Source link: http://www.sunzia.net/documents_pdfs/01_front_matter_and_application.pdf

Exhibit PTE-17 is identical to Exhibit **NMM-40**: Southline-Sunzia routes on GoogleEarth, *PTE-17 will not be docketed in addition to NMM-40*

Exhibit PTE-18 is identical to Exhibit **NMM-39**: Southline Transmission Project Route, draft EIS, 2014, *PTE-18 will not be docketed in addition to NMM-39*

Exhibit PTE-19: Southline Transmission Project Objectives, DEIS, 2014.
Source link for Volume 1 of Southline draft EIS:
http://www.blm.gov/nm/st/en/prog/more/lands_realty/southline_transmission.html

Exhibit PTE-20: Change in Arizona Electrical Demand Forecast, 2014, from 8th ACC Biennial Transmission Assessment, ACC Docket No. E-00000D-13-0002.
Source link:
http://www.azcc.gov/Divisions/Utilities/Electric/Biennial/2014%20BTA/Workshop%20Announcements%20&%20Agendas/Final%20-%208th%20Biennial%20Transmission%20Assessment%20-%2010-29-2014%20-%20Complete.pdf

Exhibit PTE-21: EPA Clean Power Plan for AZ, 2015.
Source link: http://www3.epa.gov/airquality/cpptoolbox/arizona.pdf

Exhibit PTE-22: EPA Revised Ozone Standard 2015.
Source link: http://www3.epa.gov/ozonepollution/pdfs/20151001designationsfs.pdf

Exhibit PTE-23: Else/FAR comments on SunZia draft EIS, 2012.
Note: These submitted comments and BLM response are in Appendix J of Applicant's Exhibit B-1 of their CEC Application, which is sourced from this link:
http://www.blm.gov/nm/st/en/prog/more/lands_realty/sunzia_southwest_transmission/feis/feis_appendices.html

Exhibit PTE-24: Else/FAR protest to SunZia RMP Amendments, 2013.

Exhibit PTE-25: Else/FAR comments on SunZia Line Burial Mitigation Environmental Assessment, 2014.

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-01

High Plains Express Transmission Project

Feasibility Study Report

June 2008

Table of Contents

INTRODUCTION and EXECUTIVE SUMMARY **3**

PRIMARY CONCLUSIONS 5

Primary Benefits *5*

Technical Studies and Costs *5*

Conceptual Routing *5*

Loads and Resources *5*

Estimated Power Delivery Costs *6*

Economic Analysis *6*

Potential Benefits to HPX States *7*

NEXT STEPS 7

BACKGROUND **9**

OBJECTIVE 9

VISION 9

MEMORANDUM OF UNDERSTANDING 9

ORGANIZATION 10

PROCESS 11

LOADS and RESOURCES **12**

TRANSMISSION STUDIES **14**

BASIC CRITERIA and METHODOLOGY 14

STUDY MODELS 14

BENCHMARK ANALYSIS 20

TRANSMISSION ALTERNATIVES 20

SERIES COMPENSATION 22

RESULTS and RECOMMENDATIONS 26

COST ESTIMATES **27**

PRELIMINARY ROUTING **28**

ECONOMIC EVALUATION **29**

ASSUMPTIONS 29

RESOURCE DELIVERY COSTS 31

SCENARIOS and MODELING APPROACH 33

RESULTS 35

STAKEHOLDER COMMENTS **38**

STAKEHOLDER QUESTIONS AND RESPONSES 38

APPENDIX A ..... **PDF FILE**

POWERFLOW RESULTS

Introduction and Executive Summary

The High Plains Express (HPX) initiative is a roadmap for transmission development in the Desert Southwest and Rocky Mountain region to significantly strengthen the eastern portion of the Western grid. It would potentially incorporate the transmission projects already under development within the HPX footprint.[1] With added North-South and East-West transmission capability, markets for renewable energy would be broadened, system reliability would be enhanced, and the ability to make economic transfers of energy would provide cost-savings opportunities for consumers in the states of Wyoming, Colorado, New Mexico, and Arizona.

Seven electric utilities, three state agencies, and an independent transmission development company joined in an effort to evaluate the preliminary technical and economic feasibility of this initiative.[2] This feasibility evaluation has been conducted as an open process providing opportunities for stakeholder input and participation. The results of initial feasibility studies are presented in this report.

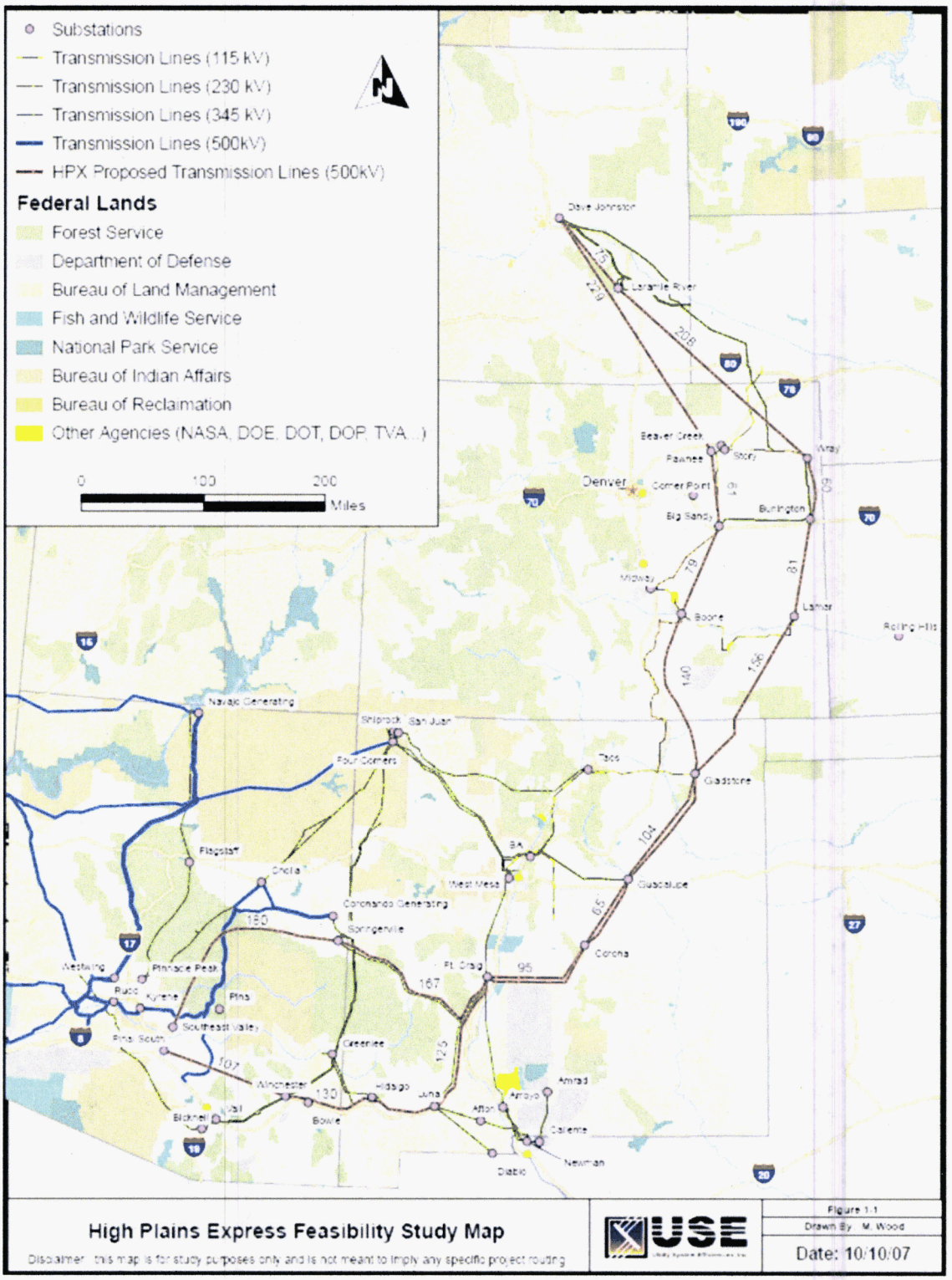
The HPX concept would extend the 500 kV AC transmission system that is used throughout much of the Western Electricity Coordinating Council (WECC) region, to connect the states of Wyoming, Colorado, New Mexico, and Arizona. This system would provide opportunities to upload power from a variety of economic resources, as well as download power for customer use within each HPX state, and would be integrated with existing generation and power delivery systems. The feasibility study focused on power transfers from northeast to southwest, but HPX could be used to transfer power in both directions.

---

[1] Eastern Plains Transmission Project (EPTP), Wyoming-Colorado Intertie (WCI), New Mexico Wind Collector, and SunZia Southwest Transmission Project

[2] Colorado Springs Utilities (CSU), Platte River Power Authority (PRPA), Public Service of New Mexico (PNM), Salt River Project (SRP), Trans-Elect, Tri-State G&T, Western Area Power Administration (Western), Xcel Energy, Colorado Clean Energy Development Authority (CEDA), New Mexico Dept. of Energy, Minerals & Natural Resources (NM-EMNR), and the Wyoming Infrastructure Authority (WIA)

***Figure ES-1*: Conceptual Routing of the HPX Project**



A. Primary Conclusions

Primary conclusions from this preliminary feasibility study effort are summarized as follows:

1) Primary Benefits: The primary benefits expected to be realized from the HPX Initiative:
   a) Enhances the reliability of the eastern portion of the WECC grid;
   b) Facilitates substantial new renewable energy integration consistent with public policy;
   c) Provides for efficient energy transfers and associated economic benefits for customers and consumers in each of the HPX states;
   d) Provides economic development stimuli for all HPX states; and
   e) Provides a "roadmap" for local and regional transmission expansion.

2) Technical Studies and Costs: Power flow simulation studies, under the direction of the HPX participants, indicate that two 500 kV AC transmission lines could effectively carry as much as 4,000 MW of bulk power. Alternatively, two double-circuit 500 kV lines could accommodate 7,000 to 8,000 MW of transfers. These lines could be connected to several substations along the HPX path. For this Feasibility Study, fourteen substation interconnections were evaluated: two in Wyoming, six in Colorado, four in New Mexico, and two in Arizona.

   Installed costs for two 500 kV lines and associated substations were estimated at $5.1 billion (in 2007 dollars), with indicative economics shown for potential major line segments below. As shown, effective transmission rates are dependent upon the extent to which a transmission line is utilized.

Segment	Ave. Miles	Cost ($MM)	Line Losses	Indicative Transmission Rates		
				$/kw-mo	$/MWh @ 40% Use	$/MWh @ 80% Use
Wyoming - Colorado	335	$1,366	2.4%	$3.21	$10.99	$5.50
Colorado - New Mexico	420	$1,680	3.1%	$3.94	$13.49	$6.75
New Mexico - Arizona	525	$2,087	3.8%	$4.90	$16.78	$8.39

3) Conceptual Routing (*Figure ES-1*): Two—1,300 mile long conceptual transmission routes were identified for purposes of study modeling. They would traverse renewable energy resource areas and nearby substations within the HPX states. These conceptual routes do not imply preliminary, specific, or final routing selections that would be evaluated in the next phase of the project's feasibility taking into account wildlife and myriad other factors. The two routes are largely separate, although they would most likely converge in New Mexico before turning west to Arizona. Routes in Wyoming and Colorado would largely be on private land, while in New Mexico and Arizona, significant portions are likely to be on Federal (BLM and Forest Service) lands.

4) Loads and Resources: The electrical generation capacity of the four HPX states approaches 50,000 MW with a majority of generation used internally and a portion exported to adjoining states. The vast majority of this generation is from fossil base

load resources, particularly coal. In the coming years, demand for electricity, particularly energy from renewable resources, is expected to expand – notwithstanding demand-side and energy efficiency programs under development by the utilities within each HPX state.

a) The region's transmission grid was developed by owners of large, jointly owned, base load power plants in order to facilitate the transfer of power from those plants to the owning utilities and for reliability purposes. As a result, Wyoming is primarily a power exporting state, New Mexico and Arizona are net exporters, and Colorado is largely self-sufficient, although it also imports power from Wyoming.
b) The use of the existing transmission grid within the HPX states for delivering renewable energy is limited by (1) the general absence of available transmission capacity and (2) undersized or non-existent transmission lines within the renewable resource areas.
c) Power demand peaks during the daylight hours and summer months for the HPX states, with a lesser peak during the winter months. These demand profiles do not align with the availability of renewable resources when aggregated as a whole, so supplemental resources will likely be required to match load requirements.

5) Estimated Power Delivery Costs: It is expected that HPX will improve the diversity, performance, and costs of resources available for use within each HPX state, largely without displacing opportunities for in-state renewable development. Intermittent wind from in-state resources generally provides the lowest cost energy supply option within each HPX state, followed by fossil generation whose costs will be influenced by future carbon regulations. It is anticipated that geographical diversity of wind and solar resources delivered by HPX will supplement local renewable options, further reducing reliance on fossil generation and reducing renewable energy integration costs.

6) Economic Analysis: Benefit/Cost studies were conducted for six 3,500 MW resource mix scenarios using a screening tool that was developed in the Frontier Line transmission study.[3] Sensitivity analyses were conducted for different CO_2 penalty levels for various resource mixes generally compared against new gas fired generation located within the load centers. While most scenarios indicate economic feasibility (i.e., benefits outweigh costs), the renewable-dominated scenarios performed progressively better at higher CO_2 penalty costs, and the reverse was true for the fossil-dominated scenarios. A "balanced" scenario consisting of near equal amounts of fossil and renewable energy performed the best under a range of circumstances.

---

[3] The HPX benefit/cost analysis used the FEAST model developed by PG&E and the Frontier Line Economics Sub-Committee (www.ftloutreach.com) which is characterized as follows: "FEAST is a screening tool, and is not intended as a substitute for necessary, in-depth analysis using production costing and/or market simulation tools."

7) Potential Benefits to HPX States: In addition to improved reliability and economic development that would be realized by all HPX states, additional benefits could include the following (which will be studied in subsequent phases of the project's development):

   a) Arizona: Ability to increase its reliance on renewables as a cost-effective power supply source by blending and supplementing in-state renewables with renewables imported from the "upstream" HPX states, particularly New Mexico;

   b) Colorado and New Mexico: Ability to optimize renewable energy use for in-state and export purposes by taking advantage of geographical diversity afforded by HPX's development, without limiting in-state renewable energy development prospects;

   c) Wyoming: Ability to export its high-quality, low-cost resources, particularly wind to the "downstream" HPX states to enhance the performance and reliability of the resources used within and exported by those states;

B. Next Steps

During the course of this feasibility study work, a number of additional issues were raised which will need to be addressed in subsequent detailed feasibility assessment and project development phases. These include the following:

1. Studies to identify corridors for siting transmission lines: these studies would incorporate assessments of wildlife habitat and migration, terrain, land management and ownership, permitting requirements, potential for shared corridors, community impact, avoidance of critical areas, impact mitigation/avoidance, and a wide range of other issues;
2. Sequential development: construction of individual segments of the HPX initiative over time following a "roadmap" approach to transmission expansion suited to each HPX state's needs, potentially incorporating the transmission projects currently under development within the HPX footprint. Options could include designing facilities to allow for initial operation at lower voltages, future expansion of conductors and adding future circuits;
3. Operational modeling to assess the performance and costs of renewable resource integration and dispatch;
4. Assessment of public and regulatory policies potentially applicable to HPX, particularly those regarding renewable development and transmission financing;
5. Further quantification of the overall cost impacts and benefits that could be achieved from the HPX initiative. This would include production cost modeling of various resource mixes, including those suggested for analysis by stakeholders;
6. Cost allocation and cost recovery mechanisms, and potential for a regional tariff for segments and/or the entire HPX project. Cost-causation and beneficiary pays principles would be applied to the largest extent possible, and where appropriate.

7. Continuing an open stakeholder approach and outreach to secure input on the transmission planning process. Begin WECC rating process and ensure the HPX initiative is properly included in the sub-regional and WECC transmission planning venues;
8. Identification of business structures, ownership shares, development funding requirements, work plans, and project development schedules for consideration in further assessing the viability of the HPX initiative.

II. Background

A. Objectives:

The primary objectives of this Feasibility Study were to:

1. Develop transmission expansion alternatives to significantly increase reliability and power transfer capabilities between the states of Wyoming, Colorado, New Mexico, and Arizona.
2. Identify potential transmission interconnection points that would allow for up-loading renewable and other economic generation resources, and dropping-off power to regional loads.
3. Examine the potential for synergies among other projects within the HPX footprint.
4. Determine economic viability of the transmission alternatives.
5. Perform high level screening analysis to determine potential siting and corridor routes, and approximate transmission line mileages.

B. Vision

In the fall of 2006 utility members from the Rocky Mountain and Desert Southwest regions met to discuss the potential for a transmission study that would coordinate efforts of individual transmission development projects throughout the region. The goal of this effort was to determine if transmission projects could be developed and coordinated in a manner that would enhance the reliability of the overall transmission system in the region, provide benefits to all interested stakeholders, provide economic benefits to consumers within each state, and facilitate future resource injection areas.

C. Memorandum of Understanding

Preliminary meetings to discuss concepts, interest, and scope lead to the development of an agreement for a transmission feasibility study. Each of the interested parties felt that the best way to conduct a joint study was to pool resources and have an independent consultant perform the bulk of the transmission studies. A Memorandum of Understanding (MOU) was drafted to enable parties to participate in the HPX Feasibility Studies. The following parties signed the MOU:

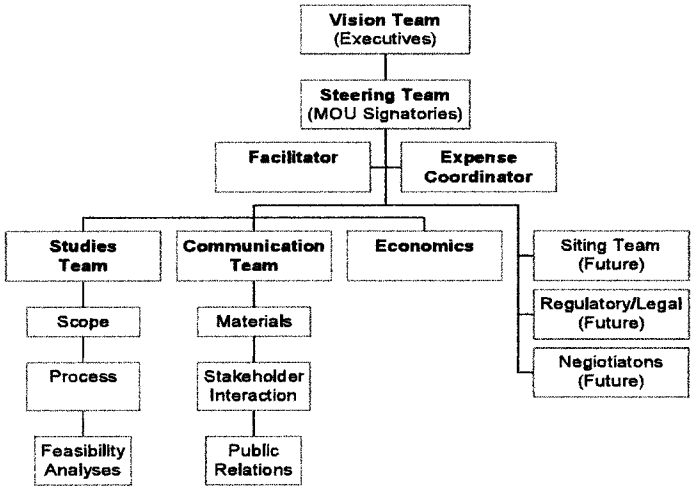
- Utilities:
  - Colorado Springs Utilities – a municipal utility
  - Platte River Power Authority - a public power authority
  - Public Service Company of New Mexico (PNM) – an investor-owned utility
  - Salt River Project (SRP) – a public power authority
  - Tri-State G&T – a rural electrical generation and transmission cooperative
  - Western Area Power Administration (Western) – a federal marketing administration
  - Xcel Energy – an investor-owned utility

- State Agencies
  - Colorado Clean Energy Development Authority (CEDA)
  - New Mexico Energy, Minerals and Natural Resources Department (NM-EMNRD)
  - Wyoming Infrastructure Authority (WIA)
- Independent Transmission: TransElect Development Company

D. Organization

The participants in the Feasibility Study organized into teams that could facilitate the various tasks of the study. *Figure 1* illustrates how the organization was designed.

Figure 1: **Organization Design**



The Vision Team developed the overall study approach with the first phase being the feasibility analyses. Subsequent phases will advance the project towards development and implementation by furthering the development of the Project scope, structure and governance.

The Steering Team consisted of representatives from each of the parties that signed the MOU, and managed the feasibility study process.

The Studies Team was responsible for managing the transmission system studies. This process began in April 2007, was followed shortly thereafter with the first stakeholder meeting in March 2007, and culminated with the second stakeholder meeting in December 2007.

The Communication Team helped manage the flow of information during this feasibility study to the public and stakeholders.

E. Process

1. Scope

Initial discussions began in the fall of 2006 among parties developing transmission projects within what has become the HPX footprint. It was noted that there were several plans for significant transmission development in the footprints of the representative utilities. These projects included the—TransWest Express Project, the Eastern Plains Transmission Project (EPTP), the TOT3 Expansion Project (now known as the Wyoming-Colorado Intertie (WCI), the Northern New Mexico Import proposal, and the SunZia Southwest Project. Most agreed that there was a need for transmission expansion in the region to accommodate renewable energy, increase reliability, and evaluate synergies among the other planned projects. The genesis of the HPX initiative was to jointly evaluate a high voltage transmission plan that could coordinate study efforts in the Rocky Mountain and Desert Southwest regions of WECC.

2. Consultant

Various consultants were interviewed and Utility System Efficiencies (USE) was chosen to perform the initial transmission feasibility studies.

3. Communication

The Feasibility effort was designed as an open process in order to facilitate stakeholder input. Two stakeholder meetings were held. The first was a kickoff meeting held on March 23, 2007 at the Embassy Suites Hotel, near Denver International Airport. Approximately 100 people attended. The second meeting provided stakeholders with an overview of the study results and was held on November 11, 2007 at the Holiday Inn Denver International Airport. Again, nearly 100 stakeholders attended. In addition to the two stakeholder meetings, the Studies Team held meetings on a weekly basis. These meetings were also open to interested stakeholders. There were approximately 35 participants on the contact list for the Studies Team.

Status reports were also provided at numerous WECC regional and sub-regional (CCPG and SWAT) meetings throughout the process. A website was formed for maintaining materials from this phase of the process at http://www.rmao.com/wtpp/HPX_Studies.html.

III. Loads and Resources

DOE has compiled the electrical generation resources and requirements for each of the HPX states for 2005 – the last year for which such data are publicly available (*Table 1*). These data indicate that nearly 50,000 MW of generation capacity is available within these states, with the vast majority of the capacity from coal and gas plants. The 3,500-4,000 MW that would be delivered by the HPX project would serve a small portion of overall load growth (tempered by the success of demand side management, energy efficiency, and conservation measures), as well as supply energy from renewable resources to meet the HPX states' Renewable Portfolio Standards (RPS).

***Table 1*—HPX States' 2005 Loads & Resources (Source: DOE)**

CAPACITY (MW)	WYOMING	COLORADO	NEW MEXICO	ARIZONA	TOTAL	SHARE
Coal	5,847	4,928	3,957	5,430	20,162	41%
Oil & Gas	166	4,706	2,031	12,647	19,550	40%
Nuclear	0	0	0	3,875	3,875	8%
Hydroelectric	303	652	82	2,720	3,757	8%
Renewables	287	238	410	16	951	2%
TOTAL	6,707	11,087	6,480	24,904	49,178	100%
Growth @ 2%/yr to 2020	2,320	3,835	2,241	8,614	17,009	35%
RPS Requirements (UCS)	NA	2,396	1,282	2,004	5,682	
GENERATION (MWH)	**WYOMING**	**COLORADO**	**NEW MEXICO**	**ARIZONA**	**TOTAL**	**SHARE**
Coal	43,345,685	35,570,135	29,947,248	40,143,310	149,006,378	64%
Oil & Gas	367,277	11,940,336	4,224,127	28,936,475	45,468,215	20%
Nuclear	0	0	0	25,807,446	25,807,446	11%
Hydroelectric	808,375	1,415,296	164,993	6,410,064	8,798,728	4%
Renewables	717,264	810,561	799,274	73,995	2,401,094	1%
TOTAL	45,567,307	49,614,265	35,135,642	101,478,655	231,795,869	100%
CAPACITY FACTOR	**WYOMING**	**COLORADO**	**NEW MEXICO**	**ARIZONA**	**TOTAL**	
Coal	85%	82%	86%	84%	84%	
Oil & Gas	25%	29%	24%	26%	27%	
Nuclear	NA	NA	NA	76%	76%	
Hydroelectric	30%	25%	23%	27%	27%	
Renewables	29%	39%	22%	53%	29%	
AVERAGE	78%	51%	62%	47%	54%	
LOADS	**WYOMING**	**COLORADO**	**NEW MEXICO**	**ARIZONA**	**TOTAL**	
Megawatt Hours	14,137,727	48,353,236	20,638,951	69,390,686	152,520,600	
% of Generation	31%	97%	59%	68%	66%	

In contrast to capacity, generation was dominated by coal-fired plants, which comprised 64% of the generation and which operated at an average 84% capacity factor. Hydroelectric and renewable power sources together comprised only 5% of the HPX states' generation mix in 2005. These resources were used primarily as follows:

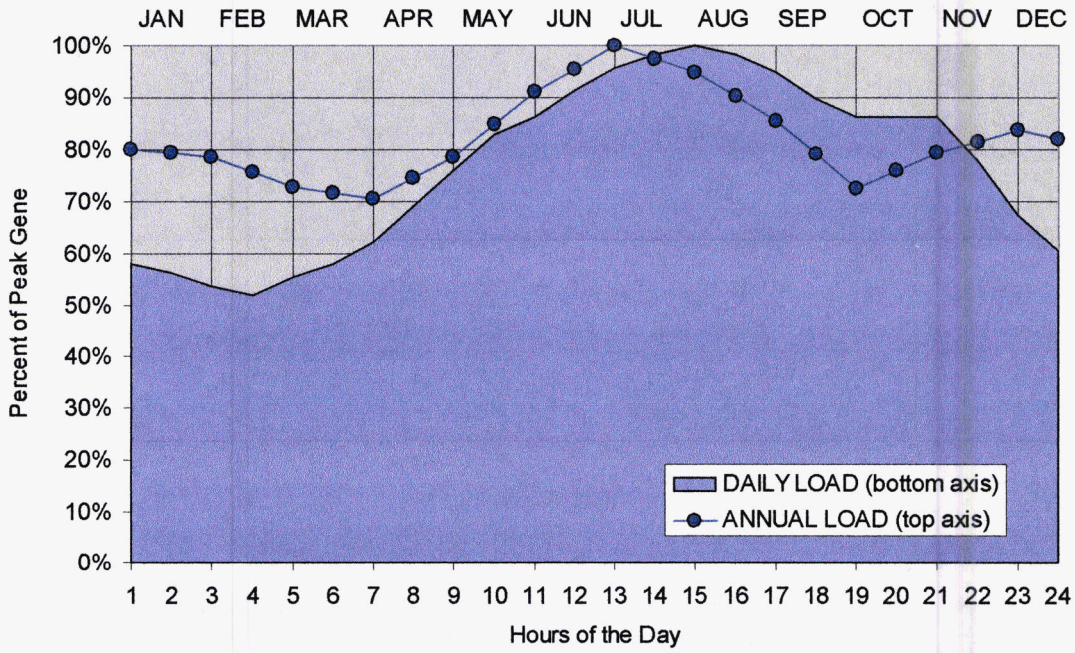
- Coal: Baseload dispatchable resource that is fully utilized
- Gas: Transitional to peaking dispatchable resource, some excess capacity?
- Nuclear: Baseload dispatchable resource that is fully utilized (Palo Verde)

- Renewables: Intermittent resource used when available (non-dispatchable)
- Hydro: Used when available (Spring runoff), limited by drought and other uses; minor pumped storage

The relationship between loads and generation for the HPX states provides an indication of the extent to which theses states participate in regional import/export power markets. The data would indicate that about one-third of the power generated in the HPX states is exported outside of the region (primarily to California), with Wyoming standing out as primarily an exporting state and Colorado as one in which its loads and resources are balanced (suggesting minimal current involvement in regional import/export power markets).

An approximation of the shape of the load profile for the HPX states on an hourly and monthly basis are shown in *Figure 2*[4]. As shown, the demand for electricity peaks during the daylight hours before dropping off gradually during the evening hours. Customer demand also peaks during the summer months, with a lesser peak near the end of the year. The low demand periods occur during the late evening and early morning hours and during the Spring and Fall seasons.

Figure 2: **Load Shapes for the HPX States**



[4] Hourly values from PSCo wind integration study; monthly values from WECC for Rocky Mtn. Power Area

IV. Transmission Studies

A. Basic Criteria and Methodology

This high level, conceptual transmission study evaluated power capacity levels of high voltage transmission alternatives that interconnected multiple points on the existing electrical system. The study considered impacts on the low voltage transmission system, but did not evaluate upgrades to address those issues.

This study consisted of traditional powerflow analysis and typical transmission planning methodologies were utilized. Post-transient, transient, and short-circuit studies were not performed. It is anticipated that those types of analyses may be done in subsequent phases of the initiative. System performance was evaluated based on system intact (N-0) and single contingency (N-1) conditions. In the WECC powerflow models, the region of interest consisted of powerflow areas 10 (Arizona), 14 (New Mexico), 70 (Public Service Company of Colorado), and 73 (Western Area Power Administration's Colorado/Missouri - WACM). The contingency analyses modeled outages of every element 230kV and above in these powerflow areas. Performance was documented through powerflow geographic diagrams and spreadsheets depicting element loadings. Element loadings were reported under contingency conditions if the loadings exceeded 100% of the elements emergency rating and if the loadings were 1% greater than the loadings in the benchmark simulations. Appendices B and C contains a listing of all of the contingencies that were run for this study.

Transmission alternatives were evaluated in the course of the Feasibility analysis. Since the objective was to interconnect the transmission with a number of energy resource zones to allow implementation of economic resources, studies were limited to Alternating Current (AC) alternatives. Direct Current (DC) transmission can be more economical to deliver large amounts of power over long distances from a single delivery point to a single point of receipt. However, it is not a favorable technology for accommodating numerous interconnection points due to high costs of AC/DC converter stations.

B. Study Models

This study utilized powerflow models that represented 2017 peak summer loading conditions. The base case modeling data was developed from the WECC 2015HS1-S case, which modeled 2015 Heavy Summer loading conditions. Participants reviewed the models and provided modifications to update case topology and increase loads to 2017 peak summer levels. No new generation resources were added to the starting point base case other than fully committed projects (except for Arizona)[5]. Imports from other areas were used to make up for any resource deficiencies that may have remained after adding fully committed projects.

[5] This Arizona generation addition did not have a significant impact on these study results, since once the High Plains Express project was added to the cases and the Arizona imports were increased, this new generation was no longer needed.

1. **Load and Resource Data**
   Table 2 below summarizes the benchmark load and generation in the regional powerflow areas before additional resources were added.

***Table 2*—Base Case Loads and Resources**

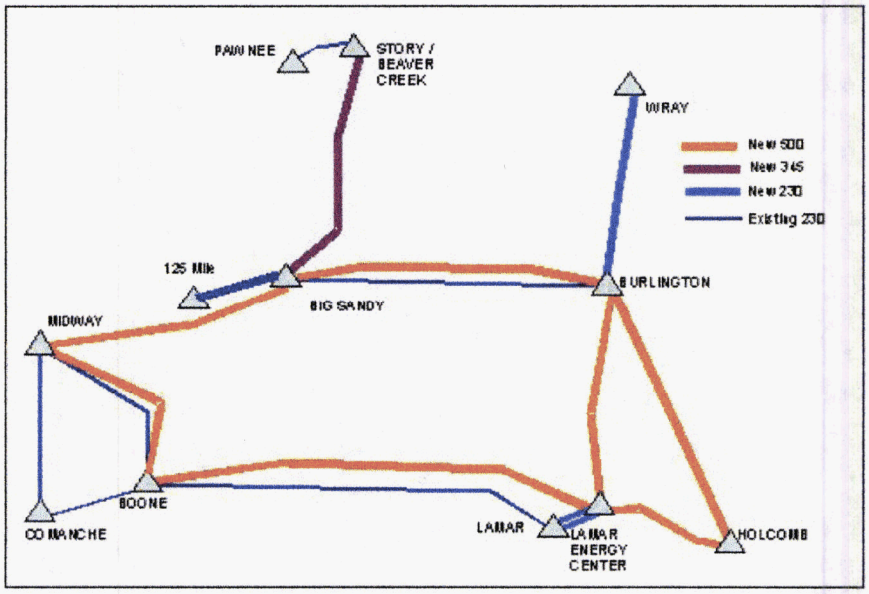
Powerflow Area	Load[6] (MW)	Generation (MW)	Imports (MW)
Wyoming (Area 73)	5,897	6,398	-501
Colorado (Area 70)	9,769	9,430	339
New Mexico (Area 10)	3,062	3,406	-344
Arizona (Area 14)	25,477	32,308	-6,831

2. **Regional Project Consideration**
   The base model included transmission and generation projects that utilities had relatively concrete plans put in service by the 2017 time frame. Other projects that were considered more conceptual were not represented in the study models.

   Significant transmission projects modeled in the base case include
   - The Eastern Plains Transmission Project (EPTP). At the time of this study, the EPTP was envisioned as a joint high-voltage project sponsored by Tri-State Generation and Transmission and Western Area Power Administration. The project consisted of over 300 miles of 230kV and 660 miles of new 500kV transmission in Kansas and eastern Colorado as shown in *Figure 3*. The EPTP modeling was included in the WECC base case, and left in the preliminary models for HPX studies. Subsequent sensitivity analyses were performed that modeled EPTP as an integral piece of HPX.

[6] Load includes customer load plus transmission losses.

Figure 3: **Eastern Plains Transmission Project**



Study handling of proposed, or conceptual regional projects

- The Wyoming – Colorado Intertie (WCI) Project is being considered by, TransElect, the Wyoming Infrastructure Authority, and Western. It has been planned as a single high voltage transmission line between Dave Johnston and Laramie River Station in Wyoming, and continuing south to the Pawnee Substation, located northeast of the Denver-metro area. Since the HPX contemplates having a transmission line from the Dave Johnston/LRS to the Pawnee area, this study considered the WCI to be an integral segment of the HPX. Therefore, a separate WCI project was not modeled.

- New Mexico Wind Collector System: Public Service Company of New Mexico has been evaluating conceptual transmission options that could deliver power from potential wind resource locations to load centers in the state or to adjacent transmission systems. No specific projects have been recommended to date, so there were no high-voltage collector system options modeled for the HPX studies. It is expected that the collector options, if pursued, will provide much of the same benefit as a comparable portion of the HPX project in New Mexico and will be designed to integrate and eliminate duplication.

- SunZia: The SunZia Southwest Transmission Project is contemplated as a 500kV transmission system that would run between southern New Mexico and southern Arizona. The SunZia Southwest Transmission Project would allow potential future development of power from renewable energy sources, such as geothermal, wind, and solar, to be transported by the

SunZia Project to the Arizona and New Mexico regional transmission systems. For this study, the SunZia project was considered to be an integral segment of the HPX. Therefore, a separate SunZia project was not modeled.

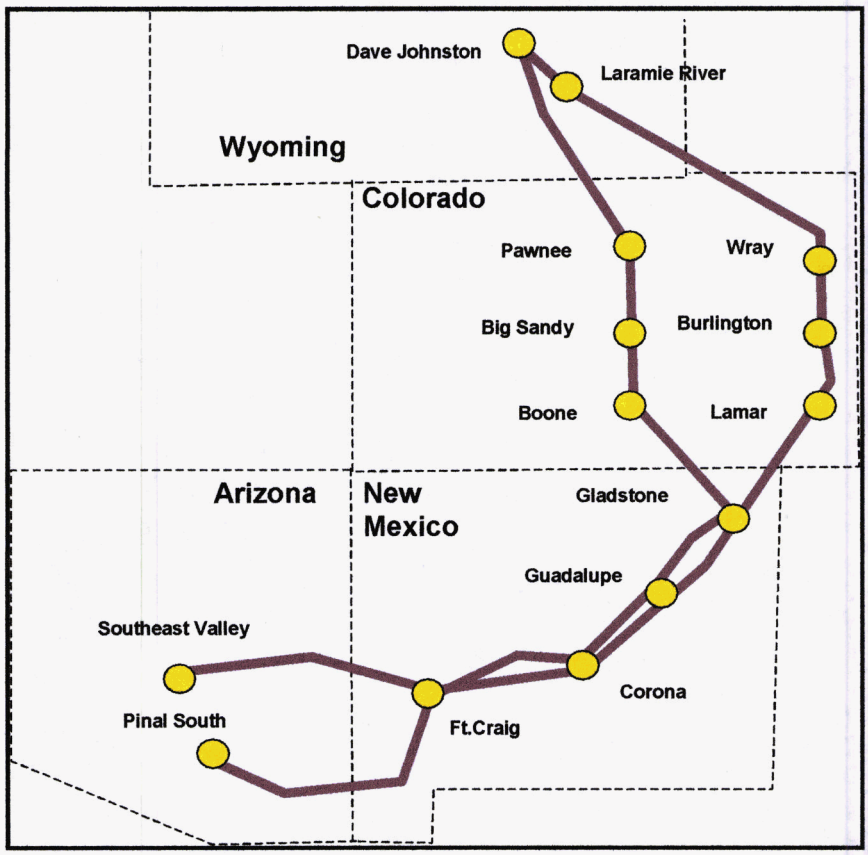
- TransWest Express Project: The TransWest Express project has been contemplated by the Arizona Public Service Company to deliver power from Wyoming resources to the Phoenix load center. The primary component of the project is a 500kV DC line, which would be routed west out of Wyoming, through Utah, and terminate either near Las Vegas, Nevada. The completion of the TransWest Express Project would provide Arizona and other western states increased capability to access electricity generated in Wyoming from coal, wind and other resources. At the time of this study, the TransWest project was conceptual in nature, primarily DC operation, and was geographically outside of the High Plains study region. Therefore, the TransWest was not modeled in the HPX study.

3. **Interconnection Selection**

Various interconnection points were evaluated in the four states within the HPX footprint in order to provide transmission access to potential resource zones. Wyoming has some of the highest potential in the nation for coal, natural gas, and wind resource development. Recent legislation in Colorado has resulted in the identification of several Energy Resource Zones that have the potential for renewable and other resource development. New Mexico also has regions where the interest in wind resource development is very strong. Based on an examination of the existing transmission system, potential resource zones, and major load centers, a list of interconnection points was developed. *Table 3* summarizes the interconnection points and the range of resource uploads modeled at each point. It also gives an indication of which points can be considered to be "downloads" for serving regional load. *Figure 4* shows the general geographic locations of the interconnections. It should be noted that the resource levels accommodated by the High Plains Express project are significantly less than the actual levels of requests for generator interconnection in each area, and less than what some documentation shows as potential renewable resource development. However, the levels were chosen to match the type of transmission envisioned for this project.

Table 3—HPX Upload and Download Scenarios					
Interconnectio Points	**Upload (MW)**	**Download (MW)**	**Interconnection Points**	**Upload (MW)**	**Download (MW)**
Wyoming			**New Mexico**		
Laramie River	500-2000		Gladstone	300-750	
Dave Johnston	500-2000		Guadalupe	300-750	✓
Total Wyoming	1000-4000		Corona	300-750	
Colorado			Ft. Craig		✓
Pawnee	300-1000	☐	Luna		✓
Wray	300	☐	**Total New Mexico**	**900-2250**	**900-1000**
Big Sandy	300	☐	**Arizona**		
Burlington	300-500	☐	Pinal South		✓
Boone	300-500	☐	Southeast Valley		✓
Lamar	300-1000	☐	Springerville		✓
			Winchester		✓
Total Colorado	**1800-3400**	**1800-2500**	**Total Arizona**		**1000-4000**

Figure 4: **Transmission Modeling**



4. **Transmission Modeling**

Once the interconnection locations were identified, potential transmission routing was determined in order to estimate mileages for the development of transmission models. Based on input from participants and the interconnection locations, the group agreed to model two corridors from Wyoming, through eastern Colorado, into New Mexico, south through central and south-central New Mexico and on to the load areas of Phoenix and Tucson (*Figure ES-1).*

Routing for each of these two corridors was determined by utilizing knowledge of where the resource and load development will likely occur to determine upload and download locations. Routing of the transmission lines between the various upload and download points was performed using input from the study participants as well as publicly available information on the locations of sensitive areas (e.g., Bureau of Indian Affairs lands, National Monuments, etc.). It should be emphasized that the routing assumed for this feasibility study is very preliminary and was only done to determine approximate transmission line distances. These distances were then used to determine the line parameters to input into the study model.

Westerly Route: The western route started in Wyoming at the Dave Johnston Power Plant and ran through the Colorado interconnection points of Pawnee, Big Sandy, and Boone. From Boone the line continued into New Mexico and connected to Gladstone. In New Mexico, from Gladstone to just west of Ft. Craig, a transmission corridor common to both routes was modeled. Intermediate interconnection points were modeled at Guadalupe and Corona. From New Mexico the western corridor took a more northerly route to Arizona. This route would connect to the Springerville power plant in eastern Arizona and the continued on to the northeast Phoenix-metro area to an interconnection at Southeast Valley.

Easterly Route: This route also began at the Dave Johnston Power Plant, but followed a more easterly route passing through Laramie River Station, and connecting to the eastern Colorado points of Wray, Burlington, and Lamar. From Lamar the line continued into New Mexico and connected to Gladstone. In New Mexico, from Gladstone to just west of Ft. Craig, the same transmission corridor was assumed as with the Westerly Route. Intermediate interconnection points were modeled at Guadalupe and Corona. The eastern corridor followed a route south from central New Mexico to southern New Mexico, then roughly followed I-10 west, and terminated southeast of the Phoenix-metro area at Pinal South. A potential variation of the easterly route was discussed that would stay in the eastern plains of New Mexico to southern New Mexico then head west to the El Paso area where the corridor would again roughly follow I-10. This alternative was not evaluated in the feasibility study, but would be expected to provide similar benefit if necessary to accommodate renewable resources in southeastern New Mexico.

The two transmission corridors and segment mileages for studies are summarized in *Table 4*.

***Table 4*—Transmission Mileages for Studies**

High Plains Express Line Segment Mileages							
Western Route				Eastern Route			
Starting Location	Ending Location	Circuit	Miles	Starting Location	Ending Location	Circuit	Miles
Dave Johnston	Beaver Creek	1	229	Dave Johnston	Laramie River Sta.	1	75
Beaver Creek	Big Sandy	1	61	Laramie River Sta.	Wray	1	208
Big Sandy	Boone	1	79	Wray	Burlington	1	60
Boone	Gladstone	1	140	Burlington	Lamar	1	81
Gladstone	Guadalupe	2	104	Lamar	Gladstone	1	156
Guadalupe	Corona	2	65	Gladstone	Guadalupe	1	104
Corona	Fort Craig	2	95	Guadalupe	Corona	1	65
Fort Craig	Springerville	1	167	Corona	Fort Craig	1	95
Springerville	Southeast Valley	1	180	Fort Craig	Luna	1	125
				Luna	Winchester	1	130
				Winchester	Pinal South	1	107
Total Mileage - Western (Approximate)			1120	Total Mileage - Eastern (Approximate)			1206

Total Mileage (Approximate)	2326

C. Benchmark Analysis

Once the powerflow base case model was established, some cursory analyses were performed to evaluate base system performance without any HPX transmission alternatives. With loads modeled at projected 2017 levels, the Arizonia powerflow area was deficient of sufficient generation resources. Therefore, fictitious generation was added west of the Phoenix area to meet resource requirements in the benchmarks analysis. This resulted in several performance issues in and around the Phoenix load center. The group recognized that these issues were associated with the modeling used to solve the initial case. The benchmark analyses also revealed several localized load-serving issues. These issues were documented so that they would not be considered to be problems associated with any proposed High Plains Express transmission additions.

D. Transmission Alternatives

The studies began with evaluating the capability of a single 500kV AC line and then moved to assessing the capabilities of two 500kV lines. Early studies modeled resource injections in Wyoming and moved the power straight through to Arizona by reducing the generation there (no resource additions were made in Colorado or New Mexico). Subsequent studies examined the various resource development scenarios in *Table 3* to see if these additional resources affected the overall transfer capability of the

project. The level of resource injection along the transmission path was first adjusted so that the increase in generation matched the corresponding state's resource requirement. Therefore, the powerflow on each HPX transmission alternatives remained relatively constant throughout its length. Next, scenarios were developed that looked at increasing the level of up-load as the High Plains transmission progressed through the states. The flows on the High Plains transmission increased as the lines passed through each state. The two types of scenarios are depicted in *Figures 5 and 6*.

***Figure 5*: Moderate Upload**

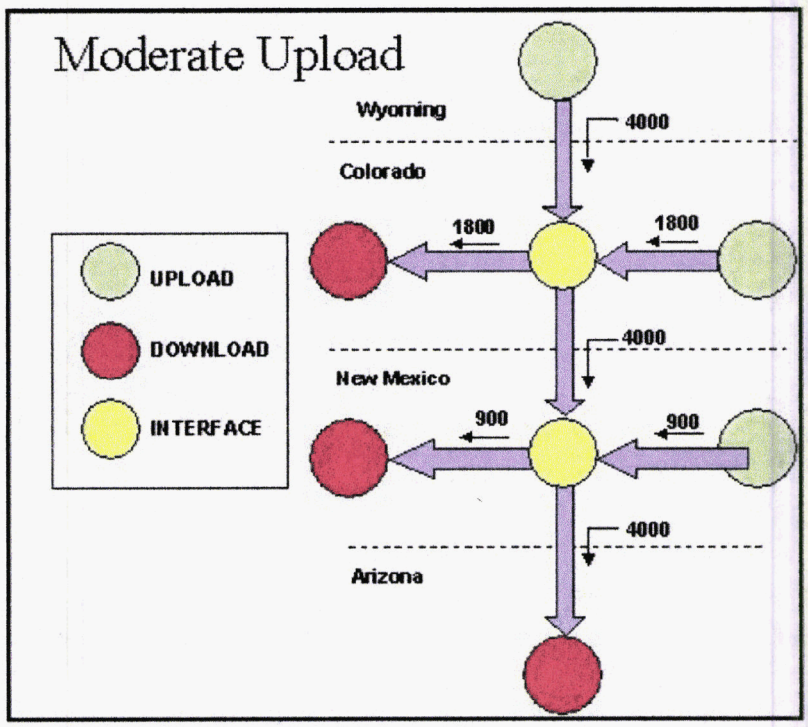
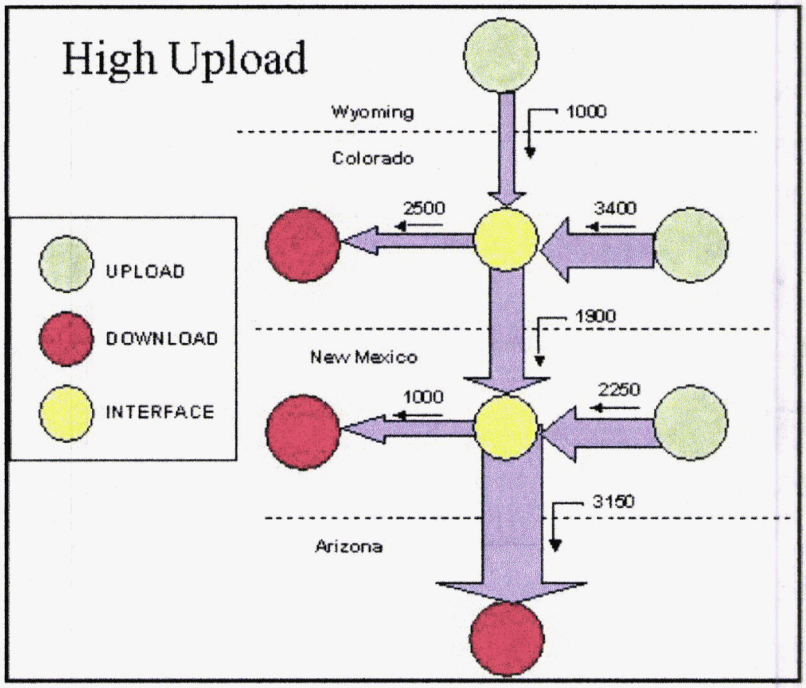


Figure 6: **High Upload**



After these resource development scenarios were examined, an ultimate build out scenario was reviewed that consisted of two double circuit 500 kV lines, one on the eastern route and one on the western route. This scenario was developed to provide information regarding the maximum feasible transfer capability that could be used to accommodate higher than expected resource development scenarios.

The final step involved evaluating potential synergies between the EPTP and High Plains Express to determine if combining the two projects along certain routes could result in similar performance while reducing the overall cost of both projects and reducing their combined environmental impacts.

E. Series Compensation

Initial studies evaluated transfer capabilities from Wyoming to Arizona without adding any series compensation to the High Plains transmission lines. After these transfer capabilities were determined, various levels of series compensation were introduced to asses what benefits could be provided, such as improved transfer capabilities and reduced system losses. Typically adding series compensation increases the amount of power that flows on the series compensated circuits. If these circuits have a lower resistance than the underlying system (which is usually the case), then overall system losses are reduced and more energy is available to serve end use customers. In addition to reducing losses, series compensation also reduces flows on the underlying transmission system, which can improve transfer capacity.

The series compensation analysis looked at three different levels of series compensation. The three levels examined were: no series compensation, 50% series compensation, and 70% series compensation. The series compensation was modeled on each individual High Plains transmission segment in equal percentages.

The analysis performed was a very basic study to determine if there were benefits to adding series compensation to the High Plains Express lines. Results were reviewed to see if any overloads were reduced or eliminated. If some overloads were reduced or eliminated for a particular level of series compensation, then it was assumed that additional transfer capacity would be available. The loss savings for this analysis are provided *Table 5*.

***Table 5*—Series Compensation Loss Savings**

Scenario	Transfers (MW)	Total Transmission Losses (MW)		
		0% Compensation	50% Compensation	70% Compensation
Western Corridor	2000	6726	6608	6636
Eastern Corridor	2000	6747	6685	6707
Two Lines	3000	6819	6730	6746

Even though the loss levels increased slightly when going from 50% series compensation to 70% series compensation, the results of the power flow analysis *(Appendix A)* indicate that higher transfer capacities may justify the higher levels of compensation. Therefore, 70% series compensation was used as the series compensation level for the remainder of the feasibility study.

It should be noted that additional studies will need to be undertaken before the final series compensation levels for each of the High Plains Express line segments is determined. This study assumed equal percentage compensation in all line segments. Some of the shorter line segments may not need compensation or the compensation for these segments may be able to be moved to other locations to reduce the overall project cost. Some of the additional studies noted above will be used to make this determination.

Summary results of the studies are provided below. Detailed results are provided in *Appendix A*.

1. **Results: Single 500 kV**
   After developing the base case, studies were run first on the single line scenarios to determine the maximum probable transfer capability from Wyoming to Arizona. Generation was added at Dave Johnston and Laramie River Station as appropriate and generation west of Phoenix at the Palo Verde/Hassayampa hub was reduced to accommodate the

transfers. The results of these studies demonstrated that the easterly and westerly single line routes had roughly equal transmission capacity of 1000 to 1500 MW. These limits were based on overloads to the regional system for loss of the 500kV line segments.

In New Mexico, limits on the underlying 115 kV transmission system occurred with addition of the alternatives prior to adding transfers from Wyoming. For the westerly route, the overloads occur on the Gladstone-Springer 115 kV line and the Belen to Elephant Butte 115 kV line. For the easterly route, overloads occur only on the Gladstone-Springer 115 kV line. The addition of the alternatives with a tie at Gladstone creates a strong source at Gladstone resulting in base flows on the 115 kV lines that are close to a limit. Flows exceed the limit for outages of 345 kV and project line segments south of Gladstone. System improvements, protective schemes, or operating procedures would need to be implemented to address these overloads for the single line alternatives.

Series compensation of 50% and 70% was explored on the single 500 kV line scenarios. In New Mexico the contingency overloads for on the Belen-Elephant Butte 115 kV line with the westerly route were eliminated and overloads of the Gladstone-Springer 115 kV were significantly reduced for both routing alternatives. The Gladstone-Springer 115 kV loading reached 125% of rating for the worst single contingency with a transfer of 2000 MW and 70% series compensation.

2. **Results: Two Single-Circuit 500kV lines**
For the two single circuit studies, the two 500 kV lines on the eastern and western corridors were added to the model. Generation was added in equal amounts at Dave Johnston and Laramie River Station while generation was again reduced in Arizona at the Palo Verde/Hassayampa hub to accommodate the scheduled power transfers. The study results indicated that the two uncompensated 500 kV lines have a combined transfer capability somewhere between 1500 and 2000 MW.

The two line system integrated reasonably well with the New Mexico system, however, overloads of the Gladstone-Springer 115 kV line were observed when transfers from Wyoming to Arizona were increased to 1000 MW or more. The overloads are well below those observed with the single line systems and could potentially be addressed through protective schemes or operating procedures.

3. **Results: Two Single Circuit 500 kV Lines with 70% Series Compensation**
The addition of series compensation increased the flow on the HPX lines and reduced contingency impacts on the underlying system. Series compensation studies were performed for the two-line cases adding 70%

series compensation to the High Plains Express lines. The results of this analysis indicate that two 500 kV lines series compensated to 70% can allow a transfer capability of between 3500 and 4000 MW level, one HPX line exhibited the potential for overloads for an outage of a parallel HPX line.

In New Mexico, transfers of 3000 MW were accommodated prior to seeing contingency overloads of the Gladstone-Springer 115 kV line. At transfers of 3500 MW, the loading reached 114% of rating with 70% compensation under the worst single contingency. This should be manageable through RAS schemes or operating procedures.

4. **Results: Renewable Generation Dispatch Scenarios**
After performing sensitivity studies to evaluate series compensation for these modeling scenarios, additional studies were undertaken to determine what, if any, impacts additional uploads and downloads along the High Plains Express route would have on the transfer capability of the project. The various dispatch scenarios described in *Table 3* were run and detailed results are provided in *Appendix A*. For the most part, the impact of these dispatch scenarios on the overall transfer capability of the High Plains Express was minimal. However, in the situations involving significant renewables dispatched in New Mexico along with high Wyoming to Arizona transfers, some potentially significant impacts were observed. Because the uploads in the New Mexico system occur upstream of the downloads (e.g., at Gladstone, Guadalupe, and Corona), this dispatch creates fairly significant flows on the High Plains Express facilities even when no transfers are scheduled between Wyoming and Arizona. When through-transfers are added on top of this flow, overloads occur at transfer levels lower than without these uploads and downloads. Further analysis will need to be done in later phases of the project development cycle to see what reinforcements might be needed to mitigate this impact.

The results in New Mexico were generally favorable. Improvements to address overloads of the Gladstone-Springer 115 kV line are likely needed for scenarios where significant resource amounts are injected at Gladstone. The worse case contingency at project injections of 4000 MW resulted in loadings of 135% of rating. Some 115 kV loadings in the Albuquerque area were identified for certain combinations of upload and download. These overloads were largely due to dispatch assumptions to accommodate the project uploads and are not directly tied to the HPX addition. Contingency overloads of HPX project elements were found when project uploads above 3500 MW or more were modeled. The highest project loadings (118% of rating) occurred on the Fort Craig to Corona 500 kV lines for a contingency of the parallel line.

5. **Two Double-Circuit 500kV lines with 70% Series Compensation**
A limited sensitivity analysis was performed to determine the transfer capability High Plains Express if each single circuit 500 kV line was replaced with a double circuit line. This analysis was performed using a case with 900 MW of renewable upload and download in New Mexico and 1800 MW of renewable upload and download in Colorado. Detailed results of this analysis are provided in *Appendix A*. The results of this sensitivity analysis indicated that two double-circuit 500kV transmission lines had the potential for 6500 to 7000 MW of transfer capability.

6. **EPTP Sensitivity Analysis**
This analysis looked at possible synergies between the High Plains Express project and the EPTP. There is a possibility that combining the two projects in certain areas where the two projects have parallel routes could result in acceptable system performance while reducing the overall cost and environmental impact of both projects.

The sensitivities examined looked at cases where the High Plains Express Big Sandy – Boone 500 kV line was removed and replaced with the Big Sandy – Midway – Boone 500 kV line that is proposed as part of the EPTP. In addition, the EPTP Burlington – Lamar 500 kV line was removed and the High Plains Express Lamar – Gladstone 500 kV line termination at Lamar was moved to the Energy Center 500 kV bus. These changes effectively removed approximately 80 miles of potentially duplicative transmission from the sensitivity cases.

The detailed results of this sensitivity analysis are provided in *Appendix A*. It appears that there is a potential for some synergies between these two projects. There are some additional contingencies that cause overloads in this sensitivity. However, there are no new facilities overloaded and the maximum loading on each facility does not increase. Additional analysis will still need to be done, but there appears to be a potential to combine some of the facilities of the High Plains Express and the EPTP.

F. Results and Recommendations

- A single 500 kV transmission alternative could provide only 100-1500 MW of transfer capability.
- Two 500 kV transmission lines showed the potential for up to 4000 MW of transfer capability. Based on the results of the analyses, this is the minimum configuration to support a reasonable portion of the planned resource development in the region.
- In order to achieve 4000 MW, the HPX lines would have to include series compensation. Studies showed that 70% could be a level that would warrant further analysis.
- Two double-circuit 500 kV lines could provide up to 8000 MW of transfer capability.

- Based on the results, 345 kV transmission, would not be adequate to accommodate the long-term demands of the region. To improve initial economic performance as the HPX project develops; it may be necessary to initially operate segments or the HPX project at 345 kV.
- Separate transmission corridors are recommended to allow the interconnection of the dispersed resources proposed for development throughout the region and to provide for better transmission system reliability.

V. Cost Estimates

For the purpose of this analysis, estimates were developed based on several recent transmission studies (Frontier Line, Rocky Mountain Area Transmission Study). Those studies also focused on the feasibility of long-distance high voltage transmission lines. Consideration of these studies, updated with more recent information from the HPX participants, resulted in the cost assumptions noted below, which drove the overall estimate of HPX costs:

- Design and construction costs/mile on new Right-of-Way – for 500-kV = $1.5 million/mile
- New substation and upgrade requirements – new 500/230-kV substation = $60 million; upgrades = $8 million
- Series compensation costs - $20/kVAr – 3000 amp, 39 ohms per 100-mile line section – installed 35% at each end.
- Dynamic voltage requirements (Static VAr Compensators) – one per state - $35 million per location

The HPX Study overall costs:

- Two separate 500 kV AC lines
- $1.5 Mil/mile for 1,280 miles x 2 = $3.84 billion
- Substations (10 new/5 upgraded): $640 million
- Series Compensation: $512 million
- SVC: $140 million
- **Total Costs: $5.13 billion**

VI. Preliminary Routing

Preliminary routing for the High Plains Express project was performed to develop an estimate of the line lengths to use in calculating the transmission line parameters for the power flow analysis and to connect known renewable resource areas with load centers. In developing this routing, parallel transmission lines were considered where feasible and new rights-of-way (ROWs) were assumed where needed for reliability. This preliminary routing was performed using the following steps.

1. Gather non-confidential public information to determine the locations of potentially sensitive areas. Data was gathered primarily from the Geographic Information System (GIS) that was used to develop the map shown in *Figure ES-1*. Examples of the non-confidential public information used are:
   - Federal Lands,
   - Hydrology Features (rivers, streams, lakes),
   - Transportation Features,
   - State boundaries,
   - County boundaries, and
   - Cities.

2. In addition to non-confidential information, some confidential transmission data (CEII[7]) was used. This data was used primarily to locate the interconnection points between the High Plains Express project and the existing transmission grid. Examples of the confidential information used and the entity contributing it are:
   - SRP - Select Arizona transmission features (Substations, Transmission Lines) and Hydrology Features (rivers, streams, lakes),
   - PNM - New Mexico Substations and Transmission Lines,
   - Tri-State GT - Select WY, CO, NM substations and transmission lines as well as EPTP information, and
   - WAPA hard copy mapping data (which was used for reference purposes).

Once the above data had been collected, preliminary routes were then selected. Once these preliminary routes were established, the project study team was requested to help locate any additional sensitive area that might have been missed on the first draft. Based on input from the study team, the following additional areas were designated for avoidance:

- DOD Maneuver Area in Colorado,
- Santa Fe Trail, and
- BIA Lands.

The routes used for the technical studies documented in this report are shown in *Figure ES-1*.

[7] Critical Energy Infrastructure Information

VII. Economic Evaluation

The High Plains Express initiative is a concept for expanding markets for renewable energy, strengthening the region's transmission system, and providing economic benefits to the states of Wyoming, Colorado, New Mexico, and Arizona, including savings in power costs for customers in those states. Seven utilities, three state agencies, and an independent transmission company, have joined in this effort to consider the technical and economic aspects of the project's development.[8] The results of initial feasibility studies are presented below.

The HPX concept is to develop a high-capacity interconnected AC transmission project that would connect at substations within the states of Wyoming, Colorado, New Mexico, and Arizona (*Figure ES-1*). While several configurations were studied, the primary alternative evaluated herein consists of two 500 kV lines with a combined capacity of 3,500 MW that would materially expand the transmission linkages between the four HPX states. This system would provide power upload/download opportunities within each HPX state. It is contemplated that the primary power flows would be from northeast to southwest, although power flows in the reverse direction may also occur (but were not studied).

A preliminary assessment of the economic feasibility of the HPX project was conducted to get an indication as to whether the project is cost-effective. This was determined via a Benefit/Cost analysis in which the delivered cost of power including HPX transmission line costs was compared against the delivered cost of power not involving HPX. This determination was made using a newly-created screening tool developed by PG&E and the stakeholders to the Frontier Line feasibility assessment: FEAST (Frontier Economic Analysis Screening Tool). As described in the April 2007 Frontier Line Economic Analysis Subcommittee report (www.ftloutreach.com):

"FEAST is a simple tool for sophisticated users. It focuses on incremental resources, not a complete supply stack, and facilitates quantification of regional cost differences. FEAST is a screening tool, and is not intended as a substitute for necessary, in-depth analysis using production costing and/or market simulation tools."

A. Assumptions

A large number of input assumptions are used in the FEAST model. Since many of these are generic assumptions applicable throughout the West that were thoroughly vetted by the Frontier Line stakeholders, they have been used herein without modification, with the sole exception of resource capital costs which were adjusted to current values[9]. However, new input assumptions had to be devised for the HPX initiative to reflect the specific aspects of HPX and

[8] Colorado Springs Utilities, Platte River Power Authority, Public Service of New Mexico (PNM), Salt River Project, Trans-Elect, Tri-State G&T, Western Area Power Administration (Western), Xcel Energy, Colorado Clean Energy Development Authority (CEDA), New Mexico Dept. of Energy, Minerals & Natural Resources (NM-EMNR), and the Wyoming Infrastructure Authority (WIA)

[9] The Frontier Line used 2015 projected capital costs for resources that are 35% less than current costs.

the unique operating characteristics of the wind resources from the HPX states (*Table 6*). The wind assumptions used were based on NREL projections of wind performance, as follows:

- Wyoming: 48% capacity factor, 39% dependability (summer peak)[10]
- Colorado: 42% capacity factor, 28% dependability (summer peak)
- New Mexico: 40% capacity factor, 36% dependability (summer peak)
- Arizona: 30% capacity factor, 45% dependability (summer peak)

***Table 6*—FEAST Input Assumptions (Bus-Bar)**

	RESOURCE CHARACTERISTICS & COSTS								LEVELIZED COST	
Plant Type	Heat-Rate BTU/kWh	Capacity Factor	Depend. Capacity Factor	Installed Cost $/kW	Fixed O&M* $/kW-Yr	Other Fixed* $/kW-Yr	Total $/kW-Yr	Variable O&M* $/MWh	Merchant Financing $/MWh	Utility Financing $/MWh
Coal - Arizona	8,860	85%	100%	2,633	47.2	109.8	400	1.7	75.5	68.0
Coal - Colorado	9,870	85%	100%	2,498	46.8	87.6	365	1.9	60.4	54.1
Coal - New Mexico	8,860	85%	100%	2,633	47.2	109.8	400	1.7	68.3	60.7
Coal - Wyoming	9,870	85%	100%	2,498	46.8	87.6	365	1.9	54.0	47.6
Gas - Combined Cycle	6,920	78%	100%	1,350	13.7	52.9	205	2.4	80.7	76.8
Solar Concentrating	NA	40%	100%	4,253	38.0	101.3	580	1.5	165.5	138.3
Wind - Arizona	NA	30%	45%	1,755	11.5	9.5	200	5.5	87.5	77.5
Wind - Colorado	NA	42%	28%	1,755	11.5	7.2	198	5.5	59.3	52.7
Wind - New Mexico	NA	40%	36%	1,755	11.5	7.2	198	5.5	62.0	55.1
Wind - Wyoming	NA	48%	39%	1,755	11.5	7.2	198	5.5	52.6	46.8

Input Cell Calculation Cell

HPX transmission costs and line losses were supplied by the HPX study team based on input from the HPX utility participants, input from consultants, and assumptions developed in the Frontier Line studies. The configuration selected for economic feasibility analysis consisted of two 500 kV lines with a combined capacity of 3,500 MW. The estimated installed cost of this configuration is $5.132 billion. The breakdown of these costs for the segments linking each HPX state and associated estimated transmission tariffs (assuming utility financing) are presented in *Table 7*.

***Table 7*—HPX Transmission Components ($2007)**

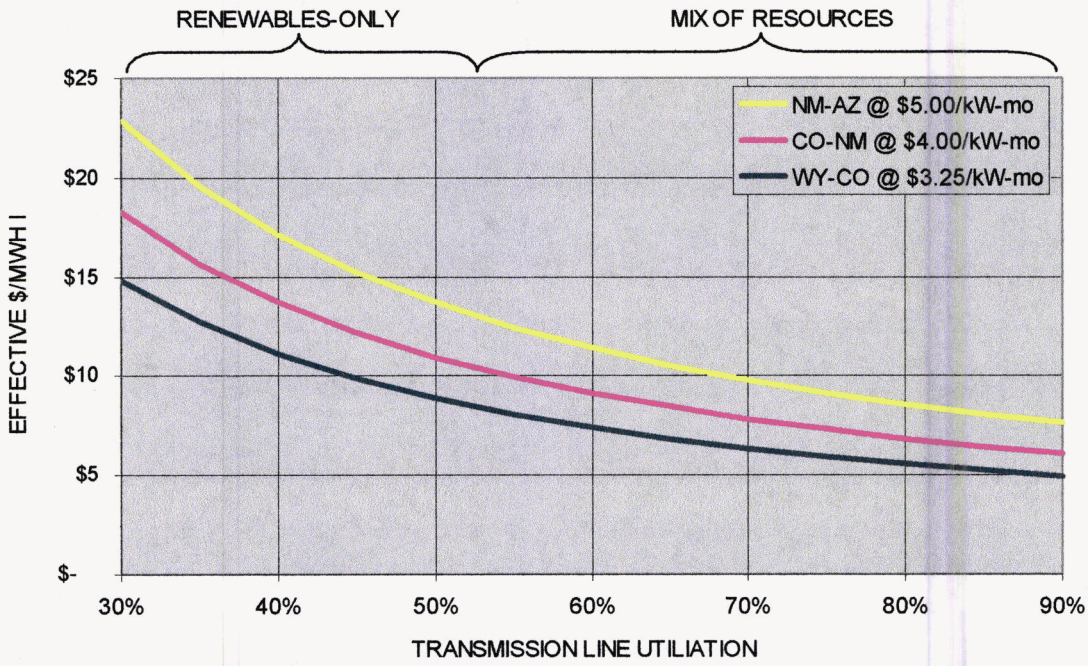
Segment	Ave. Miles	Cost ($MM)	Line Losses	Indicative Transmission Rates		
				$/kw-mo	$/MWh @ 40% Use	$/MWh @ 80% Use
Wyoming - Colorado	335	$1,366	2.4%	$3.21	$10.99	$5.50
Colorado - New Mexico	420	$1,680	3.1%	$3.94	$13.49	$6.75
New Mexico - Arizona	525	$2,087	3.8%	$4.90	$16.78	$8.39

[10] These Wyoming wind values were also used in the Frontier Line studies

B. Resource Delivery Costs

As an intermediate step before conducting the Benefit/Cost analysis for various resource mix scenarios, projections of delivered power prices were developed for each resource considered: pulverized coal, combined cycle gas, wind, and solar. These projections included the all-in generation cost (including a return) for each resource, plus an applicable transmission charge that assumed a 75% line utilization level. While such a utilization level (and associated effective $/MWh rates) would not be achieved by the renewable resources alone, it does provide an indication of HPX's effective rates if it were operated as an integrated transmission project that accommodates a mix of resources *(Figure 7)*. In the case of local resources (i.e., not delivered via HPX), no transmission charges were applied, although they may be involved.

***Figure* 7: Indicative HPX Segment Transmission Rates vs. Line Utilization**



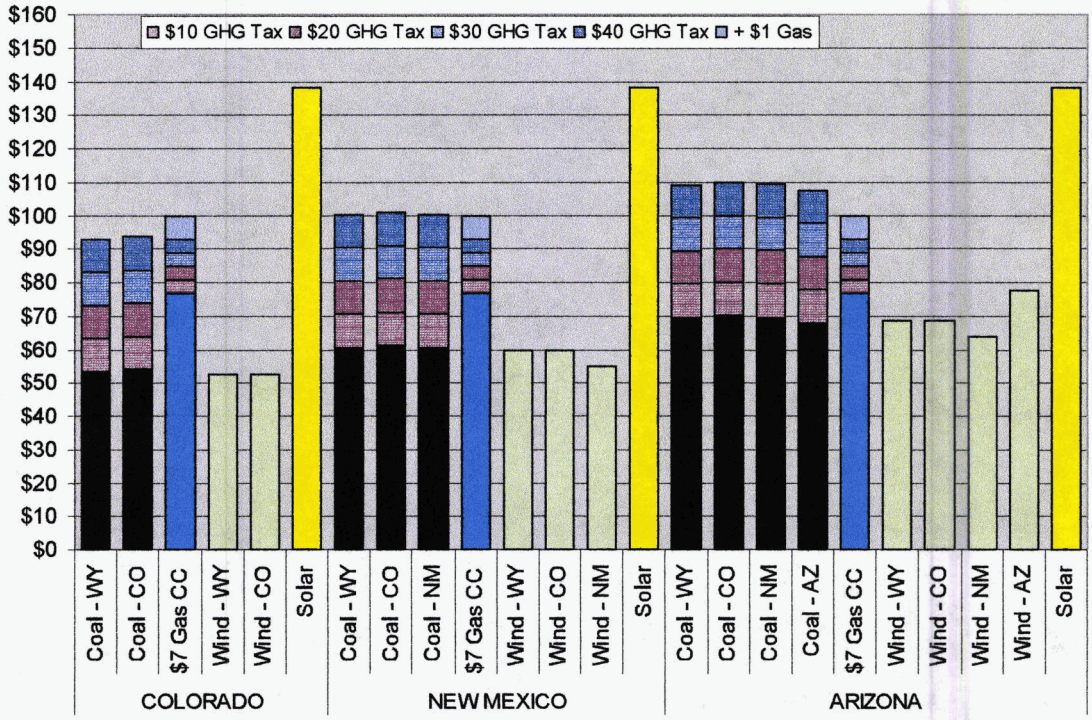
Projections were made for power delivered via HPX and compared against the projections for in-state resources (*Figure 8*). Subsidies currently available to the solar and wind industries[11] were not incorporated in the analysis, as those subsidies may change or be eliminated by HPX's proposed on-line date of 2017. In addition, the effect of varying "CO_2 tax" scenarios where modeled

[11] A Production Tax Credit (PTC) of $20/MWh is currently available to the wind industry (expiring in 2008), while the solar industry currently enjoys a 10% investment tax credit and accelerated depreciation over 5 years.

for the carbon-emitting resources (coal and gas) in $10/ton increments from $10/ton to $40/ton (*Figure 8*). The cost of integrating wind was not included in this part of the assessment, although a $3/MWh charge was applied in the FEAST Benefit/Cost analysis.

Assuming a 75% HPX utilization level, the results generally indicate that wind and coal are the lowest cost resources for each HPX state and that the delivered power costs gradually increase with proximity from Wyoming – regardless of whether they are supplied from in-state resources or delivered via HPX. However, the application of CO_2 taxes to the fossil resources materially tips the balance towards wind, with coal[12] affected more significantly than gas ($9.90/MWh and $4.00/MWh, respectively, for each $10/ton increment of CO_2 tax). Solar is the highest cost resource in all HPX states.

***Figure 8*: Estimated Resource Delivery Costs (75% transmission utilization) - $/MWh**



With regard to deliveries of wind, New Mexico wind offers the lowest delivered prices in both New Mexico and in Arizona, and Wyoming and Colorado wind offer similar delivered prices in each HPX delivery state (although higher than New Mexico wind for deliveries into New Mexico and Arizona). For coal, there don't appear to be any material differences in the delivered cost of coal within individual HPX states, whether it is delivered via

[12] Though not modeled herein, carbon separation and sequestration would materially reduce coal's CO_2 emissions and result in a $1.50/MWh penalty for each $10/ton increment of CO_2 tax.

HPX or is burned locally. For gas, only locally sited gas at $7/mmBtu was considered in this projection, with the effect of a $1/mmBtu change in gas prices also shown.

C. Scenarios & Modeling Approach

The six scenarios identified for FEAST modeling took into account both traditional and newly-emerging public policy agendas focused on fossil-based resources and renewable-based resources, respectively. As such, three renewable-dominated scenarios were developed and the results compared against two fossil-dominated scenarios and one "balanced" scenario involving near-equal amounts of energy from both resource categories.

In all of these cases, with the exception of the renewables-only scenario, HPX was modeled to meet the load requirements profile and achieve an average 75% utilization level. While this is readily achievable with fossil resources, which are "dispatchable" (coal and gas), it is a much greater challenge when material amounts of "non-dispatchable" renewable resources (wind and solar) are involved. Two of the renewable-dominated scenarios approached this problem by fist dispatching the HPX line's full capacity with renewables, and backfilling/firming with fossil resources in order to meet load requirements when renewable energy isn't available (the "renewables-first" scenarios). Such an approach is likely to involve many operational and economic challenges.

The use of FEAST to determine Benefit/Cost ratios involved the comparison of delivered power costs for a mix of resources delivered by HPX (including the cost of HPX) in comparison to a resource mix from in-state sources for each of the HPX states (i.e., a source vs. sink comparison). Sensitivity analyses were conducted for varying levels of CO_2 taxes ranging from $0/ton to $40/ton. Positive B/C ratios indicate that the benefits exceed the costs and HPX project feasibility. The six HPX source vs. sink scenarios evaluated herein are as follows:

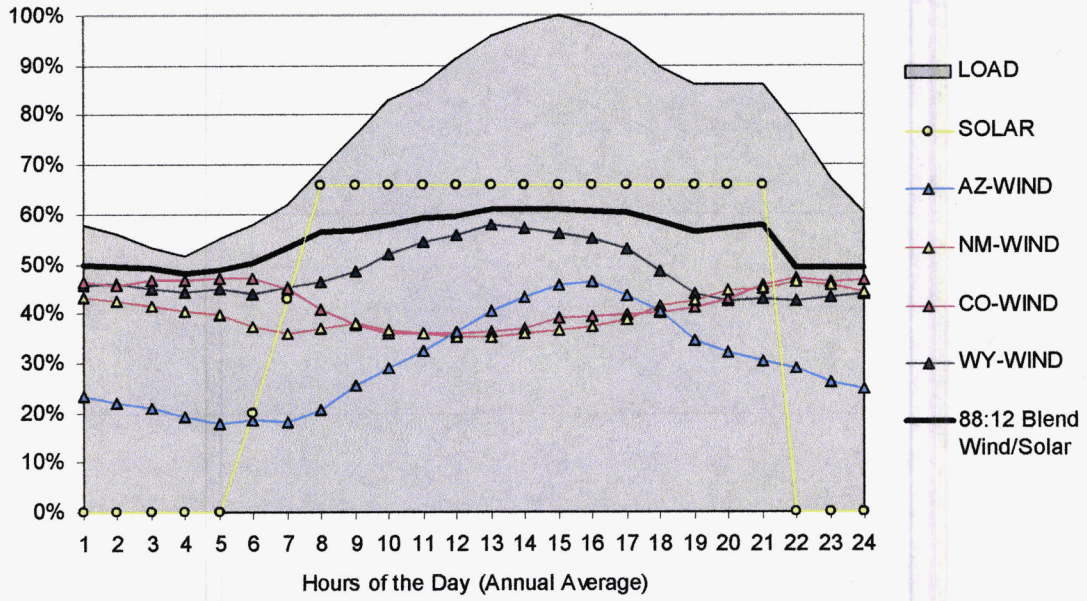
1. Renewables Only vs. Fossil (50:50 Coal/Gas at Sink)
2. Renewables-First vs. Gas at Sink
3. Renewables-First vs. Fossil (50:50) + 20% Renewables at Sink
4. Coal + Renewables Firmed with Gas vs. Gas at Sink
5. Fossil (50:50 Coal/Gas) vs. Fossil (50:50) + 20% Renewables at Sink
6. Balanced (50:50 Fossil/Renewables) vs. Gas at Sink

All of the renewable scenarios involved the blending of renewable resources to take advantage of geographic diversity and matching up wind with solar during daylight hours when wind performance commonly drops off. This involved blending 500 MW of solar (including a short-term storage component) with wind from multiple sites within all of the "upstream" HPX

states in which the wind component was "overbuilt" by 10%.[13] Such an approach yields an 88:12 wind/solar blend and is expected to reduce the intermittence of renewable resource and the amounts of dispatchable fossil resources needed to meet load requirements. The results of this approach are illustrated on an hourly and monthly basis in *Figures 9 and 10*, respectively.[14]

The hourly plot (*Figure 9*) would indicate that an 88:12 wind/solar blend will provide more power during the daylight peaking hours than the off-peak hours, thereby minimizing the amount of dispatchable fossil resources needed to meet load requirements. However, the monthly plot (*Figure 10*) suggests that there will be major shortfalls in renewable energy during the summer months that will have to be supplemented with significant amounts of dispatchable fossil resources to meet load requirements. This situation is illustrated by actual data from a 200 MW wind farm in New Mexico where there is a major mismatch between the wind farm's performance and Public Service of New Mexico's load requirements (*Figure 11*).

Figure 9: **Hourly Wind & Solar Performance vs. Load Requirement**



[13] This approach involves building more wind generation capacity than is available on a transmission line and results in higher transmission utilization and lower effective transmission rates, with any excess wind distributed via non-firm transmission paths on connected underlying transmission systems.

[14] Arizona's wind is not included in the solar/wind blend and is shown only for illustrative purposes. All wind projections are from NREL modeled for a 1.5 MW GE turbine at a 70 meter hub height.

Figure 10: **Monthly Wind & Solar Performance vs. Load Requirement**

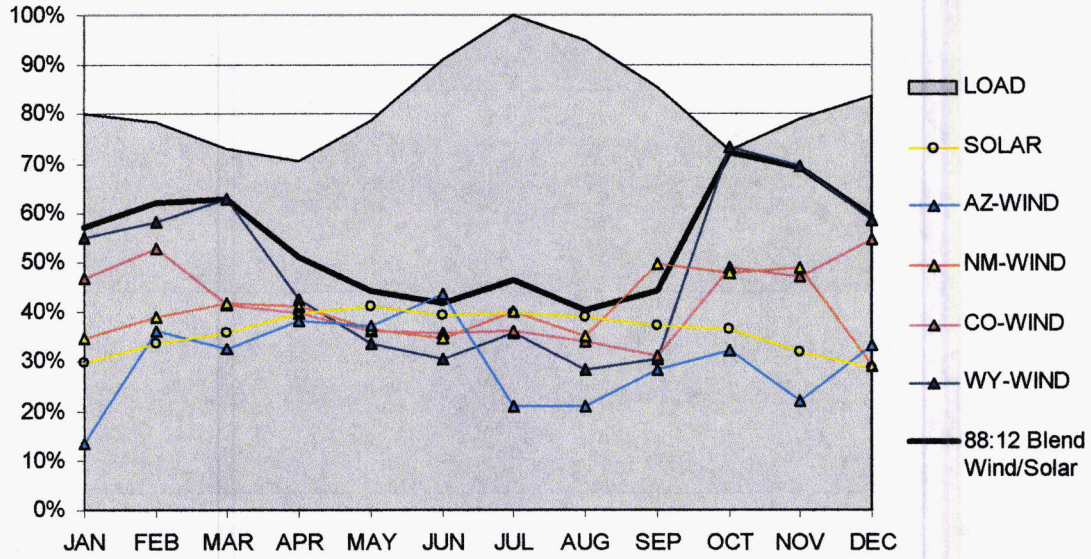
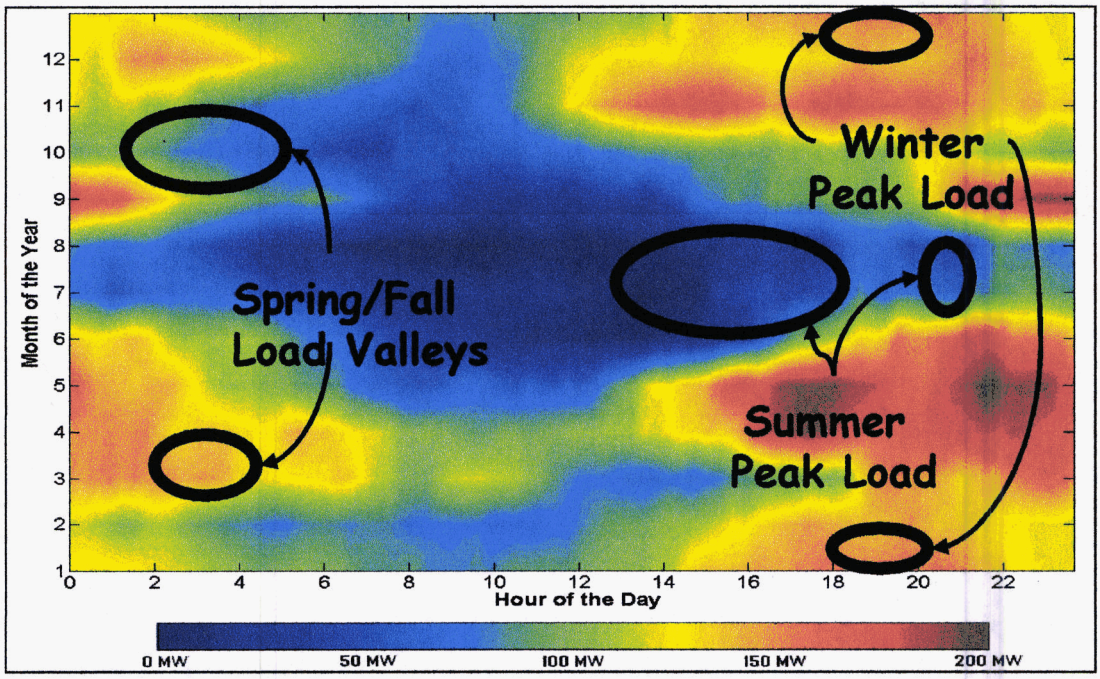


Figure 11: **Performance of a 200 MW New Mexico Wind Farm vs. PNM Load**



D. Results

The results of the FEAST Benefit/Cost analyses for the six scenarios modeled are summarized in *Table 8*, along with the savings/costs that would accrue to

customers on an annual and $/MWh basis. Also listed are the resulting transmission line utilization levels and HPX resource mixes (energy basis) for each scenario. The two renewable-first scenarios yield a 75:25 energy mix for renewables/fossil generation. The scenarios that involve a mix of renewable and fossil resources yields a 75% utilization level for HPX, while the renewable-only scenario in which overbuilt wind supplemented with solar yields a 56% HPX utilization level.

The sensitivity analysis of CO_2 taxes indicates that the renewable-dominated scenarios perform progressively better at higher CO_2 taxes, while the reverse is true for the fossil-dominated scenarios (*Figure 12*). The balanced scenario appears to be the least affected by differences in CO_2 taxes and provides the most consistently positive B/C ratios of all scenarios considered. At low CO_2 taxes, the renewable-dominated scenarios do not perform well. The fossil-only scenario does not provide positive B/C ratios for any CO_2 tax scenario.

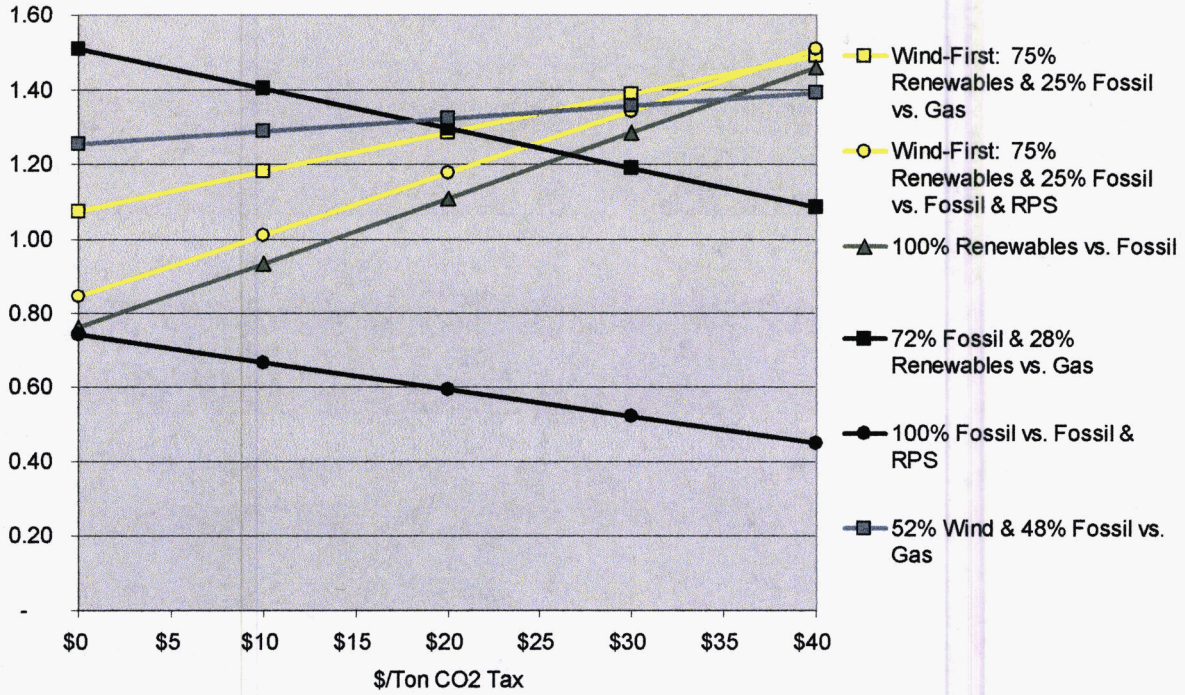
The B/C results would indicate that HPX would provide economic benefits to customers in the HPX states over a variety of resource mixes and CO_2 tax scenarios, with the sole exception of a fossil-only scenario. As such, HPX's economic feasibility appears to be sufficiently positive and consistent with emerging public policy to warrant further investigations, thereby justifying the advancement of the HPX initiative to Stage II feasibility studies.

Table 8—HPX Benefit/Cost Analyses Results

			HPX FEASIBILITY				HPX ENERGY MIX			
SOURCE	SINK	GHG	B/C	$MM/YR	$/MWH	UTLZ	WIND	SOLAR	COAL	GAS
RENEWABLES-ONLY	DISPATCHABLES (COAL/GAS)	$10	0.94	($32)	($1.87)	56%	90%	10%	-	-
		$20	1.11	$56	$3.21	56%	90%	10%	-	-
		$30	1.28	$144	$8.30	56%	90%	10%	-	-
		$40	1.46	$232	$13.36	56%	90%	10%	-	-
RENEWABLES-FIRST FIRMED WITH COAL & GAS	GAS	$10	1.18	$91	$3.97	75%	67%	8%	13%	12%
		$20	1.28	$144	$6.25	75%	67%	8%	13%	12%
		$30	1.39	$196	$8.52	75%	67%	8%	13%	12%
		$40	1.49	$248	$10.79	75%	67%	8%	13%	12%
RENEWABLES-FIRST FIRMED WITH COAL & GAS	DISPATCHABLES + 20% RPS	$10	1.01	$5	$0.24	75%	67%	8%	13%	12%
		$20	1.18	$90	$3.89	75%	67%	8%	13%	12%
		$30	1.34	$174	$7.55	75%	67%	8%	13%	12%
		$40	1.51	$258	$11.21	75%	67%	8%	13%	12%
COAL + RENEWABLES FIRMED WITH GAS	GAS	$10	1.40	$204	$8.86	75%	28%	-	61%	11%
		$20	1.30	$150	$6.53	75%	28%	-	61%	11%
		$30	1.19	$97	$4.20	75%	28%	-	61%	11%
		$40	1.09	$43	$1.88	75%	28%	-	61%	11%
50:50 RENEWABLES & DISPATCHABLES	GAS	$10	1.29	$146	$6.38	75%	52%	-	25%	23%
		$20	1.32	$163	$7.12	75%	52%	-	25%	23%
		$30	1.36	$180	$7.85	75%	52%	-	25%	23%
		$40	1.39	$197	$8.59	75%	52%	-	25%	23%
DISPATCHABLES-ONLY (COAL/GAS)	DISPATCHABLES + 20% RPS	$10	0.67	($169)	($7.33)	75%	-	-	52%	48%
		$20	0.59	($205)	($8.93)	75%	-	-	52%	48%
		$30	0.52	($242)	($10.53)	75%	-	-	52%	48%
		$40	0.45	($279)	($12.13)	75%	-	-	52%	48%

B/C <1 | 1.0 - 1.2 | 1.2 - 1.4 | > 1.4

Figure 12: HPX Benefit/Cost Analyses Results



STAKEHOLDER QUESTIONS AND RESPONSES

Q1. What is the planned generation resource mix for HPX?

- HPX is planned to enable renewable and other economic resource development.
- Dispatchable resources are needed to maximize transmission utilization to firm renewables.
- *Studies indicate that economics (B/C ratios) are most favorable with* renewable/fossil resource mix.
- Fossil only and Renewable-only scenarios were the least favorable.

Q2. Will solar power be a part of the HPX resource mix?

- At this time, solar is more expensive than wind resources. However, its availability during the times when wind generally isn't available supported its inclusion into HPX's resource mix for economic evaluation.
- The general route for HPX does not pass through solar regions in Colorado, but does in New Mexico. Transmission to accommodate Colorado solar will continue to be evaluated through SB07-100 studies.

Q3. Why is HPX needed?

- To meet a portion of the expanding energy needs in the region.
- To provide a cost-effective "pipeline" to access & deliver economic energy throughout the region.
- To expand markets for renewable power resources.
- To improve the reliability of the transmission grid.

Q4. Will the State Regulatory Authorities be asked to assist with rate recovery for HPX?

- To the extent that HPX serves/benefits native load.
- There will be merchant components, particularly for exports in excess of resources displaced by imports, which may require public policy support.

Q5. What is the role of State Transmission Authorities?

- Integral in planning and in public policy development and support.
- Potential role in cost recovery support.
- Potential source of low-cost financing backed by bonds.

Q6. Have routes been selected?

- Routes have NOT been selected – a process that will involve extensive public input prior to and during permitting activities. To date, only conceptual routing has been considered, which has been focused on intersecting major renewable resource zones within each affected state.

Q7. Will you consider avoidance of Military Training Facilities?

- HPX will seek input from the Military, as such activities are prevalent along potential HPX routes

Q8. Are you aware of sensitive habitat for species such as the Lesser Prairie Chicken in SE Colorado?

- Wildlife and vegetation habitat will be mapped and HPX routes devised to mitigate and avoid impacts
- Western Resource Advocates & WGA recently sponsored a *wildlife/transmission planning workshop to coordinate activities*

Q9. Is HPX competing with other sub-regional transmission plans?

- No. Participants in other sub-regional projects have indicated that the individual projects can be considered as "building blocks" of the HPX project. Although each project may be developed independently, coordination would be addressed through existing regional and sub-regional planning processes.

Q10. How will HPX interact with projects such as the TransWest Project?

- Although the Feasibility Study did not include TransWest or other "mega" projects, we expect that HPX will be complimentary.
- *As each of these projects matures, interactions will be studied in more detail.* WECC and other processes require such studies.

Q11. Will HPX compete with and/or preclude the development of in-state resources?

- HPX is likely to provide only a portion of each state's energy needs, thereby leaving much to be supplied from in-state sources.
- HPX could enable the development of import/export markets for renewables, which don't currently exist, thereby expanding markets for renewables.
- To some extent, HPX may facilitate the displacement of in-state fossil fuel development with renewables, although those resources will be needed to "firm" wind.

Q12. To what extent are there benefits for each HPX state?

- Wyoming: Exports of wind and associated economic development
- Colorado: Reduced power costs, blending with imported wind & downstream exports
- New Mexico: Reduced power costs, blending with imported wind & downstream exports
- Arizona: Reduced power costs and blending with imported wind

Q13. Did you consider DC Alternatives?

- While DC transmission lines may be cheaper, it is very difficult to identify benefits for parties/states along a DC line that wouldn't have access to power carried on the line, unless expensive converters were installed
- DC does little to improve reliability to the region's transmission grid

Q14. To what extent has generator tripping been considered in HPX planning?

- The intent has been to design a project that will not require generation tripping for most contingency conditions.

Q15. Did you consider 765 kV?

- Comment that Transwest studies indicated that for a cost increase of 25% could double capacity.
- There are no 765kV lines in WECC.
- Siting/Routing Issues
- *Costs are disputed, since HPX is looking at many more interconnection points.*
- Conclusion: Not a good technical alternative. Better chance of success with Double-circuit 500kV.

Q16. Why was solar upload not considered in Arizona?

- We recognize the potential for solar development in Arizona, but our focus was delivering power to Arizona.
- We did consider a significant amount of solar power in the resource mix for economic studies (10%).

Q17. In the Economic Studies, was the GHG adder in terms of metric tons or carbon equivalence (Steve Brown – PUC)?

- Not sure, but most likely metric tons of CO2.

Q18. Production cost credit carried though all years of study? (Ron Lehr – AWEA)

- Yes, it is planned to be gone in 2015, but may be renewed.

Q19. Did you make any assumptions regarding (fossil fuel) unit retirements? (Ron Lehr)

- No.

Q20. You should not assume that 2 500kV lines would increase the reliability of the system. (Inez Dominguez – CPUC)

- *Studies performed using NERC/WECC criteria.*
- If transfer capability is increased without impacting performance, reliability is improved.
- Jeff Mechenbier addressed Inez' comment later.

Q21. Did you consider that the cost of coal might increase over time? (Glustrom)

- Not for these studies.
- We also recognize that the cost of solar may decrease.
- Both of those factors would increase B/C of HPX.

Q22. You should call "dispatchable" resources "fossil fuel" resources. (Leslie Glustrom)

Q23. Can you assume that existing peaking plants would be used to firm the renewable (to increase the utilization) if they are already being used (to meet local load requirements)? (Craig Cox)

- Possible in some areas.

Q24. Have you involved all of the appropriate parties? Seems like potential purchasers are missing, including APS, SCE. (Doug Larson)

- APS and other entities have participated in the Studies Team.
- Will need to address additional participation in subsequent phases.

Q25. *Will you post the slides?*

- Yes

Q26. Have you studied interactions with Transwest?

- Not at this phase.
- Will address as projects become more defined.
- WECC processes.

➢ Please come to Baca County. We have the best wind in Colorado. (Peter Dawson – Commissioner in Baca County)

➢ Comment regarding military operations in Wyoming and Colorado.

  ➢ Addressed earlier.

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-02

Western Regional Transmission Expansion Partnership
Economic Analysis Subcommittee

Benefit-Cost Analysis of Frontier Line Possibilities

Final Report

27 April 2007

Note for printing: This report has a number of color figures.

Summary

The Economic Analysis Subcommittee was charged with building on the work of the Loads and Resources and Transmission subcommittees to perform an economic analysis of the feasibility of the list of possible new transmission, with particular emphasis on those items in the list that related to transmission lines between Wyoming, Utah, Nevada and California.

To effectively perform the feasibility study, the Economic Analysis Subcommittee sought a tool to quickly quantity benefits and costs for a multitude of possible conditions and scenarios. These possibilities included: a variety of load and resource scenarios created by the Load and Resources Subcommittee, as well as other potential resource scenarios; a myriad of conceptual transmission links and configurations identified by the Transmission Subcommittee; a wide range of natural gas prices and possible costs for new clean coal technology, including integrated gasification combined cycle (IGCC) and carbon dioxide (CO_2) sequestration; and a broad spectrum of potential policy actions such as regional and/or national renewable portfolio standards, state and federal tax incentives for preferred resources such as wind or solar or clean coal, and regulatory regimes on greenhouse gas emissions, whether regional and/or national and/or international.

The Economic Analysis Subcommittee also desired that the tool promote transparency and facilitate leveraging pre-existing work, both in the public domain and proprietary.

To meet these needs, the Economic Analysis Subcommittee designed and constructed a unique analytical tool, the Frontier Economic Analysis Screening Tool (FEAST). FEAST is a simple tool for sophisticated users. It focuses on incremental resources, not a complete supply stack, and facilitates quantification of regional cost differences. FEAST is a screening tool, and is not intended as a substitute for necessary, in-depth analysis using production costing and/or market simulation tools.

The Economic Analysis Subcommittee performed benefit-cost analysis on the overall Frontier Line. An important aspect to the feasibility of the Frontier Line is whether, for each individual state and not just collectively for the region, benefits are greater than costs. Designing cost allocation mechanisms to achieve this was outside the scope of this feasibility study.

The Economic Analysis Subcommittee developed a reference set of inputs to FEAST. For key drivers such as natural gas price, greenhouse gas (GHG) adder, and capital cost for clean coal technologies, the reference set also includes ranges of plausible values.

The Economic Analysis Subcommittee performed its work using a participatory stakeholder process. Wide participation in the Subcommittee was sought. Volunteers led the effort to create the reference set of FEAST inputs. Individual Subcommittee

members were encouraged to perform their own analysis, and enabled with the tools to do so. The Subcommittee conducted its work through regular collaborative meetings as well as frequent discussions via e-mail and telephone among its members.

The Subcommittee's two most important findings are:

1) The benefits of the Frontier Line appear greater than the costs under a variety of plausible conditions.
2) Uncertainty associated with key inputs results in a wide range of benefit-cost outcomes.
    a. Economics of the Frontier Line are very sensitive to natural gas prices. Higher natural gas prices favor the development of the Frontier Line.
    b. Economics of the Frontier Line are sensitive to values for GHG adder. Higher values for GHG adder favor the development of the Frontier Line.
    c. Economics of the Frontier Line are somewhat sensitive to capital costs for clean coal technologies, including IGCC and CO_2 sequestration. Lower capital costs for these technologies favor the development of the Frontier Line.

List of Tables and Figures

Table 1 - Benefits of the Frontier Line 6
Table 2 - Release Versions of FEAST 8
Table 3 - Regional Wind Capacity Factors 15
Table 4 - Wind Dependable Capacity 16
Table 5 - Wind Capital and Operating Costs 16
Table 6 - CSP Costs and Capacity Factor 17
Table 7 - CSP Dependable Capacity 17
Table 8 - Geothermal Costs and Capacity Factor 18
Table 9 - Biomass Costs, Capacity Factor, and Emissions 18
Table 10 - Coal Fuel Costs 20
Table 11 - Coal Plant Costs and Performance 20
Table 12 - Combined Cycle (CC) Costs and Performance 23
Table 13 - Combustion Turbine (CT) Costs and Performance 24
Table 14 - Results for Four Cases 31
Table 15 - Sensitivity to CC Capacity Factor 37

Figure 1 - Accumulating Gross Benefits 9
Figure 2 - FEAST Output Table 13
Figure 3 - FEAST: B/C Break-even Curve 14
Figure 4 - Western US Coal Plants and Coal Fields 21
Figure 5 - Long-Term Natural Gas Price Forecasts 22
Figure 6 - Case 1 Results 32
Figure 7 - Case 2 Results 33
Figure 8 - Case 3 Results 34
Figure 9 - Case 4 Results 35
Figure 10 - Case 1: Sensitivity to Natural Gas Price 38
Figure 11 - Case 2: Sensitivity to Natural Gas Price 38
Figure 12 - Case 2: Sensitivity to GHG Adder 39
Figure 13 - Case 2: Sensitivity to Cost of Clean Coal and CO2 Sequestration 39
Figure 14 - B/C Ratios for Various Transmission Configurations 41

Introduction

The Western Regional Transmission Expansion Partnership (WRTEP) is interested in determining the feasibility of constructing the Frontier Line. To this end, WRTEP initiated a Frontier Line Feasibility Study, established a Steering Committee to oversee the feasibility study, and created three Subcommittees to perform analyses for the feasibility study. This report discusses the work performed by the Economic Analysis Subcommittee.

The Economic Analysis Subcommittee was charged with building on the work of the Loads and Resources and Transmission subcommittees to perform an economic analysis of the feasibility of the list of possible new transmission, with particular emphasis on those items in the list that related to lines between Wyoming, Utah, Nevada and California.

The Economic Analysis Subcommittee focused its efforts on informing Steering Committee decision-making about feasibility. The Economic Analysis Subcommittee strived to identify possible conditions under which the Frontier Line would have benefits substantially greater than costs; possible conditions under which the Frontier Line would have benefits substantially less than costs; and possible conditions under which the Frontier Line would have benefits roughly comparable to costs. The Economic Analysis Subcommittee also strived to assess the sensitivity of benefits and costs to key assumptions.

To meet these needs, the Economic Analysis Subcommittee designed and constructed a unique analytical tool. The analytical underpinning of this tool, the Frontier Economic Analysis Screening Tool (FEAST), is described in this report. The structure of FEAST is briefly described in this report. FEAST is a simple tool for sophisticated users. A comprehensive description of the capabilities of FEAST, and FEAST itself, are not included in this report, but are work products of the Economic Analysis Subcommittee.

The Economic Analysis Subcommittee identified, collected, assessed, and synthesized data inputs to FEAST. Key drivers were identified, and special attention devoted to identifying the range of uncertainties associated with the key drivers. A reference set of FEAST inputs was determined. This report discusses FEAST inputs and the reference set. Detail is provided on costs and performance data for renewable resources, coal resources, gas-fired resources, and greenhouse gas adders.

The Economic Analysis Subcommittee performed a variety of analyses. Not all the analysis performed by the Economic Analysis Subcommittee is described in this report. This report presents analysis of four cases, which highlight the key findings of the Economic Analysis Subcommittee. ***The analysis and numerical results are presented on pages 26-41.***

The Economic Analysis Subcommittee performed its work using a participatory stakeholder process. The stakeholder process is described in this report. A list of the members of the Economic Analysis Subcommittee is included in Appendix A. A list of the activities of the Economic Analysis Subcommittee is included in Appendix B.

Process

The Economic Analysis Subcommittee was established by the Steering Committee on 16 May 2006. The initial members of the Economic Analysis Subcommittee were representatives from the footprint utilities, and also representatives from Arizona Public Service and Public Service of New Mexico. Todd Strauss of Pacific Gas and Electric Company (PG&E) became chair of the Economic Analysis Subcommittee on 9 June 2006.

At the first Stakeholder Meeting, in Las Vegas on 9 August 2006, Todd Strauss presented an initial framework for analysis. Stakeholders were invited to join the Economic Analysis Subcommittee. Fourteen individuals responded, indicating their interest in participating on the Economic Analysis Subcommittee. In September and October, several additional individuals indicated their interest in participating on the Economic Analysis Subcommittee.

At the second Stakeholder Meeting, in Salt Lake City on 2 November 2006, Todd Strauss described the proposed analytical methodology in more detail, including the notion of a spreadsheet-based tool for analysis. Again stakeholders were invited to join the Economic Analysis Subcommittee. By the end of November, membership on the Economic Analysis Subcommittee reached 39 individuals representing 33 organizations.

Weekly conference calls were instituted beginning 8 November 2006. Discussion quickly focused on three areas: inputs, outputs, and analytical tool.

The Economic Analysis Subcommittee reviewed the scenarios proposed by the Load and Resource (L&R) Subcommittee, and the conceptual transmission links and associated costs provided by the Transmission Subcommittee.

Individual members of the Economic Analysis Subcommittee volunteered to lead the assembling of key input areas. Dave Olsen of the Center for Energy Efficiency and Renewable Technologies (CEERT) volunteered to lead the assembling of inputs for renewable resources, including cost and capacity factors. Jerry Vaninetti of Trans-Elect volunteered to lead the assembling of inputs for coal prices and costs for coal-fired generating units (including integrated gasification combined-cycle (IGCC) and carbon dioxide (CO_2) sequestration, consistent with the orientation of the Frontier Line toward clean resources). Todd Strauss volunteered to lead the assembling of inputs for natural gas prices; Curt Hatton of PG&E later assumed leadership on assembling of inputs for natural gas prices inputs and costs for gas-fired generating units. Rich Lauckhart of

Global Energy Decisions volunteered to lead the assembling of inputs for greenhouse gas adders, associated with assigned costs for CO_2 emissions.

In weekly conference calls and via e-mail, the Economic Analysis Subcommittee identified the outputs required for effective analysis, and the plan for the analysis. The Economic Analysis Subcommittee discussed the merits of measuring inputs and outputs in various units, such as real or nominal dollars, levelized or initial year dollars. The Economic Analysis Subcommittee discussed the delivery time horizons to be analyzed, regional scope and resource mixes (incremental vs. average), and other technical aspects of the analysis. Darell Holmes of Southern California Edison led the effort to identify a multitude of possible benefits from the Frontier Line, and prioritize which benefits the Economic Analysis Subcommittee should focus on measuring.

PG&E led the development of the analytical tool, FEAST. A team led by Manho Yeung of PG&E worked to deliver a prototype shortly after the Thanksgiving holiday. (Hence the name Frontier Economic Analysis Screening Tool, or FEAST.)

The Economic Analysis Subcommittee met in San Francisco on 5 December 2006. Sixteen subcommittee members, representing 11 organizations, attended in person, with one additional subcommittee member attending via telephone. The Economic Analysis Subcommittee reviewed FEAST in detail, line by line of the spreadsheet. A variety of suggestions for tool development were discussed. The four volunteers leading assembling of input streams each presented their initial data for review.

PG&E continued to develop FEAST. Work continued on assembling inputs. Weekly conference calls were held, with a break for the end-of-year holidays. Members of the Economic Analysis Subcommittee continued to exchange e-mails discussing inputs and analysis.

The Economic Analysis Subcommittee met in San Francisco on 4 January 2007. Seventeen people, representing 11 organizations, attended in person, with one additional subcommittee member attending via telephone. Version 2.1 of FEAST was presented, and its capabilities discussed. Inputs were reviewed in detail. Manho Yeung presented three preliminary analyses performed by PG&E.

Economic Analysis Subcommittee members were invited to perform their own review of the inputs, and encouraged to compare the input data to their own proprietary information. Economic Analysis Subcommittee members were also invited to perform their own analyses of the Frontier Line using FEAST, and PG&E offered to assist Economic Analysis Subcommittee members in setting up and running FEAST for this purpose. A webinar was held on 10 January 2007 to increase understanding of FEAST, and capability in running FEAST, among the members of the Economic Analysis Subcommittee.

Weekly conference calls continued. Analyses performed by individual members of the Economic Analysis Subcommittee were circulated via e-mail and discussed. Meanwhile, a reference set of data inputs was being developed.

As results streamed in, members of the Economic Analysis Subcommittee began to focus on the implications of the results. Two key findings were beginning to emerge: 1) the benefits associated with the Frontier Line appear greater than the costs under a variety of plausible conditions, and 2) uncertainty associated with key inputs results in a wide range of benefit-cost outcomes.

Todd Strauss, Manho Yeung, Dave Olsen, Jerry Vaninetti, Curt Hatton, and Rich Lauckhart presented the work of the Economic Analysis Subcommittee to the Steering Committee on 23 January 2007, in San Francisco. Feedback from the Steering Committee was discussed with the entire Economic Analysis Subcommittee.

At the third Stakeholder Meeting, in San Diego on 31 January 2007, Economic Analysis Subcommittee members presented FEAST, and key inputs on renewables costs, coal costs, natural gas costs, and greenhouse gas adders. A live demonstration of FEAST was given. For a third time, stakeholders were invited to join the Economic Analysis Subcommittee. Stakeholder feedback from the Stakeholder Meeting, and from follow-up e-mail and phone conversations, was discussed among the Economic Analysis Subcommittee.

The Economic Analysis Subcommittee met in San Francisco on 14 February 2007. The reference data set was reviewed thoroughly. Analyses were reviewed. Some modifications to FEAST were identified.

Individual subcommittee members continued to perform their own analyses, some of which were circulated via e-mail and discussed during weekly conference calls. Analysis centered on a backbone transmission line, from Wyoming through Utah and Nevada, and into southern California.

Extensive discussions were held via e-mail and during weekly conference calls to finalize the reference set of data inputs. Dave Olsen, Jerry Vaninetti, Curt Hatton, and Rich Lauckhart each drafted a document describing the part of the reference set of data inputs he led assembling.

By early March, the reference set was finalized. Version 3.0 of FEAST was released for use. PG&E used FEAST 3.0 and the finalized reference set to update analyses performed earlier. The numerical results were slightly different, but the two key findings were unchanged.

At the fourth Stakeholder Meeting, in Las Vegas on 19 March 2007, Todd Strauss and other members of the Economic Analysis Subcommittee presented the work accomplished by the subcommittee since the 31 January 2007 Stakeholder Meeting. New features incorporated in version 3.0 of FEAST were discussed. The finalized

reference set of data inputs was described. Numerical results for four cases were presented, along with sensitivities. A variety of stakeholder questions were addressed.

Since the March Stakeholder Meeting, the work of the Economic Analysis Subcommittee has been winding down. The last conference call was held on March 21. Occasional stakeholder questions and comments have been discussed via e-mail and telephone. The report of the Economic Analysis Subcommittee was posted on the Frontier Line web site on April 23. In response to stakeholder feedback, further edits were made. This final version of the report is dated 27 April 2007.

Methodology

This section discusses benefit-cost analysis in the context of the Frontier Line feasibility study. This section describes the tool (FEAST) developed by the Economic Analysis Subcommittee to perform its benefit-cost analysis.

Benefit-Cost Analysis

Economic analysis of the Frontier Line has been grounded in benefit-cost analysis. Benefit-cost analysis is a widely recognized technique of economic analysis. Performing benefit-cost analysis includes such tasks as estimating dollar-denominated streams of benefits and costs, discounting future benefits and costs to account for the time value of money, and comparing the present value of benefits to the present value of costs.

To assess electric transmission possibilities and compare electric transmission alternatives, the Economic Analysis Subcommittee estimated the ratio of benefits to costs (B/C ratio). A B/C ratio greater than 1.0 indicates the value of benefits are greater than the costs, while a B/C ratio less than 1.0 indicates the value of benefits are less than the costs.

The Economic Analysis Subcommittee tried to measure all benefits and costs in 2006 constant dollars. Costs associated with transmission lines and power plants that may be built years from now are nonetheless expressed in 2006 dollars. The Economic Analysis Subcommittee assumed an in-service year of 2015 for generating resources.

purpose of the Frontier Line is to enable new clean resources to be developed and delivered to distant locations, providing a variety of benefits to customers of the WRTEP utilities, to citizens of the states associated with the Frontier Line, and throughout the WECC. The potential benefits of the Frontier Line are multifaceted. The Economic Analysis Subcommittee identified 22 kinds of potential benefits. These potential benefits are listed in Table 1. Benefits quantified by the Economic Analysis Subcommittee include energy, capacity, transmission losses (a "negative" benefit), and avoided greenhouse gas emissions. Other benefits were identified by the Economic Analysis Subcommittee, but not quantified.

To account for the difference in timing between the transmission investment and the realization of benefits, both costs and benefits are represented as levelized amounts. Levelization transforms a stream of payments (costs or benefits) that varies over time into a stream that is constant over time. Levelization results in the present value of the constant stream equal to the present value of the original time-varying stream, thus preserving a critical economic feature of the original time-varying stream. Levelization is a commonly-used technique in the energy industry to measure costs and benefits.

For benefit-cost analysis of the Frontier Line, costs are largely associated with the transmission investment. Costs associated with generation are included in the analysis, of course, but expressed as cost savings, hence a benefit. As discussed later in this report, the essential nature of the analysis performed by the Economic Analysis Subcommittee is to compare generation costs for different regions, and estimate the opportunity cost savings enabled by the Frontier Line.

Table 1
Benefits of the Frontier Line

1 Energy
2 Capacity
3 Losses
4 Emissions
5 Insurance Value against extreme events
6 Construction of transmission facilities
7 Construction of generation facilities
8 Annual tax benefits
9 Third party transmission revenues
10 Transmission reliability benefits
11 Resource reliability benefits
12 Renewable resource access
13 Synergies with other projects
14 Generation diversification benefits
15 Improved investment climate
16 Increased liquidity at trading hubs
17 FERC transmission incentives
18 Reduced market power
19 Operational efficiency benefits
20 New generation development
21 Non-emission environmental benefits
22 CO2 sequestration

The primary focus of the analysis performed by the Economic Analysis Subcommittee is economic efficiency from a total societal perspective, that is, the overall B/C ratio for the region as a whole. However, an important aspect to the feasibility of the Frontier Line is whether, for each individual state and not just collectively for the region, benefits greater

than costs. The Economic Analysis Subcommittee did not analyze how to allocate costs to achieve this. The Economic Analysis Subcommittee was mindful of the cost allocation issue and FEAST enables the user to consider cost allocation.

FEAST

To effectively perform the feasibility study, the Economic Analysis Subcommittee needed a tool to quickly quantity benefits and costs for a multitude of possible conditions and scenarios. These possibilities included: a variety of load and resource scenarios created by the L&R Subcommittee, as well as other potential resource scenarios; a myriad of conceptual transmission links and configurations identified by the Transmission Subcommittee; a wide range of natural gas prices and possible costs for new clean coal technology, including IGCC and CO_2 sequestration; and a broad spectrum of potential policy actions such as regional and/or national renewable portfolio standards, state and federal tax incentives for preferred resources such as wind or solar or clean coal, and regulatory regimes on greenhouse gas emissions, whether regional and/or national and/or international.

The Economic Analysis Subcommittee also sought a tool that promoted transparency. It was desirable to have a tool that enabled subcommittee members from different organizations to exchange and discuss data inputs and numerical results. It was desirable that the methodology underlying the tool should be readily understandable, so that causal connections between inputs and outputs be clear to subcommittee members.

The Economic Analysis Subcommittee also desired that the tool enable individual subcommittee members and their organizations to leverage internal, confidential and/or proprietary work. It was especially desirable that work performed by Arizona Public Service (APS) and others associated with development of the Transwest Express Project be leveraged for the benefit of studying the Frontier Line. It was also desirable to leverage preexisting studies such as the Rocky Mountain Area Transmission Study (RMATS), the Western Governors Association Clean and Diversified Energy Initiative (CDEAC) study, the Wyoming-California Corridor Transmission Expansion Study by the California Energy Commission (CEC), and work performed by the Northwest Transmission Assessment Committee (NTAC) of the Northwest Power Pool.

Currently, there are a number of commercially available production costing and/or market simulation tools that can be used to analyze the economics of regional electricity markets and bulk power systems. These tools are the established and preferred means of analysis in transmission planning. The Economic Analysis Subcommittee recognizes that economic analysis using production costing and/or market simulation tools is an essential step in transmission planning and assessment of proposed new transmission lines like the Frontier Line. These tools provide detail necessary for decision-making. However, using such tools is typically an activity that is data intensive, computationally intensive, and time intensive. Such tools are conducive to analysis structured around a well-defined base case with several sensitivity cases and/or scenarios.

There did not appear to be a readily available tool to perform quick, what-if screening analysis of the sort desired by the Economic Analysis Subcommittee. So the Economic Analysis Subcommittee, led by PG&E, determined to develop such a tool. The vision was of a simple spreadsheet-based tool enabling and empowering sophisticated users to execute a variety of analyses quickly, with the aim of developing user insight rather than producing overly precise numerical results. What emerged was the Frontier Economic Analysis Screening Tool (FEAST).

FEAST is not a substitute for production costing and/or market simulation tools. Analysis using FEAST may be a first step, to quickly sort through a multitude of possibilities. It must be followed by necessary, in-depth production costing and/or market simulation analysis of a few possibilities. In submitting this report, the Economic Analysis Subcommittee envisions that any further economic analysis associated with the Frontier Line is more in-depth and uses production costing and/or market simulation tools.

Similar to other software development efforts, the Economic Analysis Subcommittee first produced a prototype and followed up with a working model and subsequent improvements. Table 2 lists the five model versions released starting on 30 November 2006.

Table 2
Release Versions of FEAST

Date of Release	Version Number
30 November 2006	1.0
1 January 2007	2.0
8 January 2007	2.1
11 January 2007	2.1R
5 March 2007	3.0

Version 1.0 was a prototype that illustrated the structure and calculations to be contained in the tool. Versions 2.0, 2.1, and 2.1R were fully working versions. Version 2.1 added New Mexico as an intermediate source region, while version 2.1R added an option to consider the value of dependable capacity or resource adequacy capacity. Since these three versions used the same calculation algorithm, they produced the same numerical results given the same set of assumptions or data. Version 3.0 further refined the tool structure and included the reference set of input data. Version 3.0 is the current version of FEAST. The numerical results presented in this report were produced using version 3.0.

FEAST is structured so that stakeholders can input their assumptions in a what-if manner and see the impacts to the Frontier Line's benefits and costs.
Because FEAST is a simple interactive tool intended for sophisticated users, there are few built-in checks to validate data inputs. The user is responsible for ensuring valid and

appropriate resource costs, operating characteristics, fuel costs, price adders, and so forth are input. The user must take special care to ensure the validity of the input data set as a whole, since a number of inputs interact to produce results. The user must check that FEAST output makes sense.

Analytical Underpinnings of FEAST

Applying benefit-cost analysis to the Frontier Line is a matter of calculating gross benefits, gross costs, and comparing the two. As illustrated in figure 1, gross benefits are represented as the product of energy potential, line utilization, and regional basis.

Figure 1

Accumulating Gross Benefits

Energy Potential (MWh)	X	Line Utilization (%)	X	Regional Basis ($/MWh)	=	Gross Benefits ($)

- ***Energy Potential*** is the amount of energy that would flow over a transmission line if power flowed all the time at the full rating of the over the transmission line. For example, a transmission line rated at 2,000 megawatts (MW) would have an energy potential of 2,000 MW x 8,760 hours/year, equal to 17,520 gigawatt-hours (GWh) or 17.52 million megawatt-hours (MWh) per year.

- ***Line Utilization*** is a fraction between zero and one representing the level of use of the transmission line: the greater the number, the greater the use. Line utilization is the ratio of the actual or forecast energy flowing over the transmission line in a period divided by the energy potential of the transmission line for that period. Line utilization is a function of the quantity and characteristics of the resources available for generation at the transmission line's endpoints.

- ***Regional Basis*** describes the difference in energy cost between the generation or source region and the load or sink region. It is measured in dollars per MWh. Regional basis is influenced by many factors including resource construction costs, amount of energy production, fuel prices, environmental mitigation costs, renewable energy price premiums, just to name a few. Regional basis is essentially the opportunity cost savings associated with power flowing over the Frontier Line rather being produced locally at the sink.

Gross costs are largely associated with development and construction of transmission lines. The Transmission Subcommittee estimated total cost, on a scale of billions of dollars, for each complete transmission configuration and conceptual transmission link. FEAST enables quick conversion of this total cost for transmission to a unit cost, in

dollars per MWh. This conversion depends on a number of assumptions, and the assumptions are intended to be transparent in FEAST.

FEAST is intended to focus on incremental resources, not a complete supply curve or supply stack. FEAST focuses on the energy benefits associated with the Frontier Line. To properly do so, inputs should specify that source and sink regions are in energy balance.

Structure of FEAST

FEAST is an Excel workbook. It is comprised of eight worksheets with various formulas, drop-down menus, and lookup tables.

The first three worksheets (labeled 'Intro', 'L&R', and 'NTAC Gen') provide background and reference information. The worksheet labeled 'Intro' displays a stylized map of transmission links within the WECC. The worksheet labeled 'L&R' lists the seven scenarios produced by the Load & Resources Subcommittee. The worksheet labeled 'NTAC Gen' displays information associated with resource scenarios from the Northwest Transmission Assessment Committee (NTAC) of the Northwest Power Pool. This study preceded the Frontier Line feasibility study, and the Economic Analysis Subcommittee leveraged NTAC's work in assembling input data for FEAST.

The fourth worksheet is labeled 'Instructions' and provides instructions on using FEAST. The structure of FEAST is described in more detail in this worksheet. This worksheet also includes advice for sound use of FEAST.

The first four worksheets are for information only; cells in these worksheets are not intended to link to FEAST calculations and output.

The next three worksheets (labeled 'ET', 'General Input', and 'Source&Sink Input') are input worksheets for users to specify input assumptions and data. The worksheet labeled 'ET' displays the conceptual transmission links and combinations identified by the Transmission Subcommittee. Transmission data from this worksheet feeds the benefit-cost calculations. The worksheet labeled 'General Input' includes a variety of input data such as financial data, fuel costs, resource costs and operating characteristics. The worksheet labeled 'Source&Sink Input' is where the user specifies the transmission configuration being studied, and the resource mix at source and at sink. This worksheet requires careful attention. Providing input to just a few cells enables quick analysis. Understanding what the inputs represent is critical for successful analysis.

The last worksheet (labeled 'Output-Levelized') displays the analysis results in both tabular and graphical form. A rudimentary assignment of benefits and costs to states is displayed.

In FEAST, the Excel workbooks are password-protected to prevent unintentional accidental changes. To guide users, the data fields are color-coded.

Data Requirements of FEAST

This section discusses some aspects of the input data for FEAST. Each of the three input worksheets is discussed in turn.

The 'ET' worksheet lists the transmission configurations developed by the Transmission Subcommittee. For each transmission configuration, the worksheet displays geographical description, length, capacity, transmission type, estimated cost in 2006 constant dollars assuming a 2015 in-service year, and average transmission losses. Users also have the flexibility to define new transmission configurations and have these new configurations included in analysis. To facilitate this, all of the individual transmission links identified by the Transmission Subcommittee are listed in the 'ET' worksheet, along with their costs and other specifications.

The 'General Input' worksheet includes four types of input data: financing, fuel cost, price adders, and resource data. Resource data include cost and operating characteristics. All installed costs for resources are expressed as 2006 constant dollars assuming a 2015 in-service year. All other financial data are expressed in 2006 dollar-denominated levelized costs. Price adders require special attention. Users may specify price adders to account for greenhouse gases, renewable credit, and grid efficiency improvement due to the construction of the new transmission line. Interactions among the various price adders and resource specifications are important. For example, user must consider the effects of the greenhouse gas adder, renewable premium and production tax credits together to represent a sensible scenario.

Users can specify resource information and operating characteristics such as heat rate, capacity factor, installed cost, CO_2 emission rate. Capital costs and fixed and variable O&M costs are also included. Other financial and operating information that may be specified for each resource includes transmission interconnection costs and production tax credits.

The last section of the resource input table displays the total levelized power cost in dollars per MWh for each resource. The Economic Analysis Subcommittee used a CEC financial model to pre-process the resource data along with the financing input data to develop a set of pro-forma levelized factors. These levelized factors are then used with user-specified resource data to determine cost in levelized dollars per MWh.

In the 'Source&Sink Input' worksheet, users specify the transmission alternative to be analyzed, and resource data associated with source and sink. FEAST requires that there be a source region producing energy, and a sink region importing that energy. For valid analysis, source and sink should be in energy balance. In FEAST analysis of the Frontier Line, source and sink resources are typically considered to be incremental, rather than reflecting entire supply stacks.

Since the FEAST tool is a simple interactive tool that requires sophisticated users to input and validate data, users need to self-validate several items in the 'Source&Sink Input' worksheet: (1) total source and sink energy are consistent and that they equal to each other; (2) the amount of source and sink capacity are less than the capacity of the line unless the user purposely overbuild resources such as in the case of wind generation, (3) line utilization, based on the sum of net export from each region, is not greater than 100%, and (4) the intermediate sources and sinks selected are consistent with the selected line option.

Output of FEAST

The worksheet labeled 'Output-Levelized' contains all FEAST output. This worksheet includes a table and a B/C ratio break-even curve. An example of the output table is displayed in Figure 2. An example of the B/C ratio break-even curve is displayed in Figure 3.

The output table (Figure 2) documents the transmission alternative selected. It also lists the energy potential (or line capacity), utilization factor, and regional price difference. The product of these three terms is the gross benefit. The B/C ratio is gross benefit divided by gross cost.

The B/C break-even curve (Figure 3) displays FEAST output results graphically. The horizontal axis indicates line utilization (a percentage) while the vertical axis indicates regional price difference (in dollars per MWh). The blue curve shows the intersection of utilization factor and regional price difference where the line's benefits equal its costs. The area under the blue curve represents conditions under which the line has B/C ratio less than 1.0 while the area above the blue curve represents conditions under which the line has B/C ratio greater than 1.0. The red dot denotes the result of the FEAST model run. FEAST is a screening tool. B/C ratios produced by FEAST are intended to be indicative, not definitive.

Figure 2
FEAST Output Table

Levelized Basis (2006 dollar-denominated)

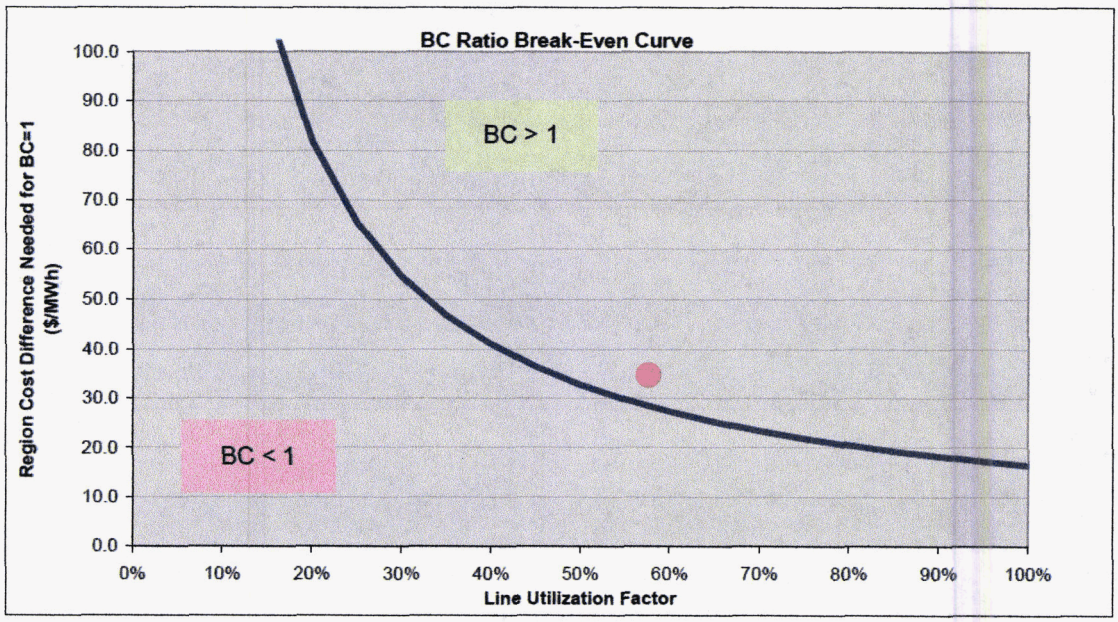
TOTAL SYSTEM

Trans Option No.	7b	Installed Cost ($Million)	4,300
		Capacity (MW)	3,000
Description	Wyoming - Mona (Utah) - S. Nevada - Southern CA		
Line Utilization	58%		

	($/MWh)	Regional Difference Source ($/MWh)	Sink ($/MWh)	Diff ($/MWh)	Annual Benefits ($Million)	Annual Cost ($Million)
Line Cost	28.4					430
Power Cost		39.8	66.3	26.5	402	
GHG Adder		0.0	16.0	16.0	242	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		3.0	0.0	-3.0	-45	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		2.8		-2.8	-42	
Grid Eff		0.0		0.0	0	
Dependable Cap Value				-2.1	-32	*
TOTAL		45.6	82.3	34.6	524	430
Benefit to Cost Ratio	1.22					

Figure 3

FEAST: B/C Ratio Break-Even Curve



Inputs

This section describes FEAST inputs for renewable costs and performance, coal fuel prices and costs and costs and performance for coal-fired generation, natural gas prices and costs and performance for gas-fired generation, and greenhouse gas adders.

Renewables

This section describes cost and performance data for wind, solar, geothermal and biomass resources selected for use in the Frontier Line feasibility study. Data sources are identified. Considerations affecting choice of particular input assumptions are discussed.

<u>Wind</u>

Capacity Factors for Wind

Wind capacity factors for the geographic areas defined by major transmission topology bubbles throughout the intermountain west were supplied by the National Renewable Energy Laboratory (NREL). This data was used in RMATS, and in scenarios run by WECC for the Western Governors Association Clean and Diversified Energy Initiative

(CDEAC) study.[1] The capacity factors shown below are net of losses from aerodynamic wake/array effects, blade contamination, icing and electrical losses within the wind farm.

Table 3
Regional Wind Capacity Factors

Wyoming		**Montana**		**Colorado**	
Dave Johnson	48%	Shelby	42%	Lamar	43%
Laramie River	41%	Broadview	42%	Peetz	41%
Miners	39%	Colstrip	32%	Uintah	40%
Bridger	39%	**Utah**		**New Mexico**	
Big Horn Basin	37%	Utah-South	32%	Region 1	40%
		Utah-North	29%	Region 2	33%
Idaho		**Nevada**		**Arizona**	
All regions	≤30%	All regions	≤30%	All regions	≤30%
California					
Tehachapi	37%				

NREL calculated power production at these sites by running hourly measured wind speeds against the power curve of the General Electric (GE) 1.5 MW wind turbine at a 70 meter hub height. NREL estimates that there is more than 84,000 MW of wind having capacity factors greater than 40% at developable sites in Wyoming, Montana, and Colorado, and more than 57,000 MW in Wyoming alone.

For purposes of comparing the costs of California wind generation to western regional wind and coal generation, the Subcommittee used the capacity factor of a 500 MW wind project in the Tehachapi Wind Resource Area as a proxy for all California wind generation. TrueWind calculated the average capacity factor at this site for the three years 2002-2004 to be 37.0%, at a 70 meter hub height and using an assumed GE 1.5 MW turbine. This same Tehachapi wind data is being used in the on-going CEC Intermittency Analysis Project.

Wind dependable capacity is its capacity factor during the hours, noon to 6:00 pm for the peak period May through September. TrueWind modeling of Wyoming, Utah, and California resource areas calculates wind dependable capacity for this peak period to be as shown below. Historical wind output during the peak period as recorded by the California Independent System Operator (CAISO) for the years 2002-2004 shows California dependable capacity to average 30%. The Economic Analysis Subcommittee selected a dependable capacity of 21% for California so that dependable capacity is calculated using the same techniques and same data source for all regions, and is appropriately comparable across regions.

[1] Wind resources were mapped to transmission topology bubbles shown in the RMATS Report (September 2004) on p. 2-6. The CDEAC Wind Task Force Report (March 2006) identifies these same wind development regions at pp. 29-34. Transmission topology is that used in WECC and subregional planning.

Table 4
Wind Dependable Capacity

California	21%
Utah	35%
Wyoming	39%

Wind power capital and operating costs were taken from the on-going national 20% wind penetration scenario study being developed by the US Department of Energy, NREL, American Wind Energy Association (AWEA) and Black & Veatch. These capital costs shown below also correspond closely to those used in recent WECC studies[2]—when increased roughly 35% to account for commodity price increases (steel, copper, cement), and for the effect of the worldwide shortage of wind turbine supply. California installed wind project cost was increased a further $200/kW to account for transmission necessary to connect wind resource areas to the state high-voltage grid. Wind power capital costs are expected to decline from $1,680/kW in 2007 to $1,300/kW in 2015, the Frontier Line study year, due to efficiency improvements, manufacturing economies, easing of the turbine supply shortage and stabilization of commodity prices.

Table 5
Wind Capital and Operating Costs

Installed Cost, 2015, California	$1,500/kW
Installed Cost, 2015, non-California	$1,300/kW
Fixed O&M	$11.50/kW-year
Variable O&M	$5.50/MWh

Fixed O&M costs include land lease/royalty payments; taxes, insurance, on-site electricity, and administrative/management fees associated with operating the wind projects.

Wind integration costs are those of any incremental generation committed and/or dispatched to balance the system with variable-output wind added. The many integration studies of different regions of the US and Europe for wind penetrations up to 20% indicate that such costs typically range from $1.50/MWh to $5.00/MWh. The reference data set uses a value of $3.00/MWh, roughly at the midpoint of this cost range.

Solar Photovoltaic

Solar photovoltaic generation provides peaking power in load centers and avoids new transmission. It is best evaluated similarly to energy efficiency resources rather than as wholesale power supply. Central station photovoltaic projects are significantly more

[2] CDEAC/SSG-WI 2005 Transmission Planning Program, 2015 Reference Case Key Assumptions Matrix; NTAC 2005-2006 Canada-California Assumptions.

expensive than concentrating solar power. For these reasons, the Economic Analysis Subcommittee decided to exclude photovoltaics from the evaluation of Frontier Line transmission alternatives.

Concentrating Solar Power (CSP)

Various CSP technologies provide large-scale peaking power. Capital and operating cost data were taken from an April 2006 study of CSP technology and projects performed by NREL and Black & Veatch for the California Energy Commission.[3] Consultation with developers of CSP projects proposed for California and the desert Southwest indicated the cost and performance information in this report to be in the expected range for construction in 2015.

Costs are shown for parabolic trough technologies, with six hours of storage. Size is assumed to be 200 MW. Storage raises the effective capacity factor from 28% to 40%, and accounts for roughly 18% of total direct project cost. Fixed operations and maintenance (O&M) costs include costs of labor, administration, water treatment, spares and equipment; other fixed costs include land payments, taxes and insurance.

Table 6
CSP Costs and Capacity Factor

Installed Cost, 2015	$3,157/kW
Fixed O&M	$38.00/kW-year
Other Fixed Costs	$75.20/kW-year
Variable O&M	$1.50/MWh
Capacity Factor	40.4%

As with wind power, CSP dependable capacity is its capacity factor during the hours, noon to 6:00 pm for the peak period May through September. Using solar output load shapes supplied by NREL for various locations, the reference set values for CSP Dependable Capacity are displayed in Table 7.

Table 7
CSP Dependable Capacity

	CSP, no storage	CSP, with storage
California (Barstow)	87%	100%
Non-California (Las Vegas)	80%	100%

[3] L. Stoddard, J. Abiecunas, and R. O'Connell, "Economic, Energy and Environmental Benefits of Concentrating Solar Power in California," NREL Subcontract Report SR-550-39291, April 2006.

Geothermal

Geothermal project capital and operating costs vary widely with the very different physical characteristics of Known Geothermal Resource Areas (KGRAs). For purposes of the Frontier Line feasibility study, the Subcommittee decided to focus only on geothermal resources at the Salton Sea, in California's Imperial Valley, and to exclude Geysers, Northern California and western Nevada resource areas. The Salton Sea KGRA has the largest amount of development potential—approximately 2,000 MW of proven reserves—of any region in the US. Because of very high concentrations of dissolved solids in a highly corrosive brine, along with very high temperatures and pressures, capital and operating costs in the Imperial Valley are much higher than at other KGRAs. Costs were provided by MidAmerican Energy, which operates 540 MW of geothermal plants at the Salton Sea and owns development rights to an additional 2,000 MW of resource capacity there. Other Fixed Costs are negative, after incorporating the Geothermal Depletion Allowance afforded to such plants.

Table 8 displays the costs associated with a generic geothermal project in California's Imperial Valley, and are not intended to apply to costs for a geothermal project elsewhere.

Table 8
Geothermal Costs and Capacity Factor

Installed Cost, 2015	$3,600/kW
Fixed O&M	$64.00/kW-year
Other Fixed Costs	($6.20)/kW-year
Variable O&M	$23.60/MWh
Capacity Factor	95%

Biomass

Biomass capital and operating cost data was taken from the CDEAC Biomass Task Force Report, and confirmed with the California Biomass Energy Alliance, an association of owners/operators of biomass projects. No new biomass projects have been built in California for more than 20 years, so cost estimates are approximations. Heat rate data was taken from US DOE Energy Information Administration data.

Table 9
Biomass Costs, Capacity Factor, and Emissions

Installed Cost, 2015	$2,196/kW
Fixed O&M	$95.70/kW-year
Other Fixed Costs	$62.70/kW-year
Variable O&M	$5.20/MWh
Capacity Factor	90%
Net CO_2 Emissions Rate	0 tons/MWh

Under California policy, biomass plants are considered to have zero net CO_2 emissions. This treatment is intended to incorporate the fact that the agricultural and forest waste burned would otherwise decompose and be released into the atmosphere largely as methane, which has 21 times the Global Warming Potential (radiative forcing effect) of CO_2.

Coal

This section describes cost and performance data for coal resources selected for use in the Frontier Line feasibility study. Data sources are identified. Considerations affecting choice of particular input assumptions are discussed.

Input assumptions were derived from publicly available sources, primarily CDEAC[4] and DOE/EIA[5], updated in 2006 dollars for facilities installed in 2015. As was the case with input costs for the other resources considered in the FEAST modeling process, the recent run-up in fuel and construction costs has been tempered to better reflect cost levels anticipated to be prevalent in 2015.

The Economic Analysis Subcommittee considered mine-mouth plants located within the states of Montana, New Mexico, and Wyoming, and rail-served plants located within the states of Arizona, Nevada, and Utah. These are shown by the black dots on Figure 4. It is assumed that all plants utilize Powder River Basin (PRB) sub-bituminous coal, with the exception of the Montana mine-mouth plant that utilizes lignite and the New Mexico mine-mouth plant that utilizes local sub-bituminous coal.

Coal fuel costs are displayed in Table 10. Estimates of 2015 free on board (FOB) coal prices for the generic coal plants are based on the forecast presented in DOE/EIA's 2006 Energy Outlook (Table 111), updated to 2006 dollars. In the case of the rail-served plants, projections of delivered coal costs were vetted with the utilities considering coal-fired plants in those states, and the resulting feedback was incorporated in the final coal input assumptions used in the FEAST reference data set.

[4] Western Governors Association sponsored Clean and Diversified Energy Committee (CDEAC), Advanced Coal Task Force Report, January 2006

[5] Department of Energy/Energy Information Administration, Annual Energy Outlook 2006, February 2006

Table 10
Coal Fuel Costs

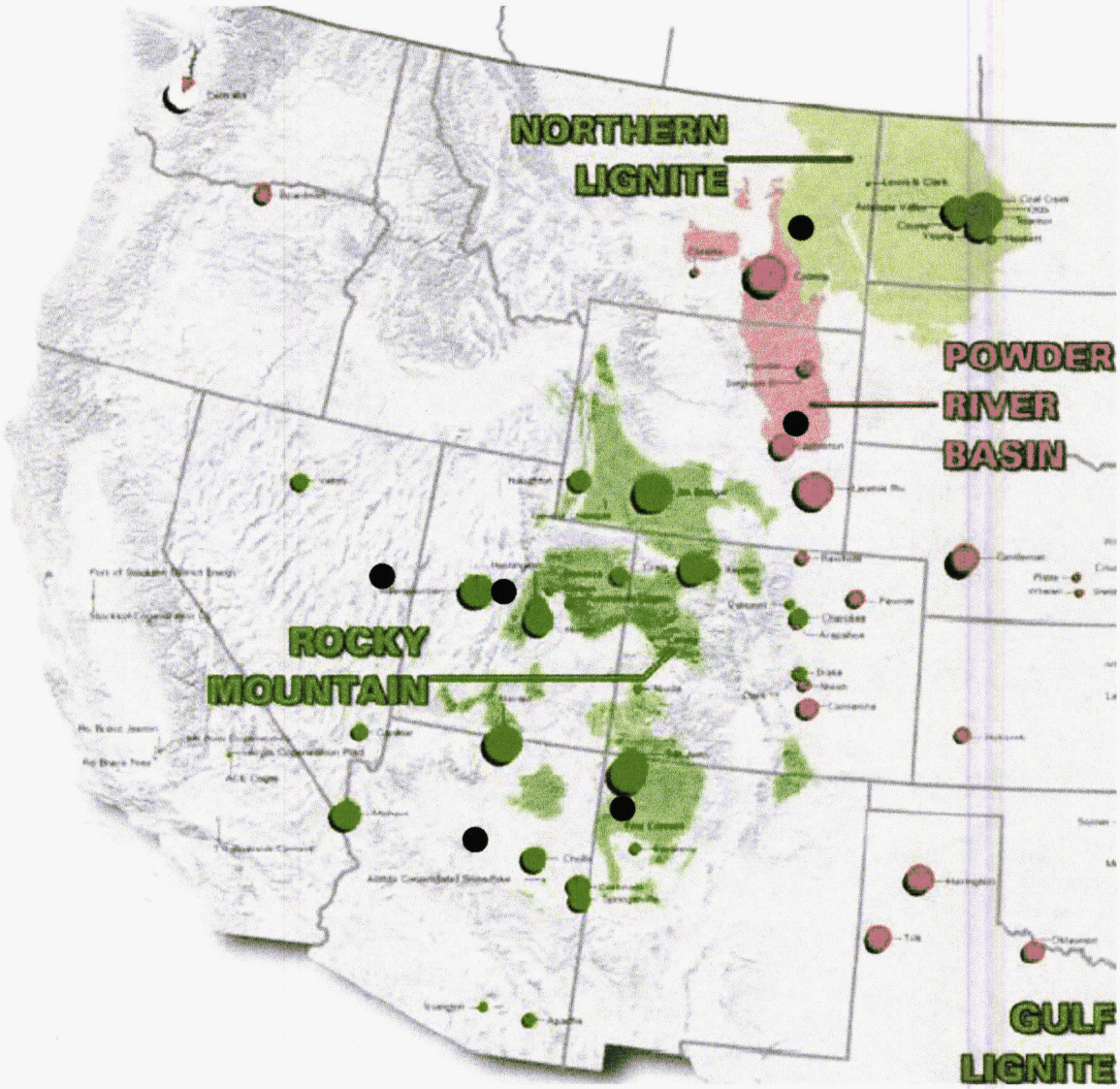
Plant Site	Coal Source	Btu/lb	Unit Prices ($/mmBtu) Coal	Rail	Total
Wyoming	Wyoming (PRB)	8,800	0.49	0.00	0.49
Montana	Montana (Lignite)	6,600	0.92	0.00	0.92
New Mexico	New Mexico (NM)	9,300	1.13	0.00	1.13
Utah	Wyoming (PRB)	8,800	0.49	1.21	1.70
Nevada	Wyoming (PRB)	8,800	0.49	1.35	1.84
Arizona	Wyoming (PRB)	8,800	0.49	1.44	1.93

Coal plant cost and operating assumptions are based on information compiled by the CDEAC Advanced Coal Task Force, updated to 2006 dollars for a 2015 installation. As such, the assumptions reflect continued improvement in technology, particularly for the advanced technologies considered for the Montana and Wyoming plant site locations. The assumptions provided for these latter two situations included the cost and performance resulting from the capture and sequestration of CO_2 in local oil and gas fields. To the extent that such costs are offset by sales of CO_2 for enhanced oil recovery, it is not reflected in the levelized cost of power reported in the FEAST input tables. However, a value associated with these sales for enhanced oil recovery is included in the reference data set, and is estimated to be 10 dollars per ton of CO_2. The corresponding reduction in levelized cost for clean coal technologies is reflected in FEAST and in the benefit-cost analysis presented below, where applicable.

Table 11
Coal Plant Costs and Performance

State/Technology	Heat-Rate BTU/kWh	Capacity Factor	Depend -able Factor	Installed Cost $/kW	Fixed Costs $/kW-Yr	Variable O&M $/MWh
WY - Conventional	9,870	85%	100%	1,882	44.7	1.9
AZ - Conventional	8,860	85%	100%	1,966	47.2	1.7
NM - Conventional	8,860	85%	100%	1,966	47.2	1.7
NV - Conventional	8,860	85%	100%	1,966	47.2	1.7
UT - Conventional	8,860	85%	100%	1,966	47.2	1.7
MT - Conventional	10,286	85%	100%	2,068	46.8	1.9
WY - Advanced+CCS	10,300	80%	90%	2,662	74.5	6.9
MT - Advanced+CCS	11,000	80%	90%	2,911	74.5	6.9

Figure 4
Western US Coal Plants and Coal Fields



Note: generic coal plant locations shown in black
Source: Global Energy Decisions

Natural Gas

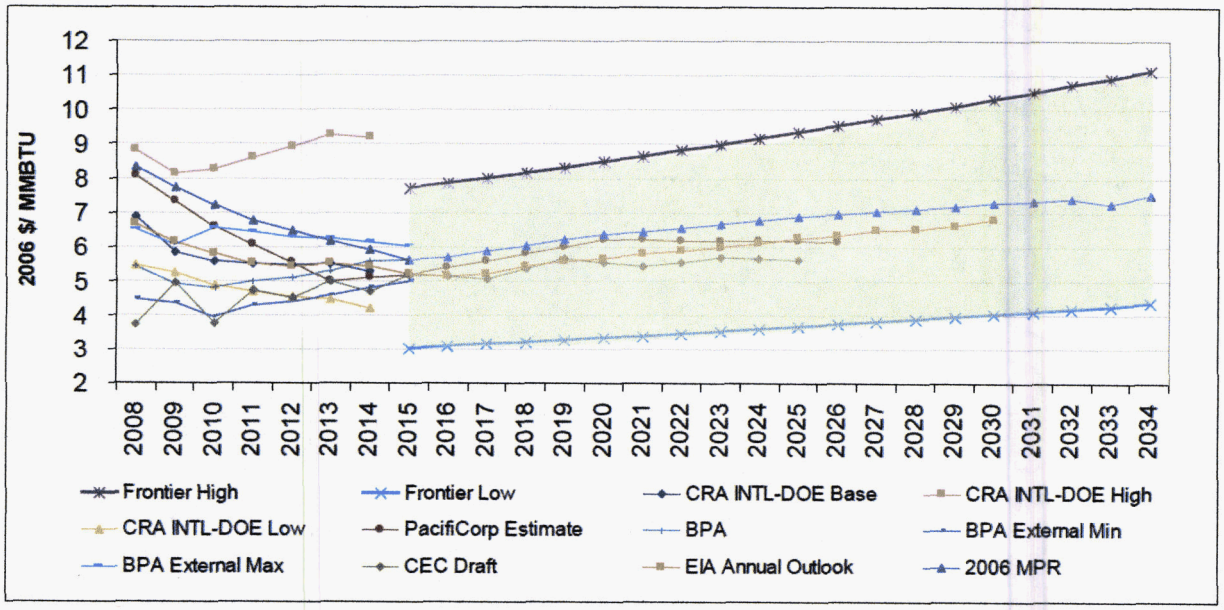
This section describes natural gas prices and cost and performance data for gas-fired resources selected for use in the Frontier Line feasibility study. Data sources are identified. Considerations affecting choice of particular input assumptions are discussed.

Natural gas price inputs to FEAST have two components: commodity and transportation. In the reference data set, commodity cost is based on a projection of the Henry Hub natural gas forecast. The transportation component is used to represent the basis difference in the cost of gas between the actual pricing point of the gas-fired generating resource and the Henry Hub price.

The commodity component is based on a projection of the Henry Hub natural gas price for a twenty-year period, 2015 to 2034. In developing the inputs for the commodity component of natural gas price, the Economic Analysis Subcommittee examined a wide range of available long-term Henry Hub gas forecasts. Figure 5 below displays a few long-term forecasts of Henry Hub gas prices. Real, not nominal, prices are displayed, that is, prices in 2006 constant dollars per MMBtu. For the most part, the forecasts exhibit a declining real price of natural gas through 2015 and then increasing for the remainder of the study period.

Figure 5

Long-term Natural Gas Price Forecasts



The two forecasts labeled Frontier High and Frontier Low indicate the upper and lower levels, respectively, of natural gas prices identified by the Economic Analysis Subcommittee for use in its analysis. These yearly streams, when converted to levelized 2006 dollars per MMBtu, result in the range of 3.50 to 9.00 dollars per MMBtu identified in the reference data set for FEAST.

The transportation component reflects the difference in price from Henry Hub to the actual pricing point. The reference set has the California transportation component equal to zero dollars per MMBtu. This is based on a combination of market quotes for near term basis swaps of approximately (0.50) dollars per MMBtu for PG&E Citygate and SoCal pricing points—that is, fifty cents less than Henry Hub—and a local distribution charge forecast at 0.40 dollars per MMBtu. The reference set has no specific transportation component for locations outside California because the transportation component is very dependent on the particular location of a gas-fired power plant. In specifying an appropriate transportation component, one should include any applicable basis differential, local distribution charges and fuel taxes.

Costs and operating characteristics for gas-fired combined-cycle (CC) and combustion turbine (CT) technologies are also part of the reference data set.

CC plant costs and operating assumptions are based primarily on information associated with setting California's 2006 Market Price Referent (MPR). For purposes of the Frontier Line study, the same cost and performance characteristics are used for CCs located within California and outside California. Since CCs outside California may have lower construction costs and easier access to gas basins, using this assumption may tend to underestimate the benefits of the Frontier Line.

The Economic Analysis Subcommittee recognized that uncertainty exists in both the cost and operating profile of future CCs. A range of plausible capacity factors was identified. A lower level of 50% corresponds to the operation of some of today's CCs, while an upper level of 90% corresponds to baseload operation. For the reference data set input to FEAST, a capacity factor of 78% was identified, largely based on the judgment of the Economic Analysis Subcommittee.

Table 12
Combined Cycle (CC) Costs and Performance

	Heat-Rate BTU/kWh	Capacity Factor	Depend. Capacity Factor	Installed Cost 2006$/kW	Fixed O&M* $/kW-Yr	Other Fixed* $/kW-Yr	Variable O&M* $/MWh
Combined Cycle - CA	6920	78%	100%	1000	13.7	37.7	2.4
Combined Cycle - Non CA	6920	78%	100%	1000	13.7	37.7	2.4

Combustion turbine plant costs are also based primarily on information from California's Market Price Referent (MPR) Process. The 2006 MPR process, however, did not address the cost structure of a new combustion turbine. The 750 dollars per kW installed cost was developed by maintaining the relative percentage cost differential

found in the 2004 MPR process and applying it to the combined cycle cost of the 2006 MPR process. The 9,300 Btu per kWh heat rate is representative of today's combustion turbine technology. Uncertainty exists in both the cost and operating profile of future combustion turbines. The technology of new combustion turbines will impact the heat rate, cost and operating profile. For example, newer technology may provide a better heat rate, but with a higher installed cost. As a package, the Subcommittee thought that the assumptions below were appropriate for use as reference inputs for the Frontier Line study. As with the CCs, the Frontier Line study uses the same cost and performance characteristics for both CA and Non-CA combustion turbines.

Table 13
Combustion Turbine (CT) Costs and Performance

	Heat-Rate BTU/kWh	Capacity Factor	Depend. Capacity Factor	Installed Cost 2006$/kW	Fixed O&M* $/kW-Yr	Other Fixed* $/kW-Yr	Variable O&M* $/MWh
Combustion Turbine - CA	9300	10%	100%	750	12.3	25.3	9.9
Combustion Turbine - Non CA	9300	10%	100%	750	12.3	25.3	9.9

*2006 dollar denominated levelized costs

Greenhouse Gas (GHG) Adders

Substantial attention is now being paid to the prospects for global warming. There is widespread interest in levels of GHG emissions, and possible policy actions to halt and reverse recent increases in levels of GHG emissions. At the world level, the UN Framework Convention on Climate Change (UNFCC) is attempting to address these issues. At the U.S. National and State level, various proposals are being put forward. California is among the leaders in passing legislation related to Global Warming. In 2006 California enacted two laws to address Global Warming. Senate Bill 1368 (restriction on CO_2 levels associated with long-term contracts for base load generation) is intended as an interim measure that essentially prohibits California utilities from contracting for new construction of conventional pulverized coal plants. Assembly Bill 32 (Global Warming Solutions Act of 2006) is the more definitive legislation. This Act caps California's greenhouse gas emissions at 1990 levels by 2020. This legislation requires the California Air Resources Board (CARB) to adopt a GHG emissions cap on all major sources, including the electricity and natural gas sectors, to reduce statewide emissions of GHG to 1990 levels. In Rulemaking 06-04-009, the California Public Utilities Commission (CPUC) proposes to develop and bring a joint recommendation of both the CPUC and the CEC to CARB for its consideration when adopting the overall "scoping plan" as called for in AB 32 to govern the GHG emissions limits in California overall. The schedule for the CARB activity is that in October 2008 the CARB staff will finalize its "scoping plan" for Board adoption in November 2008. Other western states are also formulating strategies to address GHG issues.

In this context, the Economic Analysis Subcommittee recognized the importance of reflecting current and especially future GHG policy developments in feasibility analysis of the Frontier Line.

FEAST is not designed to estimate systemwide GHG emissions. Instead, a "shadow price" approach is used, to represent the additional variable cost associated with GHG emissions from dispatch of a fossil-fuel-fired electric generating unit. By comparison, generation technologies that emit little or no GHG have enhanced benefit.

Recognizing the great uncertainty in future policy on global warming, the Economic Analysis Subcommittee determined to identify a range of values for the GHG adder. The reference set of data inputs to FEAST includes a lower level for GHG adder, an upper level, and a single point value in the range.

The range for GHG adder was established using two different approaches.

First, previous estimates of the GHG adder were considered. The Economic Analysis Subcommittee relied on the detailed report developed by the consulting firm Natsource for BC Hydro. The Natsource report is available on BC Hydro's website under 2006 IEP, Attachment 4 of Appendix D. The report describes several analyses that were done using models to replicate a worldwide cap-and-trade program for GHG that may appropriately address global warming concerns. These various analyses indicate a range of possible worldwide GHG prices, from 8 to 61 dollars (in 2001 dollars) per ton of CO_2 equivalent. Global Energy converted this to a range of 9 to 70 dollars (in 2006 dollars) per ton of CO_2 equivalent.

Second, as a check on whether such a range of prices might make sense in the context of California legislation, Global Energy Decisions looked to its own independent view of power markets in the WECC (including California) to see if a value in this range could possibly make sense. Global Energy's independent view of energy markets assumed that California would meet all its future energy needs by building a combination of new renewable resources and natural gas fired resources. This analysis showed that the California electricity sector would be emitting 94 million tons of CO_2 in 2020 as compared to the 65 million tons it emitted in 1990.[6] One approach that the California electric sector could use to reduce GHG emissions is to use natural gas fired generation to displace imported coal-fired generation. (The gas-fired generation is anticipated to exist, and its capacity to be unused during many off-peak hours.) Economic displacement is represented by the GHG adder. The specified reduction (i.e. 94 minus 65 equals 29 million tons per year) in CO_2 emissions is sufficient so that, if credited entirely to the California electricity sector, it would result in the California electricity sector emitting the same amount of CO_2 in 2020 as it emitted in 1990.[7] Global Energy's

[6] The 1990 level of 65 million tons was indicated by the CEC

[7] AB 32 does not require any particular segment of the California energy sector to meet its 1990 level of GHG emissions on its own by 2020. However, without know if other sectors or countries can make GHG credits available (and for what price they might be made available), this study identified how the California electricity sector might be able to reduce its 2020 GHG emission to its 1990 GHG emissions.

analysis indicated that a dispatch adder of 40 dollars per ton of CO_2 would meet the targeted reduction in GHG.[8] This dispatch adder of 40 dollars per ton of CO_2 is in the middle of the range indicated above (9 to 70 dollars per ton of CO_2).

The GHG adder determined in this way is obviously the result of many assumptions. Changing these assumptions may result in different values. Thus, the reference data set for FEAST input includes the point estimate, 40 dollars per ton of CO_2, and lower and upper levels of value. The lower level is 9 dollars per ton of CO_2. The upper level is 70 dollars per ton of CO_2.

Analysis

Using FEAST version 3.0 and the reference set of input values as a starting point, the Economic Analysis Subcommittee evaluated four study cases on a "backbone" transmission configuration. Transmission alternative 7b was identified as the "backbone" configuration. This is a 4.3 billion dollar, 3000 MW alternating current (AC) line from Wyoming to southern California with intermediate connection points in Utah and Nevada. The annualized cost for this line is 424 million dollars (in 2006 dollars). This cost is the same for all four cases. The cost per (flowing) MWh does vary across cases, as the line utilization varies across cases.

The four cases examined are:

- Case 1: Wyoming Wind (3600 MW) vs. California Combined Cycle (2215 MW)
- Case 2: Wyoming Wind (2600 MW) and Clean Coal with CO_2 Sequestration (1000 MW) vs. California Combined Cycle (2625 MW)
- Case 3: Wyoming Wind (3600 MW @ 48% capacity factor) vs. California Wind (4868 MW @ 35.5% capacity factor)
- Case 4: Wyoming Wind (3600 MW) vs. California Renewable (55% wind, 35% geothermal, 10% concentrating solar power)

Table 14 summarizes the four cases and benefit-cost ratio results. Figures 6, 7, 8, and 9 display elements of the output worksheets for the four cases.

Case 1

Case 1 results are displayed in Figure 6. Case 1 compares wind resources in Wyoming to CCs in California. While the transmission line capacity is 3000 MW, the Economic Analysis Subcommittee judged some amount of additional wind capacity could be

[8] The analysis indicates that power costs across WECC would increase by 1.2 billion dollars (not counting the GHG adder) in the year 2020 were a GHG dispatch included at 40 dollars per ton of CO_2 equivalent. If California were to get credit for all the reduction in GHG caused by this dispatch adder, California would likely incur the 1.2 billion dollar cost.

assigned to Wyoming, with the understanding that when more than 3000 MW of wind resources are generating, the energy is absorbed locally rather than flowed over the long-haul transmission line, or some of the excess capacity is curtailed. Relying on analyses performed for other markets, the Economic Analysis Subcommittee judged the maximum amount of additional wind capacity to be absorbed locally as 600 MW. The increased capital cost of the added wind generation capacity is included in the analysis here, and so is the resulting higher utilization of the transmission line.

Proper use of FEAST results in energy balance. 15,137 GWh is indicated in Figure 6. (This corresponds to a line utilization factor of 58 percent.) Because CCs have higher capacity factor, a smaller amount of CC capacity is needed to balance the energy from 3600 MW of wind. Thus, this case compares 3600 MW of wind with just 2215 MW of CC. The analysis can be interpreted as investigating which is a more economically efficient incremental resource for the California market: 3600 MW of Wyoming wind (including transmission costs) or 2215 MW of California CC.

In addition, the dependable capacity of a CC is substantially greater than the dependable capacity of an intermittent wind resource. The results reflect this. An annual dependable capacity value "benefit" in the amount of negative 32 million dollars is associated with the Wyoming wind resource.

Energy benefits are 26.7 dollars per MWh, levelized. This corresponds to 405 million dollars annually, in 2006 dollars. The energy benefits result from opportunity cost savings from having the wind resource and the Frontier Line rather than a gas-fired CC in California. While the capital cost of the wind resource is greater, the variable costs of the gas-fired CC are substantially higher.

In addition, the California CC resource incurs GHG cost exposure. This is incorporated in the analysis through the GHG adder of 40 dollars per ton of CO_2. This appears in Figure 6 as a net benefit for the Wyoming wind resource, associated with the GHG adder, in the amount of 16.0 dollars per MWh, levelized. This corresponds to 242 million dollars annually, in 2006 dollars.

As substantial additional intermittent resources are added to the grid, incremental costs are incurred to maintain the supply-demand balance of the grid, as discussed on page 18. This cost of delivering Wyoming wind power to California appears in Figure 6 as a negative benefit associated with system integration, assessed at 3.0 dollars per MWh or 45 million dollars annually.

Finally, transmission losses are estimated to be 1.7 dollars per MWh levelized, or 25 million dollars annually, in 2006 dollars.

The benefits sum to 524 million dollars annually, in 2006 dollars. This compares to transmission cost of 424 million dollars annually, also in 2006 dollars. The result is a B/C ratio of 1.28.

The costs and benefits may be summed differently, yielding a different interpretation of the same result. The incremental cost at the source is 44.5 dollars per MWh, which is comprised of a power cost at 39.8 per MWh, system integration cost of 3 dollars per MWh, and transmission losses of 1.7 dollars per MWh. The incremental cost at the sink is 80.4 dollars per MWh, which is comprised of a power cost at 66.5 dollars per MWh, a GHG adder cost at 16 dollars per MWh, and a dependable capacity cost of negative 2.1 dollars per MWh. The resulting regional cost difference is 35.9 dollars per MWh. Dividing the regional cost difference of 35.9 dollars per MWh by the line cost of 28 dollars per MWh yields a B/C ratio of 1.28.

It is important to note that omitted from this analysis is consideration of the value of dispatchability of the CC resource. The cost of producing MWh from wind is compared with the cost of producing MWh from a CC. Furthermore, this analysis omits consideration of the time-differentiated value of power. Incorporating the value of dispatchability and time of delivery (TOD) into the analysis would result in a lower B/C ratio. (TOD effects may be included through clever use of FEAST, but that is beyond the discussion in this report.)

Case 2

Case 2 results are displayed in Figure 7. Case 2 compares a combination of wind and clean coal resources in Wyoming to CCs in California. Compared to case 1, 1000 MW of wind is replaced by 1000 MW of clean coal with CO_2 sequestration. Because the clean coal resource has a much higher capacity factor than the wind resource, additional CC capacity is needed to maintain energy balance. Thus, case 2 includes 2625 MW of California CCs, compared with 2215 MW of California CCs in case 1. The CCs are estimated to produce 17,940 GWh, and this too is the amount of energy from the combination of wind and clean coal resources in Wyoming. More energy is produced in case 2 than produced in case 1. Hence the line utilization is higher: 68% in case 2, compared with 58% in case 1.

Replacing 1000 MW of wind with 1000 MW of clean coal increases the dependable capacity of the Wyoming source resources. The annual dependable capacity value "benefit" of the Wyoming resources for case 2 is negative 24 million dollars, compared with negative 32 million dollars for case 1.

Compared with case 1, energy benefits are reduced because MWh from clean coal costs more than MWh from wind. The energy benefit is 15.3 dollars per MWh, levelized. This corresponds to 275 million dollars annually, in 2006 dollars.

The net benefit associated with the GHG adder is 13.6 dollars per MWh, levelized. This corresponds to 244 million dollars annually, in 2006 dollars. Not all of the CO_2 produced by the clean coal resource is captured and sequestered, and this is included in the analysis.

The CO_2 that is captured and sequestered has use in enhanced oil recovery (EOR). This has value of 3.4 dollars per MWh (levelized), or 61 million dollars annually. This is based on a reference data set value of 10 dollars (in 2006 dollars) per ton for use of CO_2 in EOR.

Less reliance on wind reduces system integration costs: from 45 million dollars annually in case 1 to 32 million dollars annually in case 2. Finally, transmission losses are higher because line utilization is higher: from 25 million dollars annually in case 1 to 39 million dollars annually in case 2.

The benefits sum to 484 million dollars annually. This compares to transmission cost of 424 million dollars annually, which is unchanged from case 1. The result is a B/C ratio of 1.14.

The alternate interpretation of the results is that incremental cost at the source is 54.2 dollars per MWh, an increase from 44.5 dollars per MWh in case 1. Compared with case 1, power costs at the source are higher, system integration costs are lower, and dependable capacity benefits are higher. GHG adder benefits are about the same when measured in total dollars, but lower when measured in dollars per MWh.

Again it is important to note that this analysis does not account for the value of dispatchability and TOD effects. Incorporating the value of dispatchability and TOD into the analysis would result in a lower B/C ratio.

Case 3

Case 3 results are displayed in Figure 8. Case 3 compares wind resources in Wyoming with wind resources in California. The Wyoming wind is of higher quality, with a 48% capacity factor compared to 35.5% capacity factor for California wind. Thus, 4868 MW of California wind is needed to balance the energy produced by 3600 MW of Wyoming wind.

Proper use of FEAST results in energy balance. 15,137 GWh is indicated in Figure 8. This corresponds to a line utilization factor of 58%.

The dependable capacity of the Wyoming wind resource is substantially greater than the California wind resource. The results reflect this. An annual dependable capacity value benefit in the amount of 15 million dollars is associated with the Wyoming wind resource.

Energy benefits are 19.7 dollars per MWh, levelized. This corresponds to 298 million dollars annually, in 2006 dollars. The energy benefits result from the higher quality Wyoming wind resource, which lowers cost per MWh, compared to California wind resource.

Because incremental resources at both source and sink are solely wind resources, there is no GHG adder benefit attributed to substituting wind energy with wind energy. Of course there is GHG benefit from the Wyoming wind resource; however, this analysis compares the Wyoming wind resource to incremental wind resources in California, and so there is no net GHG benefit when incremental wind energy substitutes for incremental wind energy.

Similarly, no system integration benefit is reported. Because Wyoming wind resources may be less negatively correlated with California load than California wind resources, there may be system integration benefits to the Wyoming wind resources. However, this is not captured by this FEAST analysis. If one had external information about the existence and magnitude of such benefits, it could be represented in FEAST.

The benefits sum to 287 million dollars annually. This compares to transmission cost of 424 million dollars annually, also in 2006 dollars. The result is a B/C ratio of 0.68.

The alternate interpretation of the results is that incremental cost at the source is 44.5 dollars per MWh, while incremental cost at the sink is 63.5 dollars per MWh. The opportunity cost savings of 19 dollars per MWh is less than the transmission line cost of 28 dollars per MWh. The result is a B/C ratio of 0.68.

Again, TOD effects are not included in this analysis. The regional cost difference (and the resulting B/C ratio) may change accordingly.

Case 4

Case 4 results are displayed in Figure 9. Case 4 compares wind resources in Wyoming with a mix of renewable resources in California. This case may be interpreted as representing a tight market for renewables in California, in which the incremental renewable resources in California are a mix of higher-cost resources and not exclusively wind. A related interpretation is of a policy scenario representing a higher Renewable Portfolio Standard (RPS) in California, requiring incremental supply to include higher-cost resources, not just wind. Yet another interpretation is that a diversified portfolio of California renewables is desirable, and the incremental mix includes wind and other resources.

The resource mix at the source is 3600 MW of wind, the same as in cases 1 and 3. The resource mix at the sink is 2400 MW of wind, 750 MW of geothermal, and 405 MW of concentrating solar power. This resource mix at the sink has corresponds to 55% wind, 35% geothermal, and 10% CSP.

The energy balance is the same as in cases 1 and 3: 15,137 GWh, corresponding to a line utilization factor of 58%. The dependable capacity at source and sink are comparable, and there is little net benefit attributed to the Wyoming resource.

Energy benefits are 32.4 dollars per MWh, levelized. This corresponds to 490 million dollars annually, in 2006 dollars. The energy benefits result from the higher average cost of the California incremental mix.

Because incremental resources at both source and sink are solely renewable resources, there is no GHG adder benefit attributed to substituting renewable energy with wind energy. Of course there is GHG benefit from the Wyoming wind resource; however, this analysis compares the Wyoming wind resource to incremental renewable resources in California, and so there is no net GHG benefit when incremental wind energy substitutes for incremental renewable energy.

The benefits sum to 443 million dollars annually. This compares to transmission cost of 424 million dollars annually, also in 2006 dollars. The result is a B/C ratio of 1.04.

The alternate interpretation of the results is that incremental cost at the source is 44.5 dollars per MWh, while incremental cost at the sink is 73.7 dollars per MWh. The opportunity cost savings of 29.2 dollars per MWh is greater than the transmission line cost of 28 dollars per MWh. The result is a B/C ratio of 1.04.

Again, TOD effects are not included in this analysis. While the CSP resource may cost more than wind, it is likely to be generating at peak, so its MWh are more valuable. Similarly, geothermal is a baseload resource; it may have more favorable TOD patterns than intermittent wind. Overall, TOD effects associated with the California incremental mix is likely to result in somewhat lower B/C ratio.

Table 14
Results for Four Cases

Case	Source: Wyoming	Sink: California	Line Utilization	Regional Basis	Line Cost	B/C Ratio
				$/MWh	$/MWh	
1	• 3600 MW wind	• 2215 MW Combined Cycle	58%	35.9	28.0	1.28
2	• 2600 MW wind • 1000 MW IGCC with CO_2 Sequestration	• 2625 MW Combined Cycle	68%	27.0	23.6	1.14
3	• 3600 MW wind	• 4868 MW wind	58%	19.0	28.0	0.68
4	• 3600 MW wind	• 2400 MW wind • 750 MW geothermal • 405 MW CSP	58%	29.2	28.0	1.04

Figure 6
Case 1 Results

Wyoming Wind (3600 MW) vs. California Combined Cycle (2215 MW)

	Financing	Installed Capacity MW	Energy GWh
Source: Montana/Wyoming			
Wind - Wyoming	Merchant	3,600	15,137
Sink: California			
Combined Cycle - CA	Merchant	2,215	15,137

Trans Option No.	7b	Installed Cost ($Million)	4,300
		Capacity (MW)	3,000
Description	Wyoming - Mona (Utah) - S. Nevada - Southern CA		
Line Utilization	58%		

	($/MWh)	Regional Difference Source ($/MWh)	Sink ($/MWh)	Diff ($/MWh)	Annual Benefits ($Million)	Annual Cost ($Million)
Line Cost	28.0					424
Power Cost		39.8	66.5	26.7	405	
GHG Adder		0.0	16.0	16.0	242	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		3.0	0.0	-3.0	-45	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		1.7		-1.7	-25	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-2.1	-2.1	-32	*
TOTAL		44.5	80.4	35.9	544	424
Benefit to Cost Ratio	**1.28**					

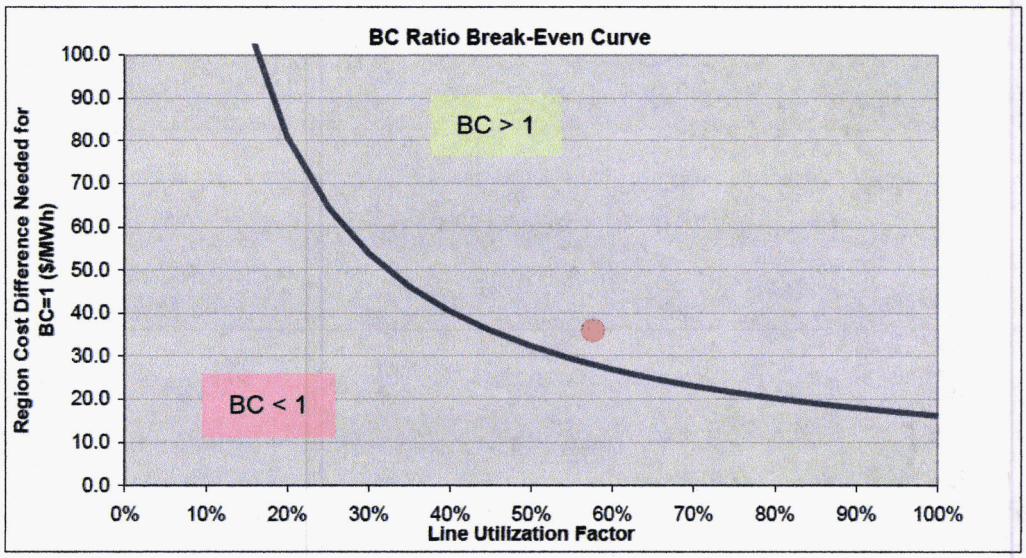


Figure 7
Case 2 Results

Wyoming Wind (2600 MW) and Clean Coal with CO_2 Sequestration (1000 MW) vs. California Combined Cycle (2625 MW)

	Financing	Installed Capacity MW	Energy GWh
Source: Montana/Wyoming			
Coal - WY Sequestration	Merchant	1,000	7,008
Wind - Wyoming	Merchant	2,600	10,932
Sink: California			
Combined Cycle - CA	Merchant	2,625	17,940

Trans Option No.	7b	Installed Cost ($Million)	4,300
		Capacity (MW)	3,000
Description	Wyoming - Mona (Utah) - S. Nevada - Southern CA		
Line Utilization	68%		

	($/MWh)	Regional Difference Source ($/MWh)	Sink ($/MWh)	Diff ($/MWh)	Annual Benefits ($Million)	Annual Cost ($Million)
Line Cost	23.6					424
Power Cost		51.2	66.5	15.3	275	
GHG Adder		2.4	16.0	13.6	244	
CO2 for EOR		-3.4	0.0	3.4	61	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		1.8	0.0	-1.8	-33	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		2.2		-2.2	-39	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-1.4	-1.4	-24	*
TOTAL		54.2	81.2	27.0	484	424
Benefit to Cost Ratio	**1.14**					

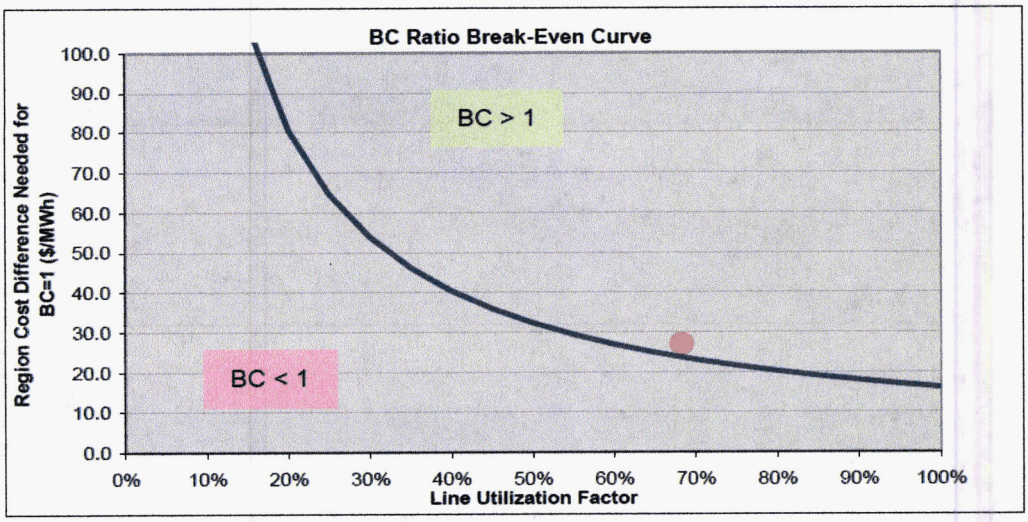


Figure 8
Case 3 Results

Wyoming Wind (3600 MW @ 48% capacity factor) vs.
California Wind (4868 MW @ 35.5% capacity factor)

	Financing	Installed Capacity MW	Energy GWh
Source: Montana/Wyoming			
Wind - Wyoming	Merchant	3,600	15,137
Sink: California			
Wind - California	Merchant	4,868	15,137

TOTAL SYSTEM				
Trans Option No.	7b		Installed Cost ($Million)	4,300
			Capacity (MW)	3,000
Description	Wyoming - Mona (Utah) - S. Nevada - Southern CA			
Line Utilization	58%			

	($/MWh)	Regional Difference Source ($/MWh)	Sink ($/MWh)	Diff ($/MWh)	Annual Benefits ($Million)	Annual Cost ($Million)
Line Cost	28.0					424
Power Cost		39.8	59.5	19.7	298	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		3.0	3.0	0.0	0	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		1.7		-1.7	-25	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			1.0	1.0	15	*
TOTAL		44.5	63.5	19.0	287	424
Benefit to Cost Ratio	**0.68**					

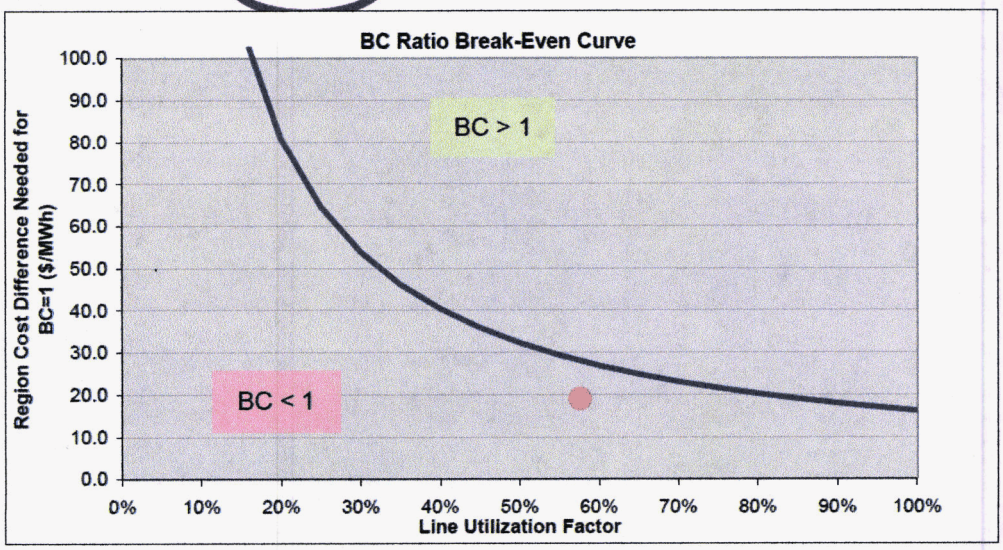


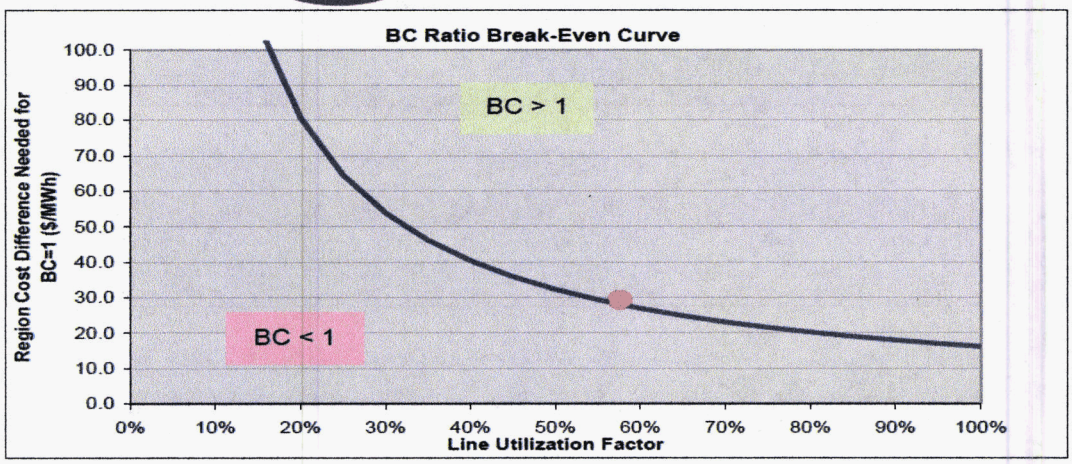
Figure 9
Case 4 Results

Wyoming Wind (3600 MW) vs. 3555 MW of California Renewable
(55% wind, 35% geothermal, 10% concentrating solar power)

	Financing	Installed Capacity MW	Energy GWh
Source: Montana/Wyoming			
Wind - Wyoming	Merchant	3,600	15,137
Sink: California			
Wind - California	Merchant	2,400	7,464
Geothermal	Merchant	750	6,242
Solar Concen. - CA	Merchant	405	1,432

Trans Option No.	7b	Installed Cost ($Million)	4,300
		Capacity (MW)	3,000
Description	Wyoming - Mona (Utah) - S. Nevada - Southern CA		
Line Utilization	58%		

	($/MWh)	Regional Difference Source ($/MWh)	Sink ($/MWh)	Diff ($/MWh)	Annual Benefits ($Million)	Annual Cost ($Million)
Line Cost	28.0					424
Power Cost		39.8	72.2	32.4	490	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		3.0	1.6	-1.4	-21	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		1.7		-1.7	-25	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-0.1	-0.1	-1	*
TOTAL		44.5	73.7	29.2	443	424
Benefit to Cost Ratio	1.04					



Sensitivities

At the outset, before any analysis was performed, the Economic Analysis Subcommittee identified critical uncertainties that would drive results. Commodity prices and technology costs were identified as critical uncertainties. Thus, sensitivities were performed on natural gas price, value of the GHG adder, and costs for clean coal technology including IGCC and CO_2 sequestration. As the Economic Analysis Subcommittee performed its analyses, capacity factor of the gas-fired CC emerged as an uncertainty the effects of which were worth investigating. This section presents some of the sensitivity analyses performed by the Economic Analysis Subcommittee.

Natural Gas Price

Case 1 compares Wyoming wind and California CC resources. The cost of the California CC is highly sensitive to natural gas prices. Figure 10 displays how the B/C ratio changes as natural gas prices change. The horizontal axis indicates values for natural gas price from 3.50 to 9.00 per MMBtu (levelized for the period 2015-2034, in 2006 dollars), the lower and upper levels of the FEAST reference data set. The vertical axis indicates the B/C ratio. The blue line plots how B/C ratio varies with natural gas price. The red dot indicates the case 1 result, with natural gas price at 6 dollars per MMBtu (reference data set value) and B/C ratio equal to 1.28. The horizontal green line represents B/C ratio at 1.0.

As anticipated, the B/C ratio increases as natural gas price increases. The slope of the blue line is quite steep. The B/C ratio equals 1.0 at approximately 4.80 dollars per MMBtu, levelized for the period 2015-2034, in 2006 dollars. As natural gas price increases, the Frontier Line appears more beneficial.

Figure 11 displays, for case 2, how B/C ratio changes as natural gas prices change. The slope of the blue line is even steeper than it is in case 1, largely because more MWs of gas-fired CC are in the California incremental mix.

GHG Adder

Figure 12 displays, for case 2, how the B/C ratio changes as the value of the GHG adder changes. Case 2 compares Wyoming wind and clean coal resources with California CCs. Higher GHG adder is associated with more costs for the California resources and thus greater benefit for the Frontier Line, since wind resources have no GHG emissions and clean coal has little GHG emissions. The red dot indicates the case 2 result, with GHG adder at 40 dollars per ton of CO_2 equivalent (reference data set value) and B/C ratio equal to 1.14. The B/C ratio equals 1.0 at approximately 30 dollars per ton of CO_2 equivalent. The slope of the blue line is somewhat steep. As GHG adder increases, the Frontier Line appears more beneficial.

Cost of Clean Coal and CO_2 Sequestration

Figure 13 displays, for case 2, how the B/C ratio changes as the capital cost for clean coal changes. Case 2 compares Wyoming wind and clean coal resources with California CCs. As capital cost for clean coal increases, B/C ratio decreases. The red dot indicates the case 2 result, with capital cost at 2650 dollars per kW (reference data set value) and B/C ratio equal to 1.14. The B/C ratio equals 1.0 at approximately 3100 dollars per kW for capital cost. The slope of the blue line is not steep. As capital cost increases, the Frontier Line appears less beneficial.

Capacity Factor of CC

The reference data set has the capacity factor for a California CC at 78%. This may be a typical value from production simulation runs. Capacity factors for actual operating CCs seem to be lower. Option models may yield even lower capacity factors, such as 50%. Table 15 displays, for cases 1 and 2, the B/C ratios corresponding to CC capacity factor of 50%. As the capacity factor of the California CC decreases, the B/C ratio increases. As discussed above, this analysis does not include the value of dispatchability or TOD effects, which would tend to lower the B/C ratios reported here.

Table 15

Sensitivity to CC Capacity Factor

			B/C Ratio	
Case	Source: Wyoming	Sink: California	CC @ 78% Capacity Factor	CC @ 50% Capacity Factor
1	3600 MW wind	2215 MW Combined Cycle	1.28	1.62
2	2600 MW Wind, 1000 MW IGCC w/ Sequestration	2625 MW Combined Cycle	1.14	1.54

Figure 10

Case 1: Sensitivity to Natural Gas Price

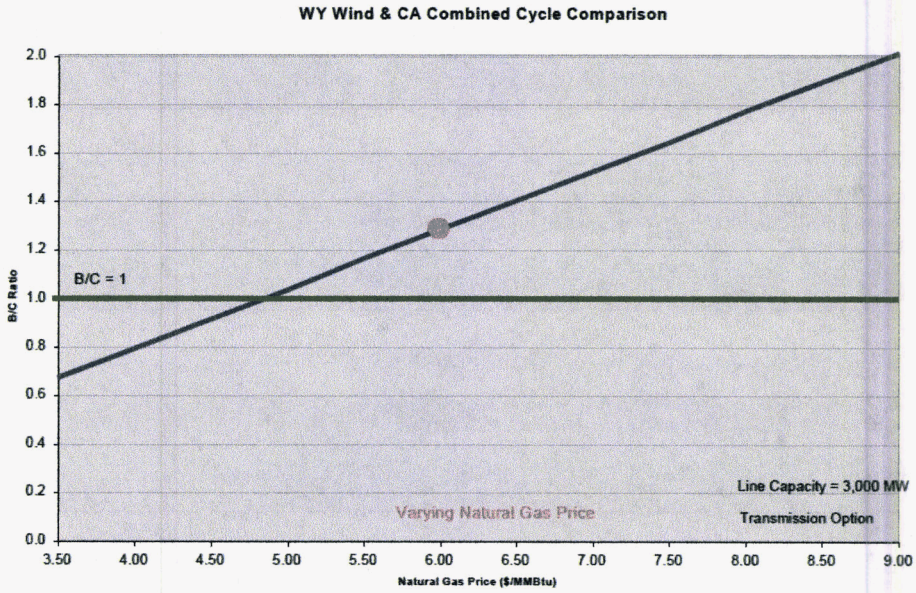


Figure 11

Case 2: Sensitivity to Natural Gas Price

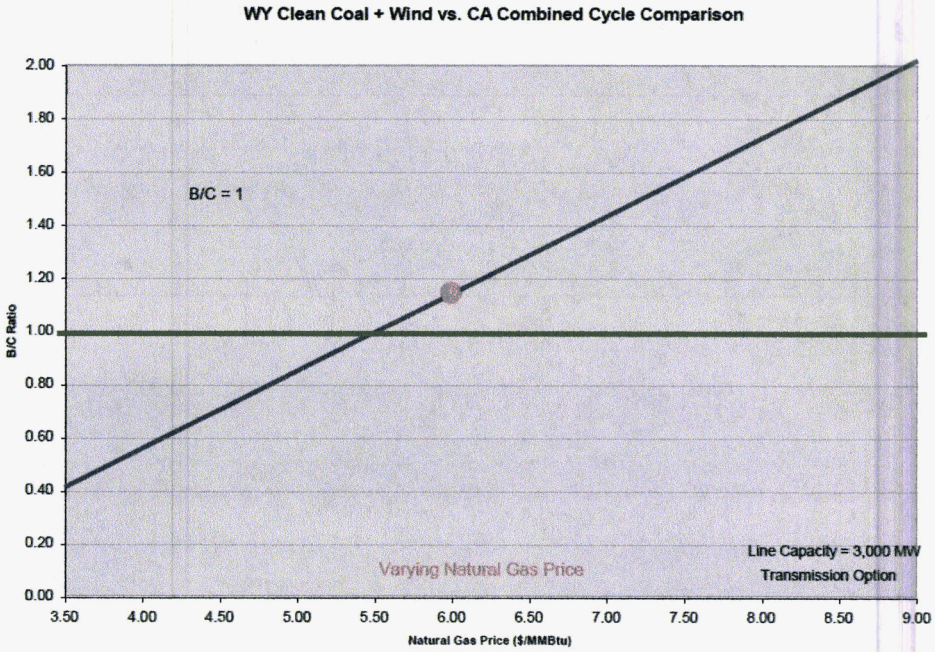


Figure 12
Case 2: Sensitivity to GHG Adder

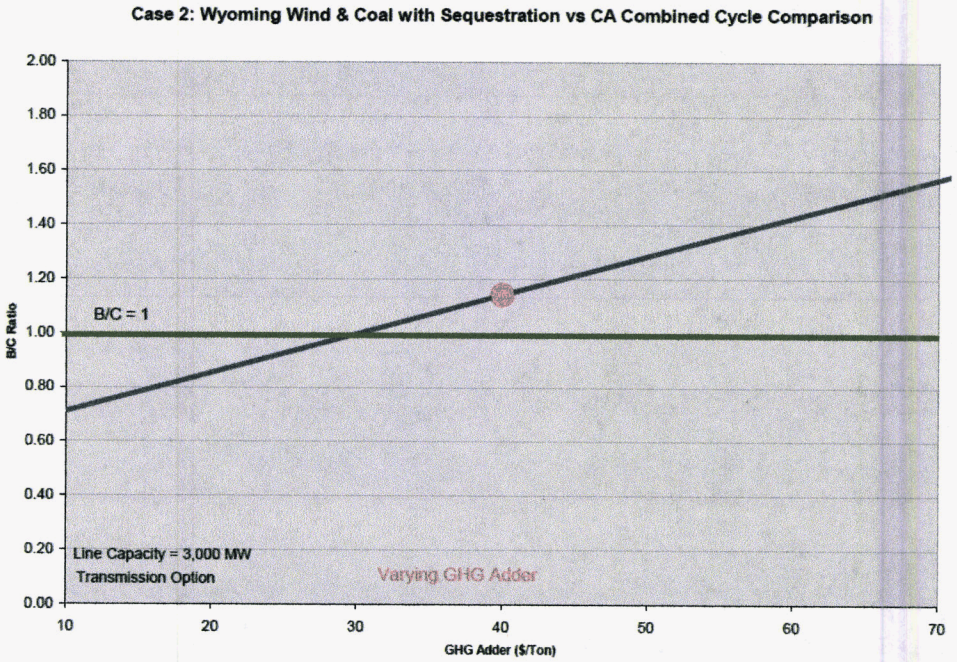
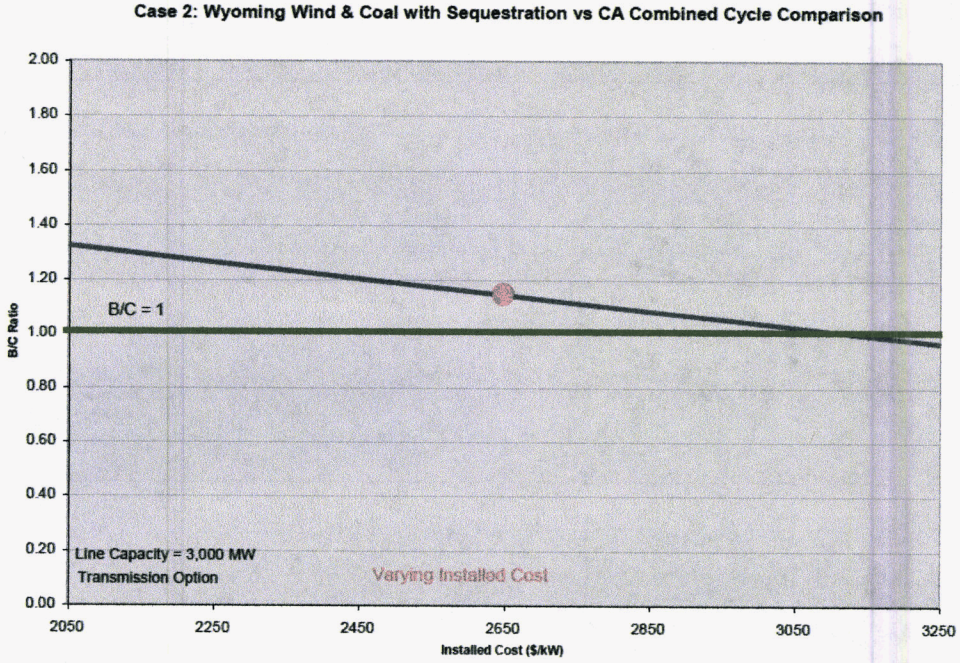


Figure 13
Case 2: Sensitivity to Cost of Clean Coal and CO_2 Sequestration



Transmission Configurations

The Economic Analysis Subcommittee focused its efforts on analyzing a backbone transmission configuration. Transmission alternative 7b was identified as the "backbone" configuration. This is a 4.3 billion dollar, 3000 MW AC line from Wyoming to southern California with intermediate connection points in Utah and Nevada. The annualized cost for this line is 424 million dollars (in 2006 dollars).

Two additional analyses are presented here to provide information on the implied values of intermediate points as on-ramps/off ramps, and to narrow the transmission option possibilities.

Case 1 with DC Line

In general, direct current (DC) transmission options have lower cost than comparable AC transmission options. However, one drawback of a DC line is the elimination of intermediate points as on-ramps or off-ramps for power delivery or pickup. By comparing an AC configuration with a DC configuration and estimating the cost savings, the Economic Analysis Subcommittee attempted to identify an implied value or break-even value for the presence of intermediate points.

Case 1 included transmission alternative 7b, the AC line. Transmission alternative 5a is for a DC line from Wyoming to southern Nevada, and AC from southern Nevada to southern California. The capital cost for transmission alternative 7b is 3.3 billion dollars, one billion dollars less than for the AC line (alternative 7b). The lower capital cost translates to an annualized cost 96 million[9] dollars lower. This can be viewed as the "break-even" implied value of immediate points. In other words, the on-ramps and off-ramps associated with the AC line from Wyoming through Utah to southern Nevada need to generate an annual benefit of at least 96 million dollars (in 2006 dollars) to economically support the choice of AC rather than DC. Of course, this analysis does not include other attributes that may distinguish the AC line from the DC line, such as incremental effects of reliability and congestion.

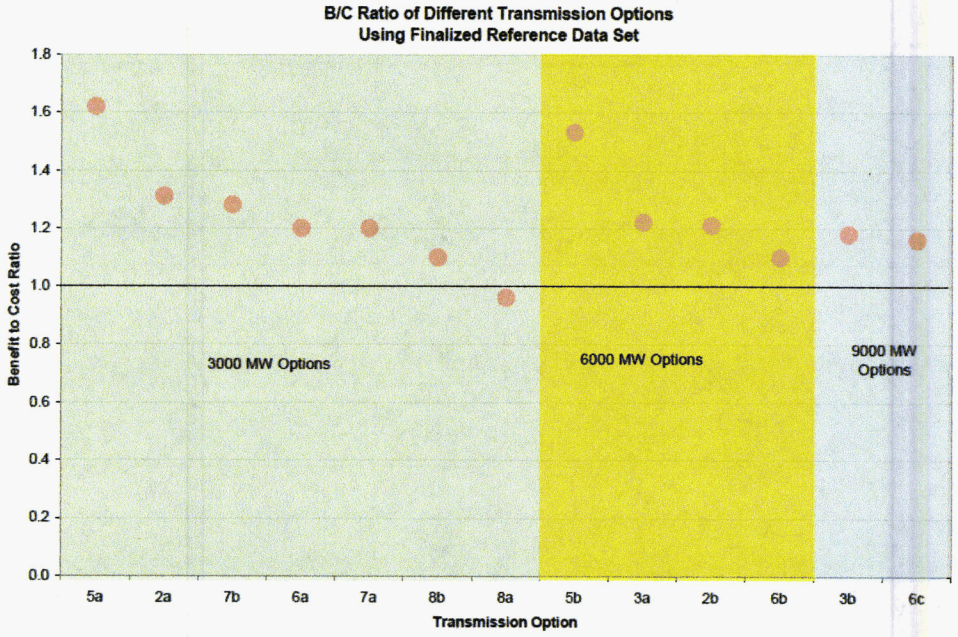
Case 1 with Other Transmission Configuration

To provide information on the other transmission configurations, Case 1 was repeated for all transmission configurations from Wyoming to southern California identified by the Transmission Subcommittee. In performing this screening analysis, the amount of source and sink resources was increased, if necessary, to match the different line capacity. For example, for transmission configuration 5b, which is a 6000 MW line from Wyoming to southern California with southern Nevada as an intermediate point, the amount of Wyoming wind was increased to 6600 MW. Figure 14 displays the results. While preliminary analysis suggested greater benefit in a smaller-size transmission line, the finalized results presented here are not conclusive.

[9] To simplify this comparison, difference in transmission losses was ignored since DC construction should have slightly lower transmission losses than AC construction.

Figure 14

B/C Ratios for Various Transmission Configurations[10]



Combinations		Straight Line Mileages	Capacity (MW)	Transmission Type	Estimated Installation Cost (in $Million)	Line Losses @ full load
2a	Wyoming - N.E. Nevada - S. Nevada - Southern CA	1230	3000	AC & DC	4,100	7%
2b	Wyoming - N.E. Nevada - S. Nevada - Southern CA	2460	6000	AC & DC	8,100	7%
3a	Wyoming - N.W. Nevada - Northern CA - Southern CA; Northwest - Northern CA	2370	6000	AC & DC	8,100	6%
3b	Wyoming - N.W. Nevada - Northern CA - Southern CA; Northwest - Northern CA	3690	9000	AC & DC	12,000	7%
5a	Wyoming - S. Nevada - Southern CA	1090	3000	AC & DC	3,300	6%
5b	Wyoming - S. Nevada - Southern CA	2170	6000	AC & DC	6,400	6%
6a	Wyoming - Arizona - Southern CA	1590	3000	AC & DC	4,400	8%
6b	Wyoming - S. Nevada - Arizona - Southern CA; Wyoming - Arizona - Southern CA	3170	6000	AC & DC	8,800	8%
6c	Wyoming - S. Nevada - Arizona - Southern CA; Wyoming - Arizona - Southern CA; Wyoming - Mona (Utah) - S. Nevada - Southern CA	4260	9000	AC & DC	12,300	7%
7a	Wyoming - Mona (Utah) - N.E. Nevada - S. Nevada - Southern CA	1250	3000	AC	5,000	5%
7b	Wyoming - Mona (Utah) - S. Nevada - Southern CA	1092	3000	AC	4,300	4%
8a	Wyoming - Midpoint (Idaho) - N.E. Nevada - S. Nevada - Southern CA	1400	3000	AC	5,700	5%
8b	Wyoming - Midpoint (Idaho) - N.W. Nevada - Northern CA	1210	3000	AC	5,000	5%

[10] Figure 14 in this report supersedes a similar chart (slide No. 41) presented at the 19 March 2007 Stakeholder Meeting. There were some errors in the chart presented at the Stakeholder Meeting; the errors have been corrected in the chart presented in Figure 14.

Findings

Benefit-cost analysis performed by the Economic Analysis Subcommittee leads to the following findings regarding the Frontier Line:

1) The benefits of the Frontier Line appear greater than the costs under a variety of plausible conditions.
2) Uncertainty associated with key inputs results in a wide range of benefit-cost outcomes.
    a. Economics of the Frontier Line are very sensitive to natural gas prices. Higher natural gas prices favor the development of the Frontier Line.
    b. Economics of the Frontier Line are sensitive to values for GHG adder. Higher values for GHG adder favor the development of the Frontier Line.
    c. Economics of the Frontier Line are somewhat sensitive to capital costs for clean coal technologies, including IGCC and CO_2 sequestration. Lower capital costs favor the development of the Frontier Line.
3) The results are inconclusive with respect to sizing the Frontier Line.
4) Assessing the economics of AC vs. DC configurations requires careful analysis of the benefits associated with intermediate points.

Appendix 1

Members of the WRTEP Economic Analysis Subcommittee

- PG&E: Jim Filippi, Curt Hatton, Eric Law, Tom Miller, Todd Strauss, Manho Yeung
- SDG&E: Jan Strack, Lawrence Truong
- SCE: Darell Holmes
- Sierra Pacific and Nevada Power: Mario Villar, Jim McMorran
- PacifiCorp: Kurt Granat
- APS: Paul Smith
- PNM: Mike D'Antonio
- Wyoming, Governor's Office: Steve Ellenbecker
- Montana, Governor's Office: Evan Barrett
- Environmental Defense: Jeff Greenblatt
- Sierra Club: Tricia Mynster
- CEERT: Dave Olsen
- NAPG: Dennis Pungitore, Mike Ruffatto
- Trans-Elect: Jerry Vaninetti
- National Grid: Robert Stade
- Invenergy: Mike Logsdon
- Shell Wind Energy: Kevin Simmons
- Shell Trading: Mike Evans
- SMUD: Dilip Mahendra
- Deseret Power: Curt Winterfield
- ITC: Joe Dudak
- TANC: Patrick Mealoy
- BP: Lisa Szot
- Energy Strategies: Kelly Francone
- Wyoming Infrastructure Authority: Steve Waddington
- Wyoming Business Council: Ted Ladd
- ABB: Lan Trinh
- Babcock & Brown: David Parquet
- IES: Curt Hildebrand
- KEMA: Mani Venkata
- Woodruff Expert Services: Kevin Woodruff
- Global Energy Decisions: Rich Lauckhart
- Electric Power Group: Fred Mobasheri
- Policy Communications: Jim Sims
- New Energy Associates: Brent Hendrickson
- Aspen Environmental Group: Carl Linvill

Appendix 2

Activities of the WRTEP Economic Analysis Subcommittee

5/16/06	Steering Committee authorized formation of the Economic Analysis Subcommittee and appointed Ben Morris of PG&E as interim Chair.
6/9/06	Todd Strauss of PG&E becomes Chair of Economic Analysis Subcommittee.
8/9/06	*Las Vegas Stakeholder Meeting.* Initial analytical framework presented. Initial call issued for stakeholders to join Economic Analysis Subcommittee.
11/2/06	*Salt Lake City Stakeholder Meeting.* Methodology and analytics utilizing spreadsheet-based screening tool described. Second call issued for stakeholders to join Economic Analysis Subcommittee.
11/8/06	*Conference call.* Discussed spreadsheet-based screening tool, inputs, and outputs. Rich Lauckhart of Global Energy Decisions identified as lead for inputs on greenhouse gas adder. Todd Strauss identified as lead for inputs on natural gas prices.
11/15/06	*Conference call.* Discussed spreadsheet-based screening tool, inputs, and outputs. Jerry Vaninetti of Trans-Elect identified as lead for inputs on coal prices and capital costs for coal-fired generation, including CO2 capture.
11/16/06	Darell Holmes of SCE distributed, to Economic Analysis Subcommittee, list of 22 possible benefits associated with Frontier Line. Top four benefits identified for consideration in analysis.
11/20/06	PG&E distributed design document for spreadsheet-based screening tool to Economic Analysis Subcommittee for review.
11/21/06	Dave Olsen of CEERT identified as lead for inputs on renewable technologies, including costs and capacity factors.
11/22/06	*Conference call.* Discussed design document for spreadsheet-based screening tool, and inputs. Spreadsheet-based screening tool named Frontier Economic Analysis Screening Tool (FEAST).
11/29/06	*Conference call.* Discussed agenda for Dec. 5 Economic Analysis Subcommittee meeting, key drivers and inputs, and scenarios from Load and Resources Subcommittee.
11/30/06	FEAST prototype (version 1.0) circulated to Economic Analysis Subcommittee.
12/5/06	*Economic Analysis Subcommittee meeting in San Francisco.* Performed in-depth review of FEAST, and inputs for renewables, coal, natural gas, and greenhouse gas adders. Curt Hatton of PG&E identified as lead for inputs on natural gas prices and capital costs for gas-fired generation.

12/13/06	*Conference call.* Discussed inputs: generation resources by location.
12/20/06	*Conference call.* Discussed FEAST development.
1/1/07	FEAST version 2.0 released.
1/4/07	*Economic Analysis Subcommittee meeting in San Francisco.* FEAST, inputs, and initial analytical results reviewed.
1/8/07	FEAST version 2.1 released.
1/10/07	*Webinar.* For Economic Analysis Subcommittee. FEAST reviewed.
1/11/07	FEAST version 2.1R released. Analytical results distributed to Economic Analysis Subcommittee.
1/11/07	*Conference call.* Discussed analytical results.
1/17/07	*Conference call.* Discussed analytical results and prospective analyses.
1/23/07	*Steering Committee meeting in San Francisco.* FEAST, inputs, and preliminary analytical results presented.
1/24/07	*Conference call.* Discussed feedback from Steering Committee.
1/31/07	*San Diego Stakeholder Meeting.* FEAST and inputs presented. Third call issued for stakeholders to join Economic Analysis Subcommittee.
1/31/07	*San Diego Stakeholder Meeting.* FEAST and inputs presented. Third call issued for stakeholders to join Economic Analysis Subcommittee.
2/7/07	*Conference call.* Discussed feedback from Stakeholder Meeting.
2/14/07	*Economic Analysis Subcommittee meeting in San Francisco.* Reference set of inputs reviewed. Analytical results reviewed.
2/21/07	*Conference call.* Discussed inputs.
2/28/07	*Conference call.* Discussed inputs.
3/5/07	FEAST version 3.0 released.
3/7/07	*Conference call.* FEAST version 3.0 discussed. Updated results discussed.
3/14/07	*Conference call.* Results and findings discussed.
3/15/07	*Webinar.* FEAST presented to WECC.
3/19/07	*Las Vegas Stakeholder Meeting.* Results and findings presented.
3/21/07	*Conference call.* Discussed feedback from Stakeholder Meeting.
4/23/07	Draft report posted on Frontier Line web site.
4/27/07	Final report accepted by Steering Committee.

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-03

Table 4-36. Present, Future, and Reasonably Foreseeable Future Renewable Energy Projects				
Name	**County**	**Land Area (acres)**	**Generation (MW)**	**Status**
La Sierrita Wind, LLC/Invenergy	San Miguel	5,783	N/A	Future
Cedar Hills Wind, LLC/First Wind	Torrance	4,640	N/A	Future
Red Canyon Wind, LLC/First Wind	Torrance	12,576	N/A	Future
New Mexico Renewable, LLC	Union, Torrance, and Chaves	21,429	N/A	Future
Wind Projects – Arizona				
Type 2 Wind Application; Tucson BLM Field Office[1]	Pinal	10,115	N/A	Future
Red Horse Wind 2	Cochise	5,760	51	RFF
Geothermal Projects – New Mexico				
Lighting Dock (Raser Technologies)[1]	Hidalgo	N/A	10	Future

[1] These projects are also included in Table 4-35. Some of these projects are located outside of the project area but within a resource cumulative analysis area
N/A indicates information is not available
PV – photovoltaic
RFF – reasonably foreseeable future

Along with the existing and planned renewable energy projects identified above, transmission facilities other than the proposed Project could be built. For these projects, land area requirements for access roads and transmission facilities should be considered for cumulative effects.

Land area for access roads for transmission facilities could range from 1.6 acres per mile up to 6.7 acres per mile, depending on slope and distance to existing access roads.

Land area for transmission facilities, which includes construction yards, concrete batch plants, laydown sites, wire pulling and tensioning sites, and wire splicing sites for 115 kV line, is assumed to be 3 acres per mile.

4.17.3.3 Energy Development Forecast Analysis

As identified in Chapter 1, the Project is proposed to increase transfer capability in an electrical grid that is currently insufficient to support the development, access, and transport of additional energy-generating resources, including renewable energy, in New Mexico and Arizona. It is the intent of the Applicant to provide infrastructure to increase transfer capability in areas of potential renewable energy generation. Increasing interstate transfer capability and access to renewable resources is needed to meet federal energy policy objectives, such as the EPAct of 2005, as well as state RPS.

The Applicant's purpose for the proposed Project is to provide access to renewable energy resources in the Southwest and to increase general reliability. At this time, the Applicant is not accepting, reviewing, or processing any interconnection requests. In addition, the BLM is unaware of any generators planning to interconnect with the SunZia Project. In light of the Applicant's stated purpose, an attempt to provide an analytical tool has been developed herein to

provide a means to assess the cumulative effects of the types of renewable energy projects that may ultimately interconnect with the Project. These development scenarios are offered as analytical tools, and not meant to imply that there are currently specific or known cumulative effects from generators.

A Final Wind PEIS (BLM 2005) and a Final Solar PEIS (BLM and DOE 2012) have been used to assess cumulative impacts, alternatives, and mitigation measures associated with wind and solar energy development on BLM-administered land. The Restoration Design Energy Project completed by the Arizona State BLM Office, intended to identify suitable areas for renewable energy development in Arizona, was also assessed during the cumulative analysis.

Renewable Energy Development Setting

New Mexico

Wind: New Mexico ranks seventeenth in total wind capacity installed in the United States, and twelfth in wind potential; with an annual potential estimated to be 435 million MWh (AWEA 2011; New Mexico Energy 2011a). Current wind development within New Mexico is located primarily on its central and eastern plains. New Mexico has the potential to produce many times its own electrical need, which puts it in a position to export wind electricity.

Solar: New Mexico contains some of the best potential for solar energy development, and ranks second for potential solar power in the United States (New Mexico Energy 2011b).

Geothermal: In New Mexico, low (less than 190 degrees Fahrenheit), moderate (190 to 300 degrees Fahrenheit), and high (greater than 350 degrees Fahrenheit) temperatures for geothermal resources can be found in many locations throughout the state (Bland 2010). Areas along the Rio Grande corridor and the southwest corner of the state provide some of the best geothermal resources, but few areas in these locations have been developed. The majority of current geothermal uses in New Mexico are for spas, space heating, greenhouses, and fish farms.

Arizona

Wind: A 2003 wind energy survey conducted by the National Renewable Energy Laboratory (NREL) identified several areas in the state as having commercial-grade wind resources. According to NREL Data, wind speeds and conditions are greater in the northern portion of the state. The potential for wind development for the state of Arizona is more than 30 million MWh (AWEA 2011); annual wind speed averages at 50 meters above the ground greater than 16 mph (NAU 2011).

Solar: Arizona is among the four states with the highest concentrations of solar resources (NREL, WREZ 2009). There is a large potential for solar energy development in Arizona due to land availability, identified solar resources, and the state's goal of accelerating renewable energy development through incentives and the ACC-mandated renewable energy standards (RES). The land and water resources in Arizona are sufficient to support the amount of solar generation that would be required to meet RES requirements for the next 20 years (Frisvold 2009).

Geothermal: These resources are present in Arizona, especially in the south. While Arizona does not contain any high (greater than 350 degrees Fahrenheit) temperatures for geothermal resources, there is substantial heat flow that could be used. Arizona geothermal potential is in the low-to-moderate range, which is excellent for geothermal heat pumps and space heating, as opposed to electricity generation, which requires a higher temperature resource (Allison 2011).

Qualified Resource Areas

Qualified Resource Areas (QRA) were developed using the Western Renewable Energy Zones (WREZ) (WGA and DOE 2009) (Table 4-37; Figure 4-1, Figure 4-2 and Figure 4-3). The WREZ were developed in 2008 by the Western Governors' Association and the DOE, with the Zone Identification and Technical Analysis (ZITA) workgroup (WGA and DOE 2009).

Table 4-37. Potential Renewable Energy Resource Capacity by QRA in MW

QRA	Solar[1]	Wind[1]	Geothermal[1]
AZ-SO	6,623	0	—[2]
NM-CT	3,183	0	—[2]
NM-EA	83	11,290	—[2]
NM-SE[3]	0	1,894	—[2]
NM-SO	4,347	0	—[2]
NM-SW	6,149	0	—[2]
Total	**20,385**	**13,184**	**2,527**

[1] Source: Western Governors' Association. "Western Renewable Energy Zones-Phase One Report: Table 1 Renewable Energy Generating Capacity Summary." June 2009. Available at www.westgov.org/wga/publicat/WREZ09.pdf

[2] Geothermal sources are believed to exist within the study areas, because of the presence of geological systems that have been correlated with geothermal resource potential in other areas; but specific locations have not been identified.

[3] Although it is possible for the proposed Project to interconnect with NM-SE, the QRA is located at a distance that would make the feasibility of interconnection unlikely, and would only contribute marginally to the energy potential of the region when compared to the larger NM-EA QRA.

The criteria used in developing the WREZ for wind and solar included: (1) locations where NREL wind power class is 3 or greater, at 50 meters above the ground, and slope is less than 20 percent; (2) solar is greater than 6.5 kilowatt hours per square meter per day of direct normal insolation[1], and slope is greater than 2 percent. The QRA boundaries were defined to encompass areas within which future renewable energy generation projects could feasibly interconnect with facilities provided by existing local utility owners or the proposed Project.

Overall Potential of Renewable Resources within Qualified Resource Areas

Table 4-38 lists the overall potential generation capacities (in total megawatts) of renewable resources within QRAs that are within the vicinity of the proposed Project.

Summary of Present and Reasonably Foreseeable Future Renewable Energy Projects

Table 4-38 is a summary of the generating capacities and land areas of present renewable energy projects. Approximately 2,600 MW of solar power developments have been identified as

[1] The rate of delivery of direct solar radiation per unit of horizontal surface.

reasonably foreseeable future projects. According to available records, future wind development projects have been identified that could comprise more than 119,000 acres (see Table 4-36), primarily consisting of leases or options on New Mexico state lands.

It is assumed that large land leases will not be developed in their entirety; facility siting processes and future demand will determine the specific development configurations of wind generation facilities. These projects fall within or near the QRAs identified on Figure 4-2 and Figure 4-3, and in Table 4-37; and could interconnect with facilities provided by existing local utility owners or the proposed Project. Specific information is not available to determine the individual generating capacities, configuration, development timing, or impacts of these future wind projects. However, it is reasonable to assume that between 5,000 and 10,000 MW of wind generation capacity will be developed in the future, given the large land areas that have been leased or optioned, and the combined renewable energy potential of over 13,000 MW within these areas (Table 4-38).

Table 4-38. Existing Renewable Energy Projects within the Project Area[1,2]

		Wind	Solar
New Mexico	MW	342	49
	Land Area (acres)	Up to 17,000	Up to 500
Arizona	MW	0	2.6
	Land Area (acres)	0	Up to 21

[1] Includes projects that are currently in production of electricity or under construction within the study area and in proximity to the QRAs (see Figure 4-1)
[2] Megawatt total is based on existing Project information

Methods

A potentially large number of wind, solar, and geothermal development combinations could be considered; but for the purposes of this analysis, three energy development scenarios are provided, based on (1) the overall potential for renewable resources, (2) two transmission facility scenarios, and (3) typical renewable EDUs.

Overall Potential for Renewable Resources

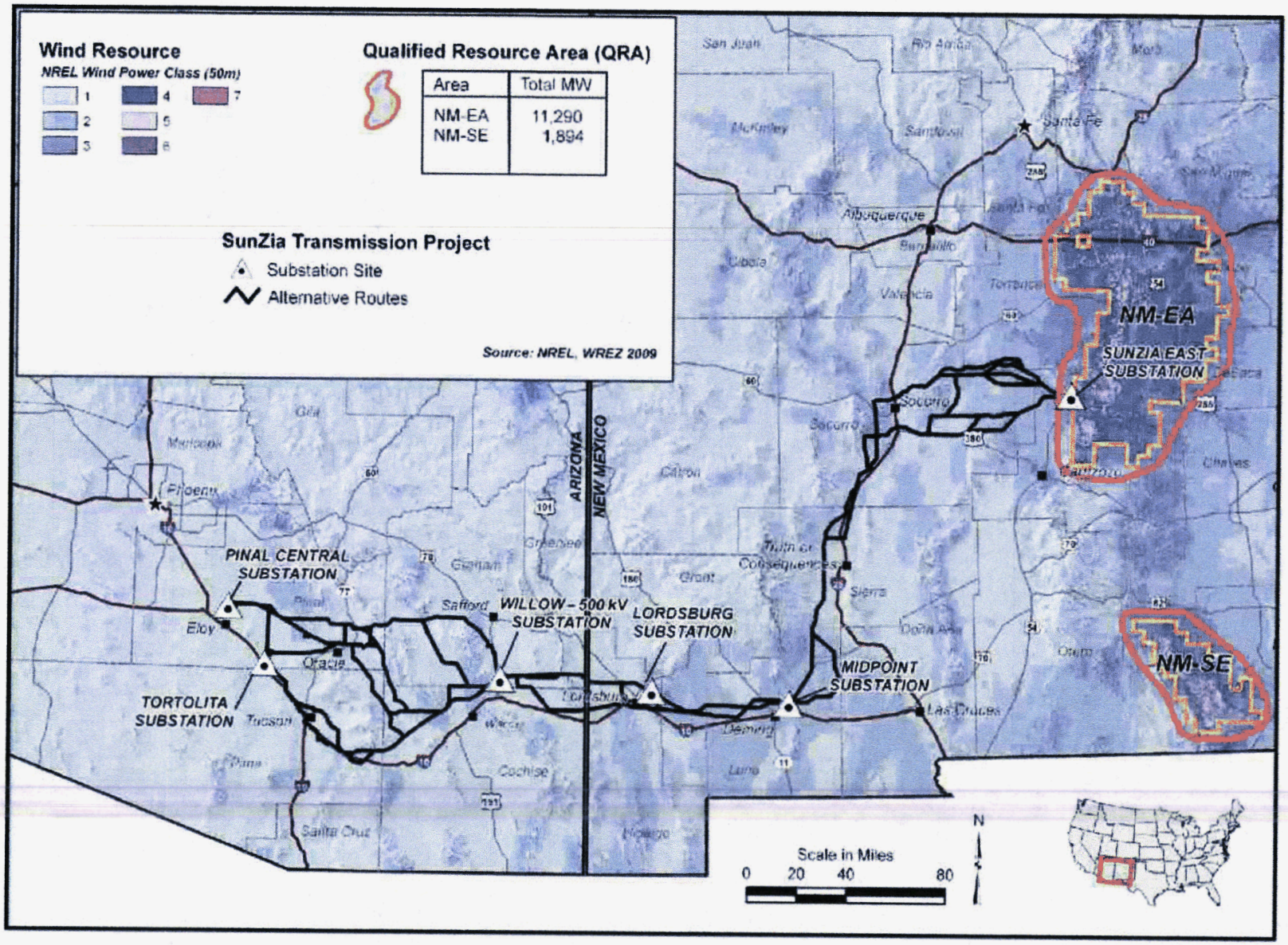
A reasonable overall potential for renewable resources is estimated based on the following four factors:

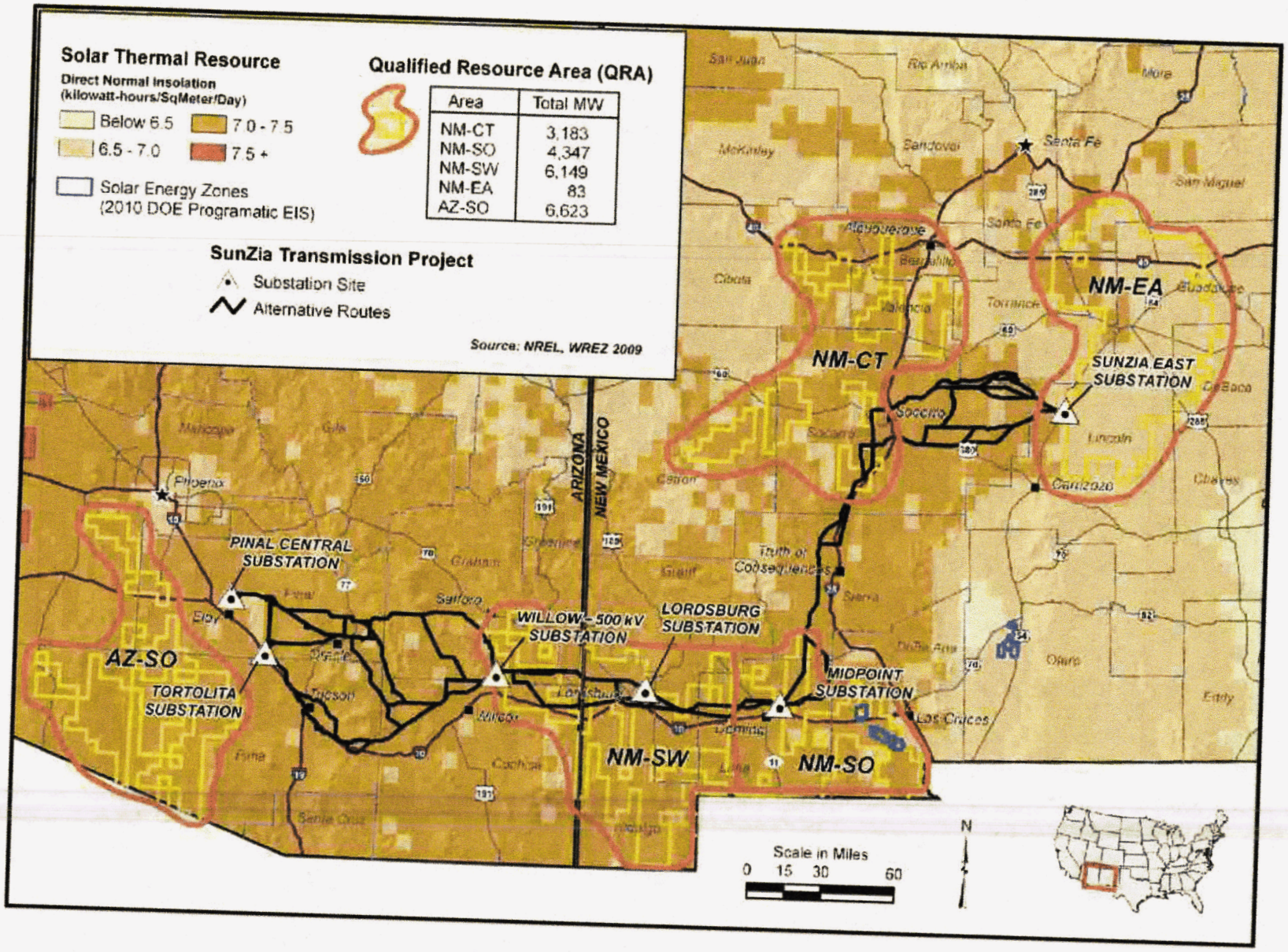
Physical potential areas identified within the western United States that exhibit the necessary qualities of raw renewable resource potential (WGA and DOE 2009)

Renewable portfolio standards adopted by individual states that provide market-based mechanisms to increase renewable energy generation (EPA 2009)

Development applications for leases to site individual renewable energy generation facilities on public land.

Interconnection requests (contractual or transactional) for potential generation projects to interconnect with existing transmission owners (see Table 1-2, Summary of Generation Interconnection Requests to Existing Transmission Owners within the Project Area).


Wind Resource
NREL Wind Power Class (50m)
1
2
3
4
5
6
7
Qualified Resource Area (QRA)
Area | Total MW
NM-EA | 11,290
NM-SE | 1,894
SunZia Transmission Project
Substation Site
Alternative Routes
Source: NREL, WREZ 2009
NM-EA
SUNZIA EAST SUBSTATION
NM-SE
PINAL CENTRAL SUBSTATION
WILLOW - 500 kV SUBSTATION
LORDSBURG SUBSTATION
MIDPOINT SUBSTATION
TORTOLITA SUBSTATION
ARIZONA
NEW MEXICO
Santa Fe
Albuquerque
Socorro
Phoenix
Eloy
Tucson
Safford
Las Cruces
Deming
Scale in Miles
0 20 40 80
N


Solar Thermal Resource
Direct Normal Insolation
(kilowatt-hours/SqMeter/Day)
Below 6.5
6.5 - 7.0
7.0 - 7.5
7.5 +
Solar Energy Zones
(2010 DOE Programatic EIS)
Qualified Resource Area (QRA)
Area | Total MW
NM-CT | 3,183
NM-SO | 4,347
NM-SW | 6,149
NM-EA | 83
AZ-SO | 6,623
SunZia Transmission Project
Substation Site
Alternative Routes
Source: NREL, WREZ 2009
NM-CT
NM-EA
NM-SW
NM-SO
AZ-SO
SUNZIA EAST SUBSTATION
PINAL CENTRAL SUBSTATION
TORTOLITA SUBSTATION
WILLOW-500 kV SUBSTATION
LORDSBURG SUBSTATION
MIDPOINT SUBSTATION
ARIZONA
NEW MEXICO
Phoenix
Tucson
Albuquerque
Santa Fe
Socorro
Truth or Consequences
Las Cruces
Scale in Miles
0 15 30 60
N

Transmission Facility Scenarios

The following two combinations of transmission facilities are considered by the proposed Project:

> *Option A* – Construction of two 1,500 MW AC transmission facilities, with a combined total of 3,000 MW transmission capability
>
> *Option B* – Construction of one 1,500 MW AC and one 3,000 MW DC transmission facility, with a combined total of 4,500 MW transmission capability

Typical Potential Renewable Energy Development Units

Renewable EDUs represent the likely incremental building blocks of renewable energy projects that could be economically constructed. Individual renewable energy projects could consist of multiple EDUs. Four potential types of renewable EDUs that could interconnect with the SunZia transmission lines include a 100 MW solar PV facility, a 160 MW solar thermal facility, a 100 MW wind facility, and a 50 MW geothermal facility.

Energy Development Scenarios

Using the overall potential for renewable resources, two different transmission facility scenarios identified for the proposed Project, and the EDUs identified above, two energy development scenarios were developed and are described below (options A and B). Option A is based on the assumption that two AC lines would be built with a combined total of 3,000 MW of transmission capability, and on the assumption that a total of 24 EDUs would be constructed: 6 in Arizona (4 solar PV, 1 solar thermal, and 1 geothermal) and 18 in New Mexico (4 solar PV, 1 solar thermal, 12 wind, and 1 geothermal). These projects would use 2,420 MW of the 3,000 MW of transmission capability built in Option A, with the remaining 580 MW being used by other existing types of generation facilities.

Option B is based on the assumption that one AC line and one DC line would be built with a combined total of 4,500 MW of transmission capability, and on the assumption that 42 EDUs would be built: 3 in Arizona (2 solar PV and 1 solar thermal) and 39 in New Mexico (36 wind, 2 solar PV, and 1 geothermal). These projects would use 4,210 MW of the 4,500 MW of transmission capability built in Option B, with the remaining 290 MW being used by other existing types of generation facilities.

In developing these scenarios, it is assumed that some portion of the Project's transfer capability would be utilized by nonrenewable generation resources. As previously discussed, FERC Order 888 compels transmission owners to provide open access to its facilities without discrimination, including discrimination as to type of generation requesting interconnection and transmission service.

Further, renewable generation (depending on type, location, local and regional meteorology, and other factors) exhibits certain patterns of availability and intermittency. Should buyers of renewable generation so desire, they may arrange for regulation generation services from other

sources on the grid, or from within their own inventory of generation assets. Some of the generation noted above in the two options that is indicated to come from "other types of generation facilities" might be comprised from such regulation generation services and may, in fact, flow over and across all or part of the Project's transmission facilities.

Although no specific existing or planned project is identified to interconnect with the proposed Project, probable areas are estimated for any of the potential renewable energy projects, based on the amount of potential energy resources identified by QRA.

Potential land area requirements per energy development scenario were calculated based on the percentage of renewable energy production by type per QRA, and the energy mix determined above for options A and B, which yielded a potential capacity per QRA for each option. The results were then calculated with the assumed land area per megawatt to yield the total land area estimate per QRA per option. The results can be found in Table 4-39.

Table 4-39. Potentially Affected Land Area for the Energy Development Scenario

QRA	Wind (MW)	Solar (MW)	Geothermal (MW)	Total Land Area[1] (Acres)
Option A				
NM-CT	—	100	—	700
NM-SO	—	200	—	1,400
NM-SW	—	260	50	2,170
NM-EA	1,200	—	—	12,000
NM-SE	—	—	—	—
AZ-SO	—	560	50	4,270
Option B				
NM-CT	—	—	—	—
NM-SO	—	100	—	700
NM-SW	—	100	50	1,050
NM-EA	3,600	—	—	36,000
NM-SE	—	—	—	—
AZ-SO	—	360	—	2,520

[1] Land area calculations are based on 7 acres per MW for solar energy development and 10 acres per MW for wind energy development, and is an estimate for area of potential ground disturbance.

As indicated in this forecast, the projected ground disturbance associated with up to 4,500 MW of potential electrical generation development would be 40,270 acres. Estimates for potential ground disturbance would vary based on site-specific conditions, design, and technologies.

4.17.4 Cumulative Effects by Resource

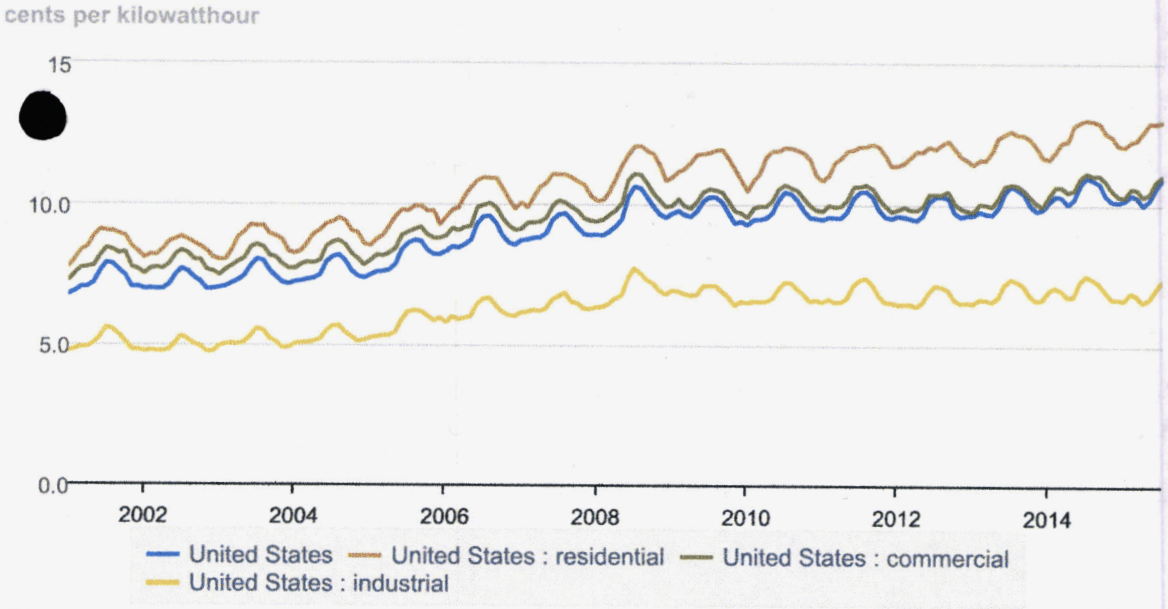
4.17.4.1 Introduction

The results of the cumulative effects analysis are presented below for each of the resources. Cumulative effects were evaluated with respect to each of two scenarios, described as follows.

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-04

Average retail price of electricity, monthly



Source: U.S. Energy Information Administration

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-05

http://www.eia.gov/electricity/state/arizona/index.cfm

U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

State Electricity Profiles

Data for 2013 | **Release Date:** July 8, 2015 | **Next Release:** October 2015

Archived State Electricity Profiles

Choose a Year: Select a Year

Arizona Electricity Profile 2013

Table 1. 2013 Summary statistics (Arizona)

Item	Value	U.S. Rank
Primary energy source	Coal	
Net summer capacity (megawatts)	27,910	13
Electric utilities	20,668	12
IPP & CHP	7,242	16
Net generation (megawatthours)	113,325,986	12
Electric utilities	92,740,582	8
IPP & CHP	20,585,405	15
Emissions		
Sulfur dioxide (short tons)	23,716	31
Nitrogen oxide (short tons)	59,416	15
Carbon dioxide (thousand metric tons)	55,342	16
Sulfur dioxide (lbs/MWh)	0.4	42
Nitrogen oxide (lbs/MWh)	1.0	29
Carbon dioxide (lbs/MWh)	1,074	27
Total retail sales (megawatthours)	75,668,218	20
Full service provider sales	75,668,218	16
Energy-only provider sales		
Direct use (megawatthours)	228,315	41

Table 1. 2013 Summary statistics (Arizona)

Item	Value	U.S. Rank
Average retail price (cents/kWh)	10.14	19

kWh = Kilowatthours.

Sources: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report." U.S. Energy Information Administration, Form EIA-861,"Annual Electric Power Industry Report." U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor forms.

More Tables on Arizona's Electricity Profile: **Formats**

Table 2. Ten largest plants by generation capacity, 2013

Table 3. Top five retailers of electricity, with end use sectors, 2013

Table 4. Electric power industry capability by primary energy source, 1990-2013

Table 5. Electric power industry generation by primary energy source, 1990-2013

Table 6. Electric power delivered fuel prices and quality for coal, petroleum, natural gas, 1990-2013

Table 7. Electric power industry emissions estimates, 1990-2013

Table 8. Retail sales, revenue, and average retail price by sector, 1990-2013

Table 9. Retail electricity sales statistics, 2013

Table 10. Supply and disposition of electricity, 1990-2013 (megawatthours)

Table 11. Net metering, 2010-2013 (megawatthours)

Table 12. Advanced metering, 2007-2013

EIA - 1000 Independence Avenue, SW, Washington, DC 20585

Table 6. Electric power delivered fuel prices and quality for coal, petroleum, natural gas, 1990 - 2013

Arizona

Fuel, quality	2013	2012	2011	2010	2009	2008	2007	2006	2005	
Coal (dollars per million Btu)	**2.07**	**2.08**	**1.98**	**1.80**	**1.81**	**1.74**	**1.59**	**1.44**	**1.41**	
Average heat value (Btu per pound)	9,761	9,623	9,685	9,685	9,712	9,828	9,946	10,011	10,088	1
Average sulfur content (percent)	0.66	0.65	0.71	0.66	0.65	0.59	0.57	0.57	0.57	
Petroleum (dollars per million Btu)	**24.29**	**23.44**	**23.09**	**18.07**	**13.00**	**21.02**	**16.71**	**16.25**	**14.03**	
Average heat value (Btu per gallon)	134,942	135,266	136,533	135,992	135,340	138,424	140,914	139,114	140,912	13
Average sulfur content (percent)	0.00	0.00	0.47	0.05	0.06	0.14	0.38	0.16	0.31	
Natural gas (dollars per million Btu)	**4.48**	**3.43**	**4.94**	**4.77**	**4.07**	**8.37**	**6.70**	**6.36**	**8.04**	
Average heat value (Btu per cubic foot)	1,025	1,021	1,016	1,016	1,022	1,028	1,022	1,018	1,025	

Petroleum includes petroleum liquids and petroleum coke.
Note: Due to different reporting requirements between the Form EIA-923 and historical FERC Form 423, the receipts data from 2008 and on are not directly comparable to prior years. There may be a notable increase in fuel receipts beginning with 2008. For more information, please see the Technical Notes in the Electric Power Annual.
Source: U.S. Energy Information Administration, Forms EIA-423, " Monthly Cost and Quality of Fuels for Electric Plants Report." and EIA-923, "Power Plant Operations Report."Federal Energy Regulatory Commission, FERC Form 423, "Monthly Cost and Quality of Fuels for Electric Plants."

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-06

TITLE: **FEASIBILITY STUDY FOR 500 kV AC UNDERGROUND CABLES FOR USE IN THE EDMONTON REGION OF ALBERTA, CANADA**

REPORT No: **ER 381**

CUSTOMER: **AESO**

AUTHORS: **Alan Williams BSc CEng MIET**
Brian Gregory BSc CEng FIEE

DATE: **18 February 2010**

INTRODUCTION

CCI has been engaged to perform a feasibility study into the use of 500 kV underground cables for the Edmonton region of Alberta. The design requirements used within this study are generic and based on those of the 500 kV 3,000 MW system known as the "Heartland Project".

This document contains a description of the available cable technology, recommendations on the feasibility of the cable technology and how underground cable technology needs to be developed so as to be suitable for use in the Edmonton region.

Also included are:

- Definitions and glossary (Section 16) for words that have been Capitalised.
- An appendix recording individual studies, including:
  - Total cost estimates (in 2009 Canadian dollars) for nine scenarios comprising different proportions of underground cable and overhead line, which were provided by the Heartland Project Team (HPT) based on estimated cable system costs provided by cable manufacturers and estimated civil cable installation costs provided by HPT. HPT also provided the estimated costs of the overhead line and all of the other equipment required for each scenario.
  - Preliminary project schedules, which were provided by HPT.

Distribution: AESO, HPT, CCI

Cable Consulting International Ltd
Registered in England and Wales No. 4234974
Registered office: 74 College Road, Maidstone, Kent, ME15 6SL, United Kingdom

CONTENTS

INTRODUCTION 1
1 EXECUTIVE SUMMARY 13
1.1 Introduction 13
1.2 Method of approach 14
1.3 Technical feasibility findings 16
1.3.1 Choice of cable technology 16
1.3.2 500 kV XLPE cable system: supply capability and experience 17
1.3.3 Choice of installation technology 18
1.3.4 500 kV Study Project size 19
1.3.5 Project specific requirements 19
1.3.6 Low ambient temperatures 20
1.3.7 Proving the performance of the cable system before it is supplied 21
1.4 Estimates of reliability 22
1.5 Estimates of capital cost 24
1.5.1 Scenarios considered for costing 26
1.5.2 Estimated capital cost: comparison between scenarios 28
1.5.3 Estimated Net Present Value: comparison between scenarios 29
1.5.1 Summary of cost estimates 30
1.5.2 Cost differences between cable and overhead line 31
1.6 500 kV Study Project duration 32
1.7 Power losses 33
1.7.1 Relationship of power loss to power transfer for the 500 kV Study Project 34
1.7.2 Cumulative power losses for the 500 kV Study Project 36
1.7.3 Estimated NPV of cumulative power losses 37
1.8 Recommendations for next steps 38
1.8.1 Study of end to end reliability and availability 39
1.8.2 System and design studies 39
1.8.3 Carry out additional engineering studies, as required 39
2 REQUIREMENTS FOR UNDERGROUND POWER TRANSMISSION SYSTEM FOR THE 500 KV STUDY PROJECT 44
2.1 Functional requirement: 44
2.1.1 Functional requirement: power transmission 44
2.1.1 Functional requirement: ambient temperatures 46
2.2 Scenarios considered 48
3 BASIC DESCRIPTION OF 500 KV AC UNDERGROUND TECHNOLOGY 56
3.1 Alternating current transmission system 56
3.2 Voltage, current and power 56
3.2.1 Voltage 56
3.2.2 Power 58
3.2.3 Current 58

3.3 Component parts of the cable ... 59
3.4 Cable system ... 61
3.4.1 Component parts of the cable system ... 65
3.4.2 Cable spans ... 65
3.4.3 Cable Terminations ... 66
3.4.4 Cable Joints ... 68
3.4.5 Bonding equipment. ... 69
3.5 Ancillary equipment ... 71
3.6 Hydraulic system for SCFF cable systems only ... 72
3.7 Thermal design ... 72
3.8 Thermomechanical design ... 72
3.9 Installation design ... 73
3.9.1 Cable installation ... 73
3.9.2 Assembly of joints and terminations ... 76
3.10 Route protection and identification ... 78
3.11 Forced cooling ... 79
3.12 Operation, maintenance and repair ... 81
3.13 Testing ... 81
3.13.1 Proving tests ... 82
3.13.2 Quality tests ... 85
3.14 Permissible length of an AC underground cable circuit ... 87
4 STATE OF THE ART FOR 500 KV UNDERGROUND POWER TRANSMISSION ... 90
4.1 Introduction ... 90
4.2 Self-Contained Fluid Filled Cables (SCFF) ... 91
4.3 Cross-Linked Polyethylene Cable (XLPE) ... 94
4.4 Advantages of extruded cross-linked polyethylene cables ... 96
4.4.1 XLPE cable has the advantage over the SCFF type of : ... 96
4.4.2 XLPE cable technology ... 97
4.5 Accessories for XLPE cable systems ... 98
4.6 Cumulative service experience of XLPE cable systems ... 105
4.7 Electrical tests for XLPE cable systems ... 111
4.7.1 Importance of prequalification tests for EHV XLPE cables ... 112
4.7.2 Prequalification test recommendations for the 500 kV Study Project ... 113
4.8 Low temperature operation ... 115
4.8.1 Ambient temperature levels for the Edmonton region of Alberta ... 115
4.8.2 Low temperature risks ... 118
4.9 Types of cable installation ... 123
4.9.1 Direct Buried Installation ... 123
4.9.2 Duct-manhole system ... 126
4.9.3 Tunnel Installation ... 128
4.9.4 Service experience with different methods of installation at 400 kV and 500 kV ... 129
4.9.5 Service experience with forced cooled systems ... 130

4.10 Gas insulated lines ... 130
4.10.1 Description of GIL ... 131
4.10.2 GIL Experience ... 134
4.10.3 GIL: Advantages and Disadvantages ... 136
4.11 High Temperature Superconducting Cable ... 137
4.11.1 Superconductivity ... 137
4.11.2 Low temperature superconductors ... 138
4.11.3 High temperature superconductors ... 139
4.11.4 Construction of a conceptual HTSC cable ... 140
4.11.5 HTSC Cable System Experience ... 144
4.11.6 Installation of a conceptual HTSC cable system for the Study project ... 147
5 ESTIMATES OF RELIABILITY ... 152
5.1 Repair times for 500 kV XLPE cable ... 153
5.2 Fault statistics for underground 500 kV XLPE cable ... 153
5.2.1 Cable system fault statistics ... 153
5.2.2 Application of fault statistics to the 500 kV Study Project scenarios ... 155
5.2.3 500 kV Study Project fault rate ... 159
5.2.4 Types of cable faults ... 159
5.3 Overhead line fault statistics ... 160
6 OVERVIEW OF POTENTIAL ENVIRONMENTAL EFFECTS OF UNDERGROUNDING .. 161
7 PRELIMINARY 500 KV UNDERGROUND CABLE SCOPING STUDY ... 163
7.1 Description of the cable type used for the preliminary scoping study ... 163
7.2 Cable installation options ... 166
7.3 General installation configuration ... 167
7.4 Preliminary scoping study: duct-manhole system ... 169
7.4.1 Configuration of cables in ducts ... 169
7.4.2 Duct for scoping study ... 170
7.4.3 Trench filling ... 171
7.5 Preliminary scoping study: Cable installation direct in the ground ... 172
7.6 Minimum spacing between groups of cables of each circuit ... 175
7.7 Installation Swathe and spacing between circuits, ... 176
7.8 Sample ampacity calculation (XLPE cable) ... 178
7.9 Stabilised backfill ... 180
7.10 Effect of obstructions on the route ... 181
7.10.1 Methods of maintaining the ampacity where the cable depth must be increased. ... 181
7.10.2 Installation at increased phase spacing. ... 181
7.10.3 Installation in tunnels. ... 184
7.10.4 Further methods of obstruction crossing. ... 185
7.11 Cable lengths between joint bays ... 186
7.11.1 Outline reel dimensions ... 186
7.11.2 Cable reel transportation study ... 188
7.12 Manholes and joint bays ... 188

7.13 Tunnels ... 190
7.13.1 Tunnel ampacity ... 190
7.13.2 Cable installation in tunnels ... 191
7.13.3 Tunnel cross sections ... 192
7.14 Staging of the cable installation ... 194
7.15 Staged duct manhole cable installation ... 196
7.15.1 Installation layout ... 196
7.15.2 Reasons for proposal ... 197
7.16 Staged cable installation direct in the ground ... 198
7.16.1 Installation layout ... 198
7.16.2 Reasons for proposal ... 199
7.17 Staged cable installation in deep tunnel ... 199
7.17.1 Installation layout ... 200
7.17.2 Reasons for proposal ... 200
7.18 Staged cable installation in cut and cover tunnel ... 200
7.18.1 Installation layout ... 201
7.18.2 Reasons ... 202
7.19 Alternative staging arrangements ... 202
7.20 Alternative SCFF cable type for scoping study ... 203
7.20.1 SCFF cable power losses ... 205
7.20.2 SCFF LPP cable installation configuration ... 205
7.21 Cable system routine maintenance ... 207
7.21.1 Maintenance for 500 kV XLPE cable systems ... 207
7.21.2 Recommended routine maintenance on 500 kV SCFF cable systems ... 210
7.22 500 kV cable system spares and repairs ... 211
8 ELECTROMAGNETIC FIELD PROFILE ... 213
9 DESIGNS PROPOSALS FROM PROSPECTIVE SUPPLIERS: SYSTEM DESIGN ... 215
9.1 Inquiry and questionnaire documents ... 215
9.1.1 Inquiry document ... 215
9.2 Requests for technical information from prospective suppliers of 500 kV cable systems ... 216
9.3 System designs proposed by prospective suppliers ... 219
9.3.1 Duct-Manhole systems ... 222
9.3.2 Direct buried systems ... 222
9.3.3 Tunnel systems ... 222
9.3.4 Sheath bonding systems ... 222
9.4 Designs proposals from prospective suppliers: cable ... 223
9.4.1 XLPE cable designs: general ... 224
9.4.2 Conductors for XLPE cable designs ... 224
9.4.3 Core design for XLPE cable designs ... 224
9.4.4 Sheath design for XLPE cable designs ... 224
9.4.5 Distributed Temperature Sensing ... 225
9.4.6 Jacket design for XLPE cable designs ... 226

9.4.7 SCFF cable designs ... 226
9.4.8 GIL design ... 226
9.4.9 Cable design types proposed ... 227
9.5 Cable electrical values provided by suppliers ... 237
9.6 Splice designs proposed by prospective suppliers ... 238
10 TRANSITION STATION ... 240
11 POWER LOSSES ... 242
11.1.1 Relationship of power loss to power transfer for the 500 kV Study Project ... 242
11.1.2 Cumulative power losses for the 500 kV Study Project ... 244
11.1.3 Estimated Net Present Value of Losses ... 246
12 GENERIC COST STUDY FOR THE 500KV STUDY PROJECT ... 248
12.1 Cable system unit costs ... 248
12.2 End-to-end estimated capital costs for the 65 km route length ... 249
12.3 Capital cost estimates: comparison of components in each scenario ... 250
12.4 Estimated Net Present Value of the life cycle costs for the 65 km route length ... 255
12.5 Comparison of the cost of each scenario ... 256
12.6 Differences between the estimated cost of underground cable and overhead line ... 257
12.7 Sensitivity studies on the estimated capital cost of the cable system ... 261
12.7.1 Sensitivity: Effect on cost of SCFF cable ... 261
12.7.2 Sensitivity: Canadian Dollar value falls against other currencies by 20% ... 261
12.7.3 Sensitivity: Metal prices change by 50% ... 263
13 500 kV STUDY PROJECT DURATION ... 265
13.1 Cable ... 266
13.2 Transition station ... 266
14 UNDERGROUNDING THE ENTIRE 65 KM ROUTE LENGTH ... 267
14.1 Scenarios considered ... 267
14.2 Technical limitations ... 267
14.2.1 Voltage control ... 267
14.2.2 Reduction in useful power transmission capacity because of cable charging current .. 267
14.3 Supplier capability ... 268
14.4 Cost estimates ... 269
14.5 Cable system fault statistics for 65 km underground route length ... 269
15 500 kV STUDY PROJECT RISKS ... 271
15.1 Technical risks ... 271
15.1.1 Inability of the accessories to meet the required minimum winter design temperatures. 271
Remedial Action: ... 271
15.1.2 Uncertainty of the winter minimum design temperature ... 271
15.1.3 Failure of the joints to demonstrate reliability in the Proving Tests ... 272
15.1.4 Failure of the cable system to achieve reliable service performance ... 272
15.1.5 Inability to repair the circuit at winter minimum ambient temperature: ... 273
15.2 Contractual risks ... 274

15.2.1 Failure to attribute responsibility: ... 274
15.3 Schedule risks ... 274
15.3.1 Delayed development: ... 274
15.3.2 Delayed manufacture: ... 275
15.3.3 Delayed installation and commissioning: ... 275
15.3.4 Damage to cable during delivery or installation ... 276
15.3.5 Commissioning test failure and repair ... 277
15.4 Common mode failure ... 278
15.4.1 Repeated latent defect in manufactured cable or accessories ... 278
15.4.2 Repeated jointing error ... 279
15.4.3 Third party damage. ... 279
15.4.4 Fire in tunnel. ... 280
15.5 Collateral Damage ... 280
15.5.1 Failure of one cable causes damage to another ... 280
15.5.2 Failure of one joint causes damage to another ... 281
15.5.3 Failure of one termination causes damage to another ... 281
15.5.4 Testing of one cable system causes damage to another ... 281
15.5.5 Repair of one cable causes damage to another ... 282
15.6 Cost risks ... 282
16 DEFINITIONS AND GLOSSARY ... 284
FEASIBILITY STUDY REFERENCES ... 299
APPENDICES ... 304
1 Appendix: Overhead line performance and statistics ... 304
2 Appendix : Total capital cost estimate for each scenario ... 304
3 Appendix : Economic comparison of scenarios for the 500 kV underground cable feasibility report 304
4 Appendix: Project schedule ... 304
5 Appendix: System study (reactor requirements, voltage profiles and losses) ... 305
6 Appendix: Generic crossings route maps: East TUC ... 305
7 Appendix: Generic crossings route maps: West TUC ... 306
8 Appendix: Transmission System Requirements ... 306
9 Appendix: Analysis of the minimum winter temperatures recorded on the 240kV DESS circuit in Edmonton in 2009 ... 306
10 Appendix: The Damage Prevention Process In Alberta ... 306
11 Appendix: Potential overview of environmental effects of undergrounding ... 307
12 Appendix: Cable reel transportation study of feasibility and costs ... 307
13 Appendix: Magnetic fields for cable and overhead line ... 307
14 AESO introduction letter for CCI ... 307
15 500kV Heartland inquiry ... 307
16 Appendix: 500kV Heartland transmission project response template ... 308
17 Appendix : AIS transition station scope of work ... 308
18 Appendix: Heartland underground construction: construction overview ... 308

19 Appendix : Heartland underground line-civil estimate 308
20 Appendix: 'Heartland underground crossing requirements' 309
21 Appendix : Heartland overhead line scope of work 309
22 Appendix : Substation 1 scope of work 309
23 Appendix : Substation 2 scope of work 309
24 Appendix: Owners risk briefing 310
25 Appendix: Overhead and underground line maintenance 310
26 Appendix: Drawings of termination stations, cable trenches, and obstruction crossings 310

TABLE OF FIGURES

Figure 1. 500 kV Study project – estimated capital cost main components 25
Figure 2 Comparison of scenario trench cross sections 27
Figure 3. Estimated capital costs in 2009 dollars. 29
Figure 4 Estimated NPV of the life cycle costs for each scenario 30
Figure 5. Power losses for selected scenarios at different levels of transmitted power 35
Figure 6. Overhead line: Normal operation 45
Figure 7. Overhead line: Contingency operation 46
Figure 8 Comparison of scenario trench cross sections 50
Figure 9 Scenario 1A.10 and 1B.20 52
Figure 10 Scenario 2A.10 and 2B.20 52
Figure 11 Scenario 3A.10 and 3B.20 53
Figure 12 Scenario 4A.10 and 4B.20 53
Figure 13 Scenario 5A.65 54
Figure 14 Scenario 5B.65 54
Figure 15 Scenario 6 : No cable 55
Figure 16 Key to scenario diagrams 55
Figure 17. Three parallel lines or cables are required to form an AC circuit 56
Figure 18. Relative voltages of a 500 kV system 57
Figure 19. Voltages between individual 500 kV cables 57
Figure 20. Voltage across the insulation of a 500 kV cable 58
Figure 21. Component parts of a 500 kV XLPE cable 59
Figure 22. The component parts of a cable system 61
Figure 23. Two circuits comprising four groups of underground cables 62
Figure 24. 400 kV transition station with terminal gantry 63
Figure 25. 400 kV transition station with terminal tower 64
Figure 26. Two overhead line circuits connect to four groups of underground cable 64
Figure 27. Delivery with cable reel axle cross-wise 65
Figure 28. Delivery with cable reel axle length-wise 65
Figure 29. Loading cable reels in ship's hold 66
Figure 30. Outdoor cable terminations 67

Figure 31, Cable terminations into gas immersed switchgear 68
Figure 32. A joint on a 400 kV XLPE cable prepared for burial 69
Figure 33. Part assembly of a joint on 240 kV XLPE cable inside a vault in Edmonton 69
Figure 34. An above-ground link box housing the components for a cross bonded position 70
Figure 35. Above ground link kiosks connected to 400 kV underground cable 71
Figure 36. Duct-manhole cable installation 73
Figure 37. Direct buried cable installation 74
Figure 38. Typical formations for cables installed in ducts 74
Figure 39. Typical formations for direct-buried cables 75
Figure 40. Preparation of cable trench crossing agricultural land 75
Figure 41. Jointing in progress in clean conditions 77
Figure 42. Completed joints 77
Figure 43. Temporary cable termination assembly structure 78
Figure 44: 400 kV cable system being prepared 83
Figure 45: A Cable being prepared for type approval 83
Figure 46. High voltage AC commissioning test equipment 86
Figure 47. Three reactors located in a substation 87
Figure 48. SCFF 525 kV 1,000 mm^2 cable commissioned in Grand Coulee Dam in 1976 92
Figure 49. SCFF LPP 2,500 mm^2 cable, similar to that commissioned in Japan in 1994 93
Figure 50. 500 kV XLPE cable 94
Figure 51. Increase of cable shield stresses at higher transmission voltages 95
Figure 52. Chart of XLPE cable design stress with system voltage. 99
Figure 53. Extrusion moulded joint (EMJ) schematic 99
Figure 54. 500 kV XLPE cable and extrusion moulded joints in a tunnel 100
Figure 55. One-piece joint (OPJ) schematic 101
Figure 56. 275 kV EPR OPJ in manufacture 101
Figure 57. 400 kV silicone OPJ in manufacture and routine test 102
Figure 58. Prefabricated composite joint (PJ) schematic 103
Figure 59. Prefabricated composite joint (PJ) during assembly 103
Figure 60. 500 kV PJ joints on test 105
Figure 61, Outdoor termination with capacitor stress control 120
Figure 62. Outdoor termination with prefabricated composite, premoulded stress cone 121
Figure 63. Typical direct buried 400kV cable trench containing one Group of Cables 124
Figure 64. Component parts of a 400 kV gas insulated line 131
Figure 65. Two groups of 275 kV gas insulated line installed in a tunnel 134
Figure 66. One group of 400 kV gas insulated line installed on stilts in a substation 134
Figure 67. Cross section of a conceptual HTSC cable 141
Figure 68. 13 kV, three phase, concentric HTSC cable construction 144
Figure 69. Conceptual arrangement of an HTS cable in buried trough 149
Figure 70. Conceptual cross section dimensions of a HTSC buried, three phase group / trench arrangement 150
Figure 71. Conceptual installation swathe dimensions for a HTS cable trenches 151

Figure 72: Construction and dimensions of Scoping Study 500 kV, 2500 mm², XLPE cable 164
Figure 73 Scenario 1 167
Figure 74: Preliminary duct block arrangement 169
Figure 75: Preliminary direct burial arrangement 172
Figure 76: Trench with sloped sides 174
Figure 77: Spacing between Groups of Cables 176
Figure 78: Arrangement of circuits and construction Swathe 177
Figure 79: Photograph of construction swathe for four trenches 178
Figure 80: Sample ampacity calculation 179
Figure 81: Required phase spacing at increased laying depth 182
Figure 82: Requirement for cable installed by trenchless method 183
Figure 83: Typical directional drill arrangement, plan view 183
Figure 84: Typical naturally ventilated tunnel 184
Figure 85: Compound containing two headhouses for naturally ventilated tunnels 185
Figure 86: Typical reel dimensions and weight 186
Figure 87: Conventional delivery 187
Figure 88: Longitudinal reel on lowboy 187
Figure 89: Plan of typical joint bay 188
Figure 90: Longitudinal elevation of typical joint bay 189
Figure 91: Elevation cross section across typical joint bay 189
Figure 92:Tunnel temperatures over a 10 year period 191
Figure 93: Typical tunnel cable clamp (cleat) for a sagged system 192
Figure 94:Tunnel cross section: deep tunnel 193
Figure 95:Tunnel cross section: cut and cover 193
Figure 96 Scenario 2, one group per circuit installed initially (black), the second later 194
Figure 97: Staging summary 195
Figure 98: Scenario 2, staging for the duct-manhole system 196
Figure 99:Scenario 2, staging for cables direct buried in the ground 198
Figure 100: Scenario 2, staging for cables installed in deep tunnels 199
Figure 101: Scenario 2, staging for cables installed in cut and cover tunnels 201
Figure 102: Alternative SCFF 500 kV cable 204
Figure 103. Underground cable: design requirement 220
Figure 104 Cable spacing 221
Figure 105. Cross bonding schematic 223
Figure 106. Detail of cross bonding components 223
Figure 107: Proposed 500 kV design: extruded lead sheath 228
Figure 108: Proposed 500 kV design: welded aluminium sheath 229
Figure 109: Proposed 500 kV design: corrugated aluminium sheath 230
Figure 110: Proposed 500 kV design: copper wire screen and corrugated stainless steel sheath 231
Figure 111: Proposed 500 kV design: copper wire screen and lead sheath 232
Figure 112: Proposed 500 kV design: wire screen and smooth aluminium sheath 233
Figure 113: Proposed 500 kV design: copper wire screen and aluminium laminate 234

Figure 114: Proposed 500 kV design: self contained fluid filled 235
Figure 115: Proposed 500 kV design: GIL 236
Figure 116 One piece prefabricated joint (OPJ) 239
Figure 117. Prefabricated composite joint (PJ) 239
Figure 118. Indoor GIS switchgear 240
Figure 119. Power losses for selected scenarios at different levels of transmitted power 243
Figure 120. Power losses for an average load of 457.3 MW 245
Figure 121. Estimated capital cost components in $M for 4 groups of Cables, 10 km long 251
Figure 122. Estimated capital cost components in $M for 3 groups of Cables, 10 km long 252
Figure 123. Estimated capital cost components in $M for 4 groups of Cables, 20 km long 253
Figure 124. Estimated capital cost components in $M for 3 groups of Cables, 20 km long 254
Figure 125. Estimated capital cost components in $M for all overhead line (Scenario 6) 255
Figure 126. Historic variation in the value of Canadian dollar 262
Figure 127. Historic variation in copper price (USD) 264

TABLES

Table 1. Description of Scenarios 26
Table 2. Table of Scenarios 27
Table 3. 500 kV Study Project costs, cost differences and cost ratios compared to all-overhead line... 31
Table 4. Ratio of cost of underground cable and transition stations to an equal length of overhead line 32
Table 5. Duration of cable supply and installation for each scenario 33
Table 6. Power losses for each scenario at an average load of 457.3 MW 36
Table 7. Power losses per circuit for each scenario at an average load of 1,000 MW 37
Table 8. PV of losses and of revenue requirement 38
Table 9. Number of suppliers for each undergrounding scenario 43
Table 10. Minimum design temperatures for cable 47
Table 11. Minimum design temperatures for splices (joints) 47
Table 12. Maximum and minimum design temperatures for air insulated terminations 48
Table 13. Maximum and minimum design temperatures for gas insulated terminations 48
Table 14. Scenarios considered 51
Table 15 Cumulative quantities of underground cables of all types in each country 106
Table 16 Commercial applications of large conductor XLPE cable with joints by voltage, conductors size, and circuit length 109
Table 17 Summary of the cumulative lengths at each voltage of major XLPE circuits with large conductors, long lengths and joints 109
Table 18 XLPE Cable system component statistics: 315 kV to 500 kV 110
Table 19 SCFF Cable system component statistics: 315 kV to 500 kV 110
Table 20 Total cable system components installed up to end 2005: 315 kV to 500 kV 111
Table 21 Comparison of statistics of XLPE circuit from three sources 111

Table 22 EHV installation types, three phase cable lengths and number of projects 129
Table 23. Details of significant GIL applications 135
Table 24. Details of some HTSC cables and applications 147
Table 25 CIGRE failure rates of components in 220 kV to 500 kV XLPE cable systems 154
Table 26 Failure rates of components in 220 kV to 500 kV XLPE cable systems by cause 155
Table 27 Conditioned failure rates of components in 220 kV to 500 kV XLPE cable systems 156
Table 28 Unconditioned cable system failure rates for the study scenarios for one year in-service 156
Table 29 Conditioned cable system failure rates for the study scenarios for one year in-service 157
Table 30 Unconditioned cable system failure rates for the study scenarios for 40 years in-service 158
Table 31 Conditioned cable system failure rates the study scenarios for 40 years in-service 158
Table 32 Numbers of faults in all types of 220 kV-500 kV AC land circuits by installation type 159
Table 33 OHL failure rates for the study scenarios for one year in-service 160
Table 34 OHL failure rates for the study scenarios for forty years in-service 160
Table 35 Tunnel dimensions for scoping study 190
Table 36. Magnetic field from EMF report (Appendix, Section 13) 213
Table 37 Supplier responses: Average capacitance and dielectric losses for XLPE cable 237
Table 38 Supplier responses: Average capacitance and dielectric losses for SCFF cable 237
Table 39 Supplier responses: Average capacitance for GIL 237
Table 40 Combined conductor and sheath losses: XLPE cable – mean and maximum 238
Table 41 Conductor and enclosure losses of GIL 238
Table 42. Power losses for each scenario at an average load of 457.3 MW 245
Table 43. Power losses per circuit for each scenario at an average load of 1,000 MW 246
Table 44. Estimated NPV of power losses over a forty year period 247
Table 45. Capital cost estimates for each scenario (2009 dollars) 250
Table 46. Estimated NPV of the life cycle cost for each scenario 256
Table 47. Effect on estimated cost of number of Groups of Cables 257
Table 48. Effect on estimated cost of staging 257
Table 49. 500 kV Study Project Estimated costs, cost differences and cost ratios compared to all-overhead line 258
Table 50. Ratio of estimated installed cost of underground cable to an equal length of overhead line 259
Table 51. Ratio of estimated cost of underground cable and transition stations to an equal length of overhead line 259
Table 52. Estimated capital cost increase if SCFF cable is used 261
Table 53. Estimated capital cost change if Canadian dollar value should vary by 20% 263
Table 54. Estimated capital cost change if cable metal prices should vary by 50% 264
Table 55. Duration of cable supply and installation for each scenario 265
Table 56 Unconditioned failure rates for a 65 km cable route length for one year in-service 269
Table 57 Conditioned failure rates for a 65 km cable route length for one year in-service 270
Table 58 Unconditioned failure rates for a 65 km cable route length for forty years in-service 270
Table 59 Conditioned failure rates for a 65 km cable route length for forty years in-service 270

12 GENERIC COST STUDY FOR THE 500KV STUDY PROJECT

(Note: all costs in this report are in Canadian dollars, unless otherwise stated. All capital costs are in 2009 dollars).

The estimated capital cost for the underground part of the 500 kV Study Project has been derived from anticipated price level information from prospective suppliers of 500 kV XLPE cable together with estimates of the civil construction costs, which were supplied by the HPT. For the total route length of 65 km, the estimated costs supplied by the HPT also include the overhead line and the associated transmission equipment, such as sub-stations, transition stations and reactive compensation.

12.1 Cable system unit costs

The cable manufacturers' indicative budgetary prices for the 10 km underground route length for the Heartland Project cable system have been analysed by CCI. For the purposes of commercial anonymity and competiveness the summarised costs have been made non-attributable to individual manufacturers. In order to calculate the cable system costs for each scenario of the 500 kV Study Project, the budgetary prices were analysed into average unit costs:

- Average cost of cable system per km of each Group of Cables, including supply of 3 km of cable (i.e. sufficient single core cable for one kilometre of a Group of Cables in a single trench), splices, jointing, bonding equipment, ancillary equipment, and supervision of cable laying, delivery to Edmonton.
- Average cost per termination of each Group of Cables, including 3 terminations, jointing, bonding equipment, ancillary equipment, delivery to Edmonton
- Average cost per commissioning test for each Group of Cables
- Average cost per set of development tests per supplier, including prequalification tests, type tests, and an allowance for low temperature tests
- Average cost per set of type tests per supplier. In the event of a staged installation, repeat type tests would be performed prior to the implementation of stage 2. In the intervening period between Stage 1 and Stage 2, there may have been minor changes to materials, manufacturing processes, etc, necessitating repeat type testing.
- Average cost per set of spares per supplier, including cable, splices and terminations.

From these the capital cost estimate of the cable system for each scenario was calculated and incorporated by HPT into the total capital cost estimate for each scenario.

12.2 End-to-end estimated capital costs for the 65 km route length

HPT compiled the total estimated capital costs for the 65 km long, 500 kV Study Project. Costs were estimated for nine scenarios, comprising different proportions of cable and overhead line.

Four of the scenarios were formulated to have reduced quantities of cable and are referred to as staged options. These scenarios would initially be installed and operated with a reduced transmission capability; this is referred to as Stage 1. At a later date additional Groups of Cables would be installed to Stage 2 of these scenarios include the subsequent achieve the full 3,000 MVA transmission capability. The estimated capital cost of both stages was calculated.

The estimated costs were based on the design information summarised in Appendix, Sections 17, 18, 19, 20, 21, 22 and 23. The total costs comprised:

- Cable system components (cable, terminations, joints and ancillaries) and jointing (CCI)
- Spares (CCI/HPT)
- Underground cable civil works (HPT)
- Cable installation into the ground, (HPT)
- Overhead line components and assembly (HPT)
- Transition station construction and equipment, such as reactors (HPT)
- Works and equipment in two substations (HPT)
- Owner's costs (HPT)

The detailed estimated capital costs are given in Appendix, Section 2.

A summary of the estimated capital costs for each scenario is given in Table 45.

Scenario	Staged	Description	UGC	OHL	Route	Stage 1	Stage 2	Total
			km	km	km	$M	$M	$M
1A.10	No	4 trenches (2 per phase), all installed together	10	55	65	-	-	748
2A.10	Yes	4 trenches (2 per phase), 2 installed first and 2 later.	10	55	65	574	201	775
3A.10	No	3 trenches, all installed together	10	55	65	-	-	687
4A.10	Yes	3 trenches, two installed first and 1 later	10	55	65	606	105	711
1B.20	No	4 trenches (2 per phase), all installed together	20	45	65	-	-	1014
2B.20	Yes	4 trenches (2 per phase), 2 installed first and 2 later.	20	45	65	689	350	1039
3B.20	No	3 trenches, all installed together	20	45	65	-	-	877
4B.20	Yes	3 trenches, two installed first and 1 later	20	45	65	720	185	905
6	No	All-overhead line	0	65	65	-	-	382

Table 45. Capital cost estimates for each scenario (2009 dollars)

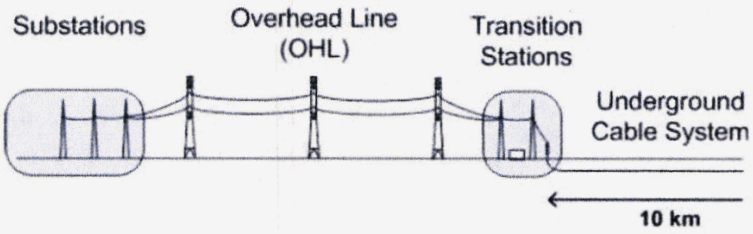
12.3 Capital cost estimates: comparison of components in each scenario

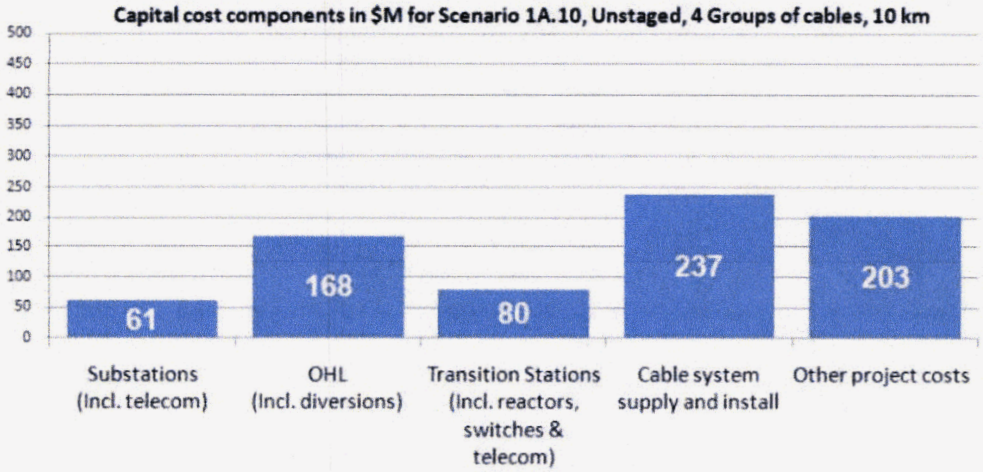
The breakdown of estimated capital cost components is shown in the following:

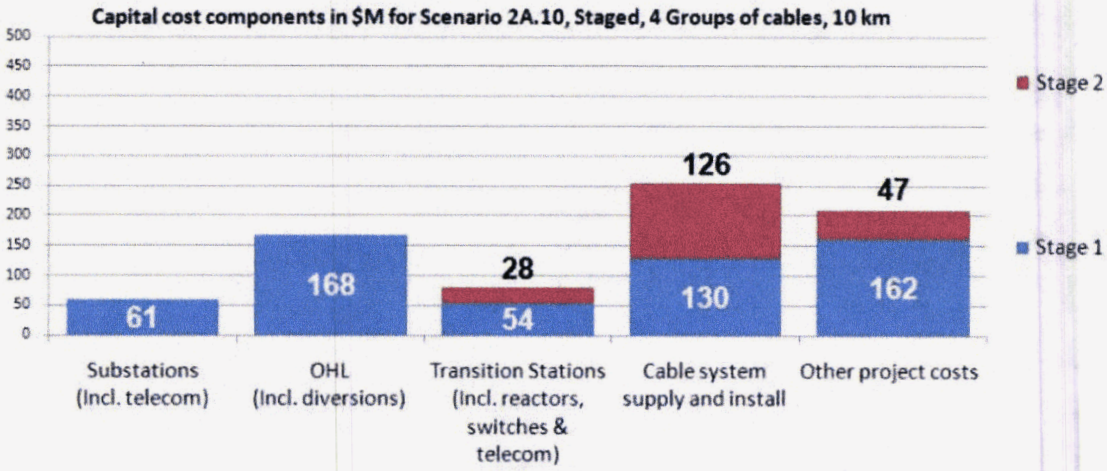
Scenario 1A.10 and 2A.10	Figure 121
Scenario 3A.10 and 4A.10	Figure 122
Scenario 1B.20 and 2B.20	Figure 123
Scenario 3B.20 and 4B.20	Figure 124
Scenario 6 (All overhead line)	Figure 125

NOTE: The diagrams only show half of the route for clarity; the values represent the total estimated capital costs for the entire 65 km route.

Estimated capital costs for 4 groups of Cables, 10 km long







Stage 1 estimated costs are given in white on blue. Stage 2 estimated costs are given in black above red.
Total estimated costs for each component are the sum of the Stage 1 and Stage 2 costs

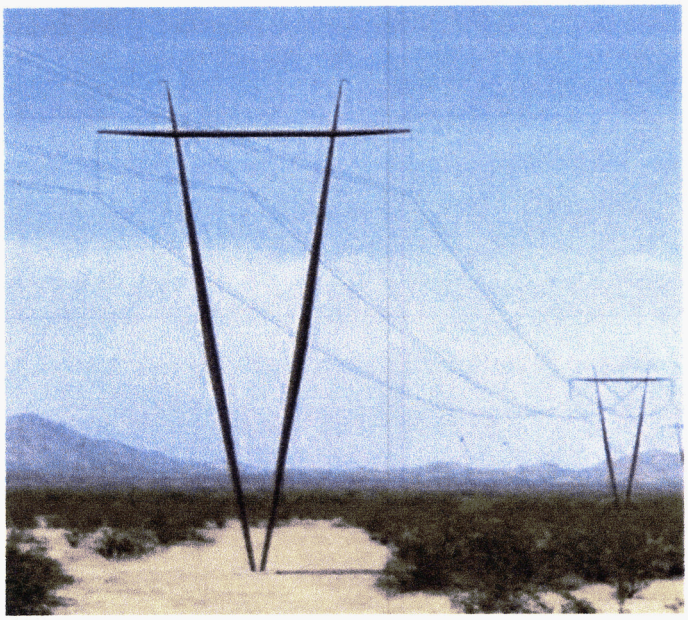
Figure 121. Estimated capital cost components in $M for 4 groups of Cables, 10 km long

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-07

ALBUQUERQUE
JOURNAL

SunZia may move north of White Sands



Pictured is an image from a SunZia brochure about the company's high-voltage transmission project.

By Kevin Robinson-Avila / Journal Staff Writer

Friday, June 19th, 2015 at 5:08pm

The battle over SunZia transmission line's incursion into White Sands Missile Range's northern extension area is on again, but this time it's the project developers who are offering to move most of the line out of the military's "call-up zone."

That's something the U.S. Department of Defense fought unsuccessfully for during the U.S. Bureau of Land Management's approval process for SunZia — a 515-mile transmission line that could eventually carry wind-generated electricity from central New Mexico to Arizona for distribution in western markets. The military feared that 45 miles of line that runs through a call-up area where ranchers and others are often evacuated for missile tests and exercises would interfere with operations.

The dispute appeared resolved last year after SunZia agreed to bury five miles of line in the extension area to avoid interference with low-flying missiles. That paved the way for BLM approval last January.

But since then, SunZia has been negotiating with the state Land Office for permits to cross over about 89 miles of state property. And during those talks, an alternative has emerged to re-route about 80 percent of the 45-mile stretch through the call-up zone farther north, outside the area, said SunZia Project Manager Tom Wray.

"I met last week in Washington, D.C., with the DOD Siting Clearinghouse in the Office of the Secretary of Defense to lay out the proposal," Wray told the Journal on Thursday. "If it would benefit White Sands, then I'm willing to entertain the alternative."

There's just one catch. Wray wants the DOD to reduce, if not eliminate, the amount of line that would still have to be buried.

"This provides an opportunity for White Sands to get a better siting arrangement then they have now, but I won't do it if we still have to bury a full five miles of line," Wray said. "In that case, we'd just stay with what we have under the BLM approval."

Reducing the amount of line subject to burial would greatly benefit the developers, since burying a full five miles would add an estimated $500 million in construction costs and push the project's total price tag to $2.2 billion, Wray said.

Alternatively, only about $1 million in extra costs would be added for each mile of line that get's re-routed north of the extension zone. SunZia proposes to move about 35 to 40 miles of line northward, although it also would have to add an extra 10 miles to the total line to accommodate the newly proposed route.

It's unclear, however, if SunZia's proposal would actually benefit White Sands, said Sherman McCorkle, a member of the state's Military Base Planning Committee.

"We don't know what the new route does vis a vis the path of low-flowing missiles," he said. "Someone in the Army, Navy or Air Force who conducts those tests has to answer that question. Yes, proximity matters, but the problem has always been low-altitude missiles that fly like 100 feet off the ground as they follow the topography."

The section of line that would remain in the extension zone would run along the western area near the Sevilleta National Wildlife Refuge. That section can't move north, because it could impact federal lands there, forcing the BLM to re-open its review of the project.

To determine how much, if any, of the remaining line would still need to be buried — and whether any of the line that gets re-routed northward could still interfere with missile testing — is something military experts must evaluate, McCorkle said.

"You need to know the flight paths in the particular area where they're talking about moving the line," he said. "For White Sands, that's the essence of the question."

Wray said the DOD is reviewing the proposal.

"The DOD people said White Sands and the Pentagon would need to do an evaluation to assess the impact of shifting the route," Wray said. "It was clear they needed some time to look at it."

State Land Commissioner Aubrey Dunn said under the proposal, all of the re-routed line would fall within state lands.

"Where the changes are proposed, no BLM land would be involved," Dunn said. "It would parallel some existing lines, which is what we would prefer."

The new route would also put the transmission line closer to wind resources, Dunn said.

Retrieved from http://www.abqjournal.com/601392/abqnewsseeker/sunzia-may-move-north-of-white-sands.html 10/16/2015

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-08

Eighth Biennial Transmission Assessment 2014-2023

Staff Report

Docket No. E-00000D-13-0002

Decision No. 74785

October 29, 2014

Prepared by Arizona Corporation Commission Staff

And

K. R. Saline & Associates, PLC.
160 North Pasadena, Suite #101
Mesa, Arizona 85201

Table of Contents

EXECUTIVE SUMMARY III
General Conclusions iv
Recommendations viii
1 OVERVIEW 1
1.1 Assessment Authority 1
1.2 Purpose and Framework 1
1.3 Assessment Process 3
1.4 Terminology and Acronyms 7
1.5 Additional Resources 7
2 TEN YEAR PLANS 9
2.1 Summary of Arizona Plan 10
2.2 Plan Changes Since the Seventh BTA 12
2.3 Driving Factors Affecting the Ten Year Plan ? Load Forecast 13
2.4 Driving Factors Affecting the Ten Year Plan ? Generator Interconnections 15
3 ADEQUACY OF THE SYSTEM 17
3.1 Utility Study Work 17
3.2 NERC/WECC Reliability Audit 18
3.3 Commission-Ordered Studies 19
3.4 2014 Summer Energy Preparedness 28
3.5 Physical Security 30
4 INTERSTATE, MERCHANT AND GENERATION TRANSMISSION PROJECTS 31
4.1 Delaney ? Colorado River 500 kV Transmission Line 31
4.2 SunZia Southwest Transmission Project 32
4.3 Centennial West Clean Line Project 33
4.4 Bowie Power Station 33
4.5 Mohave County Wind Farm Project 34

4.6 Gila Bend Power Partners 35
4.7 SolarReserve 35
4.8 Southline Transmission Project 35
4.9 TransWest Express 36
4.10 EnviroMission 37
4.11 Longview Transmission Project 37
4.12 Buckeye Generation Center 38
4.13 Sun Streams 38
4.14 Tribal Solar 39
4.15 Harcuvar Transmission Project 39
4.16 High Plains Express 40
4.17 North Gila ? Imperial Valley #2 40
4.18 Ocotillo Modernization Project 41
4.19 Abengoa 41

5 REGIONAL AND NATIONAL TRANSMISSION ISSUES 43
5.1 Regional Transmission Planning ? WestConnect 43
5.2 FERC Order 1000 47
5.3 Western Area Power Administration Transmission Infrastructure Program 50
5.4 WECC Regional Transmission Expansion Planning 52
5.5 Renewables Integration and Energy Efficiency Impacts 54
5.6 Coal Reduction Assessment 59
5.7 Seams Issues 62

6 CONCLUSIONS 65
6.1 Adequacy of the Existing and Planned Transmission System to Reliably Serve Local Load 65
6.2 Efficacy of Commission-Ordered Studies 68
6.3 Adequacy of System to Reliably Support Wholesale Market 69
6.4 Suitability of Utilized Planning Processes 70

7 RECOMMENDATIONS 73

Listing of Figures

Figure 1 - Change in Arizona Demand Forecast....14
Figure 2 - SWAT and Subcommittees Footprints....44

Listing of Tables

Table 1 - Summary of Workshop I Presentations....4
Table 2 - Summary of Utility Data....6
Table 3 - List of Parties Commenting on First Draft Report....7
Table 4 - List of Parties Filing Ten Year Plans 2014 Tabular Reference Table....9
Table 5 - Summary of Arizona Plan by In-Service Date....10
Table 6 - Summary of Arizona Plan by Voltage Class....11
Table 7 - Summary of Plan Generation and Tie-lines....12
Table 8 ? Project Name Changes or Aliases....12
Table 9 ? Significant EHV Project Changes Since the Seventh BTA....13
Table 10 - Summary of Arizona Generator Interconnection Queues....15
Table 11 ? Summary Table of Utility Study Work....18
Table 12 ? WECC Audit Results....19
Table 13 - Summary of Commission-Ordered BTA Studies....20
Table 14 - Cochise County Outage Data Summary....21
Table 15 - Santa Cruz Outage Data Summary....23
Table 16 - Summary of RTP Development Status....57

Listing of Exhibits

Exhibit 1 ? Existing and Planned Arizona EHV Transmission Map
Exhibit 2 ? Phoenix Metro Transmission System Map
Exhibit 3 ? Southeastern Transmission System Map
Exhibit 4 ? Yuma Transmission System Map
Exhibit 5 ? Pinal County Transmission System Map
Exhibit 6 ? Arizona Planned Project Lookup Table
Exhibit 7 ? WECC Path Affecting Arizona Map and Table
Exhibit 8 ? Arizona Demand Forecast Data
Exhibit 9 ? Plan Changes Between Seventh and Eighth BTA
Exhibit 10 ? Listing of QueueInterconnection Generation Projects
Exhibit 11 ? Listing of ProjectsSorted by In-Service Date
Exhibit 12 ? Listing of ProjectsSorted by Voltage Class
Exhibit 13 ? Arizona Public Service Project Summary
Exhibit 14 ? Salt River Project Summary
Exhibit 15 ? Southwestern Power Group Project Summary
Exhibit 16 ? Southwest Transmission Cooperative Project Summary
Exhibit 17 ? Tucson Electric Power Project Summary
Exhibit 18 ? UniSource Electric Project Summary
Exhibit 19 ? Ajo Improvement Company Project Summary
Exhibit 20 ? Merchant Transmission and Generation Project Summary
Exhibit 21 ? Overview Map of Delany ? Colorado River 500 kV Project
Exhibit 22 ? Overview Map of Centennial West Clean Line Project
Exhibit 23 ? Overview Map of Southline Transmission Project
Exhibit 24 ? Overview Map ofTransWest Express Project
Exhibit 25 ? Overview Map ofHarcuvar Transmission Project
Exhibit 26 ? Overview Map ofHigh Plains Express Project
Exhibit 27 ? Overview Map of North Gila? Imperial Valley #2 500 kV Project

Listing of Appendices

Appendix A - Guiding Principles for Determination of System Adequacy and Reliability
Appendix B - History of Commission Ordered Studies
Appendix C - 2014 BTA Workshop I and II List of Attendees
Appendix D - Questions Posed to Industry and Stakeholders - Workshop I
Appendix E RMR Conditions and Study Methodology
Appendix F - Listing of Terminology and Acronyms
Appendix G - Information Resources

4 Interstate, Merchant and Generation Transmission Projects

Wholesale market power purchases and sales rely on available interstate transmission. These interstate and merchant transmission projects make possible a competitive and healthy wholesale market while complementing the states? utilities el ectric infrastructures by providing additional import/export points. Several market access projects and merchant transmission projects are discussed in this BTA. This section of the BTA report highlights the status of eighteen such planned projects that affect Arizona. Exhibit 20 provides tabular listing of the interstate, merchant and generation transmission projects.

4.1 Delaney ? Colorado River 500 kV Transmission Line

The Delaney ? Colorado River 500 kV transmi ssion line project would provide an additional interstate 500 kV interconnection between Arizona and California.[57] No ten year plan has been filed with the Commission for this project nor was this project specifically discussed at Workshop I. Therefore, this project was not considered for the adequacy assessment nor included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included as Exhibit 21.

The Delaney-Colorado River 500 kV line is conceptualized as a 115-140 mile, 500 kV single circuit structure between the APS Delaney 500 kV switchyard located in Arizona and the Southern California Edison (?SCE?) Colorado River 500 kV substation.

The Delaney ? Colorado River 500 kV line was recently studied as an economic project in the California Independent System Operator (?CAISO?) 2013-2014 Transmission Plan. The project demonstrated sufficient benefits when compared to the cost and was recommended for approval by the CAISO Board.[58] At the March 20, 2014 Independent System Operator (?ISO?) Board of Governors meeting, the ISO Board of Governors failed to approve the line and CAISO staff was directed to perform further assessments and report the results back to the Board. Subsequently, at

[57] The Arizona portion of the previously planned Palo Verde ? Devers #2 Project of which SCE has already built the California portion.
[58] http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan.pdf

the July 16, 2014 ISO Board of Governors approved the Delaney ? Colorado River 500 kV transmission line project.[59]

4.2 SunZia Southwest Transmission Project

The SunZia 500 kV transmission line project would provide an interstate 500 kV interconnection between Arizona and New Mexico. A ten year plan was received and this project was presented and discussed at Workshop I. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. Overview maps showing the general routing and interconnection points of this project are included within Exhibits 1, 3, and 5.

The SunZia project is currently planned to consist of approximately 515 miles of two single-circuit 500 kV transmission lines, either two alternating current (?AC?) or one AC and one direct current (?DC?), and associated substations beginning at a new substation in central New Mexico and terminating at Pinal Central substation near Coolidge, Arizona. Approximately 200 miles of the proposed route are within Arizona. Depending on the final configuration of the project, it is expected to have a power transfer capacity of between 3,000 and 4,500 MW.

The sponsors of the SunZia Southwest Transmission Project include Salt River Project, Shell Wind Energy, Southwestern Power Group, Tri-State Generation and Transmission Association, and Tucson Electric Power. SunZia is anticipated to deliver primarily renewable energy from sources yet to be determined to markets in Arizona and California. The first phase of commercial operation is expected to commence in 2018.

Milestones achieved since the Seventh BTA include the issuance of a Final EIS for the project in June 2013, with the Record of Decision (?ROD?) expected in 2014. SunZia expects to file its CEC application following the BLM?s publication in the Federal Register of the Notice of Availability of the ROD. In addition, a Letter of Intent was signed in August 2013 with the project?s first anchor tenant, First Wind Energy, LLC, for up to 1,500 MW of capacity.

[59] http://www.caiso.com/Documents/DecisionDelaney-ColoradoRiverTransmissionProject-Motion-July2014.pdf

4.3 Centennial West Clean Line Project

The Centennial West Clean Line Project (?Clea n Line?) is planned to be a ±600 kV High Voltage Direct Current (?HVDC?) transmissi on line that would provide an interstate interconnection between New Mexico and California with routing and the potential for an interconnection point in Arizona. No ten year plan was filed with the Commission in 2014 for this project. Therefore, this project was not considered for the adequacy assessment nor included in the ten year plan statistics compiled for this BTA. This project was presented and discussed at Workshop I. An overview map showing the general routing and interconnection points of this project is included as Exhibit 22.

The Clean Line project is currently planned to consist of approximately 900 miles of HVDC beginning in northeastern New Mexico and terminating in southern California. Approximately 300 miles of the total project would be in northern Arizona. Clean Line filed an application for right-of-way across Federal lands and a preliminary Plan of Development with the Bureau of Land Management (?BLM?) in 2011, and has completed the Project Coordination Review portion of the WECC path rating process. Clean Line last filed a ten year plan in January 2012. The Clean Line Project is sponsored by Clean Line Energy Partners, LLC. The project is expected to deliver 3,500 MW of renewable energy to markets in California and the West. Commercial operation is currently planned to begin in 2020.

4.4 Bowie Power Station

Bowie Power Station is a proposed 1,000 MW natural gas generating station consisting of two combustion turbines and one steam turbine which will be located in Southeastern Arizona and will serve the load requirements of that area. A ten year plan was received and this project was presented and discussed at Workshop I. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for the Eighth BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The project is owned by Southwestern Power Group II, LLC (?SWPG?). A fifteen mile double-circuit 345 kV transmission line will interconnect the generating facilities to the transmission grid, and will run between Bowie Plant Switchyard and the proposed Willow Switchyard on TEP?s Greenlee-Winchester-Vail 345 kV line. CECs for the generating station and transmission facilities

were originally granted in March 2002, and were subsequently extended by the Commission through December 2010 and again through December 2020.[60] The proposed alignment of the transmission line was also revised in 2008 to comply with the requirements of the Arizona State Land Department.[61] In September 2013, Bowie submitted a new Class I air quality application to the Arizona Department of Environmental Quality (?ADEQ?) and the draft permit is expected soon with the final permit by the end of 2014.

SWPG and TEP entered into an interconnection facilities study agreement on October 12, 2013, and the facilities study was provided by TEP on October 29, 2013. Bowie is working with TEP to complete a large generator interconnection agreement (?LGIA?) and continues to participate in regional planning forums. Currently, initial energization of the interconnection facilities is estimated to occur by December 31, 2017, with commercial operation of the initial 500 MW power block occurring by December 31, 2018.

4.5 Mohave County Wind Farm Project

The Mohave County Wind Farm Project, formerly known as the BP Wind Energy North America Project, is comprised of a proposed 500 MW wind energy power plant and associated transmission interconnection tie-line and other facilities, either 345 kV or 500 kV. A ten year plan was received for this project, and the project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The project will be located in Mohave County, Arizona, near the city of Kingman, and will deliver to load-serving entities yet to be determined. The project will interconnect with either the 345 kV Mead-Peacock-Liberty line or the 500 kV Mead-Phoenix line via a gen-tie line approximately 5 miles in length, the final route of which has not yet been determined. A CEC for the transmission line was granted by the Commission in November 2012; commercial operation is expected to begin in 2015 or 2016.

[60] Decision No. 71951, dated 11/1/2010, the ACC granted Bowie a second extension on the durations of the CECs through 12/31/2020.

[61] Decision No. 70588, dated 11/6/2008, approved adjustment to Bowie?s approximately 15-mile, double-circuit 345 kV generator tie line on Arizona State Land Department (?ASLD?) property. This line interconnects the Willow Substation to TEP?s existing Greenlee-Winchester-Vail 345 kV line.

4.6 Gila Bend Power Partners

Gila Bend Power Partners proposes to build a 500 kV transmission line from the planned 833 MW combined cycle Gila Bend Power Project to a new switchyard interconnecting with APS?s Gila River Line and the Jojoba Switchyard, and ultimately the Hassayampa Switchyard. A ten year plan was received for this project. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibits 1 and 2.

The line would run parallel to the existing Palo Verde to Kyrene 500 kV transmission line. Three CECs have been granted for the project. The project is currently on hold due to unfavorable market conditions. However, Gila Bend Power Partners has filed ten year plans in the Eighth BTA, in both January 2013 and January 2014.

4.7 SolarReserve

SolarReserve, LLC proposes to construct the Crossroads Solar Energy Project, a new 150 MW concentrating solar power plant and transmission line, to be located near the intersection of Interstate 8 and Paloma Road in southwestern Maricopa County, to the Panda ? Gila River substation. A ten year plan was received for this project. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The new 230 kV gen tie line will be approximately 12 miles in length but its exact route has not yet been determined. However, it is expected to largely follow the Abengoa Solana power project generation tie-line. A CEC for the project was granted in February 2011, and a ten year plan was last filed in January 2014. Current forecasts are for a commercial operation date by the end of 2017.

4.8 Southline Transmission Project

The Southline Transmission Project (?Southline?) is a 345 kV line that would provide an interstate 345 kV interconnection between Arizona and New Mexico. No ten year plan has been filed with the Commission for this project, but this project was presented and discussed at Workshop I. Because there was no ten year plan filed, this project was not considered for the

adequacy assessment nor included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included as Exhibit 23.

Southline Transmission LLC is sponsoring the Southline Project to improve reliability and help facilitate the development and delivery of renewable energy in the region. The Southline Project proposes to build a 360-mile line from Las Cruces, New Mexico to Tucson, Arizona, across federal, state, and private land. Consisting of two segments, the first segment of the project proposes 240 miles of a double-circuit 345-kV line that would link an existing substation at Afton, near Las Cruces, to the existing Apache substation near Wilcox, Arizona. The second segment would upgrade and rebuild 130 miles of existing Western and TEP transmission lines from 115 kV to 230 kV between the Apache substation and the Saguaro substation near Tucson. Overall the project may interconnect with the existing transmission system at up to fourteen substation locations.

On April 11, 2014, the BLM and Western, serving as joint lead agencies, released a Draft Environmental Impact Statement for the project. The ROD is anticipated to be published in Q1 2015. The project is currently in Phase 2 of project planning with in-service anticipated for the end of 2016. When completed, the Southline Project will add 1,000 MW of bidirectional transfer capability to the grid.

4.9 TransWest Express

The TransWest Express Transmission project is a HVDC line planned for the cost-effective delivery of wind energy to Arizona, California, and Nevada. No ten year plan has been filed with the Commission for this project nor was this project specifically discussed at Workshop I. Therefore, this project was not considered for the adequacy assessment nor included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included as Exhibit 24.

If developed, the 600 kV HVDC transmission line would include 725 miles of transmission lines. The transmission will originate near Sinclair, WY near the Platte substation and will terminate in Southern Nevada in the Eldorado Valley near the Marketplace substation complex. TransWest Express expects to be rated at 3,000 MW and the transmission line is anticipated to be online in 2017.

The project is jointly being developed between TransWest Express, LLC and Western. The two agencies released a draft Environmental Impact Statement (?EIS?) in July 2013. The project is currently conducting requirements of phase 2 of the WECC path rating process.

4.10 EnviroMission

EnviroMission Inc. is sponsoring the development of a 200 MW Solar Tower located in La Paz County, south of Parker, Arizona. A ten year plan was received for this project. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The La Paz Solar Tower project would include the development of a single 2,600 foot tall solar electric generation facility and associated gen-tie line. The site selected also has room to potentially accommodate additional solar towers in the future. The project would provide clean renewable energy with dynamic scheduling capabilities and contends to be a base-load resource.

Currently the project has not selected a location for interconnection(s) to the transmission system. A possible interconnection that has been identified includes developing facilities in cooperation with Central Arizona Water and Conservation District (?CAWCD?) to jointly serve the Central Arizona Project (?CAP?) pumping plants and the project site. These facilities in all likelihood would include a 500 kV interconnection at Salome substation to access the Delaney ? Colorado River 500 kV line. The project currently has a targeted in-service date of spring 2017.

4.11 Longview Transmission Project

In January 2014, Longview Energy Exchange, LLC (?Longview?) submitted a ten-year transmission plan consisting of three potential transmission corridors that are being considered for interconnecting a 2,000 MW adjustable speed hydro-electric pump storage project by 2021. A ten year plan was presented and discussed at Workshop I. This project was considered for the adequacy assessment and included in the ten-year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included within Exhibit 1.

Longview includes the development of a new 500 kV switchyard at the project site. The 500 kV lines being considered include a 50 mile line from the Longview switchyard and terminating at a new

500 kV switchyard in the vicinity of the existing Peacock Substation to interconnect with the Mead-Perkins 500 kV line, and either a 40 mile line from the Longview switchyard interconnecting at the Navajo transmission system at the Yavapai substation, or a 30 mile line terminating at a new 500 kV switchyard to interconnect with the Moenkopi-Eldorado 500 kV line. Construction is expected to begin in 2018 with an estimated in-service date of 2021.

Feasibility, market assessment and WECC firmed resource studies have been completed for the project. A FERC preliminary permit application was filed,[62] and the FERC Order was issued April 26, 2012. A CEC application with the ACC is pending an environmental study of the routes.

4.12 Buckeye Generation Center

Buckeye Generation Center, formerly known as the Horizon Power Project, is a 650 MW natural-gas peaking facility currently planned for a site within Maricopa County. A ten year plan was received for this project. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included within Exhibits 1 and 2.

The Buckeye Generation Center would include the development of a half mile, 230 kV gen-tie line to connect the project site to a proposed 69/230 kV substation to be constructed, owned and operated by APS. The precise location of the transmission line has not yet been determined. The Buckeye Generation Center is sponsored by Buckeye Generation Center, LLC and is intended to add peaking power to Arizona electric utilities and to the interstate electrical grid. The currently estimated in-service date is 2018.

4.13 Sun Streams

Sun Streams, LLC, a wholly-owned subsidiary of Element Power, is sponsoring the Sun Streams Solar Project substation and gen-tie line to interconnect a proposed 150 MW photovoltaic solar facility. A ten year plan was received for this project. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included within Exhibit 1.

[62] Preliminary permit application was filed as project 14341-000

The Sun Streams project includes the development of a 500/34.5 kV step up transformer and 1,600 feet of 500 kV AC single circuit line to be interconnected at 500 kV at the Hassayampa Switchyard. The project is expected to be in-service in the first quarter of 2016. A CEC is pending before the Commission for this tie-line project.

4.14 Tribal Solar

Tribal Solar, LLC, a wholly-owned subsidiary of First Solar, is sponsoring the substation and gen-tie line associated with the proposed Fort Mohave Solar Project. The estimated 310 MW project is planned to include the construction of a 34.5/230 kV substation at the Fort Mohave project site located on the Fort Mohave Indian reservation in Mohave County, Arizona and San Bernardino County, California. A ten year plan was received for this project. This project was considered for the adequacy assessment and included in the ten-year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included within Exhibit 1.

The gen-tie line will be up to twenty five miles in length depending on final project configurations. The gen-tie line and substations will interconnect the proposed Fort Mohave Solar Project with the regional transmission grid at the Mohave Generating Station Substation. Currently, the project?s in-service date is uncertain.

4.15 Harcuvar Transmission Project

The Harcuvar Transmission Project (?HTP?) is sponsored by the CAWCD. The project is intended to increase system reliability, permit interconnection of potential solar and thermal generation to the grid and provide access to the Palo Verde hub, California ISO and Western?s Parker-Davis transmission system. No ten year plan has been filed with the Commission for this project nor was this project specifically discussed at Workshop I. Therefore, this project was not considered for the adequacy assessment nor included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included as Exhibit 25.

HTP is planned to consist of a 100 mile, 230 kV line originating at the proposed Delaney ? Colorado River 500 kV line and terminating at the Harcuvar 230 kV substation. The project is

dependent on interconnection to one or both Palo Verde ? California lines at a proposed Salome substation, five miles of new 230 kV transmission line connecting the Salome substation with the Little Harquahala Substation, and a new transmission between Bouse Hills and Little Harquahala substations. The transmission capacity would be approximately 2,000 MW.

HTP originally proposed an in-service date of 2018; however, the project is currently suspended while undergoing configuration and needs review.

4.16 High Plains Express

The High Plains Express project intends to enhance reliability and increase access to generation resources across the transmission grid through Wyoming, Colorado, New Mexico, and Arizona. No ten year plan has been filed with the Commission for this project nor was this project specifically discussed at Workshop I. Therefore, this project was not considered for the adequacy assessment nor included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included as Exhibit 26.

The project includes the planned development of a high-voltage, 2500 mile, 500 kV AC transmission backbone which will add 4,000 MW of capacity import and export capabilities. The list of parties participating in the development of the High Plains Express includes Black Hills Corporation, Colorado Springs Utilities, Public Service Company of New Mexico, Public Service Company of Colorado (?Xcel Energy?), SRP, Tri-State Generation & Transmission (?Tri-State?), LS Power, NextEra Energy, Western, and Wyoming Infrastructure Authority (?WIA?).

Participants completed a preliminary feasibility study in 2008. The High Plains Express Initiative finished Stage 2 in 2011 and issued a Stage 2 Report; however, the project is currently suspended. The most recent anticipated in-service date is 2030.

4.17 North Gila ? Imperial Valley #2

The North Gila ? Imperial Valley # 2 Project, sponsored by Southwest Transmission Partners, LLC, in participation with IID, would be a 500 kV transmission line, single or potentially double-circuit, interconnecting the existing North Gila Substation near Yuma, Arizona with the existing Imperial Valley Substation in the vicinity of El Centro, California. No ten year plan has been filed with the Commission for this project. Therefore, this project was not considered for the adequacy

assessment nor included in the ten year plan statistics compiled for this BTA. This project was presented and discussed at Workshop I. An overview map showing the general routing and interconnection points of this project is included as Exhibit 27.

The line would be approximately eighty five miles in length, and parallel the Southwest Power Link (?SWPL?) 500 kV line for much of its leng th. Depending on the final configuration, the project in all likelihood will increase total transfer capability (?TTC?) up to 2,400 MW for Path 46 (?West of River?) and up to 1,200 MW for Path 49 (?East of River?). The anticipated date of operation is the first quarter of 2019.

This project is new since the Seventh BTA. To date, the project participants have submitted the right of way (?ROW?) application to BLM and initiated the WECC Three Phase Rating process, as well as participated in regional planning efforts. Over the next two years, the project participants intend to continue addressing the National Environmental Policy Act (?NEPA?) and WECC rating processes.

4.18 Ocotillo Modernization Project

The Ocotillo Modernization Project (?OMP?) invo lves the planned retirement of existing generators and subsequent addition of generation at the existing Ocotillo generating facility in Tempe, Arizona. A ten year plan was received and the project was presented and discussed at Workshop I. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the interconnection points of this project is within Exhibit 1.

The existing Ocotillo generating facility is comprised of two steam generators (110 MW net each) and two gas generators (55 MW net each) which have a total net output of 330 MW. The proposed project would retire the two steam generators and replace them with five new gas turbines, with a net increase of 290 MW of capacity. The OMP is proposed by APS and is estimated for in-service in 2018.

4.19 Abengoa

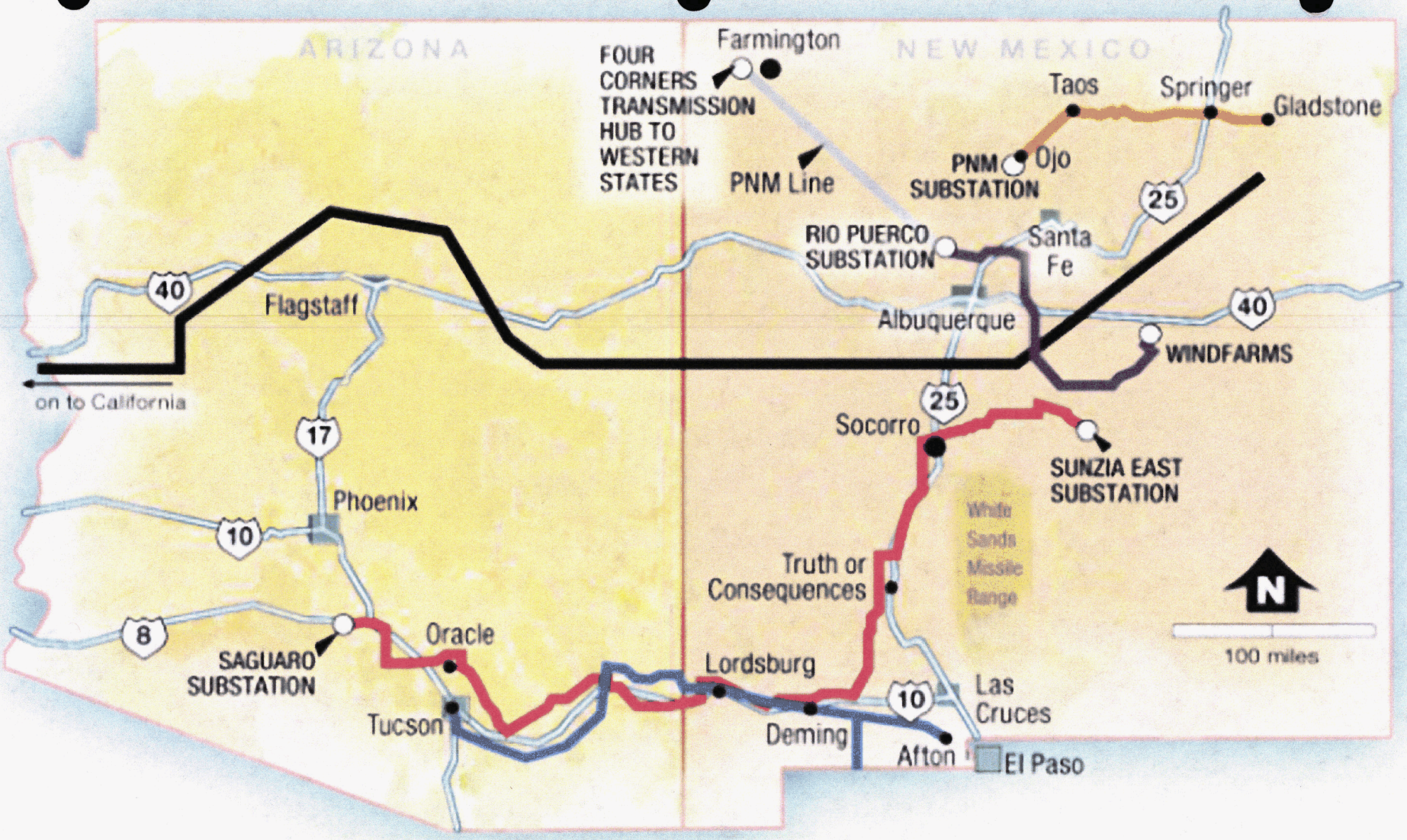
In 2013, Abengoa Solar Inc. completed construction of the 280 MW Solana Solar Generating Station near Gila Bend, Arizona. Interconnection of the plant was made to APS?s Panda Substation

via a 20 mile long, double-circuit 230 kV gen-tie line. Arizona Solar One and APS have executed a LGIA and a 30-year power purchase contract for the plant. The plant went into operation in October 2013.

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-09

PROPOSED RENEWABLE ENERGY TRANSMISSION LINES



SunZia
- 515 miles
- $2.2 billion
- 3,000 MW of transmission capacity

SouthLine
- 240 miles
- $700 million
- 1,000 MW of transmission capacity

Western Spirit Clean Line
- 200 miles
- $300 million
- 1,500 MW of transmission capacity

Centenial West Clean Line*
- 900 miles
- $2.5 billion
- 3,500 MW of transmission capacity

*routing not yet determined

Lucky Corridor
- 130 miles
- $320 million
- 850 MW of transmission capacity

SOURCE: Journal interviews with transition project developers

RUSS BALL / JOURNAL

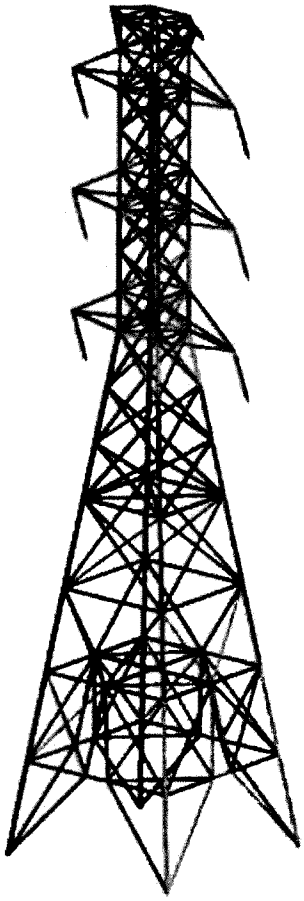
DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-10

http://www.luckycorridor.com/index-2.html

LUCKY CORRIDOR

New Mexico Transmission Projects



Lucky Corridor, LLC is a developer of transmission facilities needed to help update the western grid near the Four Corners NYMEX Hub as the electricity supply evolves away from primarily coal-fired generation toward a mixture of electricity made from wind, solar and natural gas resources.

Lucky Corridor's Mora Line project is designed to carry 180 MW at 115 kV, 102 miles. The Lucky Corridor project is designed to carry 850MW at 345 kV, 130 miles. The Projects will carry electricity made from first-rate U.S. clean energy resources toward Four Corners and the historic grid emanating from that Hub.

See the NEWS TAB for our latest updates.

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-11

CLEAN LINE
ENERGY PARTNERS

WESTERN SPIRIT CLEAN LINE

PROJECT DESCRIPTION

The Western Spirit Clean Line will collect 1,500 megawatts of renewable power from east-central New Mexico and deliver the power to markets in the western United States that have a strong demand for clean, reliable energy.

The project is estimated to bring the following economic benefits to New Mexico: new investment of over $2 billion in renewable generation and transmission, new jobs to support the renewable energy industry in the state, and improved reliability of the New Mexico transmission grid. By integrating more renewables in the energy supply mix, the project will save scarce water resources and result in meaningful reductions in air and water pollutants and carbon dioxide emissions.

WESTERN SPIRIT CLEAN LINE QUICK FACTS

- The Western Spirit Clean Line will collect 1,500 megawatts of renewable power from east-central New Mexico and deliver the power to markets in the western United States that have a strong demand for clean, reliable energy.
- The Western Spirit Clean Line will transport clean power via an approximately 200-mile transmission line, complementing the efforts of the **Centennial West Clean Line** project.
- Clean Line Energy is working with the **New Mexico Renewable Energy Transmission Authority (RETA)** to jointly develop the Western Spirit Clean Line project. The New Mexico legislature created RETA by statute in 2007 with the objective of facilitating renewable energy development in New Mexico through the agency's authority to finance, plan, acquire, maintain and operate transmission and energy storage facilities. In 2010, RETA commissioned studies by Los Alamos National Laboratory and identified the Western Spirit Clean Line project as a means of facilitating transmission in eastern and central New Mexico.

- The development and construction of the Western Spirit Clean Line is an investment of hundreds of millions of dollars that will enable approximately $2 billion of new, renewable energy projects to be built.
- The Western Spirit Clean Line will deliver enough clean, renewable energy to power approximately 830,000 homes, dramatically reducing pollutants by millions of tons.
- The Western Spirit Clean Line will reduce water withdrawal from lakes and rivers by 1.2 billion gallons per year – water that would otherwise be needed for cooling thermal power plants.

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-12

opportunity to request assistance under the Rural Water Program. No form is required to be filled out in order to submit a statement of interest. The statement of interest will include information regarding the eligibility of the project sponsor to participate in the program, whether the proposed project meets the program eligibility requirements, and the extent to which the proposed project meets the prioritization criteria.

(3) *Assistance to Conduct a Feasibility Study.* To request technical or financial assistance to conduct a feasibility study, the project sponsor must have already completed an appraisal investigation. Since a statement of interest will have already been submitted, project sponsors seeking to conduct a feasibility study may simply complete a full proposal without having to complete another statement of interest. No form is required to be filled out in order to submit a full proposal. The full proposal will be used by Reclamation to determine whether the project sponsor is eligible to participate in the program, whether the proposed project meets the program eligibility requirements, the extent to which the proposed project meets the prioritization criteria, and to evaluate the proposal in general to determine whether it is reasonable and can be successful. The content of a full proposal will be described in detail in the program announcement and will typically include a detailed scope of work for the proposed study.

Frequency: Once annually, in response to the program announcement.

Respondents: States, tribes, municipalities, water districts, and other entities created under State law with water management authority.

Estimated Annual Total Number of Potential Respondents: 185.

Estimated Number of Responses per Respondent: 1.0.

Estimated Total Number of Annual Responses: 56.0.

Estimated Total Annual Burden on Respondents: 2,100 hours.

Comments

We invite your comments on:

(a) Whether the proposed collection of information is necessary for the proper performance of our functions, including whether the information will have practical use;

(b) The accuracy of our burden estimate for the proposed collection of information;

(c) Ways to enhance the quality, usefulness, and clarity of the information to be collected; and

(d) Ways to minimize the burden of the information collection on respondents, including the use of automated collection techniques or other forms of information technology.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. A 60-day comment period soliciting comments on this collection of information was published in the **Federal Register** (73 FR 67778, Nov. 17, 2008) in an interim final rule. No public comments were received.

Before including your address, telephone number, e-mail address, or other personal identifying information in your comment, you should be aware that your entire comment (including your personal identifying information) may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Roseann Gonzales,

Director, Policy and Program Services, Bureau of Reclamation.

[FR Doc. E9–12525 Filed 5–28–09; 8:45 am]

BILLING CODE 4310–MN–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[NM–114438; AZA–35058; L51010000 ER0000 LVRWG09G0690]

Notice of Intent To Prepare an Environmental Impact Statement and Possible Resource Management Plan Amendments for the SunZia Southwest Transmission Project in Arizona and New Mexico

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of Intent.

SUMMARY: The Bureau of Land Management (BLM), New Mexico State Office, announces its intent to prepare an Environmental Impact Statement (EIS), and by this notice is announcing the beginning of the scoping process and soliciting input on identification of issues and proposed planning criteria in response to a right-of-way application filed by SunZia Transmission, LLC (SunZia).

DATES: Comments should be submitted no later than 45 days after publication of this Notice in the **Federal Register**. The BLM will announce public scoping meetings to identify relevant issues through local news media, newsletters, and the BLM Web site (see below) at least 15 days prior to each meeting. We will provide additional opportunities for public participation upon publication of the Draft EIS, including a 90-day public comment period.

ADDRESSES: You may submit comments or resource information by any of the following methods:

Web site: http://www.blm.gov/nm/st/en/prog/more/lands_realty.html.

E-Mail: NMSunZiaProject@blm.gov.

Mail: Bureau of Land Management, New Mexico State Office, SunZia Southwest Transmission Project, P.O. Box 27115, Santa Fe, NM 87502–0115.

Courier/Hand Delivery: Bureau of Land Management, SunZia Southwest Transmission Project, 1474 Rodeo Road, Santa Fe, NM 87505.

Documents pertinent to the right-of-way application may be examined at: Bureau of Land Management New Mexico State Office, Public Room, 1474 Rodeo Road, Santa Fe, NM 87505, Telephone (505) 438–7471.

FOR FURTHER INFORMATION: For further information and/or to have your name added to the mailing list, contact Adrian Garcia, SunZia Southwest Transmission BLM Project Manager, at the New Mexico State Office, P.O. Box 27115, Santa Fe, NM 87502–0115, or by e-mail at *NMSunZiaProject@blm.gov.*

SUPPLEMENTARY INFORMATION: SunZia has submitted a right-of-way application to construct, operate, and maintain two new single-circuit overhead 500 kilovolt (kV) transmission lines originating at a new substation in either Socorro County or Lincoln County in the vicinity of Bingham or Ancho, New Mexico, and terminating at the Pinal Central Substation in Pinal County near Coolidge, Arizona. The overall transmission line route would be approximately 460 miles in length, a substantial part of this length on BLM lands, and two separate transmission lines would be located on BLM, State, and private lands.

SunZia's proposal is to transport electricity generated by power generation resources, including primarily renewable resources, to western power markets and load centers. The SunZia project would enable the development of renewable energy resources, including wind, solar, and geothermal generation, by creating access to the interState power grid in the Southwest and providing increased transfer capacity. The proposed project would also increase power reliability across the southwestern United States, allow communities in southern Arizona and southern New Mexico to economically access energy generated from renewable sources, provide power

to help meet growing demand in the western United States, and enhance domestic energy security.

The Southwest Area Transmission Group—a regional transmission planning organization—identified a need for the project. Its importance is demonstrated by the abundance of proposed projects that have submitted interconnection requests to transmission owners within the proposed project area, and the potential for renewable energy sites within the SunZia project area. Additional transmission would be required to support development of potential renewable energy projects in Arizona and New Mexico. In addition, the requirement of each State to meet Renewable Portfolio Standards (RPS) and national interests in energy, demonstrate the need for the proposed project.

The proposed transmission line route and alternatives developed through the NEPA process would cross BLM lands in Arizona and New Mexico, as well as State and private lands. To the extent feasible, the proposed route would use existing transmission line corridors and designated utility corridors located on Federal land. One of the 500 kV transmission lines would be constructed and operated as an alternating current (AC) facility. SunZia may construct and operate the other proposed transmission lines as either AC or direct current (DC). The SunZia transmission lines would interconnect with planned substations along the route. Equipment additions and modifications would be required at each of the interconnecting substations. Engineering studies would determine those requirements as part of the project. A right-of-way of up to 1,000 feet in width and a lease-term of 50 years would be required to construct, operate, and maintain the transmission lines, structures and appurtenances. If constructed, the project would be in operation year-round, transporting electrical power to major substation hubs in Arizona and New Mexico. The project would have a bi-directional transmission capacity of approximately 3,000 megawatts or greater of electrical power.

The proposed project would take approximately three years to construct and would likely be constructed in phased segments with an in-service date of 2013. Specific acreages of access roads and temporary work areas would be determined through the NEPA process and project design.

In Arizona, approximately 43 miles of the proposed route would cross public land administered by the Safford and Tucson BLM Field Offices. In New Mexico, approximately 128 miles of the proposed route would cross public land administered by the BLM Las Cruces District Office and BLM Socorro Field Office. The proposed route would pass in the general vicinity of the following locations:

Arizona: Coolidge, San Manuel, Safford, Willcox, Bowie, and San Simon; and

New Mexico: Lordsburg, Deming, Hatch, Derry, Arrey, Truth or Consequences, San Antonio, Bingham, Ancho, and Carrizozo.

The BLM is the lead Federal agency for the NEPA analysis process and preparation of the EIS. Cooperating agencies identified at this time could include: The Bureau of Reclamation, the U.S. Army Corps of Engineers, the New Mexico State Land Office, and the Arizona State Land Department. Other State and local governments will be invited to participate in the process, and consultation will occur with local, State, and tribal governments.

The purpose of the public scoping process is to determine relevant issues that will influence the scope of the environmental analysis, including alternatives, and guide the process for developing the EIS. At present, the BLM has identified the following preliminary issues: The potential effects of the proposed action on wildlife habitat, plants, and animals including threatened, endangered, and sensitive species, visual resources, National Historic Trails and related viewsheds; Native American traditional cultural properties and sacred places; soils/water from surface disturbing activities; local and regional socioeconomic conditions; consistency with local government land use plans; and future reclamation/mitigation from transmission line construction or location. The BLM encourages the public to send comments concerning the project as proposed, other feasible alternative locations, possible mitigation measures, and any other information relevant to the proposed action.

Authorization of this proposal may require amendments to one or more RMPs. By this notice, the BLM is complying with requirements in 43 CFR 1610.2(c) to notify the public of potential RMP amendments, predicated on the findings of the EIS. If RMP amendments are necessary, the BLM will integrate the RMP process with the NEPA process for this project.

Your input is important and will be considered in the public scoping process. All comment submittals must include the commenter's name and street address. Comments including the names and addresses of the commenter will be available for public inspection at the above offices during business hours (7:45 a.m. to 4:30 p.m.), Monday through Friday, except Federal holidays. Before including your address, phone number, e-mail address, or any other personal identifying information in your comment, be advised that your entire comment, including your personal identifying information, may be publicly available at any time. While you can ask us in your comment to withhold from public review your personal identifying information, we cannot guarantee that we will be able to do so.

William Merhege,

Acting Deputy State Director, Lands and Resources.

[FR Doc. E9–12512 Filed 5–28–09; 8:45 am]

BILLING CODE 4310–FB–P

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Intent To Prepare a Feasibility Study and Environmental Impact Statement for Everglades National Park (Park) To Evaluate Modifications to the Tamiami Trail

SUMMARY: Notice is hereby given, in accordance with the provisions of the National Environmental Policy Act (NEPA) of 1969 (42 U.S.C. 4321 *et seq.*), that the NPS is preparing a Feasibility Study and EIS to "evaluate the feasibility of additional bridge length, beyond that to be constructed pursuant to the Modified Water Deliveries to Everglades National Park Project (16 U.S.C. 410r-S), including a continuous bridge, or additional bridges or some combination thereof, for the Tamiami Trail (United States Highway 41) to restore more natural water flow to Everglades National Park and Florida Bay and for the purpose of restoring habitat within the Park and the ecological connectivity between the Park and the Water Conservation Areas" (2009 Omnibus Appropriations Act). The NPS is the lead agency on this federal action; however, the NPS has requested the United States Army Corps of Engineers (USACOE) be a cooperating agency on this effort, with the Federal Highway Administration (FHWA) providing technical assistance.

DATES: Written comments regarding the proposed project must be postmarked no later than 30 days from the publication of this Notice of Intent (NOI) in the **Federal Register**. As part of this process, public workshops will be held to solicit public input about the proposed project. The date, time, and location of the public workshops will be

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-13

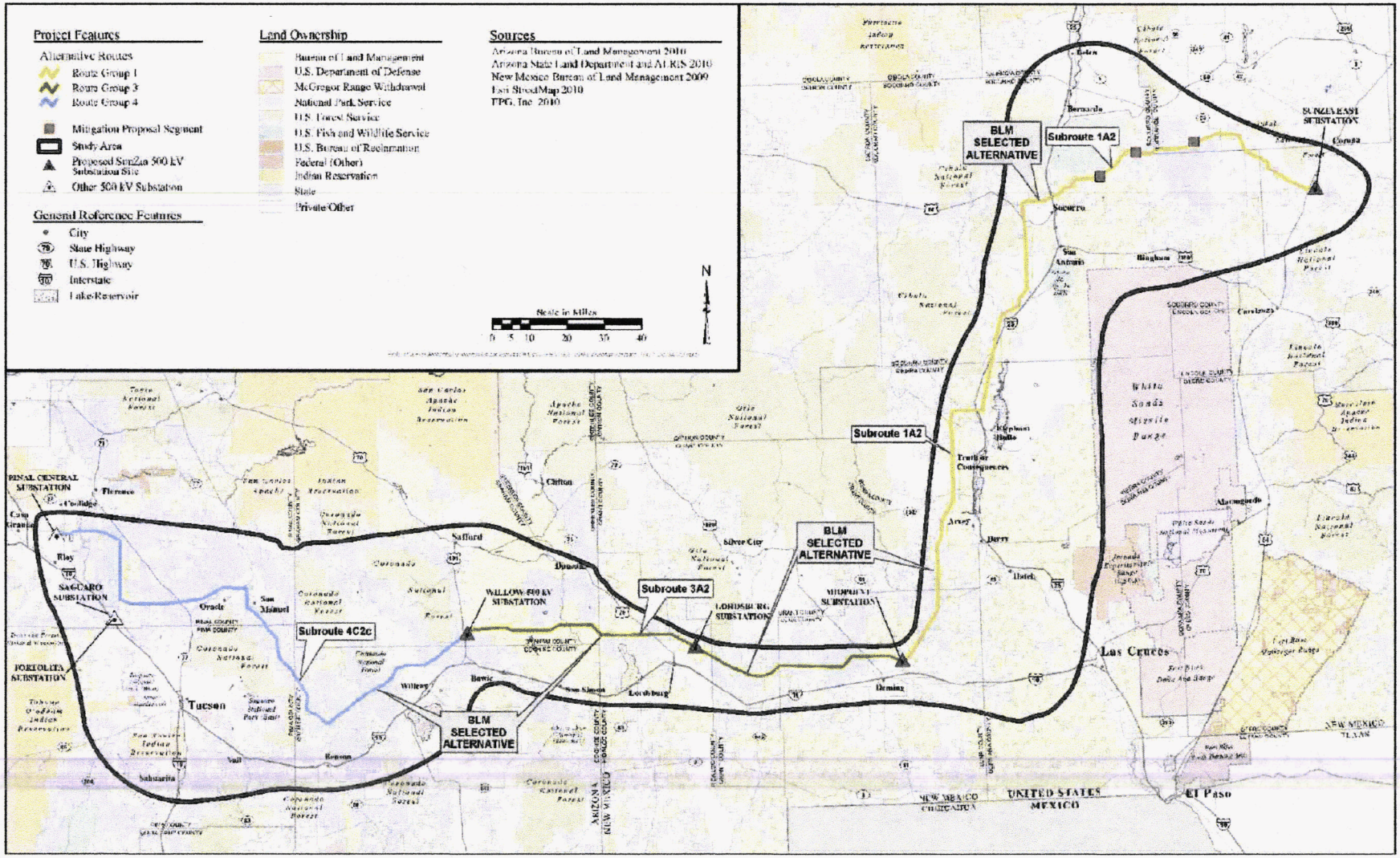


Figure 1. Bureau of Land Management Selected (Preferred) Alternative

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-14

Arizona. In order to interconnect with an AC system, the DC current must be converted to AC. Converter substations require more land and are significantly more expensive than a typical 500 kV AC substation, rendering intermediate interconnections cost-prohibitive. As such, the DC line would have no intermediate substations, unlike an AC line. This means the Project would not be capable of (1) providing energy to reach local energy consumers, (2) interconnecting with the existing transmission system, or (3) accepting energy from generators along the transmission path. The lack of intermediate interconnection with the existing transmission systems would not improve reliability or relieve congestion on the existing system, and would therefore not meet the purpose and need. Although the environmental effects of constructing two DC lines would be substantially similar to the effects of one AC and one DC line, given the reasons above, at least one AC line is needed to meet the Applicant's objectives. Thus, the alternative to construct two DC lines was eliminated from further consideration.

Underground Transmission

In response to scoping comments, an alternative to construct and operate certain portions, or the entire length, of the proposed 500 kV transmission line project underground was considered but eliminated from further consideration. A technical feasibility study was prepared to evaluate the operational, economic, and environmental factors associated with underground transmission line systems (SunZia Transmission, et. al. 2011). Burial of the entire Project or portions of the Project is considered technically infeasible due to potential reliability concerns, operational risks, environmental impacts, and high construction cost. Additional contributing factors would include a limited supply of materials, and limited manufacturing capability to produce long lengths of 500 kV buried cable systems. The SunZia Project would be 20 times longer than the longest known underground 500 kV transmission line project (Williams and Gregory 2010).[1] Accordingly, potential construction and operation of portions of the Project using underground cable systems was eliminated from further consideration. Although burial of portions of the Project were not considered feasible, in response to public concerns, the effects of undergrounding a portion of the transmission lines at the Rio Grande crossing, north of the Bosque del Apache NWR, were evaluated as a potential mitigation alternative (see Section 4.16).

High-voltage underground transmission lines have markedly different technological requirements and are more difficult to place underground than lower voltage underground distribution lines, which provide electricity to individual homes and businesses. High-voltage underground lines (138 kV, 230 kV, and 345 kV) have been constructed in some parts of the United States, primarily for short distances, and usually where circumstances dictated that overhead lines were not feasible (e.g., in the vicinity of airports and urban centers). The only 500 kV underground transmission lines in the United States are at the Grand Coulee Dam. Due to concerns regarding underground transmission line failures, Bonneville Power Administration and the BOR are currently evaluating replacing the underground lines at Grand Coulee Dam with overhead transmission lines (Bonneville Power Administration 2009).

[1] The Shinkeiyo-Toyosu Project is the longest known 500 kV underground transmission line. The double-circuit 500 kV underground cable system was built in Tokyo, Japan in the year 2000. This project was a total length of 40 kilometers (20 miles) and required nine years to test, manufacture, and install.

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-15

Technical Working Group Report for the SunZia Transmission Line Project

7 AUG 2013

Executive Summary

The Arizona and New Mexico state offices of the Bureau of Land Management (BLM) conducted an environmental analysis and on June 14, 2013, published a Final Environmental Impact Statement (FEIS) for the SunZia Southwest Transmission Project. Using the conclusions from the FEIS, the BLM will decide whether to grant, grant with modifications, or deny the proposed action. The action under consideration would construct and operate up to two 500-kilovolt (kV) above-ground transmission lines and associated substations stretching for a distance of approximately 515 miles from Lincoln County, New Mexico to the Pinal Central Substation, Coolidge, Arizona.

The FEIS analyzed the environmental consequences of installing bulk power transmission lines to connect New Mexico wind generation resources to load centers in Arizona. Additionally, the Project is designed to transport conventional energy generation that might connect to the transmission line. A primary consideration in the development of the FEIS was a Right-of-Way (ROW) agreement between BLM and the developer to allow the routing of the transmission lines across Federal lands.

The proposed routing of the transmission lines has been an issue from the onset of the Project's scoping discussion in 2008. From a Department of Defense (DOD) point of view, routing remains an issue unless a portion of the Project is placed underground or a more northern route is considered, such as the DOD preferred alternative, which does not require transmission line burial. The FEIS studied burial of the entire Project, as well as burial of a short segment of the Project under a river crossing (unrelated to DOD's mission compatibility concerns), and concluded that both of those alternatives were technically and economically infeasible.

In order to resolve these important routing issues, DOD and the Department of the Interior (DOI) agreed to form a Technical Working Group (TWG) to address the technical feasibility of burying a portion of the Project where it is proposed to cross the White Sands Missile Range (WSMR) Northern Extension Area (NEA). This report summarizes the evaluation conducted, and concludes that burying a 35 mile segment of the Project would be technically feasible. While the cost to bury 35 miles would be expensive, that cost must be compared to the loss of critical testing capability important to national security. The TWG analysis concludes that the cost to bury the transmission lines is less than the cost to the nation to replace or replicate critical testing activities available at WSMR.

The TWG, composed of subject matter experts from the DOD, and the Department of Energy's Idaho and Pacific Northwest National Laboratories, consisted of four teams, each of which was assigned a specific focus area: 1) technical feasibility of burying the transmission line, 2) mission compatibility, 3) hold harmless and indemnification considerations, and 4) procedures and operational considerations.

The 60-day study, conducted in May and June 2013, analyzed issues and documented their results. This report provides the results of the team efforts, and proposes Hold Harmless and Construction Memorandum of Agreement (MOA) documents. In summary, the conclusions of the TWG are:

1. It is technically feasible to bury a segment of two single-circuit 500 kV transmission lines. Existing underground 500 kV cables are in operation in several locations worldwide. 500 kV cables can be constructed, installed, and operated to ensure reliability, minimize operational risks and, when the construction is combined with micro-siting, lessen environmental impacts. The TWG concludes that worldwide manufacturing capability exists to produce the segment of the transmission line envisioned. DOD believes this new information calls into question the conclusions regarding transmission line burial reported in the FEIS
2. The distance required for line burial is 35 miles. This is the minimum distance necessary to prevent impairment of the Nation's unique capabilities to test DOD weapon systems in this location.
3. A *Hold Harmless Agreement* is required to indemnify DOD for any claims related to damage to the line. This clause should apply to government, state trust, and private land, and should be included in the ROW agreement.
4. An *Operations and Scheduling Agreement* is required to enable continued testing during line construction and operation. This agreement would also include provision for access to the line in the event of an emergency.

Section A of the report provides an introduction to the Project, and Section B provides the findings regarding the feasibility of transmission line burial. Section C identifies the portion of the line that must be buried in order to safely conduct military testing in the NEA. Section D provides draft language for a hold harmless and indemnification clause and associated draft operating procedures to ensure compatible power line operations and military testing in the NEA. Section E examines the economics of the DOD stipulations. The final Section F provides conclusions.

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-16

land within the City of Coolidge. ide the existing Pinal Central Substation. These substations will provide utilities and load centers with access to the energy, including renewable energy, transmitted by the SunZia Project.

At least one of the two 500 kV transmission lines will be constructed and operated as an alternating current (AC) facility. The other transmission line could be either an AC or direct current (DC) facility. If one of the lines is constructed as a DC facility, then the Project will include construction of a new DC converter station, which will be located within the requested 2500 foot corridor and within 1 mile east of the Pinal Central Substation.

PROJECT NEED AND BENEFITS

The SunZia Project benefits Arizona by providing needed increases in energy and power transfer capability and improved transmission reliability. Consequently, the Project will: (1) reduce existing transmission congestion; (2) support the development and transmission of renewable energy resources, such as solar and wind energy, currently located within areas of undeveloped renewable resource potential; (3) provide power to help meet future electricity demand in Arizona; (4) provide a strategic option for Arizona, and its utilities, to comply with increasingly burdensome federal air quality standards; and (5) provide needed jobs and state and local revenues.

The SunZia Project will enable the delivery of renewable energy essential for achieving compliance with existing and pending federal standards. By 2025,
Standard and Tariff requires regulated electric utilities to generate 15 percent of total energy from renewable energy technologies, and beginning in 2025, a significant reduction in carbon dioxide (CO_2) emissions from electricity generating units is required by the U.S. Environmental

requirement in Arizona, utilities will likely need to reduce reliance on high-emitting coal-fired power plants and obtain power from zero-emitting renewable sources. In addition, a pending regulation affecting Arizona utilities is EPA) final revised ozone standard, expected to be promulgated in October 2015. This new federal rule will likely further limit the development of new, and major modifications of existing, fossil fuel power plants in Arizona.

The Project will also provide needed jobs and revenue in Arizona. The Project will provide significant employment opportunities during its anticipated construction period (over 2500 jobs in Arizona); tax benefits through property, state, and local taxes; and significant revenue to ASLD.

PROJECT HISTORY

SunZia originated from regional transmission planning efforts.

The Southwest Area Transmission Subregional Planning Group (SWAT) is an organization within the Western Electricity Coordinating Council (WECC) that promotes coordinated regional planning of the transmission grid in Arizona, New Mexico, southern Nevada, and southern California. SWAT includes transmission owners and customers, environmental and conservation

DOCKET NO. L-00000YY-15-0318-00171

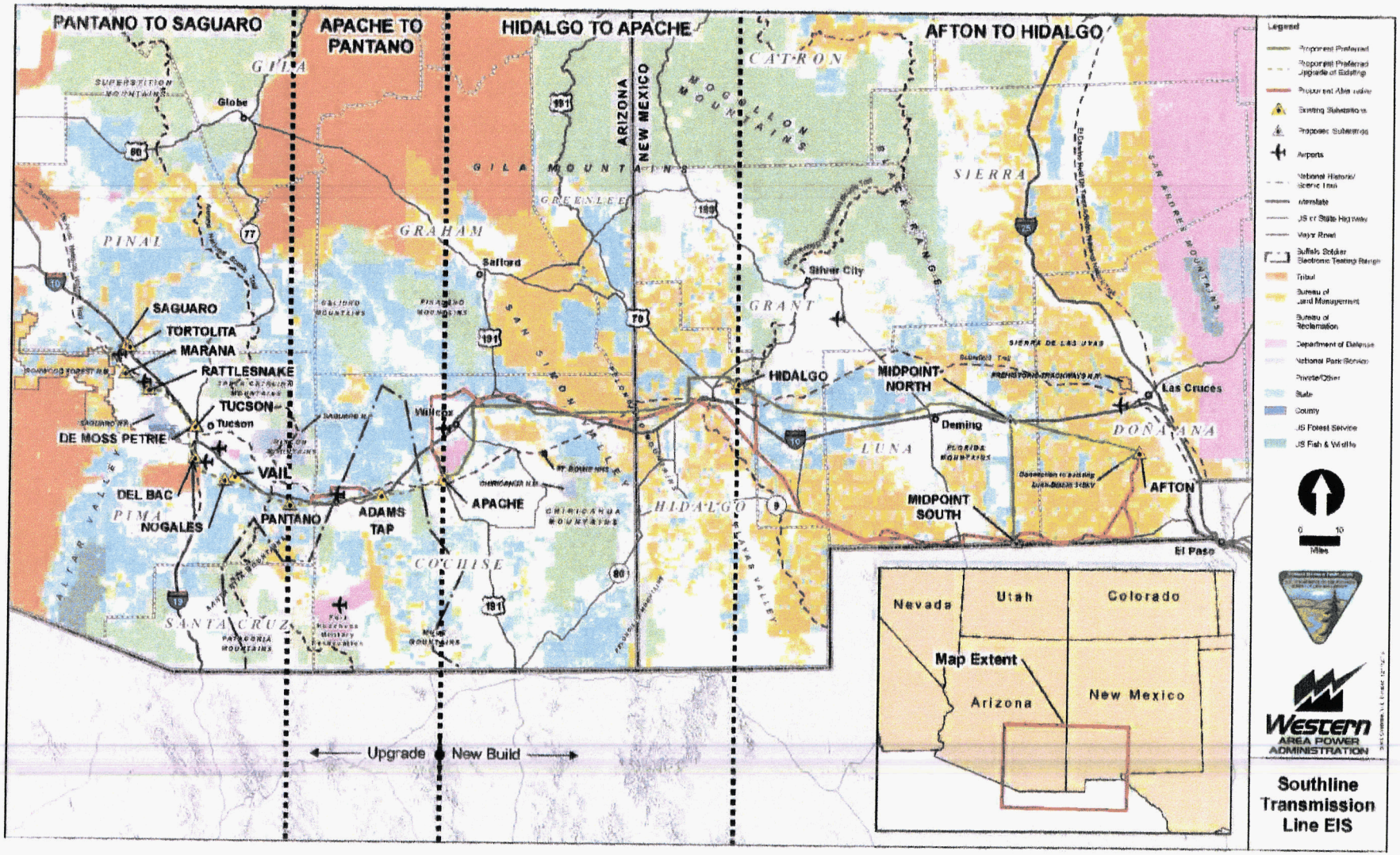
Exhibit PTE-17

New Mexico
Arizona
Phoenix
SunZia - Red
Tucson
Southline - Green
Ciudad Juarez

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-18

Figure 1-1. Project overview.



DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-19

1.2.3 Role of Bureau of Land Management and Western Area Power Administration

This EIS is being prepared by the BLM and Western in compliance with NEPA, Council on Environmental Quality (CEQ) regulations for implementing NEPA, DOE 10 CFR parts 1021 and 1022, FLPMA, and applicable U.S. Department of the Interior (DOI) and BLM policies and manuals. Other applicable authorizing Federal laws, regulations, and guidelines are described in sections 1.5 and 1.6. Southline would be responsible for obtaining all permits and approvals required to complete the proposed Project, regardless of whether they are listed in this document. Southline is working directly with the Western Electricity Coordinating Council (WECC) to establish path ratings for their proposed Project and integrate their Project with regional transmission efforts. The BLM is not involved in the transmission planning process, nor is it the responsibility of BLM or Western to make any determination of regional transmission infrastructure needs, system requirements, or system rating with regard to the Southline Project. Western is a member of WECC, however, and does participate in regional transmission planning.

In the Upgrade Section, as a co-lead on the EIS Western would need to revise, amend, and/or file new applications with the BLM and other Federal and State agencies. Western would need to update existing transmission line authorizations for those portions of the line where additional ROW would be needed owing to substantive changes in the proposed facility that are inconsistent with the original ROW grant. Western would also need to update rights and make payments for updated rights where the proposed facility would cross private lands. Western is currently negotiating renewal of its existing ROW with the Tohono O'odham Nation tribal allottees for that portion of the line located on allotted tribal lands. Western would also need to revise and reissue the existing special use permit (SUP) on the portions of the Project that cross U.S. Forest Service lands.

1.3 OBJECTIVES OF SOUTHLINE TRANSMISSION, LLC

Southline worked with WECC,[1] local utilities, and other regional transmission planning groups to design the proposed Project to help solve regional transmission needs such as congestion, reliability, capacity constraints, and limited transmission access for utilities and renewable energy zones in New Mexico and Arizona. Southline's objectives are to satisfy four primary needs; these are summarized below and described in more detail in sections 1.3.1 through 1.3.4.

1.3.1 Improve Reliability of the Electric Transmission Grid in Southern New Mexico and Arizona

Reliability of the electrical grid in southern New Mexico and Arizona is affected by load growth, inadequate electrical transmission capacity, limited electrical connections in the area, and many older electrical transmission lines that are approaching the end of their useful lives.

In recent years, key transmission lines across southern New Mexico and Arizona have experienced unanticipated outages that triggered load-shedding actions by the utilities and prompted investigation

[1] WECC and the nine other regional reliability councils were formed due to national concern regarding the reliability of the interconnected bulk power systems, the ability to operate these systems without widespread failures in electric service, and the need to foster the preservation of reliability through a formal organization. The Western Interconnection encompasses a vast area of nearly 1.8 million square miles. It is the largest and most diverse of the eight regional councils of the North American Electric Reliability Corporation (NERC). WECC's territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between (WestConnect 2012b).

by the Federal Energy Regulatory Commission (FERC) and NERC (FERC and NERC 2011). The transmission system in Cochise County has had reliability issues in the past, including the outages in 2007 that led to the ACC's requests for focused technical studies and mitigation (ACC 2008). In addition to these events, the existing Western line termination at Apache Substation is the outer edge of the Southeastern Arizona transmission system, which has several radial lines that lack redundancy (e.g., there are no other lines that would provide backup in the event of a line failure).

The condition and limited amount of the existing electrical infrastructure leads to highly utilized sections of the electrical system operating with low levels of redundancy to withstand unanticipated outages. In addition, utilities in the area have limited interconnections to hub power markets because of their location on the periphery of the WECC's grid and because of the limited existing electrical transmission capacity in the region. Therefore, access to and delivery of electricity to end users in southern New Mexico and Arizona is inadequate.

There are many older lines in the region that are reaching or beyond the end of their original design lives but that are still in service through the use of heavy maintenance regimes. For example, the Upgrade Section of the proposed Project is part of Western's South of Phoenix H-frame wood pole 115-kV transmission system, which was built in the early 1950s and is well past its engineered lifespan (Western 2012a). The wood poles have been subjected to advanced external shell rot, weathering, decay, and large cracks—conditions that can lead to reduced pole integrity and reduced ability to bear the load of mounted conductors and hardware, especially under severe weather conditions.

The proposed Project would improve system reliability in several ways. In particular, the Project would add bulk electric infrastructure to the existing grid, which would build redundant systems to resolve and allow flexibility for unanticipated and scheduled grid outages, respectively. The upgrading of the existing 115-kV lines and addition of new transmission and substation facilities would create additional connections and would increase import capability for regional utilities. Replacing aging wooden structures with steel structures would reduce the incidence of failures. Adding new equipment, including new conductors and insulators, would increase reliability. The proposed Project would also improve voltage limitations and reduce curtailment for local utilities.

1.3.2 Mitigate Existing Congestion

Existing transmission capacity in southern New Mexico and southern Arizona is presently fully utilized and congested. PL 109-58, the Energy Policy Act of 2005 (EPAct 2005), required that studies be completed detailing national electrical transmission congestion as well as areas where renewable energy development has been inhibited by a lack of sufficient transmission facilities or capacity. Consequently, the DOE produced the "National Electric Transmission Congestion Studies" in 2006, 2009, and 2012. The 2006 and 2009 DOE studies identified Path 47 – Southern New Mexico as one of the top congested paths, out of more than 20 paths in the West (DOE 2006, 2009). This congestion is demonstrated through the available transfer capability (ATC), which is a measure of the contractual transfer capability remaining in a transmission network for further use over and above those already committed uses (WestConnect 2012a) (table 1-2). Operators of the electrical grid in southern New Mexico and Arizona rely on a bilateral, contractual system to reserve transmission capacity and schedule operations that is indicated by the ATC. Path 47 (the import path to southern New Mexico) is reported to be fully committed, with zero ATC,[2] and the existing lines in the upgrade portion of the Project (which are not included in Path 47) are also fully committed, with near zero ATC.[3] This lack of available contractual capacity results in a congested condition, regardless of the electrical grid's physical state.

[2] Available at: http://www.oasis.oati.com/EPE/EPEdocs/Narrative_Explanation_for_Zero_ATC.pdf (Western 2013).
[3] Available at: http://www.oasis.oati.com/EPE/EPEdocs/Narrative_Explanation_for_Zero_ATC.pdf (Western 2013).

The electrical grid across southern New Mexico, southeast Arizona, and west Texas faces challenges from severe demand spikes resulting from large temperature swings—especially during hot summer months. Because loads on power lines are constantly changing and utilities need to reserve capacity to meet required levels of reliability, the congested state of the electrical grid exacerbates the difficulties of local utilities to provide reliable service, even when increased electrical load can be anticipated. The poor physical condition of certain components of the transmission grid, coupled with this current state of congestion, makes the entire system itself vulnerable to cascading outages and potential regional blackouts.

The proposed Project would mitigate existing and predicted future congestion, in both the east-to-west and west-to-east directions, by adding up to approximately 1,000 MW of bidirectional capacity to the electric grid. Table 1-2 demonstrates the existing transmission capacity in southern New Mexico and southern Arizona, including Path 47, compared with the transmission capacity that would exist at each stage of the WECC process (Phase 1 and Phase 2) if the proposed Project were built.

Table 1-2. Existing and Planned Transmission Capacity in Southern New Mexico and Southern Arizona

Southline Project Section	Existing ATC	Proposed Southline Rating (WECC Project Coordination Review Group)	Planned Southline Rating (WECC Phase 1)	Accepted Southline Rating (WECC Phase 2)
Afton to Apache (E-W)	151 MW (4 rates)	1,000 MW	1,038 MW	In process TBD
Apache to Saguaro (E-W)	0 MW	1,000 MW	1,001 MW	In process TBD
Saguaro to Apache (W-E)	0 MW	1,000 MW	418 MW	In process TBD
Apache to Afton (W-E)	0 MW	1,000 MW	957 MW	In process TBD

Source: WestConnect (2012a).

1.3.3 Increase the Ability to Meet Electrical Demand Growth in the Region

Southern New Mexico and Arizona have seen increased growth in recent years, according to the U.S. Census Bureau (Census Bureau). In the Afton–Apache Section, the average population growth in Doña Ana, Grant, Hidalgo, Luna, and Cochise counties was 12.9 percent between 2000 and 2010. In the Apache–Saguaro Section, the average population growth in Cochise, Pima, and Pinal counties was 15.6 percent between 2000 and 2010 (Census Bureau 2010a). Major load centers in the region (Tucson, Las Cruces, El Paso, and Phoenix) have grown by as much as 20 percent between 2000 and 2010 (Census Bureau 2013a). This increased growth has increased the demand for electricity and contributed to the congested state of the electrical grid in southern New Mexico and Arizona. In addition, the grid itself was designed for load conditions that existed more than 60 years ago that have since been far exceeded. Most of the area is expected to continue to grow at a faster rate than the United States overall (Arizona Department of Administration (ADOA) 2013).

The proposed Project would help meet future electric demand (or load growth) by adding 1,000 MW of capacity to the electric grid, which would improve regional transmission reliability and relieve congestion while improving access to energy sources. This would alleviate three of the primary factors that inhibit the local utilities' ability to meet future electrical demand.

1.3.4 Facilitate Renewable Generation Development and Achievement of Public Policy Goals

Demand for transmission capacity to serve renewable resources will increase as western states attempt to meet their renewable portfolio standards (RPSs). Mandatory RPSs have been established to encourage the development of renewable energy sources and mandate that electricity producers obtain a minimum percentage of power from renewable energy resources before a certain date. New Mexico's RPS is 20 percent by 2020, and Arizona's RPS is 15 percent by 2025 (BLM and DOE 2012). The Public Regulation Commission of New Mexico and the ACC have specific incremental goals and timetables planned so as to be able to meet their respective 2020 and 2015 RPSs (DOE 2013a).

Two Federal planning efforts identified specific locations that are well suited for renewable energy and established design features that would apply to these types of projects on BLM-administered lands. These two efforts overlap the Southline project area in Arizona and New Mexico, and include the Arizona BLM's RDEP (BLM 2012) and the Solar Energy Development PEIS (BLM and DOE 2012).

The RDEP ROD established 192,100 acres of renewable energy development areas (REDAs) on BLM land throughout Arizona. In addition, the ROD established the Agua Caliente Solar Energy Zone (SEZ) near Dateland in western Arizona. The BLM amended eight land use plans across Arizona to include the REDAs and RDEP SEZ. While these amendments only apply to BLM-managed lands, the RDEP examined all lands in Arizona.

The Solar Energy Development PEIS identified priority areas for utility-scale production of solar energy (i.e., SEZs), including the Afton SEZ in New Mexico; exclusion areas for utility-scale solar energy development; and areas potentially available for utility-scale solar development outside exclusion areas and SEZs (variance areas). Land use plans in six western states (Arizona, California, Colorado, Nevada, New Mexico, and Utah) were also amended to establish programmatic and SEZ-specific design features for solar energy development on public lands.

The fully utilized and congested condition of the transmission grid limits the development of renewable energy generation projects. For example, the available transmission capacity for the Afton SEZ is only a small fraction of the 6,900-MW nameplate development potential for the zone and would not currently enable the export of electricity to load centers. Similarly, in Arizona in 2008, the Southeast Arizona Transmission Group described many of the local systems' needs and limitations and suggested the benefits of upgrading Western's existing 115-kV lines between Apache and Saguaro. TEP and Southwest Transmission Cooperative (SWTC) further reinforced this in 2009, identifying this upgrade as one of the top three potential renewable transmission projects in their planning area.

The proposed Project would add up to about 1,000 MW of bidirectional capacity to the existing electrical grid in southern New Mexico and Arizona and relieve congestion by adding bulk electric infrastructure, including connection with up to 14 existing substations spread across the area, which would improve the local utilities' ability access to energy sources. In doing so, the proposed Project would be consistent with public policy goals promoting the increased use of renewable energy to meet RPSs.

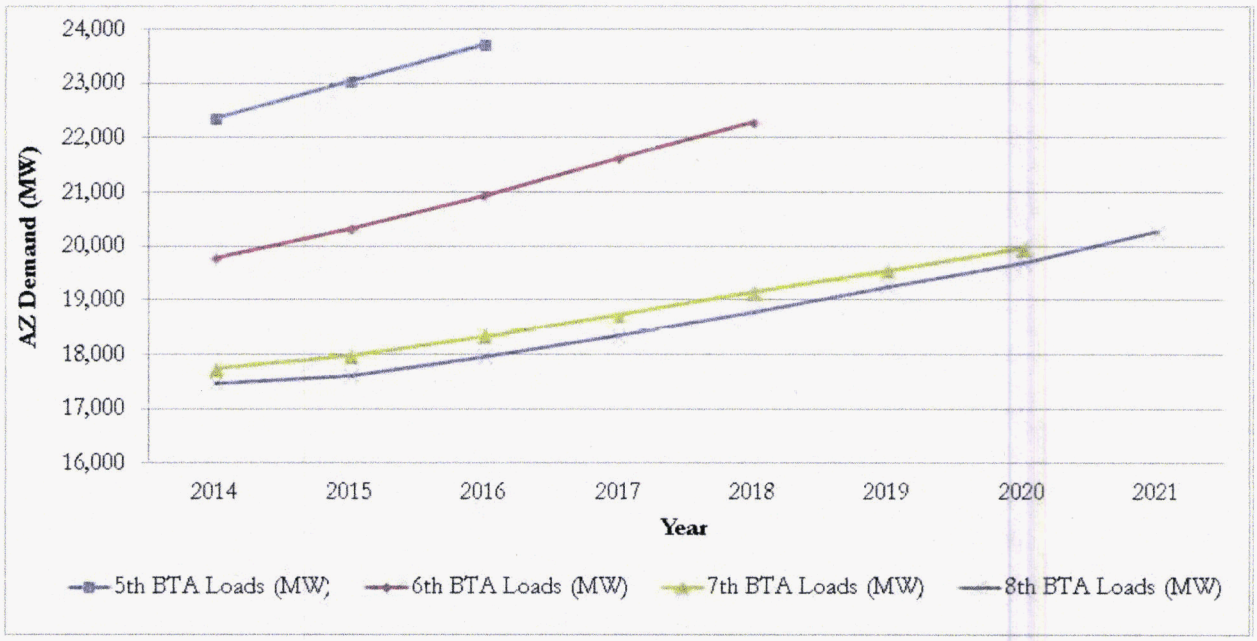
1.4 ELECTRIC TRANSMISSION REGULATION AND PLANNING

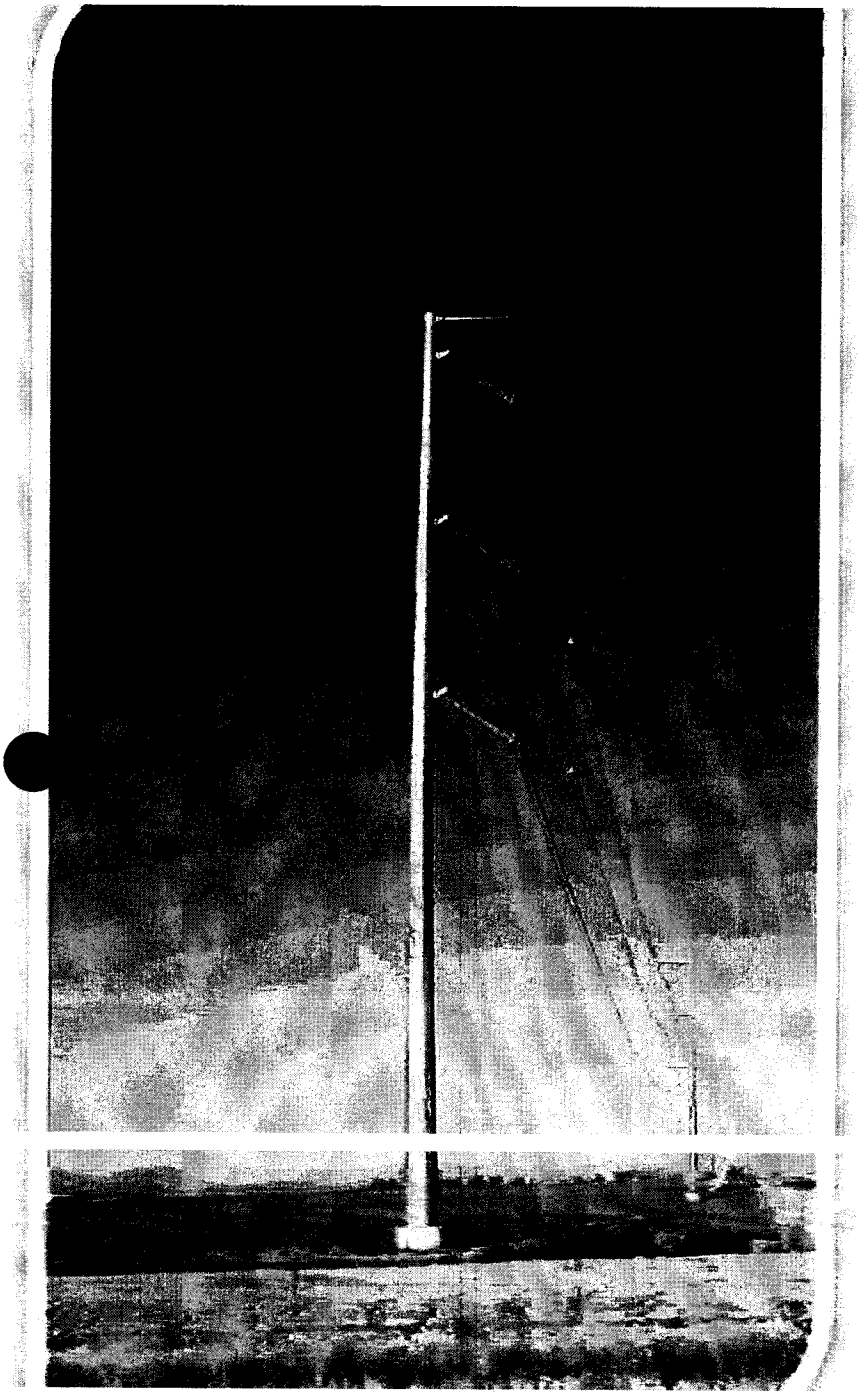
Traditionally, local utilities owned and controlled the electrical transmission network, but today's regulatory framework allows for third-party non-utility ownership, or independent transmission. In North

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-20

ACC Biennial Transmission Assessment for 2014-2023, page 14





Eighth Biennial Transmission Assessment 2014-2023

Staff Report

Docket No. E-00000D-13-0002

Decision No. 74785

October 29, 2014

Prepared by Arizona Corporation Commission Staff

And

K. R. Saline & Associates, PLC.
160 North Pasadena, Suite #101
Mesa, Arizona 85201

A list of all changes between the Seventh and Eighth BTAs for transmission projects 115 kV and above is provided in Exhibit 9. Table 9 is a list of changes that have occurred at Extra High Voltage (?EHV?) levels of 345 kV and above.

Table 9 ? Significant EHV Project Changes Since the Seventh BTA

In-Service Date	Project Description	Voltage Class (kV)	Status
2012	3rd Kyrene 500/230kV Transformer	500	Complete
2015	Jojoba Loop-in of Hassayampa - Pinal West 500kV Line	500	New Project - 2015
2016	Pinal Central - Tortolita 500kV Line	500	Deferred 2014 to 2016
2016	Delaney - Palo Verde 500kV Line	500	Deferred 2013 to 2016 & SRP Withdrawn
2016	Delaney - Sun Valley 500kV Line	500	Deferred 2015 to 2016 & SRP Withdrawn
2018	Sun Zia Transmission Project	500	Deferred 2016 to 2018
2018	Sun Valley - Morgan 500kV Line	500	Deferred 2016 to 2018 & SRP Withdrawn
N/A	Hassayampa - Pinal West 500kV Line #2	500	Deferred Indefinitely
N/A	Northeast Arizona - Phoenix 500kV	500	Deferred Indefinitely
2012	McKinley 345kV Reactor Addition	345	Complete
2012	Vail 345/138kV Transformer T3	345	Complete
2013	Youngs Canyon 345/69kV Substation	345	Complete
2015	Springerville - Vail Series Capacitor Replacement at Vail	345	Deferred 2013 to 2015
2017	Mazatzal 345/69kV Substation	345	Deferred 2015 to 2017
2020	Springerville - Greenlee Series Capacitor Replacement at Greenlee (Phil Young)	345	Deferred 2017 to 2020
Postponed Indefinitely	Greenlee 2nd 345/230kV Transformer	345	Removed
Postponed Indefinitely	Bicknell 345/230kV Transformer Replacement	345	Removed
Postponed Indefinitely	Greenlee Switching Station through Hidalgo - Luna	345	Deferred TBD to Indefinitely
Removed	Pinal Central - Abel - RS20 500 kV Line	500	Cancelled

2.3 Driving Factors Affecting the Ten Year Plan ? Load Forecast

In reviewing the filings, the chief determinant for the ten year transmission plans in Arizona was found to be the projected future load growth. Figure 1 shows the change in statewide demand forecasts between previous BTAs and the current Eighth BTA.

Figure 1 - Change in Arizona Demand Forecast

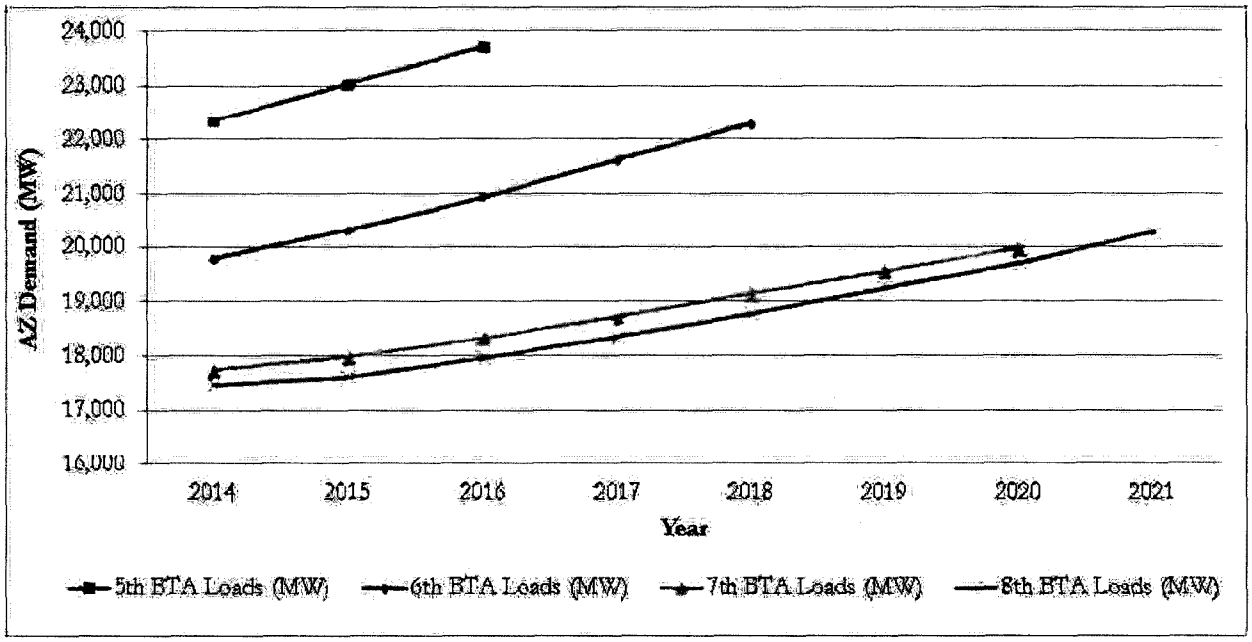


Figure 1 shows the statewide demand forecast has shifted by approximately one year since the Seventh BTA. Although the statewide forecast has slowed by one year, the overall growth rate has remained relatively constant at between 1% and 2% per year. The overall delay of most near-term transmission projects as shown in Exhibit 8 is consistent with this shift in the demand forecast. The detailed forecast data included in Exhibit 8 shows SRP and SWTC Eighth BTA load forecasts are higher than in the Seventh BTA, while TEP and APS load forecasts are lower.[30]

In its Sixth BTA Order the Commission directed Arizona utilities to ?include the effects of distributed renewable generation and energy efficiency programs on future transmission expansion needs in future ten year plan filings.? [31] The filed ten year plans for APS, SRP, TEP/UNSE and SWTC state that these factors were taken into account in developing the demand forecasts used in studies performed for the current ten year plans.

At Workshop I, Staff and KRSA asked utilities to what extent the decreased demand forecast was due to the effects of DG and/or EE. The utilities responded that DG and EE were taken into

[30] The higher SWTC load forecast is likely explained by the fact that, for the first time in the Eighth BTA, SWTC provided a load forecast that was based on non-coincident peak loads, not coincident peak loads as previously provided.
[31] Decision No. 72031 (December 10, 2010)

account in developing the load forecast for both the previous and current demand forecasts, but that the main factor behind the drop in the forecast from 2012 to 2014 was the impact of the continuing economic recession.

Over the past three BTAs load forecasts have changed substantially along with the associated transmission projects. In order to provide the Commission with additional information on the impact of load forecasts on transmission projects, Staff concludes that for reliability or load growth driven transmission projects a system load level range at which a transmission project is needed should be reported along with the projected in-service year beginning with ten year transmission plans filed on January 31, 2016.

2.4 Driving Factors Affecting the Ten Year Plan ? Generator Interconnections

Under FERC regulations, generation developers seeking to interconnect to a transmission provider?s system must file an interconnection application.[32] The rules and procedures for such applications are defined in the transmission provider?s Open Access Transmission Tariff (?OATT?). As part of the BTA process, Staff and KRSA detailed each utility?s generation interconnection queues from the Seventh and Eighth BTA. These are summarized in Table 10 and detailed in Exhibit 10, along with the difference between the two. In parallel with the FERC?s interconnection process, any party contemplating construction of transmission in Arizona, including generator tie-lines, must file a ten year plan with the Commission.[33]

Utility	Approximate Capacity (MW) of Generators in Utility Queue		Interconnection Queues from Seventh to Eighth
	Seventh BTA	Eighth BTA	
APS	8,329	4,774	(3,555)
SRP	4,424	1,725	(2,699)
TEP/UNS Electric	1,400	851	(549)
WAPA	4,300	2,660	(1,640)
SWTC	0	0	0
Total	**18,453**	**10,010**	**(8,443)**

Table 10 - Summary of Arizona Generator Interconnection Queues

[32] Generators over 20 MW are interconnected pursuant to a Large Generator Interconnection Agreement (?LGIA?); generators 20 MW or less are interconnected pursuant to a Small Generator Interconnection Agreement.
[33] ARS § 40-360.02.A

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-21

Clean Power Plan: State at a Glance

Arizona

In the final Clean Power Plan (CPP), EPA is establishing interim and final carbon dioxide emission performance rates for the two types of electric generating units - steam electric and natural gas fired power plants - under Section 111(d) of the Clean Air Act. The CPP also establishes state-specific interim and final goals for each state, based on these limits and each state's mix of power plants. The goals are expressed in two ways—rate-based and mass-based— either of which can be used by the state in its plan. States that choose a mass-based goal must assure that carbon pollution reductions from existing units achieved under the Clean Power Plan do not lead to increases in emissions from new sources. EPA is offering an option to simplify this requirement for states developing plans to achieve mass-based goals. If a state chooses this route, its state planning requirements are streamlined, avoiding the need to meet additional plan requirements and include additional elements.

EPA has a "goal visualizer" tool on the web at www.epa.gov/cleanpowerplantoolbox that walks through the exact calculations for Arizona.

Arizona's Interim (2022-2029) and Final Goals (2030)

ARIZONA			
	CO_2 Rate (lbs/Net MWh)	CO_2 Emissions (short tons)	
2012 Historic [1]	1,552	40,465,035	
2020 Projections (without CPP)	1,409	39,511,785	
[illegible]	[illegible]	[illegible]	[illegible]
Interim Step 1 Period 2022-2024 [2]	1,263	35,189,232	35,869,066
Interim Step 2 Period 2025-2027 [3]	1,149	32,371,942	34,070,025
Interim Step 3 Period 2028-2029 [4]	1,074	30,906,226	33,039,340
[illegible]	[illegible]	[illegible]	[illegible]

1. EPA made some targeted baseline adjustments at the state level to address commenter concerns about the representativeness of baseline-year data. These are highlighted in the CO_2 Emission Performance Rate and Goal Computation TSD.

2, 3, 4. Note that states may elect to set their own milestones for Interim Step Periods 1, 2, and 3 as long as they meet the interim and final goals articulated in the emission guidelines. In its state plan, the state must define its interim step milestones and demonstrate how it will achieve these milestones, as well as the interim goal and final goal. See section VIII.B of the final rule preamble for more information.

The final Clean Power Plan goals for Arizona look different from the proposed goals – the 2030 goal looks less stringent, and the interim goal looks less stringent.

States' goals fall in a narrower band, reflecting a more consistent approach among sources and states.

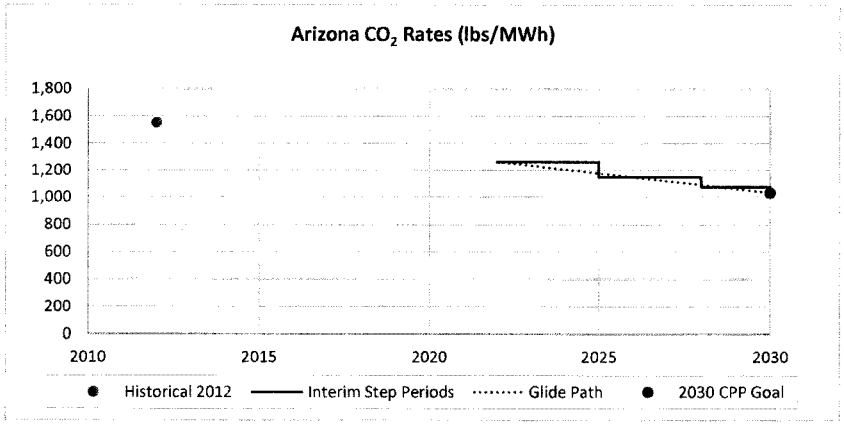
At final, all state goals fall in a range between 771 pounds per megawatt-hour (states that have only natural gas plants) to 1,305 pounds per megawatt-hour (states that only have coal/oil plants). A state's goal is based on how many of each of the two types of plants are in the state.

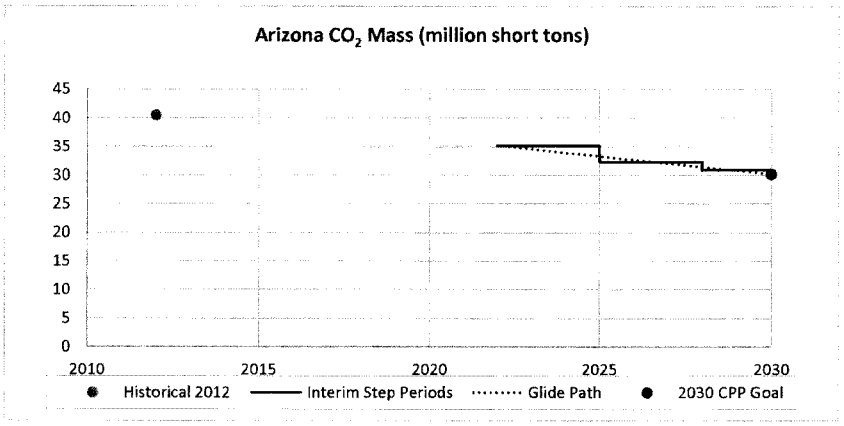
The goals are much closer together than at proposal. Compared to proposal, the highest (least stringent) goals got tighter, and the lowest (most stringent) goals got looser.

- Arizona's 2030 goal is 1,031 pounds per megawatt-hour. That's in the middle of this range, meaning Arizona has one of the moderate state goals, compared to other state goals in the final Clean Power Plan.
- Arizona's step 1 interim goal of 1,263 pounds per megawatt-hour reflects changes EPA made to provide a smoother glide path and less of a "cliff" at the beginning of the program.The "cliff" had been particularly significiant for Arizona.

Pathway to 2030: While EPA's projections show Arizona and its power plants will need to continue to work to reduce CO_2 emissions and take additional action to reach its goal in 2030, these rates – and that state goal – are reasonable and achievable because no plant and no state has to meet them alone or all at once. They are designed to be met as part of the grid and over time. In fact, the rates themselves, and Arizona's goal, reflect the inherent flexibility in the way the power system operates and the variety of ways in which the electricity system can deliver a broad range of opportunities for compliance for power plants and states. EPA made improvements in the final rule specifically for the purpose of ensuring that states and power plants could rely on the electricity system's inherent flexibility and the changes already under way in the power sector to find affordable pathways to compliance.

- **Flexibility in state plans and easier access to trading programs.** States can use EPA's model trading rules or write their own plan that includes trading with other "trading-ready" states, whether they are using a mass- or rate-based plan.
- **Clean Energy Incentive Program available for early investments.** This program supports renewable energy projects – and energy efficiency in low-income communities – in 2020 and 2021.
- **The period for mandatory reductions begins in 2022, and there is a smoother glide path to 2030.** The glide path gradually "steps" down the amount of carbon pollution. Note that states may elect to set their own milestones for interim step periods 1, 2 and 3 as long as they meet the interim goal overall or "on average" over the course of the interim period, and meet the final goals, established in the emission guidelines. To accomplish this, in its state plan, the state must define its interim step milestones and demonstrate how it will achieve these milestones, as well as the overall interim, and final, goals.
- **Energy efficiency available for compliance.** Demand-side EE is an important, proven strategy that states and utilities are already widely using, and that can substantially and cost-effectively lower CO_2 emissions from the power sector. EPA anticipates that, thanks to their low costs and large potential in every state and region, demand-side EE programs will be a significant component of state compliance plans under the Clean Power Plan. The CPP's flexible compliance options allow states to fully deploy EE to help meet their state goals.





Regional Point of Contact for Questions:

Ray Saracino / EPA Region 9

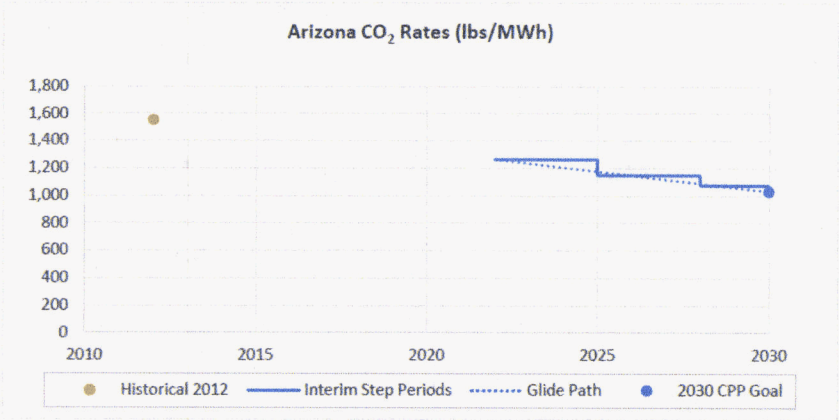
415-972-3361

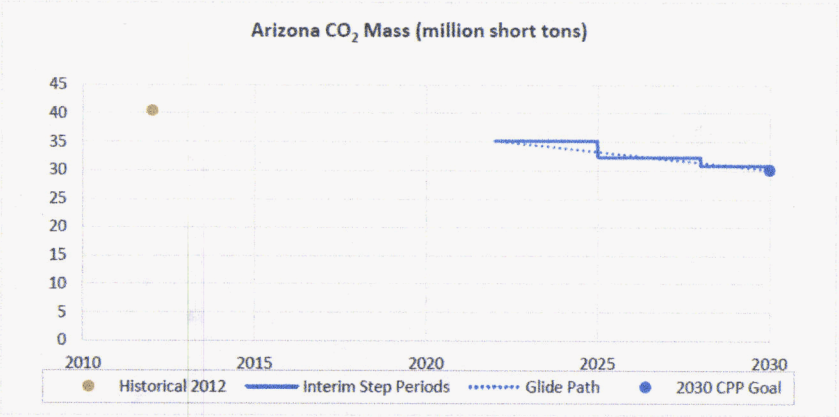
saracino.ray@epa.gov

Updated 8/3/2015 5:15 PM

Pathway to 2030: While EPA's projections show Arizona and its power plants will need to continue to work to reduce CO_2 emissions and take additional action to reach its goal in 2030, these rates – and that state goal – are reasonable and achievable because no plant and no state has to meet them alone or all at once. They are designed to be met as part of the grid and over time. In fact, the rates themselves, and Arizona's goal, reflect the inherent flexibility in the way the power system operates and the variety of ways in which the electricity system can deliver a broad range of opportunities for compliance for power plants and states. EPA made improvements in the final rule specifically for the purpose of ensuring that states and power plants could rely on the electricity system's inherent flexibility and the changes already under way in the power sector to find affordable pathways to compliance.

- **Flexibility in state plans and easier access to trading programs.** States can use EPA's model trading rules or write their own plan that includes trading with other "trading-ready" states, whether they are using a mass- or rate-based plan.
- **Clean Energy Incentive Program available for early investments.** This program supports renewable energy projects – and energy efficiency in low-income communities – in 2020 and 2021.
- **The period for mandatory reductions begins in 2022, and there is a smoother glide path to 2030.** The glide path gradually "steps" down the amount of carbon pollution. Note that states may elect to set their own milestones for interim step periods 1, 2 and 3 as long as they meet the interim goal overall or "on average" over the course of the interim period, and meet the final goals, established in the emission guidelines. To accomplish this, in its state plan, the state must define its interim step milestones and demonstrate how it will achieve these milestones, as well as the overall interim, and final, goals.
- **Energy efficiency available for compliance.** Demand-side EE is an important, proven strategy that states and utilities are already widely using, and that can substantially and cost-effectively lower CO_2 emissions from the power sector. EPA anticipates that, thanks to their low costs and large potential in every state and region, demand-side EE programs will be a significant component of state compliance plans under the Clean Power Plan. The CPP's flexible compliance options allow states to fully deploy EE to help meet their state goals.





Regional Point of Contact for Questions:

Ray Saracino / EPA Region 9

415-972-3361

saracino.ray@epa.gov

Updated 8/3/2015 5:15 PM

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-22

The National Ambient Air Quality Standards

DESIGNATIONS AND PERMITTING REQUIREMENTS FOR THE 2015 OZONE STANDARDS

On Oct. 1, 2015, the U.S. Environmental Protection Agency (EPA) strengthened the nation's air quality standards for ground-level ozone to improve public health and environmental protection. EPA will work closely with state, local and tribal air agencies to implement the ozone standards, beginning immediately. The agency's projections show the vast majority of U.S. counties will meet the proposed standards by 2025 just with the rules and programs now in place or underway.

Highlights

- EPA will designate attainment and nonattainment areas in late 2017.
- The agency will work closely with state, local and tribal air agencies to develop clean air plans for meeting ozone standards.
- The final rule includes a grandfathering provision to ensure that compliance with the updated ozone standards will not delay final processing of certain pending preconstruction permit applications.

Designating Attainment and Nonattainment Areas

- As part of the final rule, EPA has outlined initial steps the agency will take to help states implement the revised standards, including the anticipated area designations schedule.
- Once EPA sets a new air quality standard, or revises an existing standard, the Clean Air Act requires EPA to designate areas as meeting the standards (*attainment areas*) or not meeting them (*nonattainment areas*) based on local air quality. The agency also may designate an area as *unclassifiable*, meaning there is not enough information to make a determination. Governors make initial designation recommendations, and EPA works closely with states and tribes as it determines initial designations and boundaries for nonattainment areas.
- All states with nonattainment areas must develop emission inventories and implement a preconstruction permitting program designed to provide additional air quality safeguards for those areas. States with nonattainment areas classified as "Moderate" or higher must develop state implementation plans (SIPs) showing how the areas will meet the standards. These states also must adopt reasonably available control technology (RACT) standards for certain types of emission sources in the nonattainment area.

- Tribes may, but are not required to, develop their own plans for nonattainment areas in Indian country. Where necessary or appropriate to protect air quality, EPA will develop plans for any tribal area that chooses not to develop its own plan.
- EPA anticipates the following schedule for making area designations:
    - By October 1 2016: States (and any tribes that choose to do so) recommend the designation for all areas of the state, or any relevant areas in Indian country, and the associated boundaries for those areas. To assist states and tribes in preparing their recommendations, EPA intends to update its existing designations guidance in early 2016.
    - By June 1, 2017: EPA responds to states' and tribes' initial recommendations and identifies where the agency intends to modify the recommendations. States and tribes will have the opportunity to comment on EPA's response, and to provide new information and analyses for EPA to consider.
    - By October 1, 2017: EPA issues final area designations; those designations likely would be based on 2014-2016 air quality data.
    - 2020 to 2021: For nonattainment areas classified as "Moderate" and above, states, and any tribes that choose to do so, complete development of implementation plans, outlining how they will reduce pollution to meet the standards. State and tribal plans can include federal measures, and any local or statewide measures needed to demonstrate that a nonattainment area will meet the standards by its attainment date.
    - 2020 to 2037: Nonattainment areas are required to meet the primary (health) standard, with deadlines depending on the severity of an area's ozone problem.
- Clean Air Act rules will help areas meet the proposed standards by cutting emissions of ozone-forming nitrogen oxides (NOx) and volatile organic compounds (VOCs). These include rules that will reduce emissions from the nation's biggest sources of man-made NOx and VOC emissions, such as vehicles, engines and fuels, power plants, industrial processes, stationary engines and products such as solvents and paints.
- In addition, voluntary programs such as the Advance Program and ENERGY STAR help reduce emissions by encouraging states, counties, cities and tribes to take actions to maintain clean air in their communities and by reducing energy demand. Thirty-five areas in 18 states are participating in the Advance Program, implementing programs to protect air quality, such as minimizing congestion, improving public transit, reducing idling, increasing energy efficiency in buildings, and raising awareness about air quality.

- Actions taken in the coming months that improve air quality will help reduce ozone in 2016 – one of the three years that will be considered in determining attainment areas.
- Many existing regulations and guidance documents will apply to the revised standards. EPA intends to propose additional rules and develop additional guidance to assist states with implementing the revised standards within the next year. These rules will address classification and implementation issues such as:
    - Air quality thresholds for nonattainment area classifications, which determine maximum attainment dates and other required emission control programs;
    - State implementation plan (SIP) and attainment demonstration due dates;
    - Developing nonattainment area emissions inventories and attainment demonstrations
- EPA anticipates finalizing any proposed new rules and issuing any additional guidance by the time the agency makes final area designations.

Transition Mechanism for PSD Permitting Requirements

Under EPA's Prevention of Significant Deterioration (PSD) program, new or expanding sources of air pollution, such as factories, industrial boilers or power plants must obtain preconstruction permits to ensure they use modern pollution controls and do not significantly worsen air quality in areas with clean air.

- As part of the final rule, EPA is issuing a grandfathering provision for certain preconstruction permitting requirements to ensure that compliance with the revised ozone standards will not delay final processing of certain pending permit applications. This provision, similar to the provision finalized in EPA's 2012 particulate pollution standards, would apply to certain eligible applications for PSD permits that have achieved particular milestones by the time of signature or by the effective date of the rule, depending on the milestone.
- To receive a PSD permit, a source must meet several requirements, including demonstrating that emissions from a proposed project do not cause or contribute to a violation of any national ambient air quality standard. This requirement generally applies to the air quality standards -- including any revised standards -- that are in effect at the time the permit is issued.
- The grandfathering provision will apply to PSD permit applications if either:
    - The permitting agency has formally determined the application to be complete as of Oct. 1, 2015; or

- The public notice for a draft permit or preliminary determination has been published prior to the date revised ozone standards become effective (60 days after publication in the Federal Register).

- Permit applications that have not met either of these criteria would have to demonstrate that the proposed project does not cause or contribute to a violation of any revised ozone standards that are in effect when the permit is issued, including the revised standards.
- The final grandfathering provision will become part of EPA's PSD permit program but states and local agencies with EPA-approved PSD permit programs may also choose to use the provision.
- The grandfathering provision applies only to the requirement to demonstrate that a proposed project does not cause or contribute to a violation of the updated ozone standards. Proposed projects will continue to be subject to all other PSD requirements, including Best Available Control Technology (BACT) and must demonstrate compliance with the applicable previous ozone standards.
- The grandfathering provision does not apply to nonattainment New Source Review permit applications, which are subject to different requirements.

FOR MORE INFORMATION

- To read the proposed rule and other fact sheets: http://www3.epa.gov/ozonepollution/actions.html
- Information on the Advance Program http://www3.epa.gov/ozoneadvance/index.html
- About Energy Star: http://www.energystar.gov

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-23

August 17, 2012

To:
Bureau of Land Management (BLM)
New Mexico State Office
Proposed SunZia Transmission Project
P.O. Box 27115
Santa Fe, New Mexico 87502-0115

Also submitted via email to:
NMSunZiaProject@blm.gov

These comments are submitted as an integral part of the process prescribed in the National Environmental Policy Act (NEPA) for the proposed SunZia Southwest Transmission project, specifically directed toward the draft Environmental Impact Statement (DEIS). There is no need to withhold my personal information from public review.

Part One, Introduction and Rationale for the No Action Decision

These comments provide evidence that the BLM has denied the public and stakeholders due process, and is heading toward an arbitrary decision. The BLM engaged in a two-fold denial of due process by:

1) ignoring the content of written comments that were submitted during official comment periods and through Information Quality Act requests prior to the release of the draft EIS, and
2) prohibiting public questioning of the BLM's draft EIS and presentation in public meetings.

By ignoring significant written comments and denying any public questioning of the draft EIS, the BLM failed to provide a sound basis for the analysis in their environmental review process and demonstrated that the agency was on the path toward making an arbitrary decision.

As a resident of the San Pedro River Valley and as a conservation activist, I have been appalled at how the BLM has handled this particular project proposal. In this instance, we had an applicant who made exaggerated claims about how this transmission project would benefit renewable energy development. These claims were challenged in credible written documents. Assurances were given by the BLM that these challenges would be addressed in the DEIS. However, after years of challenges and assurances, we are now reviewing a document that continues to make unsubstantiated renewable energy claims. To add insult to injury, the BLM prevented the public from questioning or challenging this exaggerated renewable energy narrative, or any other pertinent issue, at the recent series of public meetings. We were simply expected to listen to the agency's approved speakers and not make any public comment.

With the NEPA process rapidly coming to a close, the BLM has failed to earn public trust in their description of the proposed project. With more red flags falling on this project's renewable energy development claims than on those of the infamous Solyndra project, and with significant environmental issues at stake, the ***No Action*** option is the only logical decision for this project. At this point, it is probably too late in the process to effectively redress the misinformation that has been so widely disseminated by the BLM over such a long period of time

Using the *fast track* argument as a reason for overriding meaningful and informed public participation does not meet the standards of the NEPA. Ignoring public input actually slows down the process, in the long run. Also, it is inappropriate for the agency to blame the applicant for the exaggerated renewable energy claims, since the oversight agency was fully informed of contradicting evidence *prior to the release of the DEIS.* There is a long paper trail of this evidence, and it is the BLM's responsibility to review all major assumptions that are used as the basis for their analysis.

As a member of my local Natural Resource Conservation District (NRCD), I know that the BLM assured the Winkelman and Redington NRCDs in three written responses and one oral response over a period of nine months that their requests for correction and disclosure regarding SunZia's energy development claims would be addressed in the DEIS. In the intervening period, the BLM continued to publish the challenged information on its website. The final response from BLM Director Robert Abbey included an agreement to add a disclaimer (addressing only two of the ten original requests for correction or disclosure) to their web-distributed scoping documents. However, as with three previous BLM responses, Mr. Abbey again stated that our other "concerns" about the BLM's project description would be addressed in the DEIS. He added that if these concerns were not addressed or acknowledged in the DEIS, we would then have to make what will be our ***fifth attempt*** to request some of the same corrections that have been out on the table since the end of the scoping comment period in September of 2010. Perhaps you can understand why I used the word *appalled* in my opening comments.

We did not have general "concerns". We had nine specific requests for correction and disclosure and one request to address systematic bias in presentation, all submitted under an act of Congress, the Information Quality Act (IQA) of 2001 (see attached Table, *Ten Specific Requests in the Information Quality Act Petition of July, 2011).* By refusing to address or even acknowledge most of these requests, and by ignoring the substance of evidence we provided to them, the BLM continued to present the project description in a systematically biased manner in the DEIS, effectively extending SunZia's misinformation campaign to a period of at least three and a half years.

In two of the documents submitted to the BLM, the NRCDs cited a specific feasibility study regarding the relative mix of renewable and non-renewable energy resources necessary for the economic and practical success of an extra high voltage (EHV) line in this region. The BLM ignored this information, as well as other specific information we provided regarding the probable generation sources for the proposed transmission lines, and instead included over 170 pages of faulty analysis in the DEIS that was based upon an unrealistic energy development forecast.

A recent response by the BLM to another IQA petition regarding the proposed Southline Transmission Project demonstrates that the Las Cruces office of the BLM understands the requirements of the IQA. In this response, all requests for correction by the petitioner were acknowledged and addressed in some way by the responding BLM project manager. However, in the case of the SunZia IQA petition, which was initially submitted to the Santa Fe office of the BLM, none of the three responses to the original petition and the two subsequent appeals met this standard. In this particular case, the petitioners were only given vague assurances that their requests would be addressed in the DEIS, which did not turn out to be the case.

When I attempted to raise this information quality problem at public meetings in Tucson and San Manuel, I was told by BLM Project Manager Adrian Garcia that, by order of the Arizona and New Mexico BLM Directors, I would not be allowed to raise any issue publicly at the so-called public meetings, nor would any other stakeholder or member of the public regarding any other issue related to the proposed project.

I learned that the only two speakers approved to speak at these meetings were Mr. Garcia and Mr. Mickey Siegel, of the Environmental Planning Group (EPG), which is the BLM's hired environmental review firm. I was also told that the only questions or comments permitted under this protocol would be handled one-on-one between attendees and official representatives of the project, the BLM, and EPG. Mr. Siegel handled the majority of the 45 minute presentation at the two public meetings I attended.

In addition to their role as the BLM's EIS contractor firm, Mr. Siegel and EPG also represented one of SunZia's owners, Southwest Power Group (SWPG), in their 2001 application for a Certificate of Environmental Compatibility related to the 1000 MW natural gas powered Bowie Power Plant owned by SWPG. These two roles placed Mr. Siegel in the position of potentially advancing his former client's interest in securing additional transmission capacity for the Bowie plant by describing the proposed SunZia project, both in the DEIS and in official BLM public presentations, in a way that would best promote public acceptance of the project by the public and stakeholders at large.

It should be noted that the energy development aspect of Mr. Siegel's presentation focused exclusively on renewable energy resources. When Mr. Siegel was describing renewable energy resources in the southern portions of New Mexico and Arizona to a small audience at the San Manuel public meeting, I asked, "What about natural gas resources in this region?" Mr. Siegel responded that he was only covering renewable energy resources zones, and that questions needed to be held until after the presentation when they would be answered by a member of the staff.

I spoke to Mr. Siegel himself after the presentation about the role of non-renewable resources, and he responded in an evasive manner. First, he pointed to the official statement of purpose on one of the nearby posters, which made no specific claim about the primacy of renewable energy. When I raised the issue of the Energy Development Forecast in the DEIS (forecasting 81 to 94% renewable energy development), he said that renewable energy development is *the intent* of the project. When I pointed out the difference between *intentions* and a *probable development forecast* (based upon imminently pending generation projects and the factors discussed in the comments below), Mr. Siegel returned to his original formal statement of purpose and the zones of potential renewable energy he had shown in his presentation. It became obvious at that point that the discussion was going in circles, and he had no interest in addressing my original question about major non-renewable resources that are awaiting transmission capacity. Frustrating interactions such as this appear to be designed to make the public give up on asking relevant questions. In my own frustration, I told Mr. Siegel that I no longer trusted his ability to be a neutral intermediary among the oversight agency, the applicant, and the public.

Contrary to the request made by the NRCDs in their IQA petition, there is no formal statement of disclosure in the DEIS about the financial connection between the owners of the Bowie Plant and the owners of the SunZia project. With these comments, I also note that there is no statement of disclosure regarding the former business connection between a major owner of the SunZia project (SWPG) and the BLM's EIS contractor (EPG).

By controlling the message about the purpose of the SunZia project, by ignoring much of what was submitted in written form, and by forbidding publicly-raised questions during or after these official presentations, the BLM was denying the public and stakeholders any opportunity to effectively challenge the narrative about renewable energy that was being presented by their environmental contractor in the DEIS and in the public meetings.

With evidence that the applicant's claims for benefits to the environment are significantly exaggerated (see comments below), we need not wait until the project is constructed to learn that this particular project will significantly increase greenhouse gas emissions, contrary to the claim made in the DEIS. If we wait that long, the impacts to the San Pedro Valley will have already occurred. The San Pedro watershed contains the last remaining major natural riparian ecosystem in southern Arizona. As such, it has become the repository for conservation investments that were needed to satisfy mitigation requirements for development that has taken place elsewhere in the state. These conservation investments were made in good faith, and should not be devalued by building a major new infrastructure corridor in the last remaining major riparian watershed. This corridor will mainly benefit the very growth areas that caused the need for these conservation investments.

There is no evidence that this project will benefit the environment as a whole, and there is plenty of evidence that this project will cause significant harm to the San Pedro riparian ecology. A recent DEIS comment letter from the applicant's own project manager documents the environmental impacts along the BLM's preferred route through the San Pedro Valley, and he admits how difficult it would be to mitigate these impacts. Another alternative route, the so-called Aravaipa option, bisects both the lower San Pedro River Valley and the second largest unfragmented wilderness zone in New Mexico and Arizona (the Galiuro wilderness zone), which would the violate principles of conservation biology in an equally significant manner as with the preferred route, as well as violating the BLM's own directive about using rights-of-way in common. The other route alternatives through the San Pedro Valley or through the Tucson area are also unacceptable or unfeasible. ***The BLM must seriously consider alternatives to this proposed project.***

Part Two, Section-Specific Comments on the DEIS

Section 1-3: Remarkably, there is no concrete statement of need for this particular project, other than fulfilling the BLM's policy objectives to offer its landholdings for multiple uses in general and energy development in particular. In this section, there are only general references to the need for upgrading transmission infrastructure, but no reference to the pressing need for *this particular transmission project*. Without a clear statement of need for this particular transmission project, there is no statement of the problem that needs to be resolved, and no clear basis for the analysis that follows.

Section 1.4: This section on the *Applicant's Objectives* is isolated from the BLM's statement of purpose and need. However, the BLM is ultimately responsible for assessing any statement of purpose and need that the applicant embeds in his "objectives". To evade this responsibility by simply attributing these statements to the applicant is not appropriate in an environmental review document. It is the BLM's responsibility to review and substantiate all statements of purpose and need in the DEIS, since these are the very statements that are used as the basis for analyzing alternatives to the proposed project, for analyzing cumulative effects of the proposed project, and for evaluating the benefits to society and the environment.

Regarding the discussion on Renewable Portfolio Standards (RPS) in southwestern states, the BLM was informed in scoping comments, and in the previously referenced IQA petition, that there was no evidence this particular project was needed by these states to meet their RPS. On the contrary, if the entire project is ever completed, it would import renewable energy to regions that are already swimming in local resources, passing on significant costs to ratepayers in southwestern states for importing wind energy from New Mexico that tends not to be synchronized with demand in the southwestern load centers. This information was identified in scoping comments by Jon Sjogren, Norm Meader, David Omick, and Peter Else.. In fact, all southwestern states have the ability to meet their RPS without the need for imports from New Mexico. There may be other good reasons for developing new EHV transmission lines in the Southwest, but meeting modest RPS goals is not one of them.

Table 1-1 makes the unwarranted assumption that all "Net Short" potential renewable generation sources are stranded with regard to transmission capacity, and thus presents an exaggerated estimate of "Net Short" in transmission capacity. This is a very misleading table that needs to be corrected or eliminated.

On **Page 1-7 of Section 1.4**, a statement is made that Southwest Area Transmission group (SWAT) presented the concept of the need for new 500 kV transmission in southern New Mexico and Arizona *based upon abundant wind and solar potential*. However there is no reference provided for that specific SWAT presentation. The only 2006 SWAT presentation I found in internet records included references to significant fossil fuel energy potential as well as renewable energy potential. Information on the SWAT presentation that I am referring to was given to the BLM in separate scoping comments by Sjogren, Meader, and Else. Additionally, both Meader and Else provided in scoping comments of September, 2010 extensive documentation on SunZia's interest in developing transmission capacity for fossil fueled energy resources. If the BLM cannot provide a specific reference for this statement by SWAT that was used in the DEIS, the statement needs to be removed. If the BLM cites a SWAT presentation that included fossil fuel energy, then the reference to fossil fuel energy must be included in

the DEIS in order to meet BLM information quality guidelines. To do otherwise perpetuates the same systematic bias identified by the NRCDs in their IQA petition.

On the same page there are general statements about the need for increased transmission capacity for renewable energy in the Desert Southwest, but no statements from SWAT's Renewable Energy Task Force related to this particular project. This incongruity was documented by Charles Huckelberry in scoping comments.

Table 1-2 in Section 1.4 is another misleading table, apparently intended to emphasize the interest in developing "primarily renewable energy" projects within the SunZia project area. Since the table does not include all existing transmission owners within the SunZia project area, it cannot be used to once again invoke the phrase *primarily renewable energy* as a characterization of energy development potential. Interest expressed by several of the many local utilities in the SunZia project area does not translate into the basis for a realistic prediction of energy development. As the NRCD petitioners stated, potential interest in renewable energy is a very different concept from what is required for the practical and economical operation of an EHV line, and it bears no relationship to the increasing presence of natural gas generation in the national energy portfolio and specifically along the southern portion of the proposed transmission line(s). The chances of this project actually supporting *primarily renewable energy* are extremely slim, but the BLM has again allowed the applicant to mislead the public on this point in this section and in the DEIS sections related to Cumulative Effects, Global Climate Change, Alternatives to SunZia, and Economic Impacts (see specific discussions below). This directly contradicts the documented evidence that has been presented to the BLM during the scoping period and prior to the release of the DEIS, and it contradicts the disclaimers issued by the BLM in April of 2012.

All of the above comments on Section 1.4 are more examples of presentation bias that the NRCDs identified in their IQA petition of July, 2011. The fact that the BLM continues to present biased or unsubstantiated statements in their DEIS suggests that the agency is more interested in marketing the proposed project than presenting an objective project description However, more importantly, it provides evidence that the BLM is ignoring documentation provided by the public and stakeholders and heading toward a foregone conclusion to designate a route for this project.

Section 1-5 correctly states, *"The intent of scoping is to identify important issues related to a proposed action and its alternatives."* However, **Table 1-3 (*Summary of Issues from Scoping*)** includes no mention of the most controversial issue raised during the scoping period, which was the credibility of the renewable energy development claims that the BLM allowed the applicant or EPG to make in scoping documents. These claims were challenged in separate written scoping comments by an electrical engineering researcher, two university trained scientists, a sustainable systems specialist, and a county administrator. My own scoping comments included a request for correction to these claims, and I was told by the BLM's project manager that this request would be considered by the BLM. When no response was given several months later, I took this request to my local Conservation Districts, who filed another request for correction with specific reference to the Information Quality Act. There were two subsequent appeals, a case investigation by our Congressional representative regarding response delays, and two formal meetings with Arizona BLM officials.

The fact that the most controversial issue raised during the scoping period is not acknowledged in Table 1-3 contradicts the BLM's assertion that restricting public feedback to written comments alone is

sufficient for the agency to *identify important issues related to a proposed action and its alternatives.* On the contrary, it appears that the agency was restricting public feedback to written comments alone in order to prevent the public exposure of this controversy. By ignoring prior written comments by stakeholders and the public and prohibiting any public questioning of the narrative presented in official public meetings, the BLM has violated the legal requirement of due process.

This information on renewable energy development is vital. If the energy development claims are false, then there is no sound basis to evaluate alternatives to the proposed project (see comments on Section 2.3.3.3). By not acknowledging and effectively addressing this controversial issue after all the written documentation that the BLM has received, the BLM has become complicit in the applicant's unsubstantiated claims, and the BLM has unnecessarily extended the period of disseminating *influential information* that does not meet its own information quality standards. Note that in the BLM's Information Quality Guidelines that *influential information* requires an added level of agency review prior to dissemination (Page 4 of the Guidelines). Note also that *influential information* includes "*...highly controversial information that is used to advance the BLM's priorities*" (Page 5 of the Guidelines). In this case, the policy objectives stated in Section 1-3 are the BLM's priorities.

Section 2.3.3.3 (*Alternatives to New Transmission*): This section illustrates the need for an accurate and objective statement of purpose and need. The BLM did not provide such statements, and instead, allowed the applicant to imply unsubstantiated statements of purpose and need related to renewable energy development in the section on *Applicant's Objectives*.

Section 2.3.3.3, Pages 2-38 through 2-39, *Demand-Side Management*: This section uses an unsubstantiated "need" of the proposed project, the alleged need for local EHV lines to meet southwestern states' RPS, as a justification for dismissing energy efficiency and demand- side management as partial alternatives to the proposed project . Since the BLM did not list this need in its statement of purpose and need (Section 1.3), and since the applicant did not provide conclusive evidence in Section 1.4 that the project is needed to meet state RPS, the premise for the argument is invalid.

Also, the substance of the argument for energy efficiency is totally bypassed by invoking the BLM's statement of need that is based upon fulfilling a general federal policy, i.e. the BLM's perceived bureaucratic responsibility to increase interstate transmission capacity. Fulfilling a policy does not constitute a need for a ***specific*** transmission project. There are also federal and state policies in place to increase energy efficiency, and this is why that alternative must not be dismissed based upon bureaucratic policies. It is the BLM's obligation to conduct a rigorous examination of alternatives in the region, and not simply cop out with the policy argument.

This section on demand-side management and energy efficiency contains no consideration of displacing some portion of current non-renewable generation sources in southern New Mexico and Arizona with renewable energy resources, as a means of providing transmission access for renewable energy. With this approach, demand-side management and energy efficiency programs would reduce the need for massive increases in transmission capacity, while existing or upgraded lines would provide access for new sources of renewable energy and reduce greenhouse gas emissions overall. Energy efficiency programs in Arizona and New Mexico have the potential to cut energy usage *significantly* (by up to 50%, relative to California efficiency standards), reducing the need for massive increases in transmission capacity. Arizona is currently under a state mandate to increase energy efficiency by 22%

by the year 2020. At the same time that energy efficiency improvements are in progress, solar production in the southern part of these states, in both distributed and locally concentrated forms, has the potential to significantly increase supply at times of peak demand. This argument was made in scoping comments by Sjogren, Omick, and others, but was not considered in this section.

Lastly, this section ignores the obvious principle that significantly increasing power production reduces the incentive for energy efficiency. Providing a glut of new energy resources that are primarily non-renewable will discourage energy efficiency, significantly increase greenhouse gas emissions, and destroy incentives for demand-side management.

Section 2.3.3.3, Page 2-39, *New Generation*: New large scale renewable energy generation could be accommodated in southern Arizona and southern New Mexico by upgrading existing lines and using renewable energy to partially displace existing non-renewable generation in the region. In this situation, existing non-renewable resources would be used on a dispatchable basis for reliability purposes. Also, with an alternative proposal such as the *Southline Transmission Project*, a reasonable increase in total generation could be accommodated at the same time, without developing an entirely new major infrastructure corridor through many parts of New Mexico and Arizona, as proposed by the SunZia project.

The New Mexico wind energy resources mentioned in this section would be better served by an east-west line that also provided access for wind resources along the same latitude in Arizona. There are several alternative project proposals directed at this objective, but none of these project alternatives are mentioned in this section. In a rigorous and objective analysis, all energy options and transmission alternatives would be listed in a table and discussed. This particular analysis is dismissive of all alternatives except for the proposed project. This is another example of bias in presentation and the tendency to support an arbitrary and capricious conclusion.

Section 2.3.3.3, Page 2-40, *Distributed Generation*: While the DEIS summarily dismisses the effectiveness of distributed generation, the fact is that distributed generation has been a key factor in providing Arizona with the ability to meet its RPS, without the need for imported power. It appears that New Mexico and California will also be able to meet their RPS without importation of renewable energy, in large part due to the success of distributed or locally produced generation. This DEIS section once again invokes the general policy of increasing transmission capacity, to the exclusion of any other policies related to energy efficiency and optimum use of existing infrastructure corridors.

This section also makes the statement that distributed generation does not increase reliability, when in fact, distributed generation can provide local areas with a valuable backup to energy transported by long-distance transmission lines that are vulnerable to interruptions. The only reliable backup I have at my own residence is the solar array on my roof. Without it, I would have no power for lighting, the telephone system, and ventilation during the main grid's power outages that occur frequently, and sometimes for long duration, during storm seasons. There are now residential and commercial areas in Tucson that have thousands of kilowatts of local solar production based on rooftops. These local systems, coupled with local dispatchable generators, are a significant source of reliability. Over-dependence upon a nationwide grid greatly increases vulnerability to outages and reduces reliability of service.

While distributed energy does not provide the solution to all energy issues, it could, when combined with a grid upgrade alternative such as the *Southline Transmission Project,* address the energy needs in the southern parts of New Mexico and Arizona while providing the means for exporting surplus renewable energy, whenever that point in renewable energy development occurs. This section needs to reflect the importance of distributed generation *in the context of all the other energy alternatives* in order to evaluate the distributed mode in an objective manner.

Section 2.3.3.3, Pages 2-40 to 2-41, *Existing Transmission Systems Upgrades:* The problem with the SunZia proposal, is that although the applicant is not revealing the imminent expansion of natural gas powered generation in the southern new Mexico and Arizona, in reality the SunZia transmission project is attempting to accommodate over 1000 MW of new non-renewable resources in this region, while at the same time accommodating some portion of new renewable resources. This is the actual reason why proposed line is scaled to the minimum capacity of 1500 MW. By recognizing this *elephant in the room* and dropping the whole charade about the need to transport massive amounts of renewable energy over hundreds of miles, there is an entirely different analysis that can take place in the discussion of the ***upgrade alternative***. This exemplifies why an objective statement of purpose and need is so vital to the validity of the analysis of alternatives.

If you eliminate the need to accommodate the excessive amount of unacknowledged new fossil fuel sources of energy, including a SunZia owner's interest in their 1000 MW of natural gas holdings, it becomes entirely possible to meet renewable energy transmission goals in southern New Mexico and Arizona, as well as accommodate an appropriate increase in non-renewable resources, by upgrading the existing transmission systems. The *Southline Transmission Project* proposes to do just that, and it must be considered in the range of reasonable alternatives.

The above discussion on the ***Upgrade Alternative*** also applies to other portions of Section 2.3.3.3:

Section 2.3.3.3, Page 2-41 through 2-43, *Tucson Area Upgrades:* With the proposed *Southline Transmission Project*, existing transmission systems can be upgraded in the Tucson Area, because *Southline* is appropriately scaled for this region.

Section 2.3.3.3, Page 2-43 through 2-44, *Double-circuit Structures:* These structures would become feasible with an appropriately scaled transmission project, such as the *Southline Transmission Project.*

Section 2.3.3.3, Page 2-44 through 2-45, *Environmental Impacts:* With the appropriately scaled *Southline Transmission Project*, there would be no need to install 500 kV lines through densely populated areas.

Section 4.17.3.3, *Energy Development Forecast Analysis:* In the draft EIS, the BLM has apparently adopted the notion that if they insert a one paragraph disclaimer about the uncertainties of future access to the proposed transmission lines (page 4-269, top of page), they are then free to present the applicant's unsubstantiated Energy Development Forecast Analysis which:

a) bears very little relationship to the only cited economic feasibility study for an EHV line in this region, and,
b) bears even less relationship with an objective analysis of the most likely generation sources.

The disclaimer mentioned above cannot be used as an "immunity pill" against the virus of unsubstantiated energy development assumptions:

On page 4-274 are two energy development scenarios that make the assumption that 81 to 94% of the energy resources developed along the proposed lines will be renewable, with the rest being "other existing types of generation facilities". The BLM then dedicated over a third of its Cumulative Effects discussion (50 pages in **Section 4-17**) to the effects of an unrealistic energy development scenario. This Cumulative Effects section of the DEIS is effectively turned into another marketing effort to portray the project as primarily (81 to 94%) a renewable energy project. The casual reader is left with the impression that the causes of the cumulative effects are largely beneficial to the overall environment, which would tend to justify environmental impacts caused by the installation of the EHV line(s). All propaganda has a purpose, and this is the likely explanation of the underlying purpose of the exaggerated renewable energy claims.

The High Plains Express (HPX) Project Stage 1 Feasibility Study was cited by the local NRCDs in two of their Information Quality submissions to the BLM. This cited document makes the statement, "*For this study, the SunZia project was considered to be an integral segment of the HPX Project.*" The study concluded that the benefit/cost ratios for an EHV line in this region are most favorable with a renewable/fossil resource mix of nearly equal parts, due to the highly variable output of most renewable energy resources in the region. The conclusion was: "*A 'balanced' scenario consisting of near equal amounts of fossil and renewable energy performed the best under a range of circumstances.*" The two facility scenarios presented by the BLM on page 4-274 bear very little relationship to the optimum energy development scenario predicted by the HPX feasibility study, and thus bear very little relationship to what investors and regulators would accept as an economical and practical energy development scenario. The BLM did not provide in the draft EIS another feasibility study that would either contradict the conclusions of the HPX study or support the energy development forecast that was presented in the DEIS.

The local NRCDs in their petition, as well as others in scoping comments, also cited the "imminently pending" non-renewable energy resources located along the proposed route. These include the planned and permitted 1000 MW Bowie plant, as well as existing natural gas powered plants located in southern New Mexico, that cannot expand production without increased transmission capacity. One of the limitations of an EHV line is the high expense of providing "on-ramps and off-ramps" (substations) for transmission access. The proposed SunZia project only has six substations, and three of them are located in the region of the natural gas powered plants.

The highest estimate for non-renewable energy development in either of the energy development scenarios presented by the BLM is 580 MW, which is a gross misrepresentation of the probable

development of non-renewable energy resources resulting from this proposed increase in transmission capacity. The Bowie plant could contribute 1000 MW on its own, which would constitute up to two thirds of the transmission capacity on the first proposed line. Also, with natural gas based generation currently having the least expensive start-up and operating costs among large-scale energy generation modes, it is unrealistic to assume that other plants along the El Paso Natural Gas line will not wish to expand production.

Since SunZia has not disclosed its "anchor customers", a term used in the 2011 Federal Energy Regulatory Commission (FERC) decision, and since FERC will regulate access for all other generation sources primarily on a first come/first served basis, the BLM is in no position to support the speculation that only 290 to 580 MW of new non-renewable energy would be developed as a result of the proposed transmission project. By significantly underestimating the development of non-renewable resources, the BLM also significantly underestimated their cumulative effects, thus rendering the analysis of cumultative effects invalid.

Section 4.17.4.2, *Climate and Air Quality,* Pages 4-279 through 4-280, *Global Climate Change*: The lack of objective analysis is especially evident in the DEIS discussion on Global Climate Change, with the wildly speculative statement that "*... construction of either of the proposed* [SunZia] *options could potentially result in a net decrease in GHG* [greenhouse gas] *emissions relative to the No Action alternative*" (page 4-280). This assertion by the BLM totally ignores the burgeoning role that natural gas is playing in the expansion of energy resources in the Southwest when transmission capacity is available. The only scenario that has any probability of reducing GHG emissions is one in which ***no*** new fossil fuel resources are built and existing ones are replaced by renewable resources. No informed and objective observer would conclude that the SunZia project will accomplish this particular goal. This point has been made to the BLM in written scoping comments by Sjogren, Meader, Else, and others, as well as by the local NRCDs in their IQA petition. Given the extensive documentation on this issue, it is inappropriate for the BLM to allow this sort of conclusion to be presented in the DEIS. This demonstrates the lack of a good faith effort to provide the public with useful and objective information, and provides evidence that the BLM is more interested in selling this project than fulfilling its role as a neutral oversight agency in a formal environmental review process.

Appendix G1, Second Part, *SunZia Economic Impact Assessment Supplement on the Impacts of Potential Renewable Generation Facilities*: The identical unsubstantiated assumptions about energy development in the Energy Development Forecast were applied to the *SunZia Economic Impact Assessment Supplement on the Impacts of Potential Renewable Generation Facilities*. This portion of the SunZia economic benefits study is 121 pages in length, all based upon the unsubstantiated claim that 81 to 94% new energy development along the proposed line(s) would be renewable. Because of this faulty assumption, this is a *garbage in/garbage out* study that mainly serves to reinforce a marketing myth for the project as a whole and give the public the impression that this project will stimulate many more "green" jobs than it actually would. Since it is not the role of the BLM to act as a marketing agent for this project, this economic impact supplement must be eliminated from the EIS, and the ever-mounting effects of presenting this project in a systematically biased manner over a 3.5 year period must be addressed immediately. Since it appears at the time of this writing that the BLM is not going to revise the glaring DEIS information quality errors described in many of the comments above or hold public hearings before the end of the DEIS comment period, the best action to recommend at this late stage is the ***No Action*** decision for this particular project.

Part Three, Conclusion

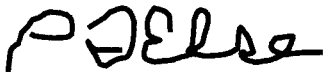
By consistently ignoring the need to address specific requests for correction and disclosure over a 23 month period and by not acknowledging in the DEIS that exaggerated renewable energy claims were an area of concern, the BLM has significantly misled the public, stakeholders, and the media about the need for and purpose of this proposed project, as well as the closely related energy development forecast. As such, the BLM has significantly undermined the established judicial standard of fostering informed participation by the public and stakeholders in a NEPA process.

To treat these long-standing comments about exaggerated renewable energy claims as simply DEIS feedback would not be sufficient to repair the harm done by an extended propaganda campaign. This approach would simply repeat the same ignore-or-delay pattern established by the BLM during the first three years of the process and further extend the period of misleading the public. Vague assurances that "concerns" will be addressed at a perpetually postponed "later date" is a paternalistic approach to dealing with the public and stakeholders, one that obviously has not led to the resolution of specific issues.

Given that the BLM has refused to allow public questioning and commenting at the DEIS public meetings, has refused to extend the comment period to effectively address and revise this misleading DEIS, and has refused to even acknowledge the most controversial issue associated with the project, the only option that deserves consideration at this late stage in the process is the ***No Action*** decision.

It is with sincere regret that I have been forced to provide this negative critique of the BLM's role in the SunZia project. I have had a good relationship with the BLM in the past, and I look forward to the same in the future, particularly because of the important role that the BLM plays in the San Pedro River Valley. I postulate that the BLM was under considerable pressure from the Department of the Interior to fast track this project. However, fast tracking does not justify sacrificing information quality and meaningful public participation.

Respectfully submitted,



[signature via mouse]

Peter Else
Friends of the Aravaipa Region
P.O. Box 576
Mammoth, AZ 85618

Attachment: ***Ten Specific Requests in the Information Quality Act Petition of July, 2011***

Ten Specific Requests in the Information Quality Act Petition of July, 2011

Request for Correction of Information Contained in Scoping Documents for the SunZia Southwest Transmission Project, submitted by the Winkelman and Redington Natural Resource Conservation Districts to the BLM

REQUEST	*RESPONSE*
1) Drop repeated phrase "including primarily renewable resources" from statements of purpose	Word "primarily" dropped on BLM web site, after two appeals, in April of 2012
2) Include all energy resources likely to gain access in statements of probable energy development	Bias toward exclusive focus on renewable resources persists in the DEIS
3) Transmission access statements included no mention of "stranded" non-renewable resources	DEIS continues to only discuss "stranded" renewable resources
4) Drop inference that this project is needed to meet Renewable Portfolio Standards in SW states	DEIS (page 1-7) continues to infer that this project is necessary to meet SW states' RPS
5) Retract the claim that the project would provide "economical access" to renewable energy in southern Arizona	No correction or clarification made at any point in the NEPA process thus far. No discussion of cost impacts to Arizona ratepayers
6) Disclose Federal policies regarding access to the proposed lines, with resulting uncertainties	Brief disclaimers issued by BLM, after two appeals, in April of 2012
7) Disclose potential conflict of interest between between Bowie plant and stated focus of the proposed project, and disclose potential expansion of other non-renewable resources	Not disclosed, and non-renewable resources were significantly underestimated in the Energy Development Forecast, contrary to the closely related High Plains Express Feasibility Study.
8) Disclose that applicant is not obliged to build all route segments approved, thus potentially affecting future access for NM wind resources	Not disclosed. No reference to the economic factors that will determine ultimate build-out and probable generation sources.
9) Disclose the existence of fossil-fueled plants along the proposed route	Done in one DEIS table, but significantly underestimated the future role of these plants in the Energy Development Forecast
10) Eliminate systematic bias in project description. Cease using the NEPA process as a marketing tool for the applicant.	The BLM presented applicant's unsubstantiated Energy Development Forecast, indicating 81 to 94% renewable energy development. Over 170 pages of faulty analysis in the DEIS was based upon this biased Forecast.

NOTE: *There was no acknowledgement in the DEIS that exaggerated renewable energy claims were an area of concern in scoping comments (Table 1-3). Also, the petitioners' requests were either ignored in the DEIS (items 3,4,5,7,and 8 above), or given brief responses that were subsequently dwarfed by consistently biased presentation and over 170 pages of faulty analysis.*

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-24

July 12, 2013

Copy emailed to:
bhudgens@blm.gov

Original sent via U.S. certified mail to:
Director (210)
Attn: Brenda Hudgens-Williams
P.O. Box 71383
Washington, D.C. 20024-1383

Dear Ms. Hudgens-Williams:

In Section 2.6 of the Final Environmental Impact Statement (FEIS) for the proposed SunZia transmission project, the BLM presented three alternatives for the amendment of Resource Management Plans (RMPs) that would be affected by the proposed action of the applicant (SunZia Transmission LLC). These three alternatives were the No Action Alternative, a 400-foot corridor, and a 2500-foot corridor. The BLM's preferred alternative is the 400-foot-wide corridor that may be included as an amendment to RMPs for conformance with visual resource management and right-of-way management objectives. Under the full range of route alternatives, the following RMPs in New Mexico and Arizona would be subject to amendment:

- Socorro RMP, Socorro Field Office (2010) – BLM preferred alternative
- Mimbres RMP, Las Cruces District Office (1993)) – BLM preferred alternative
- Final Safford District RMP and EIS, Safford District Office (1991)"

Concise statement of why the BLM's preferred RMP amendment alternative is the wrong choice:

As coordinator of The Friends of the Aravaipa Region (FAR), I protest this Resource Management Plan (RMP) amendment alternative, and request that the No Action RMP amendment alternative be taken instead. The Bureau of Land Management (BLM) has a mandate under the National Environmental Policy Act (NEPA) to analyze the effects of the proposed action by the applicant. There are specific federal requirements for developing a Final Environmental Impact Statement (FEIS), which is the final report on these effects. These federal requirements include fostering meaningful participation in the development of the FEIS by stakeholders and the general public and developing a plan to mitigate impacts that cannot be avoided. This protest references information and requests that were submitted by FAR and others during the environmental review process but were not adequately considered in the FEIS. These submittals are critical to analyzing the effects of and alternatives to the proposed action. **It is premature to proceed with amending the RMPs until federal requirements for the development of the FEIS have been met.**

FAR is a communication network that includes over 300 conservation activists who support ecological conservation in the lower San Pedro watershed, which contains the second largest unfragmented

wilderness zone in New Mexico and Arizona. FAR's interest in the proposed action is based upon avoiding significant impacts associated with the proposed action.

Contact information for Friends of the Aravaipa Region (FAR):

Peter Else, coordinator
P.O. Box 576
Mammoth, AZ 85618

Phone 520-487-1903
Email: bigbackyardfar@gmail.com

FAR incorporates by reference the following documents that were submitted during the planning process, all part of the public record:

- *Draft Environmental Impact Statement Contributions for the Proposed SunZia Transmission Line Route Traversing the Aravaipa Watershed and Lower San Pedro River Valley* (by Omick, Baker, Evans, & Stephens), a 144 page volume co-sponsored by FAR and submitted during the SunZia scoping period on 09/27/2010
- Scoping comments submitted by FAR coordinator, Peter Else, on 09/28/2010.
- Comment ID package 2197 in SunZia FEIS Appendix J, submitted by FAR coordinator, Peter Else, on 08/17/2012.
- Comment ID package 1606 in SunZia FEIS Appendix J, submitted by the Winkelman and Redington Natural Resource Conservation Districts, co-authored by Peter Else, on 08/20/2012.

The initial statement of protest indicated that the *No Action* alternative for these RMP amendment proposals is the appropriate choice, because federal requirements for the development of the associated FEIS have not been met. The following <u>underlined</u> section headings describe why these requirements have not been met:

<u>1) The BLM failed to consider submitted evidence in the development of a statement of purpose and need for the proposed transmission project, and instead:</u>

a) **<u>deferred to the applicant in characterizing the proposed project as one that would primarily facilitate the development of renewable energy resources.</u>**
b) **<u>deferred to the applicant on the relationship of the planned and permitted Bowie natural gas powered generation plant to the proposed project.</u>**
c) **<u>deferred to the applicant in defining the necessary transfer capacity of the proposed transmission project</u>**

Taking these points one at a time:

1-a) Characterization of the project as a renewable energy endeavor.

The proposed project involves the construction of an electrical transmission system. In the Notice of Intent on May 29, 2009, the applicant indicated that the primary purpose of this project is to facilitate the development and transfer of renewable energy resources. The BLM disseminated this characterization of the project's purpose in scoping documents. FAR challenged this characterization in scoping comments of 09/28/2010 and requested correction, but received no response to this request. The Winkelman and Redington Natural Resource Conservation Districts (NRCDs) challenged the same statement of purpose in a formal Information Quality Act petition of July 12, 2011 and in two subsequent appeals (see Attachment A, p. 15 in this protest). On April 19, 2012, BLM Director Robert Abbey agreed to publish a disclaimer to the web-disseminated scoping documents regarding the open access policies of the Federal Energy Regulatory Commission (FERC), but declined to address other requests for correction regarding the challenged statement of purpose (Attachment A).

The disclaimers about FERC's open access policies were presented in the DEIS when it was released in May of 2012, but the project continued to be characterized as primarily facilitating the development and transfer of renewable energy resources in the energy development forecast, which was used as the basis for analyzing economic impacts, cumulative effects, alternatives to the proposed project, and overall impact on greenhouse gas emissions, as well as providing a justification for the stated necessary transfer capacity. Relevant information related to the most probable forecast of energy development has been submitted to the BLM by FAR members and others dating back to early in the scoping period. These submittals are contained in the public record for the SunZia environmental review. One of the most compelling submittals that contradicts the SunZia energy development forecast in the DEIS and the FEIS is the High Plains Express (HPX) Economic Feasibility Study (2008).

Despite at least eight attempts over a two-year period (see Attachment A) requesting that the BLM consider specific findings in the HPX feasibility study, these findings were not acknowledged by the BLM until the FEIS was released, and then they were casually dismissed in an appendix (see details below). This extended refusal to even acknowledge the specific findings of the HPX study contradicts the BLM's response to FAR's DEIS comment #1-2197 that the BLM followed necessary protocol with regard to public participation in the preparation and review of the DEIS, and it indicates that restricting public comments to either written submissions or one-on-one discussions with BLM officials at public meetings was not effective in fostering meaningful public participation in this particular NEPA process.

In their response to the NRCDs' DEIS comments regarding the HPX study (FEIS response #57-1606), the BLM extracted one quote from the HPX study, stating that *"...results would indicate that HPX would provide economic benefits to customers in the HPX states over a variety of resource mixes and CO2 tax scenarios, with the sole exception of a fossil only scenario. As such, HPX's economic feasibility appears to be sufficiently positive and consistent with emerging public policy to warrant further investigations."* **The BLM's response concluded that "The HPX report does not rule out the use of a higher percentage of renewable energy."**

It appears that the BLM reviewers did not examine the actual data points in the HPX benefit/cost (B/C) analysis, in which **a *higher percentage of renewable energy* was indeed ruled out under market conditions that are projected for SunZia's construction and operation timetable.** A copy of the summary table and graph is attached (Attachment B, p.18 in this protest). While it is indeed true that favorable B/C results were possible *over a variety of resource mixes and carbon tax scenarios*, it is also true that the United States of America currently does not have a CO2 emissions tax, nor is it reasonable to expect that one will be enacted during the BLM's stated construction and operation timetable for the proposed transmission project.

According to the HPX analysis, the energy development forecast presented in the FEIS ("wind first" scenario vs. existing mix of fossil fueled generation and minimum renewables to meet RPS) will not break even economically (B/C=1) on an Extra High Voltage (EHV) line unless CO2 emissions are taxed at $10 per ton, and does not perform as well as the more balanced energy scenarios until CO2 emissions are taxed at $25 per ton. Further, the energy mix that has, by far, the highest B/C ratio and the highest economic advantage to investors and consumers under current market conditions is actually the **inverse** of the energy development forecast presented in the FEIS, one that consists of 75% fossil fueled generation and 25% renewable generation. In Attachment B, note that Table 8 assumes a minimum CO2 emissions tax of $10/ton. However, the Figure 12 graph does model the absence of a CO2 emissions tax.

The BLM response to FAR's criticism of the energy development forecast (FEIS Appendix J response #20-2197) stated:

> *Although FERC rules do not allow for discriminatory preference among generation subscribers to a transmission line, "it is the intent of the Applicant to provide infrastructure to increase transmission capacity in areas of potential renewable energy generation" (see DEIS, p.1-8). Table 1-1, Renewable Energy and Transmission Capacity Needed to Meet RPS, and Table 1-2, Summary of Generation Interconnection Requests to Existing Transmission Owners within the Project Area, illustrate, respectively, a need for additional renewable generation sources and a need for transmission capacity.*

Remarkably, there is no mention of the market factors affecting the economic feasibility of operating an EHV line under various energy development scenarios. Just as the proposed Tucson routes were deemed unfeasible to build, certain energy transmission scenarios are not economically feasible on expensive EHV lines under the market conditions expected during the stated construction and operation period. **If a route segment on a merchant line is not economically advantageous to investors, it will not be built, and if it is not built, it will not carry energy resources located along its proposed route.**

The BLM failed to consider the HPX study's findings, and allowed the applicant and the contracted environmental firm to claim that an energy mix deemed unfeasible for transfer on EHV lines is the most probable scenario for development. The alleged *intent* of the applicant to facilitate 81 to 94% renewable energy development is irrelevant to the project's ultimate purpose. Market and regulatory factors determine economic feasibility on a merchant line, not intentions. While the FEIS includes disclaimers related to open access regulatory factors, it still has not addressed the economic feasibility of the energy development forecast presented in the FEIS.

The applicant's original Notice of Intent (May, 2009) stated that the proposed project "*would likely be constructed in phased segments*". Under current market conditions, it is unreasonable to expect that

investors will accept significant construction and operational losses on the route segment between SunZia's proposed East and Midpoint Substations. This large section of the proposed route would primarily be supplied with wind resources originating near the East Substation.

Also, given the results of the B/C analysis in the HPX study, it is very likely that investors will insist that the first *phased segment* should originate in southern New Mexico or Arizona. If this first segment becomes operational, market conditions projected for the stated construction and operation timetable will favor power purchase agreements that provide the best economic benefits to investors and consumers, which, according to the HPX study, involves transmitting a mix of primarily high-dependability fossil-fueled resources and a smaller portion of renewable resources.

If SunZia becomes operational before the proposed Southline transmission line, it is likely that the first line proposed by the SunZia project would eventually fill to capacity with the resource mix described above, and with generation resources located in the southern portions of Arizona and New Mexico. This route segment and this configuration of energy resources is the same as what was described in the original 2006 configuration of the SunZia project, which was designed to accommodate significant amounts of non-renewable energy from the owner's planned and permitted Bowie generation plant. This original project configuration was brought to the BLM's attention repeatedly, dating back to the scoping period. The currently unfeasible wind energy segment of the project proposal was introduced to the SunZia project proposal in 2008, and at that time SunZia's marketing strategy shifted to the promotion of an almost exclusively renewable energy development scenario. **By failing to consider contradictory evidence, the BLM has allowed the applicant and the contracted environmental firm to reinforce this renewable energy marketing strategy in the federal environmental review process**.

Regarding the BLM's RPS-related justification for its energy development forecast (BLM's #20-2197 response to FAR), the minimal renewable energy standards in the affected states are already being met without the additional transmission capacity that would be provided by the SunZia project. RPS is not expected to be a major factor regarding demand on the first SunZia line. A footnote to FEIS Table 1.1 concedes that the "net short" in RPS-related transmission would not necessarily have to be provided by the SunZia project.

And finally, regarding the BLM's #22 -2197 response to FAR that the 81 to 94% in low-dependability renewable energy transfer could be supplemented with "regulation generation services from other sources on the grid, or from within their own inventory of generation assets", page 33 of the HPX study has a clear statement:

> *In all of these cases, with the exception of the renewables-only scenario, HPX was modeled to meet the load requirements profile and achieve an average 75% utilization level. While this is readily achievable with fossil resources, which are "dispatchable" (coal and gas), it is a much greater challenge when material amounts of "non-dispatchable" renewable resources (wind and solar) are involved. Two of the renewable-dominated scenarios approached this problem by first dispatching the HPX line's full capacity with renewables, and backfilling/firming with fossil resources in order to meet load requirements when renewable energy isn't available (the "renewables-first" scenarios). Such an approach is likely to involve many operational and economic challenges.*

These *operational and economic challenges* are reflected in the prohibitively low economic feasibility ratings for the *renewable-dominated* scenarios in the absence of a CO2 emissions tax. Note that the HPX study considered 75% renewables to be the high limit for the *renewable-dominated* category. SunZia's 94% renewable scenario is considered to be a *renewables-only* scenario, which provides less than 60% EHV line utilization (Attachment B).

The economic feasibility of transferring different mixes of energy resources on an EHV line will determine which parts of the proposed transmission project are most likely to be constructed. Thus, the energy development forecast must be consistent with the best available feasibility study. The HPX study is highly relevant, because the SunZia project was cited in the HPX study as being an integral part of the HPX project. The BLM has not presented any other feasibility study that contradicts the findings of the HPX study.

As stated before, the energy development forecast is very important in the FEIS. It was used in large part as the basis for developing a statement of purpose and need, justifying the necessary transfer capacity of the proposed project, analyzing (and dismissing) alternatives to the proposed transmission project, assessing the proposed project's overall impact on greenhouse gas emissions, and analyzing the cumulative effects of the proposed project. **These important assessments must be based upon the best available data. It is premature to amend the RMPs when this standard has not been met in the FEIS.**

1-b) Relationship of the Bowie power plant to the SunZia transmission project.

In scoping comments of 09/28/2010, FAR pointed out that the planned and permitted gas-fired Bowie power plant could provide up to 1000 MW of power to the SunZia transmission lines. This point was repeated in detail by the NRCDs in their IQA petition/appeals (referenced in Attachment A), as well as by FAR and the NRCDs in their comments to the DEIS. However, the greatest detail on this point was provided by Norm Meader of the Cascabel Working Group. Mr. Meader made this point explicitly through DEIS comments (see Attachment C) that referenced detailed reports. In responding to these comments, the BLM deferred to the statement of the applicant:

> *The Applicant states that, although the SunZia Project may have been initially conceptualized as an interstate generation-tie line for Bowie with a transfer capability of 1,500 MW (thus only adding an additional 500 MW of capacity to the electrical grid), the configuration of the proposed SunZia Project (two 500kV transmission lines adding an additional 3,000-4,500 MW of capacity to the electrical grid), and Bowie are not "connected actions," as each has an "independent utility" from the other.*

Despite repeatedly receiving submittals containing evidence regarding the close relationship between the two *actions*, the BLM again deferred to the applicant's declaration that the Bowie plant would not benefit from nor be a major contributor to the SunZia transmission lines. A summary of this close relationship is provided by Mr. Meader in Attachment C on pages 21-23 of this protest. The conclusion states:

"The Bowie power plant is just as likely to use SunZia as any of the renewable energy facilities envisioned, and the plant could use up to 1,000 MW of capacity once fully built. This is the project proponent's intent. The FEIS does not mention this possibility, whereas SunZia's initial 2010 application to the Federal Energy Regulatory Commission for a Declaratory Order explicitly states it. The statement from this application follows:

> *It is possible that other LLC Members will also use some or all of their portion of the Project for affiliated generation (e.g., SWPG's Bowie power plant, ECP SunZia-affiliated generation projects in early-stage development located in the vicinity of the Project). Such generation may also be renewable or may be combined-cycle gas-fired generation.*

It would be consistent for the Bureau of Land Management to make the same admission of Bowie's use of SunZia in the Environmental Impact Statement and evaluate the project accordingly."

In dismissing the close relationship between the Bowie power plant and the SunZia transmission project, the BLM failed to independently consider submittals dating back to early in the scoping period, opting instead to simply accept the statement of the applicant. This neglect of neutral oversight responsibility allowed the applicant to obscure the relationship between the proposed transmission project and applicant's long history with the Bowie Power Plant and convince a largely unsuspecting public that the project has nothing or very little to do with expanding markets for fossil fueled generation. This is not consistent with the requirement to foster meaningful participation in the planning process by the public and stakeholders.

1-c) Statement of necessary transfer capacity.

The proposed SunZia project is scaled to be one of the largest in American history. Numerous comments by FAR have indicated that it is not appropriate to site this industrial scale transmission project in long expanses of previously undisturbed wild lands. The applicant and the BLM have responded that the project is scaled to accommodate the vast potential of renewable resources, and the FEIS energy development forecast indicates that 81 to 94% of the resources developed will probably be renewable. The clear implication has been that sacrifices will need to be made to accommodate the development of renewable energy. However, the previous discussions in this protest indicate that there is a very low probability that the project will actually be used primarily for that purpose.

In a response to DEIS comment #1-1604, the BLM states that the minimum transfer capacity for the proposed project is based upon the ***applicant's*** identification of existing demand:

> *The Applicant identified the 3,000 MW mark as a minimum increase based on the existing demand for increased transmission capacity to relieve congestion, improve reliability, and provide future energy sources, including renewables, with access to market, balanced by marketing factors and engineering constraints.*

Rather than conducting an independent assessment of all factors that typically constitute the definition of *existing demand*, the BLM is deferring to the applicant, who has carefully defined the term in a way that avoids considering the *existing demand* for power purchase agreements by utility companies.

FAR contributor, Norm Meader, responded in this way (Attachment C, page 20 of this protest):

> *The project's scope is not based upon an assessment of the transmission and generation needs of specific utilities in the region, the fundamental criterion used in the past for sizing any transmission project. Rather, it is a highly speculative project aimed at expanding energy markets... However, it is important to give the underlying motives for proposing such a huge project, the largest ever proposed in U.S. history except for the double 500-kV lines leading from the Grand Coulee Dam to southern California.*

As discussed in the previous section, the *underlying motives for proposing such a huge project* include the applicant's financial interest in the Bowie power plant and certainly do not rule out providing transfer capacity for other fossil fueled generation plants.

By simply deferring to the applicant's energy development forecast *and* the applicant's statement of necessary transmission capacity, and by dismissing contradictory information, the BLM allowed the applicant to mislead the public about the actual purpose of the project. This does not meet acceptable standards for formulating an objective understanding of the purpose the proposed project.

The BLM's statement of purpose and need mainly referenced its role in considering an application for right-of-way in the context of federal energy development policies. The BLM deferred to the applicant to describe the actual objectives of the proposed project (SunZia Project FEIS, p. E-2). Although this formal statement of objectives carefully avoided making the original and challenged claim that the project would primarily facilitate the development of renewable energy, the energy development forecast, presented later in the FEIS, indicates that 81 to 94% of the energy development facilitated by the project would be renewable. This conflicting and evasive presentation of the purpose of the proposed project was used in a confusing and evasive way throughout the document.

It is the responsibility of the oversight agency to develop an objective statement of purpose and need for the proposed project, one that is not based upon the applicant's over-riding interest in obtaining a favorable Record of Decision, but one that takes into account the best available data related to the most probable use of the proposed transmission project. **The BLM deferred to the applicant on critical information related the purpose of the project, failed to take into account relevant information that had been submitted by stakeholders, and thus failed to present an objective statement of purpose and need, one that could be consistently be applied to assumptions and analyses throughout the FEIS.**

2) Lacking an objective and clear statement of purpose and need, the BLM failed to provide a valid basis for conducting an analysis of alternatives to the proposed project.

Given the significant impacts that would take place as a result of constructing a new major transmission route through long expanses of natural landscape that were previously undisturbed by industrial scale development, it is imperative that a rigorous analysis of alternatives, based upon valid assumptions of purpose and need, takes place before the RMP amendments are considered.

In FAR's comments #13 through #19 in the SunZia DEIS comment package 2197, a request was made for the BLM to consider alternatives to the proposed SunZia action in a multivariate analysis, in order to think "outside of the box" that the applicant has constructed. FAR presented combinations of possible alternatives that could achieve increased transfer capacity, increase proportional use of renewable energy, and reduced grid congestion, while avoiding major impacts in the lower San Pedro watershed.

In the responses to these comments, as well as in the final discussion of these alternatives in the FEIS, the BLM opted to simply dismissed all proposed alternatives individually, based upon SunZia's stated purpose to provide at least 3000 MW in transfer capacity, which was, in turn, based largely upon a currently unfeasible transfer of wind energy from central New Mexico (see BLM response to comment #15-2197). Given that there is no assurance that the wind segment of the project will ever be constructed and that the most likely configuration of the first SunZia line is similar to the proposed Southline project, this minimum figure for transfer capacity is highly speculative and has been misrepresented to the public in the energy development forecast as a requirement for rescuing over 2400 MW in stranded renewable resources.

The sweeping dismissal of all alternatives to the proposed project is based upon an enormous sizing of the "necessary" transfer capacity.

By sizing the project at a minimum capacity of 3000 MW, based upon a development scenario that is currently unfeasible and highly speculative, and by defining the study area narrowly, **the applicant was able to construct parameters that provided simplistic rationales for both dismissing alternatives to the project and requiring the project to pass through long expanses of wild lands previously undisturbed by any type of linear infrastructure.**

In both the DEIS and the FEIS, the analysis of alternatives to the proposed SunZia project is far too simplistic to meet any sort of rigorous standard. Rather than exercising independent review in their oversight functions, both the BLM and the contracted environmental firm have simply deferred to the applicant's assessment on the most critical assumptions related to the purpose of the proposed project. **It is premature to sanction the impacts associated with the proposed RMP amendments until the major energy development assumptions underlying the stated need for 3000 MW of transfer capacity have been independently reviewed and until a subsequent and rigorous multivariate analysis of alternatives to the proposed project has been conducted.** To do otherwise will simply sanction the use of this NEPA process for manipulation by the applicant.

3) **<u>If the BLM approves the RMP amendments and ultimately grants rights-of-way without correcting deficiencies in the FEIS, it will fail to meet its stated objective to grant rights-of-way in accordance with federal directives, as stated in the SunZia FEIS, p. 1-5:</u>**

> *Pursuant to 43 CFR 2801.2, it is the BLM's objective to grant rights-of-way and to control their use on public lands in a manner that: (a) protects the natural resources associated with public lands and adjacent lands, whether private or administered by a government entity; (b) prevents unnecessary or undue degradation to public lands; (c) promotes the use of rights-of-way in common, considering engineering and technological compatibility, national security, and land use plans; and (d) coordinates, to the fullest extent possible, all BLM actions under the regulations in this part with state and local governments, interested individuals, and appropriate quasi-public entities.*

There is strong evidence that the applicant intends to ask the Arizona Corporation Commission to overturn the BLM's preferred route selection in the Group 4 route segment when the project seeks state approval. The applicant's route choice would least comply with the BLM's co-location directive, among all the alternatives available in the Group 4 segment. Also, there are strong indications that the BLM's overall preferred route alternative will cause much greater impact to undisturbed lands than two other transmission proposals that are pending in the same region. Until a comparative analysis among transmission proposals has been developed and disseminated, it is premature to sanction the impacts associated with the proposed RMP amendments.

The BLM's preferred route in the FEIS is co-located with existing utilities and corridors for approximately 64% of the entire route. However, the applicant has stated that it is likely the project would be constructed in *phased segments*. The "co-location factor" for various route groups needs to be considered, and this data needs to be compared to the proposed Southline Transmission project. This was not done in the FEIS. FAR submitted comments regarding the alternative of using the proposed Southline project as a means of increasing transfer capacity without building a whole new infrastructure corridor through the lower San Pedro watershed (DEIS comment #17-2197).

As stated in the previous section of the protest, the findings of the HPX study indicate that there is a high likelihood that construction of the Group 1 SunZia route segment (between the East and Midpoint substations) would be postponed until market conditions favored an energy transmission mix consisting primarily of low-dependability wind resources. This would be consistent with the postponement of other long- distance wind energy transmission projects in the West, and is likely to stay that way until a) a substantial CO2 emissions tax is enacted, or b) the current glut of natural gas resources subsides, or c) the federal government provides significant subsidies for the construction and operation of long-distance EHV lines that primarily transmit renewable resources. These conditions are not likely to change during the BLM's stated construction and operation timetable, and these conditions could remain relatively static for an unknown number of years following the proposed project's goal of becoming operational by 2016. The current market conditions are the very reason why investors did not jump right into the long distance wind energy transmission proposals of the HPX project.

The SunZia project must then be evaluated in terms of the most likely construction configuration for the first line, which would probably originate in southern New Mexico or Arizona and terminate at the Pinal Central substation (SunZia route groups 3 and 4). This route portion is likely to be the first *phased segment* of the SunZia project and would compete with the proposed Southline Transmission project for

many of the same generation resources. The two projects would be built adjacent to each other for 100 miles across southwestern New Mexico and southeastern Arizona. Each project would connect with the 345-kV grid fairly close to one another in southwestern New Mexico, permitting a similar exchange of power. Both the Southline and SunZia projects would interconnect with the same Lordsburg substation. Southline is proposed to terminate about 35 miles from SunZia's terminus. Southline is proposed to carry between 1000 and 1500 MW of power, while the first SunZia line is rated at 1500 MW. These points contradict the BLM's assertion that the purposes of the two projects are so different that the Southline project cannot be considered an alternative to the SunZia project (FEIS response to comment #17-2197). The most likely build-out of the first SunZia line mainly differs from the Southline proposal in terms of impacts on the lower San Pedro watershed and the number of substations available for transmission access in southern Arizona.

If the first "phased segment" of the SunZia line runs from the Willow Substation to Pinal Central Substation, the BLM's preferred route will have a co-location factor of 57%. However, the applicant has made it clear in both letters and an extensive lobbying effort that SunZia will accept nothing less than its own original preferred route, the route segment that bisects the confluence of the Aravaipa and Galiuro Wilderness zones (SunZia subroute 4B), which would have a co-location factor of 17%.

SunZia's lobbying effort took place during the same time period that the BLM was conducting meetings related to the DEIS, and SunZia lobbyist Stan Barnes was observed at the Tucson meeting trying to convince a Pima County Supervisor that, with enough local support, the Arizona Corporation Commission could be persuaded to accept the 4B route segment and overturn the BLM's preference. Although Pima County did not cede to this effort, at least nine other different local government and commerce units wrote letters of resolution between July and September of 2012. These include Bowie Chamber of Commerce, City of Benson, City of Willcox, Cochise County Board of Supervisors, Willcox Chamber of Commerce and Agriculture, Graham County Board of Supervisors, Southeast Arizona Economic Development Group, Pinal County Board of Supervisors, and the Willcox Regional Economic Development Alliance. The first seven of the referenced letters explicitly stated support of the 4B subroute over the BLM's preference, with rationales citing impacts and local control over line siting decisions on non-federal land. Some cited these reasons despite their remote relationship to the affected routes. The latter two letters of resolution expressed support for the "shortest route" and for the "more northern route".

With SunZia's intentions for Subroute 4B in mind and if the project proposal receives federal approval, this NEPA process could ultimately result in a final siting that will least comply with the BLM directive to co-locate new infrastructure projects with existing infrastructure to the highest degree practical among feasible route alternatives. Below are the co-location factors for each Subroute associated with the route segments most likely to be constructed, expressed in percent, with the fraction of co-located miles over total miles in parentheses:

- BLM preferred subroute 3A2 (Midpoint to Willow Substation) 56% (69/124) co-location

- BLM preferred subroute 4C2c (Willow to Pinal Central) 57% (92/161) co-location
- Subroute 4B, Aravaipa (Willow to Pinal Central) 17% (22/133) co-location

- BLM preferred 3A2 plus 4C2c (Midpoint to Pinal Central) 56% (161/285) co-location
- SunZia intended 3A2 plus 4B (Midpoint to Pinal Central) 35% (91/257) co-location

It should be noted that none of these co-location factors are particularly high. In the best case, nearly half of the proposed route is new territory for linear infrastructure. On the BLM's preferred Group 4 route segment (4C2c), the first 30 miles north of the San Pedro River crossing opens an entirely new corridor parallel to the river through previously unspoiled rangeland, while bisecting a large tract of conservation land managed by Pima County. **If that is the best case scenario, the proposed Southline project deserves serious consideration.**

Through a public-private partnership, Southline plans to upgrade existing lines and follow already disturbed lands on the vast majority of their proposed route. The Southline study area parallels the Interstate 10 corridor. The proposed line will add 1000 to 1500 MW of additional transfer capacity (similar to the first SunZia line), without impacting the significant conservation values and investments in the lower San Pedro watershed. Given the potential for a great difference in environmental impacts between the two transmission proposals (SunZia and Southline), a comparative analysis is essential.

Further, we request that before moving forward with sanctioning the impacts associated with the RMP amendments, the BLM consider in this comparative analysis the Corona-to-Phoenix "wind-first" route segment proposed in the HPX study. This proposed route segment begins and ends at essentially the same points that the SunZia Project does, and is designed to accomplish the same purpose stated by SunZia, to transport wind energy from Corona area to the central growth region of Arizona. However, the proposed HPX route segment would co-locate with an existing 345kV line between central New Mexico and Springerville and with an existing 500kV line between Springerville and east Phoenix, would take a more direct route to major load centers, and would benefit Arizona's wind energy development interests as well as those in New Mexico. The proposed HPX wind segment appears to be much more in accord with the BLM co-location directive, and must be considered before committing to the SunZia wind energy routing proposal

There is so much at stake in the lower San Pedro watershed. This protest incorporates through reference all of the impacts described by almost every conservation group in Arizona during the federal environmental review process for the SunZia project. **It would be premature and contrary to federal directives to sanction the impacts associated with RMP amendments and clear the way for significant effects along the rest of the SunZia route before this vital comparative analysis of the SunZia, Southline, and HPX project proposals takes place**.

4) **<u>The FEIS did not include specific mitigation measures to address many of the most significant impacts.</u>** Guidelines for preparing a NEPA document are presented in 40 CFR § 1502. That includes development of mitigation (§ 1502.14). Mitigation is defined below:

§ 1508.20 Mitigation.
Mitigation includes:
(a) Avoiding the impact altogether by not taking a certain action or parts of an action.
(b) Minimizing impacts by limiting the degree or magnitude of the action and its implementation.
(c) Rectifying the impact by repairing, rehabilitating, or restoring the affected environment.
(d) Reducing or eliminating the impact over time by preservation and maintenance operations during the life of the action.
(e) Compensating for the impact by replacing or providing substitute resources or environments.

During this environmental review process, FAR and many others have identified hundreds of significant impacts that will take place as a result of the proposed transmission project, and have requested information about mitigation measures.

The FEIS provides a catalog of anticipated impacts, including 2,871 acres of permanent ground disturbance spread along 515 miles of lines (Appendix H). However, the mitigation provisions in the FEIS and in the preliminary Plan of Development (POD) only provide best management practices to avoid or minimize impacts to soil, water, vegetation, threatened species, endangered species, cultural resources, visual resources, existing land uses, and future land uses. **This permanent disturbance of 2,871 acres, and any remaining impacts to a whole range of resources after minimization takes place, have been left unmitigated in the FEIS.**

The effects of the proposed action cannot be objectively stated until post-mitigation impacts are assessed. **The RMPs should not be amended until the EIS has followed NEPA guidelines for the development of mitigation, and until post-mitigation impacts are assessed.**

Summary.

The lower San Pedro watershed has become the repository for off-site mitigation of impacts taking place as a result of rapid growth in the nearby "Sun Corridor". It would be irresponsible to devalue the enormous conservation investments that have been made in this important watershed for a misrepresented project that will mainly benefit the very growth centers that caused the need for these investments. Local conservation investments in off-site mitigation were made in good faith, swapping sacrificed environmental values for a compensatory replacement that was intended to be protected in an unfragmented ecosystem.

By deferring to the applicant on critical assumptions and dismissing information submittals that contradict these assumptions, the BLM has allowed this applicant to take advantage of a nation's inexperience with a newly unfolding shift in our energy paradigm and use this NEPA process to grossly misrepresent the proposed project's renewable energy benefits. As indicated in this protest, if the BLM continues to defer to the applicant on all critical assumptions underlying the analyses of effects in the FEIS, **the final route selection will likely be the one that least meets the federal directive to site projects with existing rights-of-way and the final energy development scenario will likely be the inverse of what was presented in the FEIS.** The BLM would then be accountable for a serious breach in public faith.

If the project is constructed and the expected results take place, additional safeguards to protect the integrity of the NEPA process and ensure meaningful public participation will become imperative. For example, in this process, a public hearing may have been the only option that could have motivated the BLM and the contracted environmental firm to finally consider the *specific findings* in the repeatedly

submitted feasibility study. Due process concerns were discussed in FAR's DEIS comments #1, #3, #4, #5, and #6 in comment package 2197. These concerns were summarily dismissed in the corresponding responses by the BLM or the contracted environmental firm.

Indeed, we are at the very beginning of a new energy paradigm in our nation, but market conditions have not changed sufficiently to make the long-distance transport of the "wind-first" energy mix a feasible proposition on high-investment EHV lines, without significant subsidies for construction and operation. No availability of subsidies has been reported in the FEIS, and if subsidies do become available, it would make much more sense to use them in a way that would benefit wind energy development in both of the states affected by this proposal, conform to the BLM's federal directive to co-locate new transmissions lines with existing rights-of-way to the highest degree practical, and avoid major impacts in the lower San Pedro conservation corridor. **Construction of the wind segment of the proposed SunZia project (between the East and Midpoint Substations) is not likely to take place in the reasonably foreseeable future, and should not be used as a mechanism to avoid consideration of alternatives to the project proposal, including comparison with the proposed Southline project.** And, with SunZia's wind segment so far off in the future, it is imperative that the BLM exercise due diligence and consider the alternative HPX route segment between Corona, NM and Phoenix, AZ.

FAR urges the BLM to follow the requests in this protest before approving any pending amendment to the Resource Management Plans. Federal requirements have not been met in the preparation of the FEIS. Please make the necessary corrections to the statements and analyses that are currently based upon an obscured purpose and an unfeasible energy development forecast, conduct a rigorous analysis of alternatives to the proposed project, develop and publish a comparative analysis of project proposals, and develop a mitigation plan that meets NEPA standards before proceeding with consideration of the proposed RMP amendments.

This protest respectfully submitted,

Peter Else, Coordinator
Friends of the Aravaipa Region
P.O. Box 576
Mammoth, AZ 85618

Telephone 520-487-1903

Three Attachments Follow (A, B, and C)

Attachment A- Submittal of the High Plains Express Economic Feasibility Study to the BLM.

Critical information related to the High Plains Express Economic Feasibility Study has been formally submitted to the BLM on at least eight occasions during the past two years:

1. July 12, 2011-- "Request for Correction of Information Contained in Scoping Documents for the SunZia Southwest Transmission Project" was submitted under the Information Quality Act (PL 106-554-Section 515), by two local Natural Resource Conservation Districts (NRCDs) in the lower San Pedro/Aravaipa watershed. The HPX study was cited as evidence contradicting the statements of purpose and need for the proposed project. In his response of 08/17/2011, New Mexico BLM Director Jesse Juen did not acknowledge the specific requests for correction, and stated that NRCD concerns would be addressed in the draft EIS (DEIS). Challenged statements made by the BLM in scoping documents continued to be disseminated on their SunZia website

2. September 6, 2011-- Response by Jesse Juen was appealed to the Assistant Director, BLM Information Resources Management, as per the Information Quality Act (IQA). Key information from the HPX Economic Feasibility Study was re-submitted. Response to this appeal was delayed for four months. In his response of 01/06/2013, Ronnie Levine, an Assistant Director at the BLM in Washington, D.C., did not acknowledge the specific requests and stated that the NRCD concerns would be addressed through the public comment processes. The challenged statements by the BLM continued to be disseminated on the BLM's SunZia website.

3. January 20, 2012-- Response by Ronnie Levine was appealed to the Director of the BLM. It was again stated that the HPX Economic Feasibility Study was relevant and contradictory to the renewable energy development claims that were continuously being disseminated by the BLM. The 04/19/2012 response by BLM Director Robert Abbey included an agreement to add a disclaimer to the BLM's SunZia website regarding the Federal Energy Regulatory Commission's open access policy, but did not include any acknowledgement of the HPX study and its associated economic feasibility analysis. Mr. Abbey gave the NRCDs no assurance that their specific requests and information submittals would necessarily be considered or addressed in the DEIS, and indeed, this information was not included when the DEIS was released on 05/29/2012.

4. July 30, 2012- The NRCD's sent the BLM a request for an errata appendix to the DEIS, citing specific requests for correction that had not been addressed, as well as the submission of the HPX study. The BLM did not respond to this request.

5. December 18, 2012- The NRCDs requested that Jesse Juen, New Mexico BLM Director, issue a Supplement to the DEIS to address the outstanding information deficiencies. Including consideration of the HPX study. This request was denied on 03/14/2013 by Mr. Juen.

6. August 17, 2012- The author of this protest, on behalf of Friends of the Aravaipa Region, submitted information on the HPX study in DEIS comments (FEIS comment ID #20-2197). No acknowledgement of the study was provided in the response to this comment.

7. August 20, 2012- The Cascabel Working Group submitted information in the HPX study that challenged the economic feasibility of the SunZia project (DEIS comment #13-2412). No acknowledgment of the study was provided in the response to this comment.

8. August 20, 2012- The NRCDs re-submitted information about the HPX Economic Feasibility Study in their comments to the DEIS. The BLM responded in an appendix attached to the FEIS (comment #57- 1606) that the HPX study did not contradict their energy development forecast.

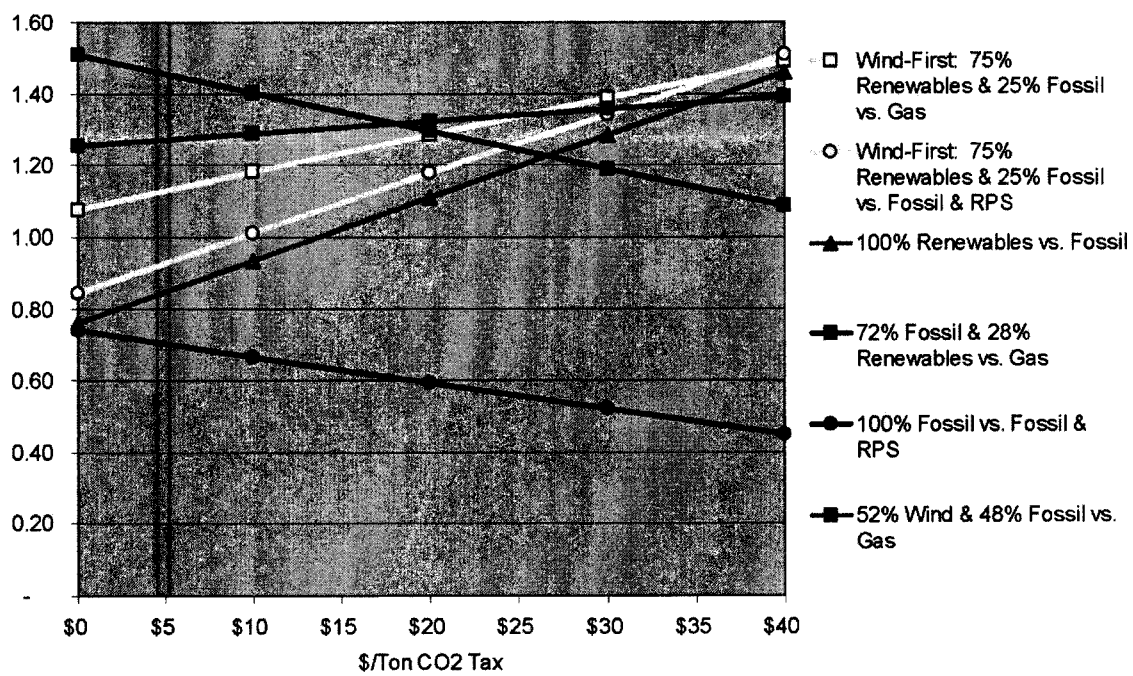
Attachment B- Summary of the High Plains Express (HPX) Benefit/Cost Analysis

Table 8—HPX Benefit/Cost Analyses Results

			HPX FEASIBILITY				HPX ENERGY MIX			
SOURCE	SINK	GHG	B/C	$MM/YR	$/MWH	UTLZ	WIND	SOLAR	COAL	GAS
RENEWABLES-ONLY	DISPATCHABLES (COAL/GAS)	$10	0.94	($32)	($1.87)	56%	90%	10%	-	-
		$20	1.11	$56	$3.21	56%	90%	10%	-	-
		$30	1.28	$144	$8.30	56%	90%	10%	-	-
		$40	1.46	$232	$13.36	56%	90%	10%	-	-
RENEWABLES-FIRST FIRMED WITH COAL & GAS	GAS	$10	1.18	$91	$3.97	75%	67%	8%	13%	12%
		$20	1.28	$144	$6.25	75%	67%	8%	13%	12%
		$30	1.39	$196	$8.52	75%	67%	8%	13%	12%
		$40	1.49	$248	$10.79	75%	67%	8%	13%	12%
RENEWABLES-FIRST FIRMED WITH COAL & GAS	DISPATCHABLES + 20% RPS	$10	1.01	$5	$0.24	75%	67%	8%	13%	12%
		$20	1.18	$90	$3.89	75%	67%	8%	13%	12%
		$30	1.34	$174	$7.65	75%	67%	8%	13%	12%
		$40	1.51	$258	$11.21	75%	67%	8%	13%	12%
COAL + RENEWABLES FIRMED WITH GAS	GAS	$10	1.40	$204	$8.86	75%	28%	-	61%	11%
		$20	1.30	$150	$6.53	75%	28%	-	61%	11%
		$30	1.19	$97	$4.20	75%	28%	-	61%	11%
		$40	1.09	$43	$1.88	75%	28%	-	61%	11%
50:50 RENEWABLES & DISPATCHABLES	GAS	$10	1.29	$146	$6.38	75%	52%	-	25%	23%
		$20	1.32	$163	$7.12	75%	52%	-	25%	23%
		$30	1.36	$180	$7.85	75%	52%	-	25%	23%
		$40	1.39	$197	$8.59	75%	52%	-	25%	23%
DISPATCHABLES-ONLY (COAL/GAS)	DISPATCHABLES + 20% RPS	$10	0.67	($169)	($7.33)	75%	-	-	52%	48%
		$20	0.59	($205)	($8.93)	75%	-	-	52%	48%
		$30	0.52	($242)	($10.53)	75%	-	-	52%	48%
		$40	0.45	($279)	($12.13)	75%	-	-	52%	48%

B/C <1 | 1.0 - 1.2 | 1.2 - 1.4 | > 1.4

Figure 12: HPX Benefit/Cost Analyses Results



ATTACHMENT C – Norm Meader's Response to BLM responses to Cascabel Working Group

Comments on the SunZia Draft Environmental Impact Statement

CWG Submission: The Purpose and Need for the SunZia Southwest Transmission Project: SunZia's Relationship to the SouthWestern Power Group's Bowie Power Station, submitted by Norm "Mick" Meader, August 20, 2013

FEIS Page No.	Comment No.	BLM Text
J271-J272	**1604-1**	**Paragraph 1:** The BLM's action in considering the Applicant's right-of-way application is provided under the authority to the Secretary of the Interior (BLM) to "grant, issue, or renew rights-of-way...for generation, transmission, and distribution of electric energy" (43 Code of Federal Regulations [CFR] 2800). *The BLM is responsible for complying with NEPA with respect to the construction and operation of the SunZia Project, but has no jurisdiction over regulating interstate transmission.* FERC is responsible for analyzing and making decisions based upon (1) the justness and reasonableness of rates; (2) the potential for undue discrimination; (3) the potential for undue preference, including affiliate preference; and (4) regional reliability and operational efficiency requirements. *The BLM is responsible for complying with NEPA with respect to the construction and operation of the SunZia Project, but has no jurisdiction over regulating interstate transmission.*

CWG Response:

This information is unrelated to the submitted comments, and it is unclear why it is included. These are all basic statements of fact and are not a matter of contention by myself or an issue that was raised. Please note that sentence 4 repeats sentence 2, as highlighted by italics and underlining.

FEIS Page No.	Comment No.	BLM Text
J271-J272	1604-1	**Paragraph 2.** The Applicant's objectives, as stated in Section 1.4 of the Draft EIS, include "...to increase available (transfer capability) in an electrical grid that is currently insufficient to support the development, access, and transport of additional energy-generating resources including renewable energy, in New Mexico and Arizona." As reflected in the proposed action, the SunZia Project was designed to increase transmission capacity (i.e., transfer capability) by at least 3,000 MW, and could ultimately be designed for an increase of up to 4,500 MW. The Applicant identified the 3,000 MW mark as a minimum increase based on the existing demand for increased transmission capacity to relieve congestion, improve reliability, and provide future energy sources, including renewables, with access to market, balanced by marketing factors and engineering constraints.

CWG Response:

The first two sentences regarding the portrayal of the project in the DEIS are correct, although they avoid the central issue of my submittal. The SouthWestern Power Group proposed SunZia in part to provide the additional transmission capacity needed to bolster the economic viability of its proposed Bowie, Arizona, 1,000-MW natural gas-fired power plant. This first sentence does apply to this intention. The second sentence is merely a statement of fact and does not address any comments made.

The third sentence, however, mischaracterizes the project proponent's actual intent: "The Applicant identified the 3,000 MW mark as a minimum increase based on existing demand..." The project's scope is not based upon an assessment of the transmission and generation needs of specific utilities in the region, the fundamental criterion used in the past for sizing any transmission project. Rather, it is a highly speculative project aimed at expanding energy markets. The applicant proposed the largest project possible in order to obtain the necessary permits to build that much capacity should it ever become profitable. Currently it is not, and it may never be, although the project proponent presumably hopes that it will be. Obtaining the necessary permits for that much capacity, however, leaves open the possibility of building it without seeking additional environmental review.

SunZia will build only as much of the project as is profitable, when and if it is profitable. The project as proposed is a matter of speculation, not calculation. It is a gamble, in other words. Nothing is wrong with this strategy and it is nothing to criticize *per se*, as corporations routinely use it in our capitalist economy. However, it is important to give the underlying motives for proposing such a huge project, the largest ever proposed in U.S. history except for the double 500-kV lines leading from the Grand Coulee Dam to southern California.

FEIS Page No.	Comment No.	BLM Text
J271-J272	1604-1	**Paragraph 3:** The Bowie Power Station (Bowie) was permitted to interconnect with the existing TEP 345kV Greenlee-Winchester-Vail transmission line at the Bowie Willow-345kV substation. The Bowie Willow substation does not afford Bowie a direct interconnection with the SunZia Southwest Transmission Project. The Applicant states that, although the SunZia Project may have been initially conceptualized as an interstate generation-tie line for Bowie with a transfer capability of 1,500 MW (thus only adding an additional 500 MW of capacity to the electrical grid), the configuration of the proposed SunZia Project (two 500kV transmission lines adding an additional 3,000-4,500 MW of capacity to the electrical grid), and Bowie are not "connected actions," as each has an "independent utility" from the other.

CWG Response:

This third paragraph is based upon a lack of understanding of how the Bowie power plant will interface with Tucson Electric Power Company's lines and SunZia's lines. To help explain this, I have taken the following from my reply to EPG's responses to the Cascabel Working Group's primary commentary on the SunZia DEIS. It appears from the text above that SunZia itself provided the response ("The Applicant states..."). *The Applicant has from the beginning hidden its intentions about this use, and having the Applicant provide the reply here is inappropriate*. It is incumbent on EPG and the BLM to act independently from the Applicant and not allow themselves to be manipulated in this way.

The SouthWestern Power Group (SWPG) initially proposed SunZia specifically to serve as another delivery option for its Bowie, Arizona, power plant, as EPG's own response states. This is carefully documented in my full submittal and was the reason for submitting it. *SWPG did not abandon this purpose because the project was expanded, as the Applicant's response above would seem to imply*. SunZia's 500-kV Willow substation will interconnect with TEP's 345-kV lines near the permitted but not built 345-kV Willow substation associated with the Bowie plant. This close siting will facilitate direct power exchanges between the power plant and SunZia's lines and is a fundamental reason for placing SunZia's 500-kV substation here.

Without SunZia transmission capacity, power delivery options for the Bowie plant through TEP's lines are very limited because the lines are already so heavily used. This restricts the plant's economic viability. Building SunZia would eliminate these restrictions and is a major reason why the SouthWestern Power Group proposed the project. The majority of Bowie's power would likely be delivered through SunZia if both projects are built, as explained below. A primary purpose of an environmental impact statement is to accurately characterize how a project may be used, which has been consciously avoided in this case. *The FEIS instead dismisses what could easily be the largest single use of this project*. This distorts the project's actual use and raises serious questions about the process used to generate the FEIS.

The use of SunZia by the Bowie power plant will occur in two ways, (1) by actually carrying power from the plant (the electrons generated), and (2) through contractual use of SunZia by the SouthWestern Power Group and purchasers of Bowie power. Preventing Bowie power from flowing in SunZia's lines will be physically impossible, as electricity follows the path of least resistance. What is more important, however, is the contractual use of SunZia to deliver this power. Any Bowie power not purchased by Tucson Electric Power Company, which owns the 345-kV lines that the Bowie plant and SunZia will interconnect with, will most likely be delivered through contractual arrangements with SunZia. This is because SunZia transmission capacity will be the most direct, unencumbered, and available to use. Economic and physical simplicity will ensure Bowie's use of SunZia if both projects are constructed.

EPG's response states that these two projects are "not connected actions, as each has an independent utility from the other," yet both will strongly complement, if not be necessary to, the function of the other. If SunZia is not built, it is far less likely that the Bowie power plant will be, and demonstrating the Bowie plant's use of SunZia could be crucial in obtaining funding for the project. To secure funding, SunZia must demonstrate concrete usage of its transmission system through sufficient *a priori* power purchase agreements from utilities – not expressions of interest by speculating energy developers – no matter the generation source. SWPG is very likely to employ Bowie's projected use of SunZia to demonstrate the level of use required for financing.

Nothing is wrong with this strategy, as it will likely be vital to building both the power plant and at least part of this transmission system. It is a sound financial approach and one that the SouthWestern Power Group will undoubtedly use. The great problem with the Environmental Impact Statement is that it ignores and obscures this relationship, which greatly distorts the project's overall use. This could easily be a matter of legal challenge when it otherwise would not be if the EIS merely acknowledged the relationship.

Preferential Treatment for Solar Facilities

In contrast to this treatment of the Bowie power plant, EPG has portrayed and evaluated three potential solar power projects proposed before SunZia was conceived as being dependent upon SunZia. The developers of these projects proposed them with the intention of using existing transmission capacity to deliver power, not SunZia capacity. These projects thus have the same relationship to SunZia as the Bowie power plant, yet because they are renewable, EPG has evaluated them as if they were connected to SunZia and has determined cumulative impacts for them on this basis. These projects include enXco Development Corporation's Afton solar project, Iberdrola Renewables' Lordsburg Mesa solar project, and New Solar Ventures Deming solar project. This is a highly biased comparison and use of these projects.

While the FEIS notes that existing natural gas power plants and foreseen solar energy facilities will share cumulative effects with SunZia, the Bowie power plant is not mentioned except in the assessment of land use. The FEIS should treat the Bowie power plant in its relationship to SunZia in the same way that it treats these other facilities.

Conclusion

The Bowie power plant is just as likely to use SunZia as any of the renewable energy facilities envisioned, and the plant could use up to 1,000 MW of capacity once fully built. This is the project proponent's intent. The FEIS does not mention this possibility, whereas SunZia's initial 2010 application to the Federal Energy Regulatory Commission for a Declaratory Order explicitly states it. The statement from this application follows:

> It is possible that *other LLC Members will also use some or all of their portion of the Project for affiliated generation* (e.g., *SWPG's Bowie power plant*, ECP SunZia-affiliated generation projects in early-stage development located in the vicinity of the Project). *Such generation* may also be renewable or *may be combined-cycle gas-fired generation*.

It would be consistent for the Bureau of Land Management to make the same admission of Bowie's use of SunZia in the Environmental Impact Statement and evaluate the project accordingly.

DOCKET NO. L-00000YY-15-0318-00171

Exhibit PTE-25

December 28, 2014

To: Bureau of Land Management (BLM), New Mexico State Office
Submitted electronically as an attachment to: NMSunZiaProject@blm.gov

Regarding: Comments on the Environmental Assessment for the SunZia Southwest Transmission Project Mitigation Proposal

Dear BLM officials:

This comment package is submitted on behalf of the Friends of the Aravaipa Region (FAR), a network of conservation activists dedicated to the protection of wildlife habitat in the lower San Pedro watershed of southern Arizona. FAR has submitted comments on the SunZia draft Environmental Impact Statement (EIS) and a protest to the Resource Management Plan Amendments associated with the SunZia final EIS. FAR incorporates by reference all comments submitted to the BLM by the Cascabel Working Group, including those related to the subject EA.

Contact information for FAR is provided at the end of this comment letter, following the signature of the FAR's chairperson, Peter Else.

SUMMARY-- After completing a review of the Environmental Assessment (EA) for the SunZia Southwest Transmission Project Mitigation Proposal, FAR has concluded that it is not appropriate for the BLM to issue their proposed Finding of No New Significant Impact (FONNSI), and thus should require a supplement to the final EIS for this proposed project.

The reasons for this conclusion are stated below:

1) The EA contains a misleading statement that the Project would be constructed as a whole in a 2 to 3 year time period. The applicant's 2009 Notice of Intent (NOI) is found at http://www.blm.gov/pgdata/etc/medialib/blm/nm/programs/more/lands_and_realty/sunzia/sunzia_docs.Par.38874.File.dat/SunZiaFRN.pdf This NOI makes it clear that the project would likely be constructed in phased segments, Also, there is no federally imposed contractual obligation for the applicant to complete all segments of the proposed project at any time in the future. However, in Section 3.2.4 of the subject EA, the BLM states that the Mitigation Proposal "...would be constructed within the same time frame as the entire SunZia Project, from 2 to 3 years."

   This statement is misleading for two reasons. First, as stated by the Cascabel Working Group in their EA comments, this time frame does not allow for line testing and certification required for the manufacturing of buried Extra High Voltage (EHV) lines. However, this statement is even more misleading, because it states that the project would be completed as a whole, despite economic factors that will favor early construction of the Arizona route segments for development of natural gas generation to meet the high near-term demand of Arizona utilities. Those segments will provide the highest profit potential to investors on this proposed merchant line. If the western segments are completed and filled to transmission capacity (through federal open access policies) long before the far less economically feasible eastern segments of the project, wind resources near the eastern terminus may never dominate the energy mix of the

project as a whole. There is a very high likelihood that the overall development of renewable resources forecast in the cumulative effects section of the final EIS will not come to fruition in the reasonably foreseeable future. Regulations associated with the National Environmental Policy Act (NEPA) require that only reasonably foreseeable actions be considered in an EIS.

2) The EA contains no specific figures for the significant cost impacts of the Mitigation Proposal. While the contracted environmental firm, Environmental Planning Group (EPG), and the BLM went to great lengths to document the significant increase in construction costs associated with line burial in section 4.16 of the final EIS when making the case that line burial was not necessary or cost effective to avoid impacts to the Rio Grande avian migration corridor, no similar detailed analysis was provided in the subject EA when making the case that line burial would be economically feasible for mitigating future impacts to the White Sands Missile Range (WSMR) mission. This significant cost information is highly relevant, given that a merchant transmission project is so dependent upon economic factors.

   From the above referenced burial cost information in the final EIS, it can be assumed that burial costs for the Mitigation Proposal will exceed $300 million dollars, thus doubling the line construction cost of the subject line segment 1A2. This is an enormous increase in construction cost, and must be considered in an analysis of economic feasibility in the final EIS.

3) The EA contains no reference to the only relevant economic feasibility study submitted during the SunZia environmental review process. FAR and others have repeatedly submitted to the BLM the 2008 High Plains Express Transmission Project Feasibility Study Report (HPX Study): http://www.rmao.com/wtpp/HPX/HighPlainsExpress%20First%20Stage%20Feasibility%20Report%2006_08.pdf
   The relevant findings of this study were ignored in the draft EIS, dismissed in Appendix J of the final EIS, and never mentioned in the subject EA. Ignoring specific findings in a relevant economic feasibility study has caused this particularly federal environmental review process to become a renewable energy propaganda tool for the applicant rather than an objective analysis of cumulative effects based upon the most likely use of the proposed line(s).

   The HPX Study indicates that the Corona-to-Pinal segment of HPX, which essentially coincides with the current SunZia plan, had the highest projected transmission costs of all HPX segments considered (Table 7 on p. 30 and Figure 7 on p. 31), and these figures were based upon the assumption that all dual 500 kV lines could be constructed at an average cost of $1.5 million per linear mile, indicating all above-ground construction. Further, this Study appropriately indicated that line segments with only 40% line utilization would incur twice as much transmission cost per MW as line segments with 80% utilization. The projected line utilization on the subject SunZia 1A2 segment, based upon the BLM's energy development forecast in the final EIS, would be closer to the 40% figure than the 80% figure. The HPX Study concluded that even if all EHV lines were built above ground, the so-called "wind first" segments of the HPX project would not be economically competitive unless there were a significant tax on carbon emissions (Figure 12 on p. 37).

By doubling the line construction cost of SunZia segment 1A2, the economic feasibility of constructing and operating this line segment becomes an even more remote possibility than was described in the HPX Study.

It has been a circumvention of NEPA for the oversight agency to ignore specific findings of a relevant economic feasibility study in the EIS and in the subsequent mitigation proposal EA. In order to protect the integrity of the NEPA process, a supplement to the SunZia EIS is necessary.

4) The EA contains no discussion of the highly speculative nature of proposed SunZia route segment 1A2. By ignoring the specific findings of the only relevant economic feasibility study submitted during the SunZia NEPA process, the BLM has allowed the applicant to mislead the public and our elected representatives about the most likely long term effects of the project. The cumulative effects analysis in the final EIS was based upon an energy development forecast that was not supported by the HPX Study and which has now become an even more remote possibility with the addition of another $300 million in construction costs. NEPA regulations and relevant court decisions require that analyses in an EIS be only based upon reasonably foreseeable future actions, not upon unsupported speculation.

   Thus, a supplement to the EIS is necessary to consider not only the relevant findings of the HPX Study, but also the degree to which the significant increase in construction cost to segment 1A2 will affect the most likely energy development scenario and resultant cumulative effects.

5) The EA does not consider the projected lack of a carbon emissions tax and other governmental supports for renewable energy development. In addition to the economic factors in the HPX Study that have been ignored by the federal oversight agency, there are also political factors that need to be taken into consideration. There is no indication that the recently elected federal legislative branch has any intention of imposing a carbon emissions tax, and there is no indication that the current Corporation Commission in Arizona has any intention of significantly increasing the renewable energy standards in the main destination state for SunZia's power. A one-third billion dollar increase in construction cost for the SunZia 1A2 line segment is highly unlikely to be subsidized by any state or federal entity, as is the increased operation cost per MW on a low-utilization long-distance EHV line.

   There is no reason to believe that these proposed transmission lines will transmit or promote the development of a higher proportion of renewable energy than any other new long distance EHV project in the Southwest. In the reasonably foreseeable future, there is an increasingly competitive energy market, a glut of natural gas resources, and very limited support for significantly increasing renewable energy development. The final EIS must be revised to reflect these conditions, both in its analyses of cumulative effects and of alternatives to the proposed project. The analysis of alternative should include sensitivity analyses, such as those described in the HPX Study. With such sensitivity analysis, it can be determined if combining two proposed projects along certain route segments could result in similar performance while reducing the overall costs and environmental impacts of both projects.

CONCLUDING STATEMENTS

Contrary to popular belief, the proposed SunZia project is a merchant transmission line, not a renewable energy project, and thus will live or die according to economic and political factors in what is essentially a free market environment. The contracted environmental firm and the oversight agency have consistently deferred to the applicant's statements of intent for the proposed project, while ignoring specific findings of the only relevant economic feasibility study that was submitted during the environmental review process. **The *intent* of the applicant is irrelevant to the ultimate use and long term effects of this particular transmission proposal.** It should also be noted here that while the EIS contractor has repeatedly emphasized the intent of the applicant and has forecast 81% to 94% renewable energy development, they have not evaluated or summarized the integrated resource plans of regional utilities.

If the project gets through the federal and state permitting process, the resultant permits will simply become a saleable commodity, and the current personnel associated with SunZia, such as Mr. Wray, may have no substantial role in the project after that point, as was the case with Panda's Gila River Power Station project in Arizona. After the permits are issued, we can be sure that economic reality will prevail, and the long term use and resultant cumulative effects of the SunZia project will become obvious. Those who facilitated the obfuscation of cumulative effects will be remembered and held publicly accountable by conservation activists who are trying their best to protect the last remaining major natural river ecosystem in southern Arizona from a misrepresented project that has consistently tried to justify significant ecological impacts by making unsupported ecological benefit claims. SunZia's hired lobbying firm has publicly referred to these activists as "hypocrites" for not blindly accepting that SunZia will result in greater ecological benefits than costs. This unsupported claim of net ecological benefit is the core of SunZia's marketing strategy during the federal permitting process.

So far, the BLM has allowed the applicant to make unsupported renewable energy development claims. With the significant increase in construction cost for the main wind energy segment of the proposed project, it is essential that the BLM now develop a supplement to the final EIS that takes into account the most important economic factors affecting the use and ultimate effects of this merchant transmission line. Please take the time to prevent the subversion of the NEPA process into a "green-washing" campaign for SunZia. We urge you to acknowledge the huge cost impact of this Mitigation Proposal, recognize its effect on the economic feasibility of line segment 1A2, and refrain from issuing a Finding of No New Significant Impact.

Respectfully submitted,

Peter Else, chair
Friends of the Aravaipa Region (FAR)
P.O. Box 576
Mammoth, AZ 85719
Email: BigBackYardFAR@gmail.com
Phone: 520-487-1903