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Project 11876-001
February 3, 2006

Mr. Paul Phelan
Mr. Larry Johnson
Mr. Brian Watts
Mohave Continued Operation Project
Southern California Edison, Inc.
300 N. Lone Hill Ave.
San Dimas, California 91773

Dear Messrs. Phelan, Johnson, and Watts,

Attached is the following final report prepared by Sargent & Lundy LLC for Southern California Edison, Inc.:

Study of Potential Mohave Alternative/Complementary

Generation Resources, Pursuant to CPUC Decision 04-12-016

SL-008587

February 2006

If there are any questions, please do not hesitate to call me at (312) 269-6404 or Paula Scholl at (312) 269-6645.

Yours very truly,

David W. Cohn

David W. Cohn
Principal Consultant

Enclosures - All recipients
Copies:
P.L. Scholl

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Study of Potential Mohave Alternative/Complementary Generation Resources

Pursuant to CPUC Decision 04-12-016

Report Prepared for
Southern California Edison

SL-008587
February 2006

Synapse
Energy Economics, Inc.

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Study of Potential Mohave Alternative/Complementary Generation Resources

Pursuant to CPUC Decision 04-12-016

Report Prepared for
Southern California Edison

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February 3, 2006
Date

SL-008587
February 2006

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MOJAVE GENERATION ALTERNATIVES

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ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
ACC	Arizona Corporation Commission
ACEEE	American Council for an Energy Efficient Economy
ADEQ	Arizona Department of Environmental Quality
ANA	Administration for Native Americans
APS	Arizona Public Service
ARI	Advanced Resources International, Inc.
ASU	Air separation unit
ATC	Available Transmission Capability
BACT	Best Available Control Technology
BAT	Business Activity Tax
bbl	Barrel
CAMR	Clean Air Mercury Rule
CCN	Certificate of Convenience and Necessity
CDD	Cooling degree days
CDE	Community development entity
CDFI	Community development financial institution
CEMS	Continuous emissions monitoring system
CGE	Computable general equilibrium
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
CPV	Concentrating photovoltaic
CSEGR	Carbon sequestration with enhanced gas recovery
CSP	Concentrating solar power
DAQEM	Clark County Department of Air Quality and Environmental Management
DEP	Division of Environmental Protection
DEQ	Department of Environmental Quality

ACRONYMS AND ABBREVIATIONS (cont.)

Term	Definition or Clarification
DNR	Department of Natural Resources
DOE	Department of Energy
DSIRE	Database of State Incentives for Renewable Energy
DSM/EE	Demand Side Management/Energy Efficiency
ECBM	Enhanced coal bed methane recovery using carbon dioxide
EDAWN	Economic Development Authority of Western Nevada
EIS	Environmental Impact Statement
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
EPACT	Energy Policy Act
EPC	Engineering, procurement, and construction
EPC	Emergency Planning Commission
EPRI	Electric Power Research Institute
EPS	Environmental Portfolio Standard
EWG	Exempt Wholesale Generator
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
FLM	Federal Land Managers
FMV	Fair market value
FTRs	Firm transmission rights
gpm	Gallon(s) per minute
GWh	Gigawatt-hour(s)
HHV	Higher heating value
hp	Horsepower
HRSG	Heat recovery steam generator
HTF	Heat transfer fluid

ACRONYMS AND ABBREVIATIONS (cont.)

Term	Definition or Clarification
IECM	Integrated Environmental Control Model
IGCC	Integrated gasification combined-cycle
INEEL	Idaho National Engineering and Environmental Laboratory
inHgA	Inch(es) of mercury absolute
IOUs	Investor-owned utilities
IRP	Integrated resource planning
ISO	Independent system operator
kW	Kilowatts
kWh	Kilowatt-hour(s)
LAER	Lowest Achievable Emission Rate
LDWP	Los Angeles Department of Water and Power
LGTI	Louisiana Gasification Technology, Inc.
LLC	Limited liability company
LNB	Low-NO_X burners
MBtu	10^6 Btu (or mmBtu)
MCLs	Maximum contaminant levels
MD	Mechanical draft
mmBtu	10^6 Btu (or MBtu)
MOAs	Military operational areas
MW	Megawatt(s)
MWe	Megawatt(s) electric
MWh	Megawatt-hour
N.N.C.	Navaho Nation Code
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industrial Classification System
NDOT	Navajo Department of Transportation

ACRONYMS AND ABBREVIATIONS (cont.)

Term	Definition or Clarification
NEG	New Economic Geography
NEMA	National Electrical Manufacturers Association
NEPA	National Environmental Policy Act
NFPI	Navajo Forest Products Industries
NGCC	Natural gas combined-cycle
NN	Navajo Nation
NOI	Notice of Intent
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NREL	U.S. Department of Energy – National Renewable Energy Laboratory
NSR	New Source Review
NST	Navajo Sales Tax
NTUA	Navajo Tribal Utility Authority
NV-DEP	Nevada Department of Conservation and Natural Resources – Division of Environmental Protection
NVP	Nevada Power Company
NYMEX	New York Mercantile Exchange, Inc.
O&M	Operating and maintenance
OASIS	Open Access Same-Time Information System
OC	Oxidation catalyst
OOIP	Original oil in place
PES	Portfolio Energy Standard
PIT	Possessory Interest Tax
PM	Particulate matter
PM_{10}	Particulate matter smaller than 10 µm
$PM_{2.5}$	Particulate matter smaller than 2.5 µm

ACRONYMS AND ABBREVIATIONS (cont.)

Term	Definition or Clarification
PPA	Power purchase agreement
ppm	Parts per million
ppmvd	Parts per million, volumetric dry
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
psig	Pound(s) per square inch (gauge)
PTC	Production tax credit
PUCN	Public Utility Commission of Nevada
PV	Present value
REDYN	Regional Dynamics, Inc.
ROD	Record of decision
ROE	Return on Equity
ROIP	Remaining Oil in Place
ROR	Rate of return
ROW	Right-of-way
RPS	Renewable Portfolio Standard
RTO	Regional transmission organization
S&L	Sargent & Lundy LLC
SCE	Southern California Edison
SCORE	Service Corps of Retired Executives
SCR	Selective catalytic reduction
SEGS	Solar Electric Generating Station
SES	Stirling Engine Systems
SHPO	State Historical Preservation Officer(s)
SIP	State Implementation Plan
SNL	Sandia National Laboratories

ACRONYMS AND ABBREVIATIONS (cont.)

Term	Definition or Clarification
SOAPP	State-of-the-Art Power Plant (software program)
SPCC	Spill Prevention Control and Countermeasure (
SPP	Sierra Pacific Power
SRP	Salt River Project
SWEEP	Southwest Energy Efficiency Project
SWPPP	Storm water pollution prevention plan
Syngas	Synthesis gas
TBtu	10^{12} Btu
Tcf	10^{12} cubic feet
TDS	Total dissolved solids
TEP	Tucson Electric Power
tonne	Metric ton (1,000 kg)
tpy	Ton(s) per year
TRC	Total resource costs
UGS	Utah Geological Survey
UIC	Underground Injection Control (program)
USBM	United States Bureau of Mines
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
VAR	Volt-amperes reactive
WAPA	Western Area Power Administration
WTI	West Texas Intermediate (crude oil)
ZLD	Zero liquid discharge (system)

EXECUTIVE SUMMARY

The Mohave Generating Station is a two-unit 1,580 megawatt (MW) coal-fired power plant located in Laughlin, Nevada, built between 1967 and 1971. The station covers approximately 2,490 acres. The Mohave Generating Station is operated by Southern California Edison, the majority owner (56%) of the plant, corresponding to 885 MW of capacity. The Los Angeles Department of Water and Power (10%), Nevada Power Company (14%), and Salt River Project (20%) also own interests in the plant.

Integrated gasification combined-cycle (IGCC), concentrating solar power (CSP) technology, wind, natural gas combined-cycle (NGCC), other renewables, and energy efficiency were investigated as potential alternatives to replace or complement the share of the electrical capacity of the Mohave Generating Station owned by Southern California Edison.

The California Public Utilities Commission (CPUC) ordered Southern California Edison (SCE) to perform for them a study of alternatives for replacement or complement of its share of the Mohave Generating Station under Decision 04-12-016, issued on December 4, 2004. SCE chose Sargent & Lundy and Synapse Energy Economics to jointly perform this study.

Six categories of generation options were evaluated:

- **Integrated Gasification Combined-Cycle (IGCC).** Two different sites were studied: the existing Mohave site and a site near the Black Mesa mine.
- **Solar Technology.** Four different technologies were screened: trough, power tower, dish/Stirling engine, and concentrating photovoltaics.
- **Wind Technology.** Four sites were chosen based on wind resource availability and proximity to tribal lands.
- **Natural Gas Combined Cycle (NGCC).** NGCC at the existing Mohave site was studied.
- **Other Renewable Technologies.** A screening study of geothermal and biomass resource potential was performed for the area in and around tribal lands.
- **Demand Side Management/Energy Efficiency (DSM/EE).** DSM/EE frameworks were developed for purchase of resources made available in nearby states other than California by DSM/EE efforts in those states.

Sargent & Lundy performed the evaluations with respect to the first five options in the list above, and Synapse Energy Economics studied the final option.

Outputs of the study of the generation options include the following:

- Capital and O&M costs
- Water usage
- Land requirements
- Construction and operations labor requirements

All costs are presented in year 2006 dollars.

With respect to the generation resource options, Sargent & Lundy and Synapse Energy Economics collaborated in the study of the following elements:

- **CO_2 Sequestration.** The issues surrounding the economic viability of CO_2 sequestration through various means was studied. The geologic feasibility of such means was also studied and is included as an appendix.
- **Tribal Issues.** Tribal issues associated with royalties and taxes and other economic impacts, including impacts on employment, of the generation resource options were studied.
- **Financial Issues.** Financial issues including ownership structures of the prospective options and existing financial incentives were studied.
- **Generation and Demand Profiles.** The correspondence of the possible generation profiles with SCE demand was studied.
- **Transmission Issues.** Transmission issues including contractual issues of transmission availability and physical load flows were studied.

Fuel costs and emissions costs were also estimated on a per-unit basis by Synapse Energy Economics and are included as appendixes to this report.

ES.1 GENERATION TECHNOLOGY OPTIONS

ES.1.1 Project Sizes

Project sizes differed from the 885-MW capacity of the SCE share of the existing Mohave plant for various reasons. Those reasons are summarized as follows:

- **IGCC.** IGCC project sizes are limited by the size of the combustion turbine used as the primary heat source. Combustion turbine manufacturers have a limited number of turbine models with specific size ranges. IGCC project sizes, therefore, are determined by ambient conditions and whether one, two, three, four, or more combustion turbines are employed in the design. As a result, the projects have discrete sizes depending on the number of combustion turbines. The selection, in this study, of the 540-MW size range reflects the next increment in sizing above the sizes of recent demonstration plants that have all used one combustion turbine. We expect that both developers and constructors will desire to perfect this design configuration before moving on to larger sizes.

- **Solar.** In order to estimate reasonable unit sizes for the solar technologies, recent Renewable Portfolio Standards requirements in the area were evaluated. The amount of energy corresponding to the production of Mohave Station that must come from renewable sources was estimated. The unit sizes for each technology that could provide this energy were then estimated, based on estimated capacity factors for each technology. California retail sellers of electricity are required to increase their procurement of eligible renewable energy resources such that 20% of their retail sales (on a megawatt-hour basis) are procured from eligible renewable energy resources by 2017. An 885-MW plant at 72% capacity factor (equivalent to Mohave Generating Plant capacity factor) produces approximately 5,600,000 MWh of electricity per year. Twenty percent of this value results in 1,120,000 MWh, which will theoretically have to come from renewable energy resources by the year 2017. The parabolic-trough capacity factor capability, without thermal storage, is approximately 30%. In order to produce 1,120,000 MWh, a unit size of 425 MW is required.

  In order to reduce the plant size of a parabolic trough plant and eliminate the need for a conventional steam-Rankine power plant for backup, thermal storage of six hours can be considered in the parabolic-trough plant configuration. This is consistent with the design of other parabolic-trough plants. With six hours of thermal storage, the capacity factor capability is approximately 43%, which corresponds to 300 MW of installed power for 1,120,000 MWh.

  The dish/Stirling engine capacity factor capability, without thermal storage, is approximately 30%, which for 1,120,000 MWh (same generation as considered for the parabolic-trough technology) corresponds to 425 MW of power.

- **Wind.** Sites were identified that had Class 3 or better wind resources. The available wind resources have an implied annual capacity factor related to the maximum sustained wind speed and the profile of this wind resource over a year. This, combined with the associated land area over which installation of wind turbines is feasible, provides the major input for the estimate of available maximum capacity. The Department of Energy (DOE) has estimated that Gray Mountain has a total wind resource potential of up to 800 MW; however, this estimate may not take into account physical limitations, transmission capacity, economic resources versus technical resources, or other constraints at the site. An estimate to build out to 450 MW over a three-year phased development program of 150 MW per phase is reasonable, based on the available wind resources and engineering judgment, at this time. The Aubrey Cliffs initial potential is estimated to be 100 MW. Further capacity potential may exist and depends on the degree to which the wind resource drops off further from the mesa edge and the transmission capacity available on the targeted 230-kV transmission system where interconnection will occur south of Chino Point and Route 66 near Seligman. Clear Creek is initially being developed to a size of 75 MW. There does not appear to be sufficient planned transmission capacity at this site over the near and intermediate term to exceed 75 MW. The Sunshine Wind Park is being developed to a size of 60 MW to fully use available transmission capacity on the 69-kV APS line into which the project would interconnect.

- **NGCC.** The sizing criteria described for IGCC also apply to NGCC, resulting in capacities of approximately 500 MW for a two-combustion-turbine project and 1,000 MW for a four-combustion-turbine project.
- **Other Renewables.** Given the lack of available resources, the maximum potential unit size is approximately 2.5 to 5 MW. Therefore, other renewable energy sources are not feasible in size ranges resembling those of the other options and so were not considered.
- **DSM/EE.** Capacity ranges for available DSM/EE resources depend on the ability of the entities performing the demand-side management and energy efficiency activities to free up existing capacity. By 2010 it is possible that energy efficiency initiatives in Arizona and New Mexico could replace over 40% of the energy and capacity of SCE's share of the Mohave plant, provided satisfactory regulatory and commercial terms and conditions can be developed.

Approximate project sizes studied in this report are presented in the table below:

Table ES-1 — Approximate Project Sizes (MW)

IGCC	Solar	Wind	NGCC	Other Renewables	DSM/EE
500 - 600	425	60- 450	1000	2-5	N/A

ES.1.2 Integrated Gasification Combined Cycle

Gasification is a process that converts a variety of carbon-containing feed stocks like coal, petroleum coke, lignite, oil distillates, and residues into synthesis gas (syngas) consisting primarily of carbon monoxide (CO), hydrogen (H_2), and carbon dioxide (CO_2). Syngas from the gasifier is cleaned of particulate matter (PM), sulfur, and other contaminants before being combusted in a gas-fired combustion turbine. Heat from the turbine exhaust gas is extracted in a heat recovery steam generator (HRSG) and combined with steam produced in the gasification system to drive a steam turbine/generator.

- **No CO_2 removal.** This is technically feasible today with current technology.
- **CO_2 removal without shift conversion.** In this case, 90% of the carbon dioxide generated by the standard syngas production process is removed from the fuel gas. This is technically feasible today.
- **Maximum CO_2 removal.** This assumes that all of the carbon monoxide the syngas is converted to carbon dioxide using a shift reaction and 90% of this CO2 is removed from the fuel. The shift reaction is technically feasible today. However, a combustion turbine that can use the product syngas is not yet available.

Combined with the performance of the IGCC, the effects of CO_2 removal were analyzed for three separate cases:

- **No CO_2 Removal.** The base case performance assumed that carbon was not removed from the fuel. This is how current technology operates at this time.
- **CO_2 Removal without Shift Conversion.** This case assumed that syngas was produced using current gasifier technology and a standard selection of gasifier components, with no "shift reaction" to convert carbon monoxide in the syngas to CO_2. Some CO_2 is produced in the syngas nevertheless, and this was assumed to be removed. This is technically feasible today; however, the issue of where to put the removed CO_2 must still be addressed.
- **90% CO_2 Removal.** This case assumed that the syngas was further processed using a "shift" reaction to convert the carbon monoxide (CO) in the syngas to CO_2, and that 90% of the CO_2 in the resulting syngas was removed from the fuel. At the present time, a combustion turbine capable of burning the fuel that is the result of this process is not currently available, and technical research and development is still necessary.

Estimates of performance of the IGCC option at the two sites studied are as follows:

Table ES-2 — IGCC Plant Performance

Values at 100% Load and 100% Capacity Factor		No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
Mohave				
Gross Output	MW	639.6	639.6	604.9
Net Output	MW	548.9	531.1	481.7
Heat Rate	Btu/kWh	9,909	10,402	11,730
Overall Efficiency	%	34.4	32.8	29.1
Heat Input	mmBtu/hr	5,439	5,525	5,650
Fuel Consumption	lb/hr	502,056	509,953	521,560
Fuel Consumption	tpy	2,199,007	2,233,595	2,284,432
Total Staffing	persons	145	155	155
Black Mesa				
Gross Output	MW	643.9	643.9	609.0
Net Output	MW	554.6	537.1	484.9
Heat Rate	Btu/kWh	9,927	10,421	11,751.3
Overall Efficiency	%	34.4%	32.7%	29.0%
Heat Input	mmBtu/hr	5,506	5,506	5,699

Values at 100% Load and 100% Capacity Factor		No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
Fuel Consumption	lb/hr	508,191	508,191	526,020
Fuel Consumption	tpy	2,225,878	2,225,878	2,303,967
Total Staffing	persons	145	155	155

Capital costs for the various cases, as well as for the two sites, Mohave and Black Mesa, were developed with conventional cooling and dry cooling, respectively. These are summarized below.

Table ES-3 — IGCC Capital Costs

	No CO_2 Removal		CO_2 Removal without Shift Conversion		90% CO_2 Removal	
Net output, MW	548.9 (554.6)		531.1 (537.1)		481.7 (484.9)	
Capital Costs	M$	$/kW	M$	$/kW	M$	$/kW
Const. Cost w/ Wet Cooling (Mohave)	895	1,631	987	1,858	1,143	2,373
Const. Cost w/ Dry Cooling (Black Mesa)	910	1,641	1,002	1,866	1,158	2,388
EPC Fees (12.5%)*	113.76	205	125.20	236	144.81	301
Owner's Development Costs (6.5%)	59.16	107	65.10	123	75.30	156
Total Expected Costs w/Wet Cooling (Mohave)	1,065	1,940	1,174	2,210	1,361	2,825
Total Expected Costs w/Dry Cooling (Black Mesa)	1,083	1,973	1,192	2,219	1,379	2,844

*EPC fees include the profit of the EPC contractor plus allowances embedded by the EPC contractor in the contract price for—

- Process risk, including the cost of providing a performance guarantee
- Sub-contractors performance and completion risk, including items such as bankruptcy of the subcontractor or having to hire a new subcontractor if it is not performing its contract.
- Execution risk, including cost and schedule risk.

Water consumption was also estimated for the three cases of CO_2 removal and the two cases of cooling. These results are summarized below. Values shown are for 100% capacity factor and would vary proportionately with actual plant dispatch; these are maximum values.

Table ES-4 — IGCC Water Consumption

Based on 100% Capacity Factor	No CO_2 Removal		CO_2 Removal		With CO_2 Removal	
	gpm	acre-ft/yr	gpm	acre-ft/yr	gpm	acre-ft/yr
Total Plant Use (Mohave)	4,245	6,833	4,252	6,844	4,406	7,093
Total Plant Use (Black Mesa)	1,192	1,919	1,199	1,930	1,238	1,992

Notes: Boiler feedwater make-up is 1% of main steam flow rate.
Cooling tower make-up includes evaporation, drift and blowdown with four cycles of concentration.
Cooling towers used at Mohave with Colorado River water, Dry Cooling used at Black Mesa.
All water for coal slurry to either site is assumed to come from the "C-aquifer."

Land use was also estimated for this option, as summarized below.

Table ES-5 — IGCC Land Requirements

	Units	No CO_2 Removal		No Shift CO_2 Removal		Max. CO_2 Removal	
Cooling Type		Wet	Dry	Wet	Dry	Wet	Dry
Land Use	acres	300	300	300	300	300	300
	sq. mi.	0.469	0.469	0.469	0.469	0.469	0.469
Length of Side of Square with Same Area	mi.	0.69	0.69	0.69	0.69	0.69	0.69

ES.1.3 Solar

Four different solar power generation technologies were evaluated: parabolic trough, dish/Stirling engine, power tower, and concentrating photovoltaics. This review indicated that the parabolic-trough and dish/Stirling engine technologies were the only ones that could reasonably replace or complement a portion of the generation of the existing Mohave plant, forming a part of the generation required for compliance with emerging renewable portfolio standards. The power tower and concentrating photovoltaic technologies were not selected because, in the former case, the technology has proven inferior to the trough technology and has no commercial examples, while in the latter case, the technology is still in development and, also, has no commercial examples. The trough technology is in commercial operation. The dish/Stirling engine technology has been demonstrated on a small-scale, has a very high conversion efficiency, and has entered the commercial stage of its developed as witnessed by two agreements signed with major utilities that are designed to ultimately lead to formal power purchase agreements. A summary of the results of the analysis is provided in the table below.

Table ES-6 — Solar Technology Summary

		Parabolic-Trough	Dish/Stirling engine
Plant Size	MW	300	425
Number of Units		3	17,000
Unit Size	MW	100	0.025
Thermal Storage		Yes – 6 hours	No
Annual Capacity Factor		43%	30%
Annual Generation	MWh	1,120,000	1,120,000
Capital Cost	$/kW	$3,560	$1,400
Fixed O&M Cost	$/kW-yr	$33	$3
Variable O&M Cost	$/MWh	$30	$11
Land Use	acres	870 per unit (2,610 total)	2,125
	sq. mi.	1.359 per unit (4.078 total)	3.320
Length of Side of Square with Same Area	mi.	1.17 per unit (2.02 total)	1.82
Water Requirement	gal/yr	6,800,000 per unit (20,400,000 total)	2,856,000
	acre-ft/yr	20.87 per unit (62.61 total)	8.76
Total Staffing	persons	62 per unit (stand alone units) 88 total (combined units)	118

ES.1.4 Wind

Four sites with significant potential for power generation using wind technology were identified. These sites are summarized in the following table.

Table ES-7 — Wind Sites

Site	Gray Mountain	Aubrey Cliffs	Clear Creek	Sunshine
Wind Class at 80 m	4 to 7	4 to 5	3+ to 4	3
MW	450	100	75	60

Site	Gray Mountain	Aubrey Cliffs	Clear Creek	Sunshine
Expected Capacity Factor	40%	34%	32%	25%
Location	On the Navajo reservation near Cameron, Arizona and Moenkopi Substation	On Navajo fee and State Trust lands just northwest of Seligman, Arizona	On Hopi fee and State Trust lands southwest of Winslow	On Hopi fee and private ranch lands owned by two other landowners, located 35 miles east of Flagstaff on I-40 near the Meteor Crater and west of Winslow

Table ES-8 — Wind Sites Capital and O&M Cost Estimates

Project Size and Capital Costs	Gray Mountain-3 Phases	Gray Mountain-Phase 1	Aubrey Cliffs	Clear Creek	Sunshine
Net MW	450	150	100	75	60
Project Costs $2006	755,017,000	258,031,000	169,196,000	126,570,000	99,671,000
Project Costs per kW, $/kW	1,678	1,740	1,692	1,688	1,661
Fixed O&M, $/kW-yr	23.73	23.73	24.24	24.94	27.08
Variable O&M, $/MWh	0.195	0.195	0.223	0.244	0.279

Water requirements are negligible for the wind options. Staffing requirements are as follows:

Table ES-9 — Wind Sites Operating Staffing Requirements

Project	MW	Staff
Gray Mountain	450	14
Aubrey Cliffs	100	4
Clear Creek	100	4
Sunshine Wind Park	60	3

Land requirements for the wind options are as follows:

Table ES-10 — Wind Sites Land Requirements

		Gray Mountain-3 Phases	Gray Mountain-Phase 1	Aubrey Cliffs	Clear Creek	Sunshine
Land Use	acres	34,000	11,333	5,200	4,320	8,000
	sq. mi.	53.13	17.71	8.13	6.75	12.50
Length of Side of Square with Same Area	mi.	7.29	4.21	2.85	2.60	3.54

ES.1.5 Natural Gas Combined Cycle

Combined-cycle technology has been used to generate power for a number of years, utilizing a cycle containing both combustion turbines and steam turbines. The combination of the two types of turbines generally provides efficiencies in the range of 48% to 52% on a higher heating value (HHV) basis. Combined-cycle plants generally come in discrete sizes; the combined-cycle power plant size is primarily a function of the combustion turbine size, and these are available from manufacturers in a limited number of sizes.

The overall plant performance was estimated for the Mohave site for a 2 x 2 x 1 500-MW combined-cycle power block operating on the primary fuel (i.e., natural gas) at the site average ambient conditions. To obtain the total site performance estimate (i.e., nominal 1,000-MW facility), the performance estimate for the single 500-MW power block was doubled.

The full-load estimated plant performance while operating on natural gas with an air-cooled condenser is as follows:

Table ES-11 — Plant Performance Data with Dry Cooling

Ambient Temperature	20°F	67°F	108°F	125°F
Gross Generator Output, MW	1,063	1,017	902	880
HHV Heat Input, mmBtu/hr	7,412	7,028	6,478	6,404
Auxiliary Power Estimate, MW	23	23	22	21

Ambient Temperature	20°F	67°F	108°F	125°F
Net Generator Output, MW	1,040	994	880	859
Net Plant Heat Rate, Btu/kWh HHV	7,130	7,070	7,355	7,460

Note: Ambient temperatures shown correspond to the following:
20 ºF – site minimum design temperature
67 ºF – site average annual temperature
108 ºF– site summer design temperature
125 ºF – site maximum design temperature

As part of this study, CO_2 sequestration was evaluated. Based on information from the Department of Energy's Integrated Environmental Control Model (IECM) computer program, the performance of the combined-cycle facility is affected by the addition of CO_2 sequestration. From the program, the performance impact is approximately 15% less output and approximately 18% higher heat rate at the average ambient conditions.

Current capital cost estimates for the NGCC technology were developed using S&L's in-house database. A single 2 x 2 x 1 500-MW combined-cycle power block cost estimate was developed for each of two different cooling methods. The first case was for a plant with a mechanical draft (MD) cooling tower with a wet surface condenser. The second case was for a plant with an air cooled condenser. The capital cost estimates are as follows:

Table ES-12 — Capital Cost Estimates

Configuration	Estimated Capital Cost	Capital Cost per Installed kW*
Single 2x2x1 500-MW combined-cycle power block with MD cooling tower	$300,000,000	604
Two 2x2x1 500-MW combined-cycle power blocks with MD cooling tower	$540,000,000	544
Single 2x2x1 500-MW combined-cycle power block with air-cooled condenser	$306,000,000	616
Two 2x2x1 500-MW combined-cycle power blocks with air-cooled condenser	$551,000,000	555

* Based on net power at average ambient conditions

In addition to the costs that were developed for the two cooling methods, a cost estimate was developed for CO_2 sequestration. This estimate is based on the DOE IECM program data. The estimated capital cost for CO_2 sequestration is approximately $350/kW to $400/kW higher than the capital cost estimates provided above. Therefore, for a nominal 1,000-MW combined-cycle plant with mechanical draft cooling towers, the estimated capital cost with CO_2 sequestration is approximately $894/kW to $944/kW. Similarly, for a nominal 1,000-MW combined-cycle plant with air-cooled condensers, the estimated capital cost with CO_2 sequestration is approximately $905/kW to $955/kW.

Operations and maintenance (O&M) costs were also estimated. The fixed O&M costs are those spent regardless of how much the plant operates. The fixed O&M costs include costs for direct and indirect labor for operations and maintenance staff that are permanently employed at the plant site, as well as home office support costs allocable to the plant. In addition, the fixed costs include O&M contract services and materials and power purchased for in-house plant needs during plant outages. The variable O&M costs are those costs that change with the amount of power generated. The variable O&M costs include chemicals and consumables, catalyst replacement, and major maintenance of the combustion turbines, steam turbines, HRSG, and balance-of-plant.

The fixed and variable O&M costs for the NGCC power plant for each of the two cooling methods studied in this report are presented in the following table.

Table ES-13 — Estimated O&M Costs

Current $	MD Cooling Tower with Wet Surface Condenser	Air-Cooled Condenser
Fixed, $/kW-yr	$5.47	$5.47
Variable, $/MWh	$1.97	$1.77

CO_2 sequestration O&M costs were also estimated for this study. The fixed and variable O&M costs were estimated based on the DOE IECM program. The estimated fixed and variable O&M costs for the combined-cycle plant with mechanical draft cooling towers and with CO_2 sequestration are $6.45/kW-yr and $2.32/MWh, respectively. The estimated fixed and variable O&M costs for the combined-cycle plant with air-cooled condensers and with CO_2 sequestration are $6.45/kW-yr and $2.08/MWh, respectively.

Approximate plant land area requirements for the NGCC facility are presented in the following table. The table represents the estimated land requirements for two 500-MW combined-cycle power blocks. In addition, the table provides the approximate area required based on the method of cooling (i.e., mechanical draft cooling towers with wet surface condensers versus air-cooled condensers).

Table ES-14 — Approximate Land Area Required for 1,000-MW NGCC Facility

		MD Cooling Tower with Wet Surface Condenser	Air-Cooled Condenser
Without CO_2 Sequestration	acres	30	42
	sq. mi.	0.047	0.066

		MD Cooling Tower with Wet Surface Condenser	Air-Cooled Condenser
Length of Side of Square with Same Area	mi.	0.217	0.257
With CO_2 Sequestration	acres	34	46
	sq. mi.	0.053	0.072
Length of Side of Square with Same Area	mi.	0.230	0.268

Approximate water usage for the natural gas combined-cycle facility is provided in the following table.

Table ES-15 — Approximate Water Usage for 1,000-MW NGCC Facility

	MD Cooling Tower with Wet Surface Condenser		Air-Cooled Condenser	
	gpm	acre-ft/yr	gpm	acre-ft/yr
Cooling Tower Makeup Peak / Average	3,500 / 2,300	5,650 / 3,710	0 / 0	0 / 0
Cycle Makeup Peak / Average	66 / 44	110 / 70	66 / 44	110 / 70
Miscellaneous Peak / Average	76 / 76	120 / 120	76 / 76	120 / 120
Total Water Makeup Peak / Average	3,642 / 2,420	5,870 / 3,900	142 / 120	230 / 190

ES.1.6 Demand-Side Management / Energy Efficiency

As part of the study, potential DSM/EE resources available in the Western United States outside of California were reviewed. The specific technology option being analyzed involves SCE financing DSM implementation, coupled with power purchase arrangements under which the resultant available “freed up” power would be purchased by SCE.

This concept is based on the assumption that there are considerable low-cost efficiency resources in states neighboring California, and that SCE may be willing or directed to procure such resources (through DSM implementation coupled with a power purchase contract) depending on the overall costs in comparison to other alternatives. In doing so, SCE could create, for example, a 10-year power purchase agreement (PPA) with a neighboring utility at a price below its avoided costs, yet still high enough to entice the neighboring utility to implement the DSM. The DSM resource would be that available beyond what is already being pursued by the neighboring utility or state.

To assess the amount of energy efficiency potential in the region, the study by the Southwest Energy Efficiency Project of the economic potential for energy efficiency in the southwest (SWEEP 2002) was reviewed. As it turns out, Arizona and New Mexico have, by far, the largest potential for readily available utility efficiency savings; by 2010 there is estimated to be at least 2,394 GWh of energy per year and 408 MW of capacity available from these two states alone. To put this in perspective, SCE's share of the Mohave generation is roughly 5,700 GWh per year, and its share of the Mohave capacity is 885 MW. Thus, by 2010 energy efficiency from Arizona and New Mexico could replace over 40% of the energy and capacity from the Mohave plant. It is assumed that these savings can be achieved for a cost of $40/MWh or less. The analysis is conservative, because a relatively high estimate of cost of saved energy is assumed and because the raw efficiency potential documented in the SWEEP study is discounted.

A simple spreadsheet model was developed to gauge the effect of a DSM transfer. Based on the model, an illustrative example was created to assess the effect on each of the stakeholders (utility customers and shareholders) and the impact of peak load reduction benefits associated with the DSM procurement alternative or complement. After a consideration of the alternatives, a baseload "24 x 7" power purchase product coupled with DSM implementation was analyzed, in which the benefits associated with peak period load reductions were retained by the partnering utility while their utility customer rates were held constant. The results indicate that the economics of an interregional DSM resource transfer appear viable.

To investigate the feasibility and practicality of the DSM resource / power purchase option, PNM Resources of New Mexico was contacted. The aim of these conversations was to obtain feedback on the willingness of parties to participate in the DSM resource procurement and to determine the key issues facing potential utility partners considering a DSM/power purchase arrangement with SCE. In particular, Synapse sought to obtain information on the regulatory and institutional concerns or barriers that may exist and to determine the commercial factors that would influence the pricing arrangements that would accompany the DSM implementation / power purchase alternative. Another goal was to determine the likely range of prices or at least the driving factors in price determination; while the driving factors were discerned, no particular commercial bounds on pricing could be placed on the DSM alternative. To date, conversations indicate that regulatory reception in New Mexico remains a real concern, but it is safe to conclude that PNM Resources is interested in further discussing the concept.

The incentive for utilities to participate in agreements to implement energy efficiency programs in the states neighboring California in general, and to implement energy efficiency programs to enable power transfers to

SCE in particular, is, not surprisingly, directly related to the effect those programs are likely to have on corporate profits. Of the various methods open to utility regulators for reducing or eliminating any disincentive to pursue energy efficiency programs, the "decoupling" of utility profits from the level of sales is a concept that has been implemented or is under discussion in many states, including those in the southwest.

ES.1.7 Other Renewables

This study evaluated potential for electrical energy generation from two types of other renewable resources: biomass and geothermal.

In the case of biomass energy, the production of electricity in quantities sufficient to be considered as part of a replacement of or complement to the existing Mohave plant would require a feedstock of municipal solid waste and/or forestry residue.

Power generation from municipal solid waste requires a large source (population) and the ability to sort and provide combustible solid waste as a fuel source. The expansive area and lack of large population concentrations in tribal lands make this a difficult option. Moreover, municipal solid waste is not considered biomass. Biomass plants in the United States only use uncontaminated feedstock, which contains no toxic chemicals. Potentially hazardous materials (such as creosote-wood and batteries) would have to be removed from municipal solid waste at an additional cost to be considered true biomass.

Tribal lands have significant forest resources and the potential to support a forestry industry, but this is not a likely option in the near future. In the late 1950s, the Bureau of Indian Affairs and the Navajo Tribal Council created the Navajo Forest Products Industries (NFPI), which operated from 1962 to 1992, processing an average of 40 million board-feet of lumber each year. This program was carried out, however, with little concern for how these activities affected Navajo subsistence and spiritual use of the forests. In the early 1990s, conflict over the use of the forests developed. This conflict resulted in closure of the saw mill in 1995.

The potential, therefore, for developing feedstock for a biomass power plant on tribal lands within the next few years that would be large enough to play a significant role in replacing or complementing lost generation from the Mohave Project is extremely low.

Regarding geothermal resources, the available geological information indicates that the temperature of geothermal wells and springs within tribal lands range from 20°C (68°F) to 50°C (122°F) with the exception of two wells greater than 50°C (122°F). The water from thermal wells needs to be greater than 225°F (107°C) for generation of electricity. Given the relative lack of geothermal resources, it is estimated that the study area's geothermal resources could support a power plant of not more than 5 MW, and it is likely that no power plant is feasible in the study area.

Therefore, in both cases, the potentially viable unit size range (approximately 2.5 to 5 MW) is not meaningful in comparison to the nominal capacity of SCE's share of the Mohave power plant (885 MW), and therefore, these resources are not considered feasible as potential technology options for the replacement or complement for SCE's share of the existing Mohave plant.

ES.1.8 Generation Technology Summary Data

In order to provide a consistent set of data across all technology options studied, a common format for the data presented above was developed. Data in this format are provided below for all options studied. Summary data are not provided for the other renewable options because these technologies were not deemed viable for the size of generation desired from the technology options.

Table ES-16 — IGCC Summary Data

	Units	No CO_2 Removal		No Shift CO_2 Removal		Max. CO_2 Removal	
Cooling Type		Wet	Dry	Wet	Dry	Wet	Dry
Net Capability	MW	549	555	531	537	482	485
Capacity Factor*	%	100	100	100	100	100	100
Net Generation*	MWh/yr	4,808,364	4,858,296	4,652,653	4,704,996	4,219,692	4,248,061
Net Heat Rate	Btu/kWh	9,909	9,927	10,402	10,421	11,730	11,751
Capital Cost	$/kW	1,971	2,004	2,173	2,279	2,518	2,911
Fixed O&M Costs	$/kW-yr	49.59	49.59	67.45	67.45	80.98	80.98
Variable O&M Costs	$/MWh	1.59	1.26	1.66	1.32	2.00	1.62
Fuel Costs	$/mmBtu	1.15	1.15	1.15	1.15	1.15	1.15
Land Use	acres	300	300	300	300	300	300
Water Use	gpm	4,245	1,192	4,252	1,199	4,406	1,238
	acre-ft/yr	6,833	1,919	6,844	1,930	7,093	1,992
Total Staffing	persons	145	145	155	155	155	155
Transmission Direct Interconnection Costs**	$/kW	175.0	175.0	180.9	180.9	199.7	199.7
Transmission System Upgrade Costs***	$millions	173.0	173.0	173.0	173.0	173.0	173.0

	Units	No CO_2 Removal		No Shift CO_2 Removal		Max. CO_2 Removal	
Cooling Type		Wet	Dry	Wet	Dry	Wet	Dry
NO_X Emissions	lb/mmBtu	0.022	0.022	0.021	0.021	0.021	0.021
SO_2 Emissions	lb/mmBtu	0.13	0.13	0.02	0.02	0.02	0.02
CO_2 Emissions	lb/mmBtu	200	200	142	142	17	17

* 100% capacity factor is used as a reference; actual output will depend on dispatch conditions.

** It is assumed that direct interconnection costs and transmission upgrade costs for an IGCC plant at the existing Mohave site are zero, with the IGCC plant replacing the existing one. Costs shown are for the Black Mesa site.

*** Costs shown are for the Black Mesa site and without certain system upgrades that are already being contemplated for the near future. With those upgrades the cost is estimated at $48.0 million.

Table ES-17 — Solar Summary Data

	Units	Stirling	Trough*	
Cooling Type		N/A	Wet	Dry
Net Capability	MW	425	300	300
Capacity Factor	%	30	43	43
Net Generation	MWh/yr	1,120,000	1,120,000	1,120,000
Net Heat Rate	Btu/kWh	0	0	0
Capital Cost	$/kW	1,500	3,360	3,560
Fixed O&M Costs	$/kW-yr	3	33	33
Variable O&M Costs	$/MWh	11	30	30
Fuel Costs	$/mmBtu	0	0	0
Land Use	acres	2,125	2,610	2,610
Water Use	gpm	5.4	1,580	38.7
	acre-ft/yr	8.8	2,550	62.6
Total Staffing	persons	118	88	88
Transmission Direct Interconnection Costs (500 kV/230 kV)	$/kW	251.4/172.1	315.2/220.7	315.2/220.7
Transmission Upgrade Costs**	$000s	0	0	0
NO_X Emissions	lb/mmBtu	0	0	0
SO_2 Emissions	lb/mmBtu	0	0	0
CO_2 Emissions	lb/mmBtu	0	0	0

* Solar trough capital cost includes $600/kW for six hours of thermal storage.

** System upgrade costs are shown for Solar Site 2 as shown in the General Location Map in Appendix A.

Table ES-18 — Wind Summary Data

	Units	Gray Mountain - 3 Phases	Gray Mountain - Phase I	Aubrey Cliffs	Clear Creek	Sunshine
Cooling Type		N/A	N/A	N/A	N/A	N/A
Net Capability	MW	450	150	100	75	60
Capacity Factor	%	40	40	34	32	25
Net Generation	MWh/yr	1,566,640	522,213	304,624	204,790	146,937
Net Heat Rate	Btu/kWh	N/A	N/A	N/A	N/A	N/A
Capital Cost	$/kW	1,678	1,740	1,692	1,688	1,661
Fixed O&M Costs	$/kW-yr	23.73	23.73	24.24	24.94	27.08
Variable O&M Costs	$/MWh	0.195	0.195	0.223	0.244	0.279
Fuel Costs	$/mmBtu	N/A	N/A	N/A	N/A	N/A
Land Use	acres	34,000	11,333	5,200	4,320	8,000
Water Use	gpm	N/A	N/A	N/A	N/A	N/A
	acre-ft/yr	N/A	N/A	N/A	N/A	N/A
Total Staffing	persons	14	5	4	4	3
Transmission Direct Interconnection Costs	$/kW	83.3	85.2	126.2	91.9	96.7
Transmission Upgrade Costs	$000s	0	0	60.0	0	0
NO_X Emissions	lb/mmBtu	0	0	0	0	0
SO_2 Emissions	lb/mmBtu	0	0	0	0	0
CO_2 Emissions	lb/mmBtu	0	0	0	0	0

Table ES-19 — NGCC Summary Data

	Units	No CO_2 Removal		CO_2 Removal	
Cooling Type		Wet	Dry	Wet	Dry
Net Capability	MW	994.0	994.0	844.0	844.0
Capacity Factor	%	100	100	100	100
Net Generation	MWh/yr	8,707,440	8,707,440	8,707,440	8,707,440
Net Heat Rate	Btu/kWh	7,070	7,070	8,310	8,310
Capital Cost	$/kW	544	555	919	930

	Units	No CO_2 Removal		CO_2 Removal	
Cooling Type		Wet	Dry	Wet	Dry
Fixed O&M Costs	$/kW-yr	5.47	5.47	6.45	6.45
Variable O&M Costs	$/MWh	1.97	1.77	2.32	2.08
Fuel Costs	$/mmBtu	8.64	8.64	8.64	8.64
Land Use	acres	30	42	34	46
Water Use	gpm	2,420	120	2,500	200
	acre-ft/yr	3,900	190	4,030	320
Total Staffing	persons	60	60	75	75
Transmission Direct Interconnection Costs*	$/kW	0	0	0	0
Transmission Upgrade Costs*	$000s	0	0	0	0
NO_X Emissions	lb/mmBtu	0.0370	0.0370	0.0370	0.0370
SO_2 Emissions	lb/mmBtu	0.0	0.0	0.0	0.0
CO_2 Emissions	lb/mmBtu	114	114	11.4	11.4

* It is assumed that direct interconnection costs and transmission upgrade costs for an NGCC plant at the existing Mohave site are zero.

Other relevant parameters that may be used in an integrated resource plan process are shown in Appendix B.

ES.2 CARBON SEQUESTRATION

In this report, we examined the potential for capturing, transporting, and storing carbon dioxide that is produced by power generation facilities. Specifically, we explored five types of geologic carbon sequestration: enhanced oil recovery, enhanced gas recovery, sequestration in unminable coal seams, sequestration in deep saline aquifers, and sequestration in natural CO_2 domes. Of these, enhanced oil recovery at sites in California seems the most feasible use for carbon dioxide emissions produced by either an IGCC or NGCC facility located in Laughlin, Nevada. For the Black Mesa site, feasible locations for sequestration are discussed in Appendix C. Transportation of the carbon dioxide will require the construction of a pipeline and installation of compression equipment, which have significant costs.

The primary motivator for the advancement of sequestration technology is the expectation that anthropogenic carbon dioxide emissions will have to be controlled in order to mitigate global climate change. Despite the substantial, predicted worldwide capacity for storing carbon, a number of policy, economic, and technical barriers confront geologic sequestration. Therefore, any carbon dioxide producing power plant at the Mohave or Black Mesa sites would need to perform further economic analyses to justify the construction of a pipeline for transport.

ES.3 FINANCIAL AND ECONOMIC ISSUES

ES.3.1 Financial Incentives

Various financial incentives are available to owners and investors of electric generation facilities. The incentives are broken down into two general categories: (a) those incentives directed towards the commercialization of specific generation technologies of interest in this Study and (b) those incentives directed towards tribal activities or economic development activities for which tribes are likely to be eligible. For this study, the second category specifically focused on financial incentives directed towards tribal-owned generation facilities and those directed towards low-income communities.

Both categories of financial incentives generally come from the federal government or state governments in the form of tax advantages. These include income tax credits, exemptions and deductions for investments, sales tax exemptions on equipment purchases, variable property tax exemptions on the value of the generation system, production credits based on the quantity of energy produced, job creation credits, and accelerated or special depreciation allowances. Other non-tax incentives generally come in the form of federal, state, and private grants, loans with advantageous terms, or loan guarantee programs.

The results of our broad review indicate that there are many valuable sources of incentives that can be used to fund the development and construction of the various technologies being reviewed in this study. Many of the incentives were recently introduced through the enactment of the Energy Policy Act of 2005. Additional federal incentives are available through the Department of Agriculture, Department of Treasury, Department of Energy, and others. Furthermore, states offer many energy-related incentives, particularly with regard to renewable generation. Together, these technology-related incentives represent significant funding potential.

As an example, the federal production tax credit for wind generation is a very important assumption that must be considered in the economics of such projects. This credit, under Section 45 of the federal tax code, is set to expire on December 31, 2007. However it may be extended beyond that date. The credit amounts to a significant “after tax” benefit for each kilowatt-hour produced for the initial 10-year period of each project. Any integrated resource plan process that is considering renewable resources must take available production tax credits into account.

In addition, many incentives are available at the federal, state, and local levels to spur economic development, particularly for low-income communities, including tribes. These incentives can be significant, in terms of spawning new technologies on reservation lands.

ES.3.2 Business Structures

Depending on its ownership and specific attributes, a business organization may be defined as—

- A tribal enterprise that is owned and controlled by the tribe and subject to tribal law;
- A non-tribal enterprise that is either
  - Subject to the laws of the tribe, and perhaps also to the laws of the state in which the enterprise operates; or
  - Only subject to the laws of the state in which it operates.

Indian tribes are eligible to establish most forms of non-tribal business structures. Generally, non-tribal business structures are subject to federal and state taxes. Tribes and tribal members also can establish tribal-specific enterprises. Such businesses and organizations may offer their owners some discrete advantages, financially and socially. Tribal business structures can be subdivided into three major categories: (1) Tribal governments; (2) federally chartered tribal corporations under Section 17 of the Indian Reorganization Act of 1934; and (3) tribally chartered corporations.

The type of business classification chosen can have large consequences with regard to tax requirements, third-party funding potential, and immunity from nonconsented lawsuits. However, these are not the only considerations. Equally important are the type of business activity being considered, who has authority over day-to-day decisions, technology risks, job impacts, and other impacts of the business on the community and culture. The overall findings regarding recommended ownership structures for the technology options considered in this study are summarized below. However, it is premature to conclude that a particular technology is, or is not, suited to tribal ownership. Such decisions must, in the end, be made with full knowledge of the particular project and project financing options. However, the following points reflect reasonable *generic* conclusions that can be considered as starting points, subject to reconsideration when a specific project and its details are ready to examine.

- **IGCC.** Due to its high capital costs, business risks, and high potential for royalty income from non-tribal enterprises, it would likely be in the tribes' best interests if the proposed IGCC facility were owned and operated by a non-tribal entity formed under state law.

- **Wind and DSM/EE technologies.** For each of these, there are only moderate capital and operational costs, low technology risk, and a high potential to create future jobs for the tribes, both on and off reservation territories. In addition, the capital costs are incurred in small increments. As a result, wind and DSM technologies might be attractive as tribal business entities.

- **Solar Dish/Stirling Engine Technology.** Business risks associated with this technology probably fall somewhere between those of IGCC and wind. Dish/Stirling engines have moderate, but modular capital costs. The technology may be a source of expanded jobs for the tribes in the future. Given these consideration, solar dish/Stirling engines may be attractive to tribal businesses.

- **Solar Parabolic Trough Technology.** Solar parabolic troughs are usually very large projects: unlike solar dish/Stirling technology, parabolic troughs are not generally built in a modular fashion or to produce small amounts of energy. In addition, parabolic troughs have high capital costs. Given these factors, this technology may be more suited to non-tribal business structures.

- **NGCC.** At this time, no conclusions can be made with regard to a natural gas combined-cycle facility; the proposed location of the natural gas plant is on private land. Therefore, whether or not it would potentially be attractive as a tribal business is not relevant to this study.

- **Other Renewables.** No conclusions can be made at this time regarding biomass or geothermal technologies. Information on proposed project specifics, including proposed locations, job impacts, costs, and business risks, needed to make a solid conclusion regarding best business structure is still pending.

Finally, for the more modular technologies (wind, solar dish/Stirling, DSM/EE, and possibly, other renewables), it might make sense for the tribes to consider the option of having a diversity of business entities on their lands. For example, it is certainly feasible for one wind site to be owned and operated by a tribal government, while another is owned and operated by a non-tribal entity. Such a scenario would allow both types of owners to benefit from each other's experiences with the technology.

ES.3.3 Hypothetical Packages of Incentives Directed at Specific Technologies Owned by Specific Entities

While sections of this Study separately examine financial incentives and business structures, the Study also combines the two concepts and analyzes hypothetical packages of financial incentives that might apply to the capital costs of specific resources, owned by specific types of entities. The Study finds that, hypothetically, the packages of incentives, which include grants, sales tax deductions, tax incentives, depreciation incentives, and more, can be used to offset, on average, over 20% of capital costs for both supply- and demand-side options.

Loan guarantees and long-term contracts can further decrease project risks and costs. The Study concludes that there are a large variety of financial incentives that can potentially be used to offset the capital costs of new supply- and demand-side options both on and near tribal reservation land. Business owners, however, should not simply come to expect the realization of these incentives; many of them have strict requirements and many of them are competitive. Equally important, incentive availability changes over time; business owners should continually review available incentives to make sure they are aware of any changes or additions to offerings.

ES.3.4 Fuel Prices

Historic and future prices for electrical generation fuels in the Southwest were investigated. Costs for all fuels, except coal, have increased significantly over the last several years. Natural gas, once near half the price of oil, has moved dramatically upward, yet remains cheaper than oil. Coal prices, by comparison, have increased at less than the rate of inflation.

In terms of future fuel prices, natural gas prices (in real dollars) are likely to decline somewhat over the next several years (through 2010), but gradually rise thereafter, reaching current peaks only after 2025. The forecasted decline for the period 2006–2010 in natural gas prices is based on the rate of decline of prices for that period existing currently in the NYMEX Henry Hub futures market. On the other hand, coal prices, generally, are likely to increase gradually (in real dollars) from present time until 2025, but at a modest rate compared to that of natural gas[1]. Fuel price evaluations and data are provided in an appendix to this study.

ES.3.5 Emissions Valuation

The health and environmental effects of exposure to pollutants will impose costs on society. Through regulation, these social costs may be partially or wholly incorporated into the production costs of the polluter. An unregulated pollutant will impose a cost on society but not to the producer of the pollution. However, presently uncontrolled emissions have the potential to be regulated in the future and, therefore, represent risk. Regulation or legislation can shift an unpriced externality into a priced one, creating tangible costs and opportunities. A generator must consider, even anticipate, the possibility of new or changing regulations to be competitive over the long term.

[1] The projection provided does not apply to Black Mesa, specifically, but to open market coal and mines that can ship to open markets, in general. Coal for the Mohave plant may be purchased at a fixed price for some period. It would be not be surprising, however, if a new coal contract were a long-term contract and were for a fixed price over that term or subject to a fixed price escalation schedule over that term. Note too that market expectations are still likely to have some influence on the negotiation of such contractual arrangements involving coal from the Black Mesa mine, and such a contract might contain provisions for re-openers or other price increases over time.

With this in mind, the assessment of emissions valuation considered the economic impacts and projected market prices of seven pollutants typically emitted by fossil fuel-fired power plants. The four considered most relevant in terms of current or near-future regulations are SO_2, NO_X, mercury, and CO_2.

Air emissions are generally regulated under both federal and state law and, in some instances, tribal law. EPA oversees implementation of the Clean Air Act, although Nevada (like most states) has authority to administer the federal laws within their borders. A polluter may be subject to regulations at different levels, and federal and state laws can overlap with each other.

A summary of the historical, current, and forward allowance prices for each pollutant is provided below.

- **SO_2.** SO_2 allowances have been traded for more than a decade. Allowance prices have escalated since 2000 and most dramatically from 2003 to present. The rise in natural gas prices pushed up the demand for coal-fired generation, and SO_2 allowance prices shot up to $700/ton in 2004. Recent movement in the SO_2 allowance market has followed the upward trend of the past two years. The rise in allowance prices may reflect an increase in the spread between high- and low-sulfur coal prices.

  As for the future, SO_2 forwards markets indicate a price rise in real dollars over the next four years, and then a significant decrease starting in 2009. The near-term price rise reflects the fact that states and counties will put pressure on sources to keep SO_2 emissions down to preserve $PM_{2.5}$ NAAQS attainment status. (SO_2 is a precursor to particulate matter.) In addition, tighter regulations on regional haze will tend to drive up SO_2 prices. The decrease starting in 2009 may reflect traders' views on future carbon regulations and their effect on operation of coal plants.

- **NO_X.** Most forward price data on NO_X is based on eastern markets, including NO_X SIP call. As with current and historic prices, these data are not adjusted for economic conditions in the southwest. That being said, generally, east-coast forwards show a slight decline in prices over the next couple of years.

  Nevada does not currently participate in NO_X trading programs. However, Nevada is under mandate to develop a state implementation plan (SIP) for the federal Regional Haze rule. However, in the unlikely case the Nevada regional haze plan involves a cap and trade mechanism, NO_X prices will tend to increase. The co-benefits of emissions control technology installed to comply with the Clean Air Mercury Rule (CAMR) could depress NO_X prices on this local market but would increase total cost of compliance for NO_X, SO_2, and mercury combined.

  Like SO_2, ambient NO_X is a precursor to PM. Pressure to reduce emissions will be most acute in Las Vegas, Nevada, which is not in attainment for PM_{10}, and surrounding upwind areas. Other areas in Clark County may also have an incentive to keep SO_2 emissions down to preserve $PM_{2.5}$ NAAQS attainment status.

  In addition, NO_X allowance prices are expected to correlate negatively with the cost of complying with carbon regulations. Carbon regulations would decrease operation of coal plants, thereby increasing the amount of NO_X allowances on the market and decreasing their price.

- **Mercury.** Because mercury has not been regulated via a cap-and-trade mechanism in the past, data on historical and current prices are not available. However, projections for mercury allowance prices do exist. These show an almost 2-fold increase in prices per pound between 2010 and 2020.
- **CO_2.** The United States does not currently regulate carbon dioxide emissions. However, there are some indications that this situation is likely to change sometime in the next decade. As an indicator of what prices might look like here in the states if CO_2 becomes regulated, the European Union's market for carbon dioxide allowances has ranged between 6 and 13 euros/ton CO_2 over the last couple of years. Closer to home, in December 2004, the California Public Utility Commission ruled that utilities must consider CO_2 regulation risk in all future plant investment decisions. Specifically, the Commission ruled to require California utilities to factor in an expected regulation cost of $8 to $25/ton (escalated by 5% annually) of CO_2 to any new fossil-fuel resources.

Details of the emissions evaluation are provided in Appendix D.

ES.4 TRIBAL ISSUES

The scope of work at the outset of the study included investigating the following areas:

- Employment impacts for certain technology options
- Estimates of royalties, taxes, and other costs assumed to be paid to the tribes in the course of implementing certain technology options
- Costs of land, water, and Black Mesa Mine coal
- Requirements and likelihood of permitting for generation plants, new or renewed coal mining operations, and right-of-way (ROW) permitting for power lines, roads and pipelines
- Acceptability of development on Hopi and Navajo lands for certain technology options

Employment impacts and estimates of tax liabilities for the various technology options were developed and are presented in this study. Due to their complexity and confidential nature, it was agreed by the stakeholders that issues of royalties; land, water, and coal costs; permitting; and acceptability were not to be developed further. After a brief review of land tenure and of approval issues, the study presents estimates of the taxes that would be payable to the Navajo Nation by technology options on tribal land and estimates of the direct and indirect employment benefits expected from the technology options studied.

Numerous financial benefits may be available to the owners of energy projects on tribal land and to the tribes involved. These include tax benefits and other financial incentives outlined in Chapter 10 of this report, and other advantages and simplifications, such as (1) ability to negotiate development leases with third parties without obtaining U.S. government approval and (2) preferential standing for purchases from certain businesses located on Indian reservations or owned by Native Americans. In addition, there can be substantial benefits to tribes that host energy projects. These include tax revenue; royalties; land lease revenue; direct, indirect, and induced employment; and social benefits to communities. Depending on the nature of the project, there may be other negative or positive impacts on the community, the environment, and/or the local economy, but the balancing of all these impacts is important in choosing which energy projects best suit tribes.

The review of land tenure and of approval issues offered in this study highlights a number of complexities and challenges to development on tribal land. However, this study does not intend to convey the impression that energy projects cannot or should not be developed on tribal lands; many such developments have occurred, and no doubt, more will occur. Indeed, numerous advantages, financial and otherwise, may ease the way for such developments, depending on the project's and site's qualifications. It is important to fully appreciate, however, the requirements that potential owners, developers, tribes, and other stakeholders might face.

ES.4.1 Taxes

Tribes have the authority to levy taxes on business activity conducted on tribal land in a manner analogous to the authority of states. Among the most significant benefits for development of the various technology options is their potential as tax revenue sources. The technology options under consideration would be subject to such taxes if conducted on tribal land.

The Hopi Tribe does not at present have a tax code. The Navajo Nation has enacted three taxes that would be applicable to businesses conducted on its tribal land:

- Possessory Interest Tax (PIT),
- Business Activity Tax (BAT), and
- Navajo Sales Tax (NST).

Table ES-18 shows estimates of the taxes that would be due for options on tribal land. For the Navajo Sales Tax, there is a separate estimate of the amount due as a result of initial investment activity and an estimate (in 2006 dollars) of the ongoing annual taxes due. The PIT, BAT, and NST (annual) estimates reflect the first-year values of items that would be expected to be ongoing taxable items. It is important to keep in mind that these tax revenues exclude any royalties for coal or water and any land lease payments. Also, certain Navajo Nation taxes may apply to projects that are outside the Reservation, but on Navajo fee land. If any of the above payments are shared with or made to another entity, such as, for example, the Hopi Tribe, the deductions available under the BAT Code would be reduced accordingly. The one-time sales tax amount for wind does not include sales tax on the wind turbines themselves, estimated to be $7,166,250.

Table ES-20 — Summary of Navajo Nation Taxes

Option	PIT	BAT	NST (Annual)	Total (Annual)	NST (One-Time)
IGCC at Black Mesa	$29,028,026	$4,364,662	$94,800	$33,487,488	$719,250
Parabolic Trough	$28,581,512	$1,949,038	$18,480	$30,549,031	$2,179,528
Solar Stirling Engine	$19,569,122	$1,848,782	$24,780	$21,442,685	$6,302,190
Wind (150 MW at Gray Mountain)	$19,062,820	$907,863	$47,941	$20,018,624	$1,580,706
DSM/EE on Reservation	$188	$9,010	$916	$10,113	$0
DSM/EE from Reservation	$1,877	$108,196	$9,156	$119,229	$0

ES.4.2 Employment Impacts

Eight alternative energy options that could be developed on or near the Navajo or Hopi reservations were characterized for the purpose of estimating the potential economic impacts associated with each. All the scenarios were based on the schedules and costs set out elsewhere in this report. Three additional information sources were used to develop the detailed expenditure patterns. The Stirling Engine/Dish scenario was based on a combination of expenditure and employment data from Sargent & Lundy and SES, while the detailed breakdown of capital expenditures for wind generation was taken from a study of the inputs to wind generation manufacturing and construction. The breakdown of DSM outlays was based Synapse's experience. Only the effect of the actual outlays for capital goods, labor, and O&M expenses were modeled. Taxes and royalties were not modeled. All of the economic impacts developed represent total employment impacts, including direct, indirect, and induced jobs.

- **Simulation 1: Integrated Gasification Combined Cycle (IGCC).** Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are expected to total more than 330 jobs per year. Depending upon preferential hiring practices and job training provisions, at least 200 of these positions would be likely to be filled by Navajo or Hopi tribal members. Employment gains during the four-year plant construction period will total approximately 215 new jobs, with about two-thirds of these (approximately 140) expected to be among tribal members on the two reservations.

- **Simulation 1, Variant 1A: Integrated Gasification Combined Cycle (IGCC) with coal inputs from Navajo County.** Construction phase economic impacts for this variant are identical to those in Simulation 1. Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations, however, are expected to total 565 positions, as coal mining jobs in Navajo County to supply fuel for the plant are included. Assuming approximately 80% of the plant operation personnel and 90% of the incremental mining operation jobs are tribal members, about 280 of these positions are estimated to be Navajo nation members, with about 40 positions to be held by Hopi tribal members.

- **Simulation 2: Solar Parabolic Trough.** Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are estimated to total about 180 positions, with average annual employment during the two-year construction period exceeding 725 jobs. The magnitude of this project, its compressed construction schedule, and significant on-site assembly work is estimated to result in the largest single-year construction impacts of any of the contemplated projects. Tribal employment during the two-year construction phase is estimated to total about 530 annual jobs, with about 495 of these estimated to be filled by Navajo tribal members and about 40 by Hopi tribal members.

- **Simulation 3: Stirling Engine/Dish.** Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are estimated to exceed 240 jobs per year, with average annual construction employment during the three-year construction period of about 475 jobs in the same six counties. This project is estimated have significant on-site assembly work and related employment opportunities for tribal members, representing more than 210 jobs per year during the construction period. During operation, this facility is estimated to generate nearly 110 jobs for tribal members in the six counties encompassing the Navajo and Hopi reservations, most of which will be in Navajo County, where the plant would be located.

- **Simulation 4: Wind Turbines, Gray Mountain.** Although construction-related employment associated with this project is estimated to exceed 350 jobs per year during the two-year construction period, total permanent employment impacts following completion of this wind turbine facility in the six counties encompassing the Navajo and Hopi reservations are estimated to total about 21 jobs per year. About two-thirds of these permanent jobs are estimated to accrue to tribal members.

- **Simulation 5: Wind Turbines, Aubrey Cliffs.** Tribal employment growth during the one year construction phase of the Aubrey Cliff wind turbines is estimated to total about 65 jobs, with permanent tribal job growth of about 4 positions. Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are estimated to total 6 jobs.

- **Simulation 6: Wind Turbines, Clear Creek.** Total construction-related job growth in the six counties encompassing the Navajo and Hopi reservations during the one-year construction of the Clear Creek wind turbines is estimated to total approximately 115 jobs, with about 50 of these likely to be among tribal members. Permanent employment gains associated with this facility is estimated to total about 17 in the entire New Mexico/Arizona/Utah region, with about 6 of these in the six-county reservation area.

- **Simulation 7: Wind Turbines, Sunshine.** Employment impacts associated with the Sunshine wind turbine facility are estimated to be the lowest among the nine scenarios contemplated. With a total investment value of about $91 million, this facility is estimated to result in about 90 new jobs in the six counties encompassing the Navajo and Hopi reservations during the one-year construction phase. Total permanent employment impact in the Arizona/New Mexico/Utah region following completion of the plant is estimated to be about 12 new jobs, with approximately 4 of these in the six-county reservation area. With the facility located on Hopi fee land, it is anticipated that a higher percentage of both construction and operational positions would accrue to Hopi tribal members.

- **Simulation 8: Energy Efficiency Program.** Total employment impacts over the five-year life of the program in the six counties encompassing the Navajo and Hopi reservations are estimated to total about 205 net new annual jobs throughout Arizona and New Mexico, with the most significant job impacts in the balance of Arizona and New Mexico regions. Because the program distribution center and installation crews are assumed for the sake of this simulation to be based in Apache County, on the Arizona/New Mexico border, most of the tribal job growth is estimated to be among Navajo Nation members. About 40 full-time jobs per year during the five-year life of the program are estimated to result from this investment among Navajo tribal members.

ES.5 LOAD AND GENERATION PROFILES

One of the study's goals was to evaluate the correlation between various potential Mohave alternatives and complements and SCE load and costs. For the demand profiles, hourly load and price data for SCE were collected for the year 2002 and for the more recent 12 months of October 2004 through September 2005. The data indicate that nighttime and evening loads are fairly consistent throughout the year. The big difference occurs in afternoon loads, which are much higher during July, August, and September. The data also indicate that a portion of the peak daily loads are related to air conditioning use. Based on this information, resources that preferentially provide more energy during afternoon and evening hours and during summer days would correlate best with SCE loads and costs.

As it is a baseload generation facility, the daily generation profile for the existing Mohave Station is very flat. Thus, its most direct replacement would be another baseload generation resource, such as an IGCC or NGCC plant. Solar resources, on the other hand, provide a good match specifically with the daytime peak. However, solar output peaks earlier than the SCE load does and falls off rapidly in the early evening. Of some of the designs being considered, a dish/Stirling engine would best be able to provide power throughout the entire solar day. Systems with parabolic troughs would have lesser, but still good technical performance. Such a system with storage could shift the generation to later in the day and provide a better match with the SCE load.

As with solar, wind energy is high in summer, as are SCE loads. The daily wind pattern shows greater availability in the late afternoon and evening hours, which is a good complement to the solar option.

As for the resource output of the DSM alternative or complement to Mohave, it cannot be described in the same terms as the resource output of the supply options. The hourly profile of energy and/or capacity savings resulting from a portfolio of installed DSM measures will depend on the set of measures installed, which are yet to be determined with any specificity. As the DSM options being studied are in the Southwest, the available end uses would be, to some extent, similar to SCE's, and available savings would have a profile quite similar to SCE's, depending on the programs chosen. However, the commercial terms for such an exchange of DSM for power could shape the power provided in various ways to suit SCE loads.

ES.6 TRANSMISSION ISSUES

This study sought to determine transmission availability from Arizona and Nevada to the physical interchange points at the California independent system operator (ISO) border. It used both flow-based and contract-path based methods of analysis: power flow studies and assessments of ultimate "into-CA" transmission depend on flow-based analyses, while the OASIS-based assessment of existing transmission availability is based in large part on a contract-path based regime. From the California ISO border, the major transit paths into SCE's service territory include the Palo Verde-to-Southern California route and the set of 500-kV and 230-kV transmission lines emanating from the southern Nevada area at the McCullough, Marketplace, Eldorado, Mohave, and Mead substations. No advance transmission reservations are needed into SCE's territory once the power is transmitted to the California ISO border; thus, transmission availability to that border was scrutinized.

WesTTrans's Open Access Same-Time Information System (OASIS) data were reviewed, examining source points from the Study Area and sink points at the California ISO physical interchange tie points. Source points closest to the Mohave options, located primarily on the Arizona Public Service transmission system in northeastern and central northern Arizona were scrutinized.

The analysis demonstrates that shorter-term firm or non-firm service is available from most source points examined, but not necessarily during all periods.[2] Thus, technology options located in the Study Area connecting to the grid in the near-term might need to rely on shorter term transmission availability. It is

[2] Shorter-term transmission service generally implies hourly and/or daily capability, as opposed to monthly or yearly capability. For example, daily and hourly service for up to 329 MW was available on the Moenkopi-to-Palo Verde 500-kV path for a few days and hours in September 2005.

important to keep in mind, however, that the value of OASIS information is limited because of its time frame; it is not predictive beyond the near-term time periods, at most a few years out.

The transmission load flow evaluation analyzed the feasibility of adding generation at a number of sites in terms of upgrades required for transmission service. The interconnection cost is based on transmission upgrades required to relieve any overloaded facility that would prohibit the evacuation of power from the generation area. Upgrades required for interconnection allow the generator to inject power into the transmission system. However, this does not necessarily grant transmission service that would be need to allow the generator to transfer power to the California border.

Load flow analyses of the impact of injecting power into the transmission network in 10 different generation scenarios were performed. The 10 scenarios include 5 single-plant cases and 5 multiple-plant cases. Locations of generation sites studied are provided in the map in Appendix A. Each of the 10 cases was then run two ways—first with existing transmission only and then again with two transmission projects that are scheduled for completion by 2010 for comparison (denoted “Path 49 Upgrades”). The first of the “Path 49 Upgrades” projects are the “East of Colorado River Path 49 Short Term Upgrades,” which includes installation of capacitors, phase-angle regulating transformers, and static VAR compensators on lines and substations in Arizona, California, and Nevada. The second project is the installation of a second 500-kV transmission line between the Devers substation in California and the Harquahala substation in Arizona, just southwest of the Palo Verde Power Plant.

The results of the load flow studies indicate that longer-term[3] firm transmission service is available in some cases without additional transmission system upgrades but is not available in others without system upgrades. Results of the load flow analyses are provided in the table below.

Table ES-21 — Interconnection Cost Estimates

Case Number	Case Description	Estimated Cost *without* Path 49 Upgrades ($ in Millions)	Estimated Cost *with* Path 49 Upgrades ($ in Millions)
1	Black Mesa IGCC (500 MW)	$173.0	$48.0
2	Gray Mountain Wind (450 MW)	$0.0	$0.0

[3] Longer-term transmission service generally implies service of at least a years’ duration. For example, Tucson Electric Power offered 125 MW of yearly transmission service for 2006, 2007, and 2008 on its rights to the Moenkopi–Palo Verde 500-kV path. Longer-term service can also imply transmission service available for many years into the future. Data on availability of such long-term transmission are not readily provided through the OASIS system. However, some of the utility documents available through the OASIS system indicated ongoing availability of longer-term transmission over specific, limited segments of the Arizona Public Service system.

Case Number	Case Description	Estimated Cost *without* Path 49 Upgrades ($ in Millions)	Estimated Cost *with* Path 49 Upgrades ($ in Millions)
3	Solar Site 2 (425 MW)	$0.0	$0.0
4	Aubrey Cliffs (100 MW)	$60.0	$130.0
5	Clear Creek & Sunshine (135 MW)	$0.0	$0.0
6	Black Mesa IGCC & Solar Site 1 (925 MW)	$216.9	$158.7
7	Black Mesa IGCC & Gray Mountain Wind & Aubrey Cliffs (1050 MW)	$170.0	$195.0
8	Solar Site 2 & Gray Mountain Wind & Aubrey Cliffs (975 MW)	$272.5	$117.4
9	Solar Sites 1 & 2 (850 MW)	$214.5	$46.6
10	Gray Mountain Wind & Aubrey Cliffs & Clear Creek & Sunshine (685 MW)	$162.5	$70.0

The installation of the "Path 49 Upgrades" does not completely eliminate the need for transmission system upgrades in those cases where they were necessary in the case run without the "Path 49 Upgrades." However, in most cases, the associated scope and cost of upgrades is significantly reduced. The exceptions are Cases 4 and 7 above. These results occurred because of a particular situation:

- **Overloaded Lines in Base Case.** In the Base Case, that is, without any upgrades and without any new generation, certain lines had already been overloaded.
- **Overloads Remain without "Path 49 Upgrades," but with New Generation.** Since the overloaded lines already existed, however, the new generation of Cases 4 and 7 was not reason for the overload, and no cost was assigned.
- **Relief of Overload by "Path 49 Upgrades."** With the "Path 49 Upgrades" installed but without the new generation of Cases 4 or 7 added, those certain lines that had been overloaded were no longer overloaded.
- **Overload Caused by New Generation with "Path 49 Upgrades" Installed.** Now, since the overloads of the base case had been mitigated by the "Path 49 Upgrades," renewed overloads in certain lines required further upgrades and costs were assigned.

In addition it is important to consider that other new transmission line proposals or works in progress add significant capacity to into-California (and likely intra-Arizona) transaction paths. To the extent these lines are built, it is possible that Mohave technology options could secure firmer access to import into SCE territory.

The following conclusions can be drawn from the transmission analyses:

- **Long-Term Firm Service.** Existing conditions appear to limit the availability of long-term (i.e., one or more years) firm service from Arizona supply sources, without new transmission upgrades. Shorter-term service of more limited duration is available for some source-sink path combinations.

- **Short-Term Non-Firm Service.** Based on OASIS data, shorter-term firm or non-firm service is available from most source points examined, but not necessarily during all periods. Thus, technology options located in the Study Area connecting up to the grid in the near-term might need to rely on shorter-term transmission availability. Note that SCE's ownership of rights for transmission service from their Four Corners generation share ownership was not considered as a possible source of transmission access for any of the Mohave technology options.

- **Tradeoffs between Increased Capacity for New Supply and Use of Existing Capabilities**. The transmission interconnection requirements identified for most of the supply-side technology options are based on provision of effectively firm transmission service during peak periods. Use of existing grid capacity could be considered if curtailing output for some periods proved economically viable, and/or if short-term transmission use in additional to what is transparently available through OASIS could be secured through negotiations with existing users who have rights to use the grid during peak periods.

- **OASIS Information.** The value of OASIS information is limited because of its time frame; it is not predictive beyond the near-term time periods, at most a few years out.

- **Proposed New Transmission Upgrades.** New transmission line proposals or works in progress add significant capacity to into-California (and likely intra-Arizona) transaction paths. To the extent these lines are built, it is possible that most supply technology options could secure access to import into SCE territory.

- **Alternative Locations of Options.** Any technology options that source power from the existing Mohave site, or from the Palo Verde hub (e.g., the DSM alternative) will not face the transmission limitations identified in our review, which are generally in the northeastern and north central Arizona regions. Transmitting alternative power from the Palo Verde hub could lead to increased congestion charges into California, but such congestion does not preclude the use of Palo Verde hub resources, it just changes the total costs to import into California.

- **Effect of New Institutional Constructs.** This review did not assess the transmission availability under any new institutional constructs. If a West Connect Regional Transmission Organization (RTO) or similar regional transmission entity established coordinated transmission operations in the desert southwest area, the paradigm for transmission access and Available Transmission Capability (ATC) computation could change. One possible outcome of such arrangements is a lesser dependence on the need for source-to-sink physical transmission reservations in order to use the desert southwest grid to secure power flows into California from source points in the Study Area.

- **Wheeling Capability under Current Transmission Capacity**. The DSM and Mohave combined-cycle technology options could each move Mohave-equivalent power into the SCE territory based on existing conditions. The California border location for these options allows such transfer to occur during most if not all hours, although some congestion cost allocation from the California ISO would likely apply in some hours. The remaining Arizona area supply options would all be able to move power into the SCE territory for some hours of the year, based on securing available shorter-term firm or non-firm transmission, but it is unlikely they would be able to secure transmission for all hours, especially during peak periods, based on an examination of the OASIS data and results of the load flow studies.

- **Wheeling Capability with Reasonably Certain New Transmission Upgrades**. Most of the proposed new transmission projects that have a high likelihood of being built will result in increased transfer capability from western Arizona or southern Nevada into California, but they will not substantially affect the transfer capability from northeastern Arizona to western Arizona. There are numerous Arizona transmission upgrades proposed for the heavier load centers, such as Phoenix; these upgrades will not necessarily increase transfer capability over the major paths out of northeastern and north-central Arizona. Thus, even with implementation of certain new projects, it is not assured that the increased capacity will allow for Study Area technology options to secure firm, longer-term transmission service into the California border area. However, if intra-Arizona upgrades on the 500-kV system in the north and the northeast are realistically considered, then the increase in transfer capability from the Study Area to the California border would likely be on the order of the output associated with SCE's share of Mohave.
- **Wheeling Capability with Uncertain New Transmission Upgrades.** It is difficult to state with any certainty what the wheeling capability with new transmission upgrades might look like without conducting additional load flow studies and accounting for the location of new supply sources that might be considered if new transmission is built. This is beyond the scope of this study. For example, even if the Navajo Transmission Project is built, the potential for new generation in the northeastern Arizona region must be considered when assessing whether such new capacity might be available for the Mohave technology options. However, if any of the major northeastern/north central Arizona to southwestern/northwestern Arizona paths are upgraded, the potential for transmission capacity increases on the order of SCE's share of Mohave output is likely.

ES.7 SUMMARY

This study has estimated capital and operating costs, resource usage, and economic impacts of several different technology options that might be used as replacements for or compliments to the existing Mohave Generating Station.

The parameters of the options considered can be summarized as follows:

Table ES-22 — Technology Option Comparison

		IGCC (2)(3)	Solar Dish	Solar Trough	Wind (4)	DSM(5)	NGCC (2)(3)
Capital Cost (1)	2006 $/kW	2,004	1,500	3,560	1,702	N/A	555
Fixed Operating Costs	2006 $/kW-yr	49.59	0.00	33.00	45.96	0	5.47
Variable Operating Costs	2006 $/MWh	12.68	11.00	30.00	0.21	0	62.85
Total Operating Costs (6)	2006 $/MWh	20.54	11.00	38.76	14.41	N/A	63.72
Land Use/MW	acre/MW	0.541	5.000	8.700	75.21	0.000	0.042
Water Use/GWh	acre-ft/GWh	0.395	0.008	0.019	0.000	0.000	0.022
Operations Staffing	Employees/MW	0.26	0.28	0.29	0.04	N/A	0.06
Capacity Factor Assumed for Operating Cost Calc.	%	72.0	30.0	43.0	36.9	N/A	72.0
Approximate Construction Period	months	48	36	45	9-12	N/A	24

Notes:

1. Capital costs shown do not include the costs of direct transmission access or transmission system upgrade costs.
2. IGCC and NGCC plants are assumed to use dry cooling. IGCC plant is assumed to be at the Black Mesa site. No carbon sequestration-related costs are included in values used for comparison above.
3. Capacity factor assumptions for IGCC and NGCC are assumed to be comparable to the existing Mohave plant's average capacity factor. Such an assumption may not be true, especially for the natural gas-fired option, and depends on the dispatch and outage schedules of the respective options.
4. Wind values are weighted averages for the four sites identified.
5. The DSM technology option differs considerably from the supply options and thus cannot be characterized in the same way. See the text below.
6. Total operating costs =variable operating costs + (fixed operating costs/kW-yr)*(1yr/8760hrs)*(1/assumed capacity factor)*(1000kW/MW)

No definitive choices regarding technology options can be made strictly from the data provided above. This choice is properly made within the scope of an integrated resource plan process. However, certain conclusions can be drawn simply from looking at the capital and operating costs:

- It can be seen that the solar dish and wind options have relatively low capital and operating costs, potentially making them an economically attractive alternative.
- The DSM option includes installed demand-side technologies and a coupled power purchase contract. It does not have the same cost structure as the supply options. The alternative's cost structure (as analyzed in this study) includes not just the installed DSM costs, but also effective premiums that may be required to address lost revenue or related institutional risks. In its simplest form, the DSM option looks like an all-in power purchase contract, whose price is subject to negotiation, and the study posits a baseload resource profile for this contract (although flowing DSM peaking benefits directly to SCE is possible). What is known is that the underlying DSM resource costs are relatively low ($40/MWh based on total resource costs);

that it provides peaking benefits in the partnering utility service territory; that the resource may be shaped to provide SCE with a resource shape that is baseloaded, peaking, or in between; and that the ultimate negotiated price will rest heavily on these factors. There are also institutional issues that will affect the partnering utility's perception of risk and thus of the minimum negotiated price at which it would be willing to transact. However, the study shows that this should continue to be considered a viable option for replacing and/or complementing Mohave.

- The NGCC option has a relatively low capital cost; however, the variable cost associated with fuel makes its operating costs very high. As such, it is unlikely to be dispatched at the level assumed here.
- The IGCC option has a higher capital cost than most options, but its operating costs are slightly lower than many options.
- Operating labor requirements for the IGCC, solar dish, and solar trough options, on a per-MW basis, are similar. The wind and NGCC options have much lower operating labor requirements. The DSM option is not directly comparable in terms of labor requirements. Each year's increment of DSM resource acquisition is relatively labor intensive, but once an increment of DSM resource has been acquired, there is little, if any, ongoing labor requirement.

From the above, one may further conclude that, if SCE's need for generation resources arises from a need for peaking power, then the solar and wind options may be more attractive than the other options. However, it must be pointed out that, since these options cannot be dispatched, their generation would not necessarily have perfect correlation with SCE's peak load or its load demand profile. Therefore, gaps might have to be filled by other generation resources. It may be possible to configure DSM resources with a delivered resource shape to suit SCE's needs by varying the commercial terms, depending on the commercial and regulatory terms developed.

On the other hand, if the need for generation resources arises from an overall increase in load demand, then resources that can provide baseload would be more attractive. The solar trough resource with thermal storage can store energy for use during off-peak hours; however, its capital costs are extremely high. These costs, in fact, tend to eliminate it as an option. The NGCC option, on the other hand, has the potential to operate as a baseload resource. However, since the largest part of its variable operating costs depends on the price of natural gas, it is unlikely that it would be dispatched as a baseload resource if natural gas prices continue to rise. The IGCC or DSM options, therefore, remain the most attractive option for a baseload resource.

In general, however, the capital and operating costs should be analyzed over a particular project life span and a levelized cost of generation developed. For example, while wind and certain solar options may have low capital and operating costs, their expected energy output is low relative to the size of the units contemplated. This will tend to drive up the levelized cost of energy. Contrastingly, the DSM technologies have low total resource costs, helping to make the levelized cost of the resource, including the purchase power component, particularly attractive.

The calculation of the levelized cost of energy requires inputs that include the values shown above along with economic parameters, such as discount and escalation rates, and energy output during the project life span. The energy output requires detailed assumptions regarding availability and fuel cost. The analysis of these costs over the life time of the project is beyond the scope of this study and is rightfully to be performed as part of the integrated resource planning process. Furthermore, if the options are developed by the tribes or a private developer, then the feasibility of a technology option also depends on the terms of the power purchase agreement. While, from a levelized cost of energy or revenue requirements viewpoint, a particular technology option may be viable, it must also be viable financially to the project developer on a discounted cash flow basis. Neither the levelized cost of energy calculation nor the discounted cash flow analysis is within the scope of this study.

In addition, capital and operating costs should not be the only variables to consider when comparing options. Use of land and water and compliance with current and future environmental regulations are equally important, as discussed below.

Operating labor requirements for the IGCC, solar dish, and solar trough options, on a per-MW basis, are similar. The wind and NGCC options have much lower operating labor requirements. The DSM option is not directly comparable in terms of labor requirements. Each year's increment of DSM resource acquisition is relatively labor intensive, but once an increment of DSM resource has been acquired, there is little if any ongoing labor requirement.

Of course, capital and operating costs should not be the only variables to consider when comparing options. Use of land and water and compliance with current and future environmental regulations are equally important, as discussed below.

Use of land for the NGCC option is relatively low. The IGCC option uses 10 times the land on a per-MW basis. The solar options use approximately 100 times the land of the NGCC option on a per-MW basis. The wind option land use is 1,500 times that of the NGCC option, again on a per-MW basis. Finally, the DSM option requires minimal land only for office space, some warehousing, and miscellaneous other small land usages.

Water use for the solar dish option is lower than all options except DSM and wind, which have negligible water use. Solar trough water use is slightly greater than twice the use of the solar dish option on a per-MWh basis. NGCC water use is slightly less than three times the solar dish option's water use on a per MWh basis. The IGCC option uses the greatest amount of water on a per-MWh basis, at 50 times the usage of the solar dish option.

The foregoing summary has ignored the costs associated with environmental compliance, including the costs of CO_2 removal and sequestration. Such costs do not apply to wind, solar, and DSM options. They have, however, an extremely large negative impact upon the IGCC and NGCC options. Capital cost increments for the various levels of CO_2 removal in $/kW are given in the table below:

Table ES-23 — Capital Cost Increments for CO_2 Removal and Transport

	IGCC CO_2 Removal without Shift Conversion	IGCC 90% CO_2 Removal	NGCC 90% CO_2 Removal
Direct Plant Increase in Capital Cost, $/kW	275	632	375
Pipeline and Compression Cost, $/kW	92	179	877

Pipeline and compression costs vary due to the location of CO_2 storage. The values shown for IGCC, like the previous values, are for the Black Mesa site, for which a geological formation was found in relatively close proximity. For the NGCC option, these costs are associated with a pipeline from the existing Mohave site to Bakersfield, California, utilizing the Interstate 40 corridor, for use of the CO_2 in enhanced oil recovery operations. Values for pipeline and compression costs would be very roughly similar for IGCC located at the same site. It may be concluded from the values shown that IGCC with CO_2 removal that does not employ any shift conversion, removing between approximately 18% and 30% of the carbon present, depending on gasifier technology and coal constituents, may be feasible, but the costs for large-scale CO_2 removal, at the level of 90% removal of carbon present, are extremely high and possibly prohibitive with current technologies.

The outcome of a process of selection between the various options considered here cannot be made without a full integrated resource planning process. If land, water, and CO_2 sequestration issues were ignored, it may be possible to conclude that the solar dish, wind, or DSM options may be more attractive in the case that energy requirements are of a peaking nature, while if such requirements are of an across-the-board baseload nature, then the IGCC or the DSM option may be more attractive. However, this simple conclusion fails to take into account the other resources that are displaced by any of these options and the associated costs and benefits of such displacement. It also ignores the difference in volume of energy generation between the two energy requirements. A baseload resource will ultimately have more megawatt-hours over which to spread its capital and fixed costs in the calculation of a levelized cost of energy.

Furthermore, land, water, and CO_2 sequestration issues cannot be completely ignored. The quantity of land required for the solar and wind options must be considered for each site identified. CO_2 sequestration issues do not affect solar dish, wind, and DSM options, since no CO_2 is emitted, but may be significant for the IGCC and NGCC options. Water requirements for the IGCC, NGCC, and, to a lesser extent, the solar options must be considered. Certain options would eliminate the use of water used to create the coal slurry that is the medium by which fuel is shipped to the existing site. This may accrue certain benefits to the owners of the water rights through alternative uses for that water.

In summary, this study has compiled data necessary for input into an integrated resource plan, its primary objective. It has also made certain qualitative comparisons and conclusions. Among these, it has been concluded that

- Other renewable resources, specifically biomass and geothermal energy, are not present in the area to a sufficient extent to enable construction of plant of a size that is meaningful in comparison to the size of SCE's share of the existing Mohave plant.
- Solar trough technology is, in all likelihood, too costly for implementation, especially if thermal storage is considered.
- Some of the options are particularly suitable for tribal ownership, although project specifics will determine the ideal ownership structure.
- Total environmental compliance costs for fossil fuel plants are likely to rise whether or not the US implements a carbon policy.

The other technology options all have their associated costs and benefits. It is not within the scope of this effort to weigh these costs and benefits in a quantitative way to develop priorities or groupings of preferred generation resources. Rather, considerations that must be addressed in an integrated resource plan study have been identified.

Last page of Executive Summary.

1. INTRODUCTION

1.1 EXISTING PLANT

The Mohave Generating Station is a two-unit 1,580-megawatt (MW) coal-fired power plant located in Laughlin, Nevada, built between 1967 and 1971. The station covers approximately 2,490 acres. The Mohave Generating Station is operated by Southern California Edison (SCE), the majority owner (56%) of the plant. The Los Angeles Department of Water and Power (10%), Nevada Power Company (14%), and Salt River Project (20%) also own interests in the plant.

1.2 STUDY PLAN

Southern California Edison was ordered to perform a study of alternatives for replacement or complement of its share of the Mohave Generating Station by the California Public Utilities Commission (CPUC) under Decision 04-12-016, issued on December 4, 2004. The relevant part of the decision stated:

> Edison is hereby directed to undertake a feasibility study of the options for replacing its share of Mohave's output if Mohave closes, or to be used in conjunction with Mohave if it returns to service, from sources that will provide the fullest possible benefit to the Hopi and Navajo while protecting the interests of Edison's ratepayers. Edison is to involve any interested party in this proceeding work together with those parties to design this study and to jointly determine the independent consultants, contractors and supervisors on the study. One aspect of this study should consider the IGCC options at the Black Mesa Mine, including water use issues and an assessment of the feasibility and cost associated with the sequestration of carbon emitted from the plant. Cost assessments should include an analysis of federal funds available for IGCC development. Edison should also analyze the feasibility of renewable energy projects on reservation land, including but not limited to the proposed solar thermal facilities identified by WEC.
>
> Both the IGCC and renewable energy projects should include consideration of any enhancements to the transmission system that may be necessary to bring power into California. The final plan should be sufficiently detailed, including cost components, proposed counterparties and generation on-line dates, to allow this Commission to affirm a specific resource plan during Edison's next long-term planning process. Ownership arrangements involving the Hopi and Navajo should be given consideration in the feasibility study.

Pursuant to this scope, concentrating solar power (CSP) technology, wind technology, integrated gasification combined-cycle (IGCC), natural gas combined-cycle (NGCC), other renewables, and energy efficiency were investigated as potential alternatives to replace or complement the electrical generation of the Mohave Generating Station.

Stakeholders were involved throughout the study process. Their comments on draft versions of this report and S&L's responses are provided in Appendix E.

1.3 METHODOLOGY

The methodology for evaluating the technological, financial, economic, and social issues associated with this study is discussed below.

1.3.1 Integrated Gasification Combined Cycle

To develop the overall capital and operating costs associated with an IGCC power plant, Sargent & Lundy (S&L) planned to use data from technology developers and compare this information with published studies and other internal sources. Although four suppliers/technology developers provided a willingness to provide data for this study, no data has been received at the time of this writing. As a result of the lack of vendor-provided data, S&L determined that the best approach for developing the costs and performance for a gasification facility designed for Black Mesa coal would be to use the Department of Energy's (DOE) Integrated Environmental Control Model (IECM) and adjust the outputs as necessary to compensate for the specific application addressed in this study.

This model was selected because it can be used to directly compare the effects on the facility's design when considering either with or without carbon sequestration.

Adjustments S&L performed on the results included the following:

- Assumed that the cost and relative performance of the gasification system when using Black Mesa coal would be the same as for Illinois #6 coal.
- Assumed that the cost and relative performance of the sulfur removal system when using Black Mesa coal would be the same as for Wyoming Powder River Basin (PRB) coal.
- Adjusted the combustion turbine output for site conditions.
- Adjusted the capital costs for dry cooling where necessary.
- Added emission control costs for NO_X (selective catalytic reduction [SCR]) and mercury removal.
- Adjusted coal handling cost estimates for slurry delivery by crediting the cost for coal rail unloading, slurry preparation, and so forth.
- Compared costs of power delivery systems to S&L data base costs as appropriate.

The capital costs were obtained from the IECM model. S&L also added owner's costs and EPC contractor profit to the values computed that are not included in the IECM estimate. The resulting capital cost values are in the same range as values computed for other projects.

For this study, S&L used the consumable costs calculated for each subsystem the IECM model. Water costs were calculated separately. Ash (slag) and sulfur disposal and/or byproduct credits were developed separately. Fixed operating labor was estimated separately using the IECM shift labor requirements as a guideline. Fixed and variable labor was based on model inputs subtracting the in-plant estimate of the labor force from the maintenance labor requirements.

1.3.2 Solar Technology

In addition to parabolic trough and power tower technologies, solar dish engines and concentrating photovoltaics were evaluated. The existing technical data available on these technologies were collected, organized, and reviewed. Based on the review, potential power plant configurations were developed that are considered to be feasible based on the maturity of the technology, technical risks and expected reliability, capital costs, O&M costs, levelized energy costs, and dispatch constraints.

Specific solar technology information was integrated into an overall evaluation of the technical parameters that need to be considered for an electric power plant project. These additional parameters include, but are not limited to, balance-of-plant design considerations; site arrangement considerations for construction, operations, and major maintenance activities; geotechnical considerations; environmental and permitting considerations; power transmission considerations; and cost considerations for construction and O&M.

The technology assessment identified possible combinations of solar power technologies and associated capital and O&M costs that are considered to be the most promising for future development. A key consideration was to identify technologies that are reasonable candidates for near-term large-scale deployment as differentiated from technologies that still require significant development.

1.3.3 Wind Technology

Four candidate sites were identified based on the wind characteristics of each potential site as shown on NREL wind maps. Site walkdowns were performed during which available infrastructure and conflicts (such as public roads, barns, telephone transmission wires, available setback for falldown radius of turbines, and topography to capture the highest elevations) were reviewed. Land requirements were estimated. Township, county, or tribal zoning processes and local codes and regulations for each site were evaluated. Local, state, and federal permit requirements were evaluated to determine fatal flaws at any of the sites. Transmission access issues were reviewed. Capital and O&M costs based on a database of other projects were estimated.

An evaluation was made of the wind farm size for each potential site based on available land, capital costs, O&M costs, and estimated performance. Performance, including output and capacity factor, based on location and wind characteristics were estimated.

1.3.4 Natural Gas Combined Cycle

Capital costs were obtained from a database of recent projects. Fixed O&M costs were estimated including costs for direct and indirect labor for operations and maintenance staff that are permanently employed at the plant site, as well as home office support costs allocable to the plant. In addition, the fixed costs include O&M contract services and materials and power purchased for in-house plant needs during plant outages. Variable O&M costs include chemicals and consumables, catalyst replacement and major maintenance of the combustion turbines, steam turbines, HRSG, and balance-of-plant. The estimate was derived on the basis of an 80% capacity factor and approximately 50 starts per year. On the basis of this duty cycle, the combustion turbines will require a combustion inspection every year, a hot gas path inspection every three years, and a major inspection every six years. Performance and emissions data were obtained from the Electric Power Research Institute's (EPRI's) State of the Art Power Plant (SOAPP) program.

1.3.5 Energy Efficiency/Demand-Side Management

The states and utilities in the region that would be appropriate sellers of energy efficiency resources were identified, and an estimate of the technical and economic potential for energy efficiency resources from the candidate states was developed. The conceptual mechanism for purchasing energy efficiency resources from other states and other utilities was studied. In addition, an estimate of the amount of economic potential for energy efficiency in the neighboring states that could be sold to SCE through power purchase arrangements was developed, including consideration of the extent to which energy efficiency in the neighboring states is being developed for internal purposes. The economics of the mechanism for purchasing energy efficiency resources from other states and other utilities were also assessed. The contractual arrangements necessary for purchasing energy efficiency resources from other states and other utilities were studied with likely durations and terms and conditions assessed. The institutional challenges for purchasing energy efficiency resources from other states and other utilities were also assessed. Finally, the above assessments were used to develop a recommendation for the extent to which this sort of energy efficiency purchase can represent an alternative (or partial alternative) to Mohave.

1.3.6 Other Renewable Technology

The feasibility of other renewable energy sources, including biomass and geothermal energy, was evaluated with the following purposes:

- To determine the feasibility of the technology for the various Mohave scenarios
- To determine the megawatt scale at which the technology would be feasible
- To perform an initial economic screening to assess whether the technology can compete with the other five technologies studied as a viable option

Biomass and geothermal energy sources were evaluated on a general basis for the following:

- Commercial availability
- Expected performance in the geographical area
- Land, water, and other resource requirements
- Capital and O&M cost estimates based on published data

1.3.7 CO_2 Sequestration

The evaluation of geologic CO_2 sequestration involved the following tasks:

- **Overview.** Four types of geologic sequestration were examined: enhanced oil recovery, enhanced gas recovery, sequestration in unminable coal seams, and sequestration in deep saline aquifers.
- **Evaluation of Feasibility.** The various possible liabilities associated with geologic sequestration, including operational liability, climate liability, and in situ liability were analyzed. Furthermore, a study was performed regarding suitable options for sequestration in the vicinities of the Mohave and Black Mesa sites by URS, Inc., provided as Appendix C to this report.
- **Economics.** The market for CO_2 was evaluated for its size and prospective pricing.
- **Capital Costs.** The capital costs of compression and pipeline equipment for transport of CO_2 were estimated. The Mohave-to-Bakersfield compression and pipeline cost was estimated, as well as the cost for a representative pipeline to the Cortez, Colorado, area.

1.3.8 Tribal Issues

Acceptance by the tribes was evaluated, encompassing the following items:

- Identification of relevant tribal lands
- Identification of the relevant policies, issues, trends and disputes
- Development of relevant factors (pros and cons) for each tribe
- Analysis of each technology on relevant factors
- Identification of approaches that could make each technology more attractive to the tribes

Progress in this area has proceeded in general terms only. Tribal governance policies and opinions are closely held.

1.3.9 Financial and Economic Issues

Financial and economic issues in five areas were reviewed:

- **Financial Incentives.** The various state and federal incentives that are possibly available for generation projects with tribal involvement were compiled.
- **Business Classifications.** Businesses that are owned by Indian tribes and by tribal members can operate under a variety of legal structures. The costs and benefits of the various classification were enumerated with respect to—
  - Federal and state tax status
  - Ability to attract investment monies
  - Business strategy and day-to-day operational authority
  - Liabilities
  - Law and government
- **Job Impacts.** The construction, operation, and other economic impacts of the various generation projects were evaluated using macroeconomic models. Construction of the macroeconomic models is underway, but has not yet been completed.
- **Fuel Prices.** Fuel prices were developed and are included in Appendix F.
- **Emissions Costs.** A summary of emissions costs were developed and are included in Appendix D.

1.3.10 Generation and Load Profiles

The evaluation of the correspondence between the load profile of SCE and the various technological alternatives involved collection of information about SCE load profiles by location, time, weather, and customer class. Data for each resource type were then analyzed and converted into comparable formats.

1.3.11 Transmission Issues

The methodology used focused on three specific tasks:

- **Existing Available Transmission Capability (ATC) Evaluation.** OASIS data were used to determine existing available transmission capability.
- **Utility Study Review.** Existing California ISO and desert southwest utility studies were reviewed. An overview of future changes to the transmission system, focusing on the impact that major transmission upgrade proposals would have on changing (increasing) the level of transmission capacity available for transactions between the desert southwest and California, was developed.
- **Load Flow Studies.** Load flow studies were carried out using various cases involving the technological alternatives in combinations that were roughly equivalent to the capacity to be replaced at the existing Mohave plant.

Last page of Section 1.

2. INTEGRATED GASIFICATION COMBINED CYCLE TECHNOLOGY

Gasification is a process that converts a variety of carbon-containing feed stocks like coal, petroleum coke, lignite, oil distillates, and residues into synthesis gas (syngas) consisting primarily of carbon monoxide (CO), hydrogen (H_2), and carbon dioxide (CO_2). The technology of gasification dates back to the 18th century with the production of water-gas for lighting and cooking before the advent of electricity use. This technology was largely phased out with the expansion of electricity and natural gas usage in the mid-20th century. Recent commercial use has expanded over the past 50 years and is an important process in the chemical and refining industries. Interest in gasification for the power generation began in the 1970s and was demonstrated as technically viable with the construction and operation of the Cool Water facility in California that was funded by Southern California Edison, EPRI, and DOE. This facility used the Texaco gasifier for producing the syngas used to fuel GE combustion turbines. Starting in the 1980s Shell, Texaco (GE Energy), Dow (ConocoPhillips) and Lurgi scaled up the size of gasifiers to produce the quantities of gas needed for large gas turbines. The use of gasification for both power and as a chemical feedstock increased as facilities around the world adopted gasification as an alternative to use of premium fuels, see Figure 2-1. During the 1990s, world gasification capacity grew by almost 50%, largely for the production of chemicals, as shown on Figure 2-2.

Figure 2-1 — Growth of Syngas Production Worldwide

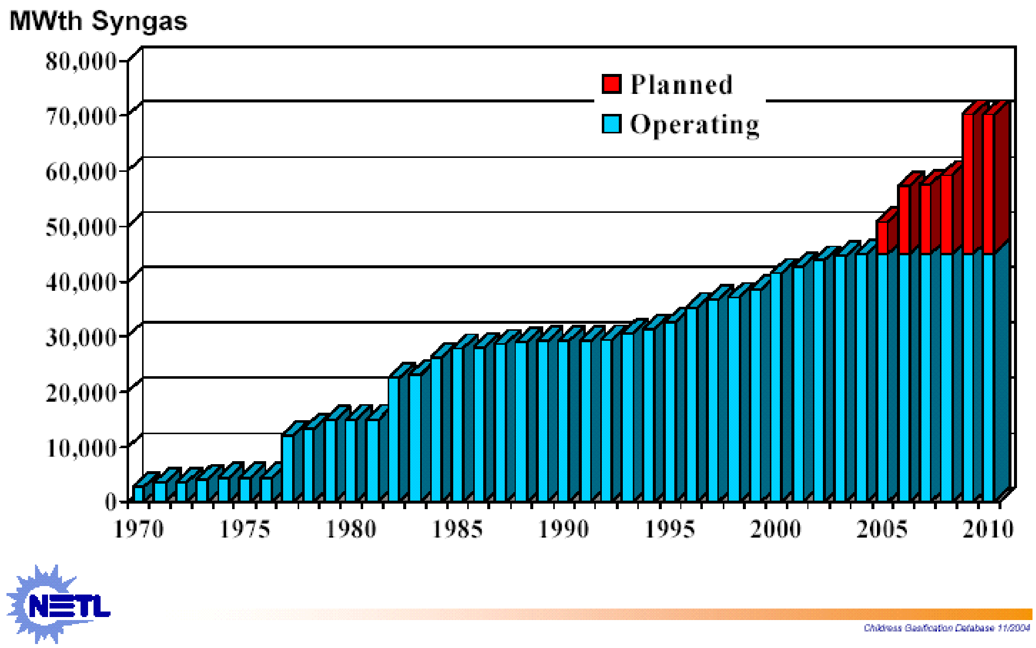
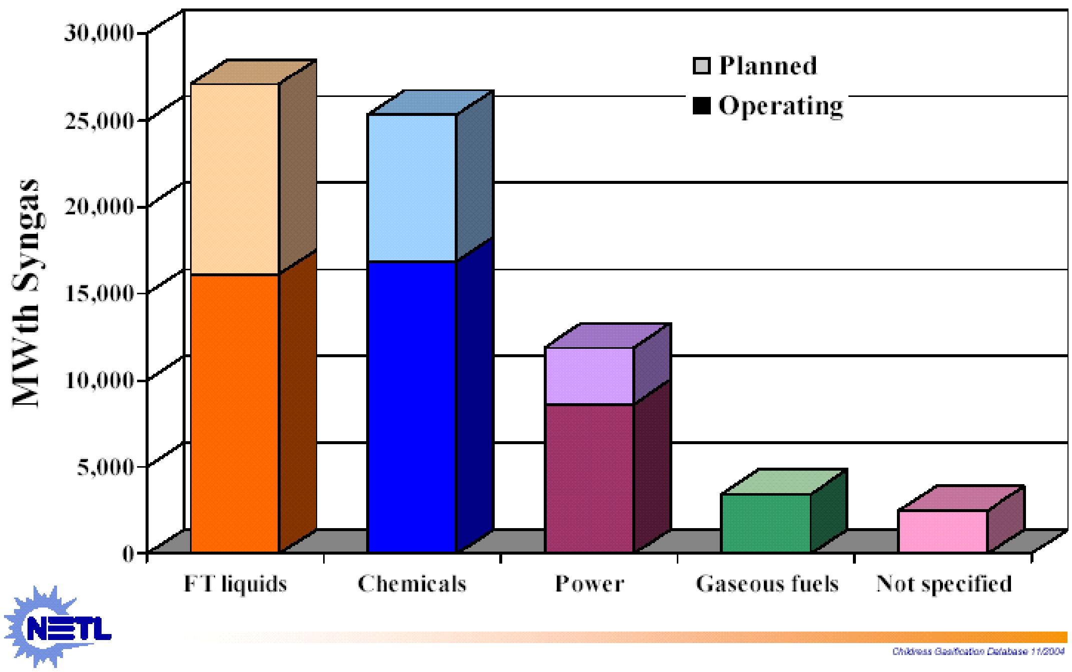


Figure 2-2 — Quantities of Syngas Product Distributed



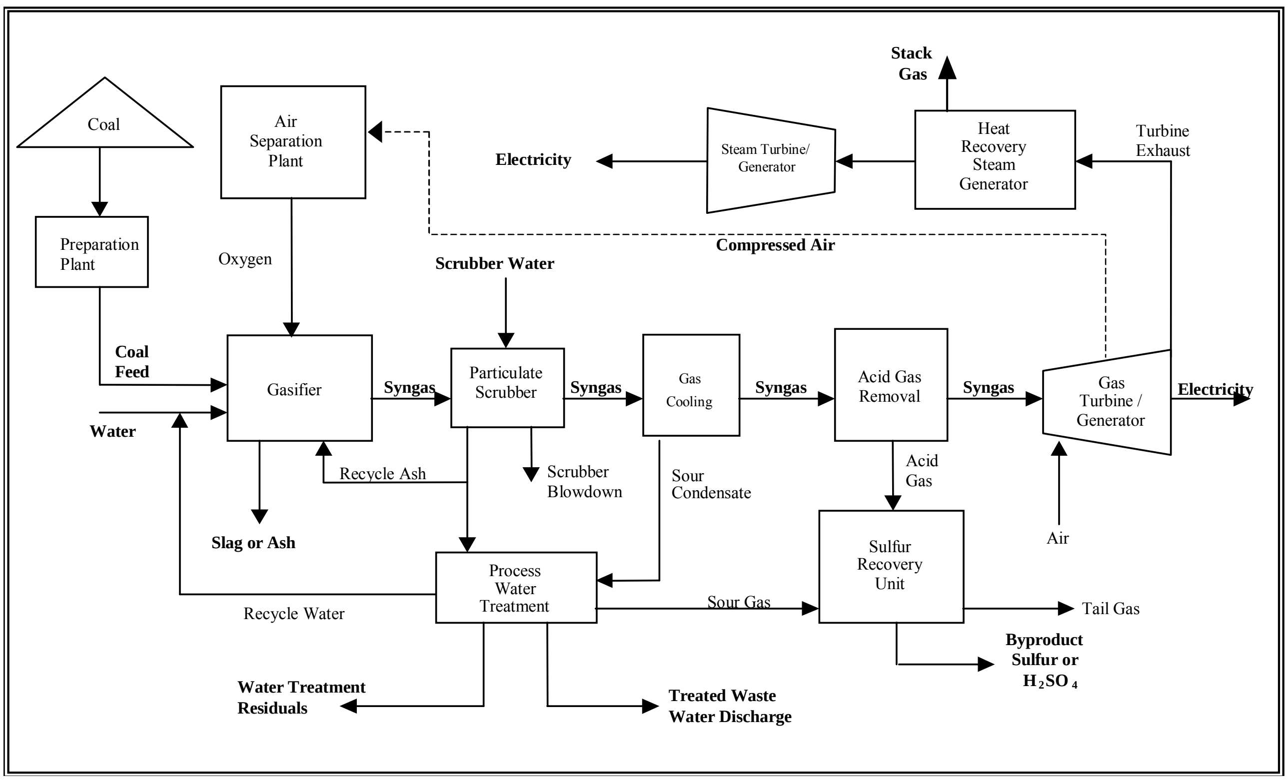
Syngas from the gasifier is cleaned of particulates, sulfur, and other contaminants before being combusted in a gas-fired combustion turbine. Heat from the turbine exhaust gas is extracted in a heat recovery steam generator (HRSG) and combined with steam produced in the gasification system to drive a steam turbine/generator.

Each gasification technology supplier applies its own unique methods of feeding coal to their reactor. In general, coal can be fed to the gasifier using either wet (slurry) or dry feed systems. The gasifier reactor is typically classified as one of three types: fixed-bed, fluid-bed, or entrained-flow type. This report focuses on the entrained-flow type, as this is the technology considered most cost-effective for power generation and sufficiently technically proven by industry experts to warrant deployment at this time. It should be noted that, in general, gasification systems may use either air or oxygen as the oxidant during gasification; currently offered entrained-bed systems only use oxygen.

The gasification process produces the syngas at high temperature (varies by technology), which must be cooled to the temperatures required by the downstream cleanup systems. This heat can be captured by generating steam and by heating boiler feedwater and will increase overall energy efficiency of the power plant when integrated with the power island. Additional integration and efficiency can be achieved by integrating the combustion turbine with the air separation plant used to produce oxygen for feeding the gasifier. This involves supplying all or part of the compressed air required in the air separation unit (ASU) from the combustion turbine compressor and returning nitrogen from the ASU to the turbine combustor.

The major components of coal-fueled IGCC power plants include coal handling and preparation equipment, gasifier, air separation unit, gas cooling and clean-up processes, and combined-cycle power block. Figure 2-3 is a simplified schematic diagram of a typical IGCC plant.

Figure 2-3 — IGCC Schematic of Generic IGCC Power Plant



The use of IGCC systems has had limited market penetration to date. There have been four IGCC demonstration facilities constructed in the United States that use coal as a feedstock and two in Europe. Table 2-1 is a listing of these early IGCC demonstration units indicating technology suppliers for the gasifier and combustion turbine facilities. The Cool Water facility was discontinued after the demonstration was completed because its production costs were not competitive with other sources of electricity. The Louisiana Gasification Technology, Inc. (LGTI) facility installed by Dow at their chemical plant in Plaquemine, Louisiana, demonstrated the viability of the technology but became uneconomic when gas prices dropped significantly in the 1990s, and the facility use was discontinued. The Pinion Pine facility had extensive operating difficulties and was never successfully operated. The Pinion Pine IGCC facility never operated successfully on coal and only operates on natural gas. The failure of this facility indicates that the risks associated with IGCC deployment are real.

Table 2-1 — IGCC Demonstration Plants

Plant Name	Owner	Output (MW)	Feedstock	Gasifier Type	Combustion Turbine	Years of Operation
Facilities in USA						
Cool Water	SoCal Edison	125	Bit Coal	Texaco	GE-7FE	1984-1988
LGTI	Dow Chemical	160	Sub Bit Coal	Dow (E-Gas)	W - 501	1987-1995
Polk County	Tampa Electric	250	Bit Coal	GE (Texaco)	GE-7FA	1996-Current
Wabash River	Destec / PSI Energy	262	Bit Coal & Pet Coke	E-Gas	GE-7FA	1995-Current
Pinion Pine	Sierra Pacific	100	Bit Coal	KRW	Siemens V94.2	1994-Current
Facilities in Europe						
Willem-Alexander	Nuon	253	Bit Coal	Shell	GE-6FA	1998
Puertollano	Elcogas	298	Bit Coal & Pet Coke	Prenflo (Shell)	Siemens V94.3	1998-Current

The operation of these plants has provided a basis for the design of future IGCC facilities and has contributed to the confidence expressed by technology suppliers that they can provide large commercial power plants sized greater than 500 MW. Suppliers GE (Texaco), ConocoPhillips (E-Gas), and Shell all are currently offering commercial facilities with warranties and guarantees.

The use of gasification technology is not limited to IGCC from coal. Gasification technology has been successfully used to provide syngas to a variety of chemical processes and to provide power at refineries using petcoke or heavy oil as the feedstock. A listing of the plants using gasification in the United States is provided in Table 2-2. The operation of these plants provides greater confidence in the use of gasification technology and in the ability of vendors to provide designs for the gasifier and downstream systems. The Dakota Gasification plant is the largest operating gasification plant in the United States. The Lurgi technology employed by this facility to produce substitute natural gas is not considered cost effective for IGCC facilities. The use of gasification technology for non-IGCC purposes does not fully reduce the risks associated with early deployment of this technology. There are many facets to IGCC operation in a power industry setting using coal that must still be addressed as a cutting-edge technology.

Table 2-2 — Other Gasification Facilities in the United States (non-coal IGCC)

Plant Name	Tech Name	Year Start	Gasifier Status	Total Gasifiers	SGCap Nm3d	MWth Out	Fuel Feed	Products
Kingsport Integrated Coal Gasification Facility	GE	1983	Operating	2	1,600,000	218.7	Bit. coal	Acetic anhydride & Methanol
El Dorado Gasification Power Plant	GE	1996	Operating	1	80,559	11.0	Petcoke, Ref. waste & Natural gas	Electricity & HP steam
Delaware Clean Energy Cogeneration Project	GE	2002	Operating	2	3,800,000	519.5	Fluid petcoke	Electricity & Steam
Coffeyville Syngas Plant	GE	2000	Operating	2	2,141,200	292.7	Petcoke	Ammonia & UAN
Convent H2 Plant	GE	1984	Operating	2	1,880,000	257.0	H-Oil bottoms	H2
Oxochemicals Plant	GE	1979	Operating	2	500,000	68.4	Naphtha & fuel oil	Oxochemicals
Baytown Syngas Plant	GE	2000	Operating	2	2,540,000	347.2	Deasphalter pitch	Syngas
Great Plains Synfuels Plant (formerly Dakota Gasification)	Sasol Lurgi Dry Ash	1984	Operating	14	13,900,000	1,900.3	Lignite & Ref. residue	SNG & CO2
Baton Rouge Oxochemicals Plant	Shell	1978	Operating	3	570,000	77.9	Heavy fuel oil	Oxochemicals

An important issue in designing IGCC power plants for commercial operation is ensuring that they operate with high availability. To be viewed as a viable technology for commercial electricity generation, power plant technologies generally need to achieve availabilities around 90%. The early demonstration facilities each started out with relatively poor availability. Performance improved with experience, and the plants currently operating are now achieving about 80% availability. This low level of availability can be attributed in part to fact that these facilities are all of a single train design. This means that there is only one gasifier feeding one cleanup system feeding a single train power block. This arrangement provides little redundancy and the forced outage of any component brings the entire plant off-line.

Achieving a high level of availability with current gasification technologies is generally believed to require redundant gasifier capacity, which increases the cost of IGCC facilities, otherwise a back-up fuel supply such as natural gas or fuel oil must be used during syngas outages. The impact on the cost of the application of redundant systems can be minimized in larger power plants. A single redundant gasifier is typically all that is required for plants ranging from 500 to 1,000 MW. The application of a redundant gasifier at the Eastman Chemicals gasification facility in Kingsport, Tennessee, results in a 98% availability for methanol production from syngas. Shell claims that its technology does not require extended, planned outages for refractory replacement and, therefore, may be able to achieve over 90% availability without spare gasifier capacity.

Texaco and E-Gas technologies use refractory-lined gasifiers. In the case of Texaco technology, "burner replacement" is needed every of 25 to 60 days and complete refractory replacement every 2 to 3 years. These tasks can be scheduled to minimize the impact on plant dispatch. If a 90% overall IGCC equivalent availability is required, then, based on experience and lessons learned at the commercial demonstration plants, a spare gasifier would be required. The spare reduces the scheduled outage time and some of the forced outage time.

Shell gasifiers do not need such extended outages and have had a higher availability. However, Shell would likely also need a spare gasifier if 90% availability were required without use of a backup fuel.

In a paper presented by E-Gas at a 2002 conference, a case for having no spare gasifier was made for those instances where spring and fall power demand is lower, so that planned outages could be taken to replace refractory on one train while the others continue to operate.

The costs associated with providing a spare gasifier can vary from 3% to 15% of total capital cost depending on the technology selected and the amount of downstream equipment included in the spare train. Careful consideration of the needed IGCC plant equivalent availability, annual power demand profile, and feasibility of utilizing the secondary fuel as a backup must be made in order to decide on the level of redundancy required.

With all these issues taken together, S&L believes that the added cost for a spare gasifier is the prudent recommendation for clients pursuing IGCC at its present level of technology development.

2.1 STUDY METHODOLOGY

To develop the overall capital and operating costs associated with an IGCC power plant, S&L planned to use data from technology developers and compare this information with published studies and other internal sources. S&L contacted the companies listed in Table 2-3. The response from these companies is listed.

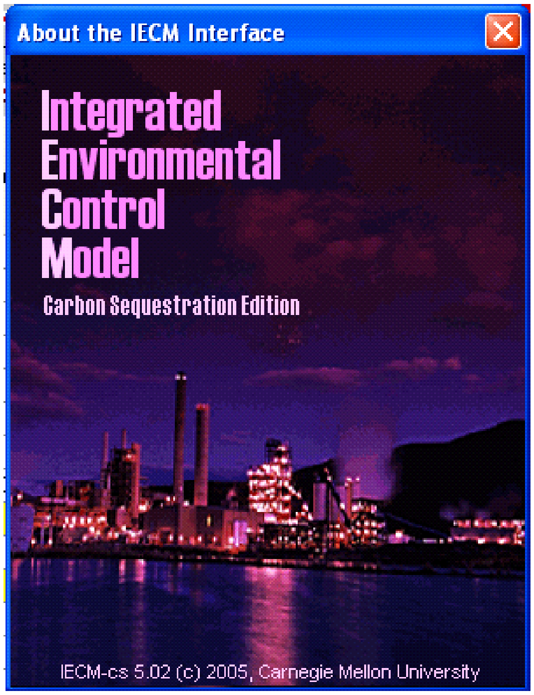
Although four suppliers/technology developers provided a willingness to provide data for this study, no data has been received at the time of this writing.

Table 2-3 — Gasification Suppliers Response to Study

Supplier/Developer	Response	Date Data Received
GE (Texaco)	Yes	None
ConocoPhillips (E-Gas)	Yes	None
Shell	Yes	None
Lurgi	None	
GTI (U-GAS)	None	
Process Energy (developer)	Yes	None
Future Energy (Schwartze Pumpe)	None	

As a result of the lack of vendor-provided data, S&L determined that the best approach for developing the costs and performance for a gasification facility designed for Black Mesa coal would be to use the DOE's Integrated Environmental Control Model (IECM) and adjust the outputs as necessary to compensate for the specific application addressed in this study. The IECM model can be downloaded from the web site: http://www.iecm-online.com/cees_download.htm (Figure 2-4). These results were compared with other studies published in the open literature and with in-house data available to S&L.

Figure 2-4 — IECM Model Opening Screen



This model was selected because it can be used to directly compare the impacts on the design of a facility when considering either with or without carbon sequestration.

The IECM model has several advantages for such a study.

- It is relatively simple to use.
- It is easy to adjust for basic data.
- Ambient conditions can be adjusted to fit site conditions.
- HRSG exhaust temperature can be adjusted to fit criteria.
- Combustion turbine NO_X emissions can be set to meet vendor guarantees.
- CO_2 compression requirements can be adjusted to meet pipeline transportation needs.
- Final capital cost and power values are generally in the range of published studies.

After exercising the model to develop the cost estimates, S&L determined that there are currently several limitations that need to be recognized when using the study for anything beyond a preliminary screening tool. These limitations include the following:

- Only one gasifier technology is available (GE [Texaco] Quench)
- Only one combustion turbine is available (GE 7FA)
- Only the Selexol + Claus + Stretford combination can be considered among cleanup system technologies.
- Only three fuel options are available:
  - Pittsburgh Seam coal
  - Illinois Seam coal
  - Powder River Basin coal
- No mercury removal is considered at this time.
- Air cooling for the condenser is not an option.
- Water usage results do not match published data (which is limited for many technologies).
- Combustion turbine model has several limitations:
  - Uses water dilution for NO_X control only
  - Does not consider nitrogen dilution
  - Does not integrate air separation unit with CT
  - Does not consider SCR
  - Result: lower efficiency, lower capital cost
- Steam turbine system model has several limitations:
  - Limited plant integration and no export steam
  - Result: lower efficiency, lower capital cost than might be expected otherwise

Although these limitations seem extensive, the results could be adjusted to meet the needs of the study. Adjustments S&L performed on the results included the following:

- Assumed that the cost and relative performance of the gasification system when using Black Mesa coal would be the same as for Illinois #6 coal.
- Assumed that the cost and relative performance of the sulfur removal system when using Black Mesa coal would be the same as for Wyoming PRB coal.
- Adjusted the combustion turbine output for site conditions.
- Adjust the capital costs for dry cooling where necessary.
- Added emission control costs for NO_X (SCR) and mercury removal
- Adjusted coal handling cost estimates for slurry delivery by crediting the cost for coal rail unloading, slurry preparation, and so forth.

- Compared costs of power delivery systems to S&L data base costs as appropriate
- The capital costs from the IECM study were computed in 2002 dollars. These values were escalated at 3% per year to 2006 dollars.[1] S&L also added owner's costs and EPC contractor profit to the values computed that are not included in the IECM estimate. The resulting capital cost values are in the same range as values computed for other projects. Screening studies of the nature preformed by S&L for this project, whether using the IECM model or other techniques, are typically considered accurate to a -20% to +30% range. To achieve a higher degree of accuracy (e.g. ±10% to 15%) for a technology requires extensive data on past installation as is common with pulverized coal fired plants. For a new IGCC facility to have this level of accuracy requires—
  - Complete process and instrument flow diagrams for all systems in the plant,
  - Detailed sizing of all major equipment and quotations from vendors for that equipment,
  - Design of foundations and buildings, and
  - Environmental Permits in place to allow detailed engineering and construction to proceed.

  This level of detail is typically provided after completion of a significant level of engineering (typically ~ \$4 to \$7 million level of effort). There are several IGCC projects currently under development across the country that have initiated this level of effort, but there are no reported costs from these projects yet published.

The operating and maintenance (O&M) costs computed by the IECM are not calculated in the same manner as is typically performed by a utility. An example is that IECM allocates an internal cost for auxiliary power (electricity use) to each section of the power plant. This is in addition to the tabulation of internal power use associated by the difference between gross and net generation. This allocation would normally be considered double counting. For this study, S&L used the consumable costs calculated for each subsystem. Water costs were calculated separately. Ash (slag) and sulfur disposal and/or byproduct credits were developed separately. Fixed operating labor was estimated separately using the IECM shift labor requirements as a guideline. Fixed and variable labor was based on model inputs subtracting the in-plant estimate of the labor force from the maintenance labor requirements.

[1] Inflation in the utility industry is trended by the "Handy Whitman" Index. The index has a table for Power Generation Construction in the Pacific Region. The index values for the period varied substantially over each year of this period. Inflation was over 8% in 2004. Only estimates may be applied for 2005 since economic data are not available. The 6-year average inflation rate from 1999 to 2005 was 3.7%, while the 4-year average rate from 1999 to 2004 was 2.7%. Since we were uncertain how inflation would fare during 2005 to 2006, a compromise rate of 3% was used for the study to compare the various project cost estimates reviewed in the literature and for the IECM results.

2.2 TECHNICAL FEASIBILITY AND MAXIMUM CAPACITY

2.2.1 Design Basis Technical Assumptions

The study requested by the California Energy Commission specified that a gasification plant be considered at either the Mohave or Black Mesa Mine sites. It also specified that the plant be considered both with and without carbon dioxide removal and sequestration.

S&L determined that this study must focus on a facility that is currently both technically and commercially viable for installation with the most rapid schedule practical to replace power that will be lost if Mohave Generating Station is retired. The following considerations were therefore developed as the basis for the study:

- Develop IGCC plant costs for commercial scale IGCC plant at two sites, operation by 2011 if possible:
  - Mohave Generating Station
  - Black Mesa Coal Mine
- Consider aspects associated both with and without CO_2 removal and sequestration:
  - Limited CO_2 removal without shift conversion
  - High degree of CO_2 removal with shift conversion
- Develop costs for a CO_2 pipeline from Mohave to Bakersfield for use as enhanced oil recovery (EOR) sequestration.
- Develop costs for a CO_2 pipeline from Black Mesa to McElmo Dome Natural CO_2 Reservoir near Cortez, Colorado.
- Minimize water consumption in the plant design.

From this basis, the study developed a conceptual plant basis for design. This basis is summarized in Table 2-4.

Table 2-4 — IGCC Facility Design Basis

	No CO_2 Removal	**With CO_2 Removal**
Number of Gasifiers	2 + 1 Spare	2 + 1 Spare
Combustion Turbine	2 “F” technology CTs	2 “F” technology CT’s
Steam Generator	2 HRSGs	2 HRSGs
Turbine Generator	1	1
Boiler Feedpumps	Motor Driven	Motor Driven
Condensing Equipment	Dry Cooling	Dry Cooling

	No CO_2 Removal	With CO_2 Removal
Sulfur Removal	Selexol 1-Stage + Claus + Stretford	Selexol 1-Stage + Claus + Stretford
NO_X Control	Syngas Modified Burners + Water Diluent	Syngas Modified Burners + Water Diluent
CO_2 Removal	None	Selexol 2-Stage Process
Particulate	N/A	N/A

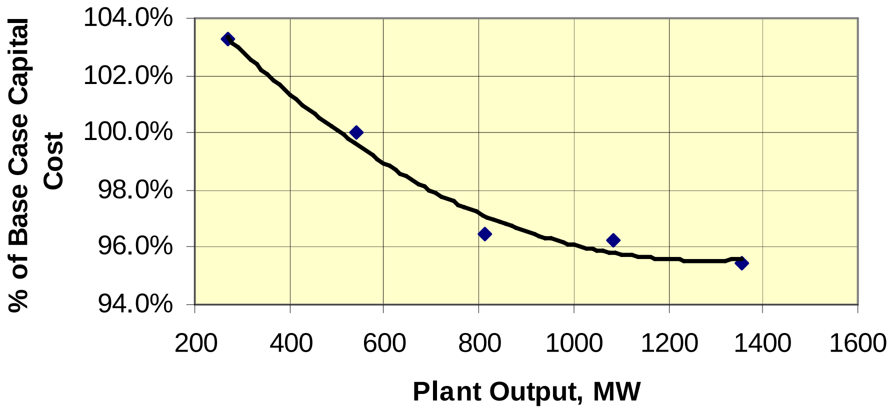
2.2.2 Feasible Capacity Ranges

The study requested by the California Energy Commission specified that a gasification plant of approximately 250 MW capacity be considered at either the Mohave or Black Mesa Mine sites. It also specified that the plant be considered both with and without carbon dioxide removal and sequestration.

S&L considered this scale to be impractical from a commercial point of view. Most companies considering commercial gasification plants are currently considering facilities with multiple trains that provide for higher reliability, availability, and improved costs of scale. A two-train facility at ISO standard conditions would provide about 540 MW, a three-train system would provide 825 MW, and a four-train would provide 1,100 MW of capacity. S&L determined that developing the cost basis for a nominal 550-MW plant would provide the best data for a replacement facility based on the current state of technology development because most of the studies conducted for new IGCC facilities being considered today are of this size. As a result, vendors would most likely be able to use existing information to readily develop estimates for use in this study. Facilities larger than 550 MW would benefit from “cost of scale” efficiencies, which can be estimated based on shared spare equipment savings and other factors. The IECM model was exercised to determine the relative cost of scale for capital costs of plants ranging in output from 265 to 1,355 MW (no carbon capture). Based on the data obtained, the curve in Figure 2-5 was constructed, which can be used to adjust the estimates from the 100% basis to alternative costs for either larger or smaller plants. As can be seen from this curve, the single train facility would likely cost about 3% more per kilowatt than a two-train facility. Similarly a three-train facility indicates a 3% cost savings compared to the two-train design. As the facility increases in size beyond the three-train size, the relative benefit decreases. The decision to construct a two- or a three-train gasification plant is dependent on the results of the integrated resource plan to be prepared by Southern California Edison.

Figure 2-5 — Cost of Scale for Typical IGCC Plants

(540 MW = 100%)



2.2.3 Fuel Requirements

The design fuel for the study is Black Mesa coal. The coal is currently delivered to the Mohave Generating Station via a pipeline as a slurry. The slurry is delivered to the mine at a typical coal/water concentration of approximately 50%. Two of the leading gasification technologies (i.e., GE and E-Gas) use coal water slurry as the means by which coal is fed to the gasifier. They typically provide their feed to the gasifier at higher coal slurry concentrations, typically 65%. For this study, S&L assumed that the existing delivered slurry meets the size criteria for these gasifiers and that the existing dewatering systems will be able to be modified to provide the desired slurry concentration. The size distribution of the coal is summarized in Table 2-5.

Table 2-5 — Black Mesa Coal Water Slurry Size Distribution

Method	Laser Diffraction Analysis					Wet Screen Analysis		
Size No.	1	2	3	4	5	6	7	8
Sieve No.					325	100	50	30
Size, µm	1.18	1.67	4.24	10.78	45	150	300	600
Quantity	3.37	2.56	4.02	17.92	17.70	21.90	22.30	10.23
	Fines			Optimum				Coarse

Minus	Plus
10.78	600
µm	µm
Sizes	Sizes
9.95	10.23
Fines	Coarse

The Black Mesa fuel is considered a subbituminous coal (ref: USGS sample data base and U.S. Bureau of Mines). The analysis of the fuel was developed from data provided by Southern California Edison and supplemented with data from the U.S. Geological Survey. Unlike subbituminous coals mined in Wyoming and Montana, which have high moisture contents of about 25% to 35%, this fuel has a moisture content (as mined) of about 10.5% to 12.5%. This moisture yields a coal with a higher heating value of 10,834 Btu/lb, which is similar to Illinois coals (typically 10,500 to 11,500 Btu/lb). The sulfur content of the fuel is relatively low at about 0.42%. The analysis of the fuel is summarized in Table 2-6. The ash fusion temperature of the coal is important for gasification processes that produce molten slag: the gasifier must operate at a temperature sufficient to melt the ash. This may require additives to "flux" the ash. Gasifiers that produce a "dry" ash, on the other hand, must operate below the ash fusion temperature to avoid slagging conditions.

Table 2-6 — Black Mesa Coal Analysis

As Received	
Proximate Analysis	**%**
Moisture	10.36
Volatile Matter	38.68
Fixed Carbon	43.50
Ash	7.45
Total	100.00

Ultimate Analysis	**%**
StdAsh	6.68
Moisture	10.36
Hydrogen	5.11
Carbon	56.71
Nitrogen	1.01
Oxygen	19.72
Sulfur	0.42
	100
Btu/lb	10,834

Hg, ppm	0.05

Ash Fusion Temperature deg F	
Initial Deformation	2,184
Softening	2,245
Fluid	2,307
T-250	2,686

Ash Mineral Analysis	**wt %**
SiO_2	54.15
Al_2O_3	21.19
TiO_2	0.96
Fe_2O_3	4.64
CaO	7.94
MgO	2.00
K_2O	0.87
Na_2O	2.04
SO_3	5.41
P_2O_5	0.22
SrO	0.10
BaO	0.44

Total feed to the gasifier for the base case nominal 550-MW plant is about 6,000 ton/day of coal.

2.2.4 Water Requirements

Determining the quantity of water required for the facility is a critical element of the study. Currently, Mohave Station receives water from the Colorado River to run the power generating plant. Fuel is delivered as a slurry with water from the N-Aquifer. The N-Aquifer water will become unavailable as of January 1, 2006. SCE is participating in negotiations to make C-Aquifer water available to replace the water from the N-Aquifer. For this study, water was assumed to cost $200 per acre-ft from the Colorado River and $1,000 per acre-ft from the C-Aquifer. It is assumed that these prices are sufficient to recovery all pumping and transportation costs, including capital costs, over time. There are essentially three primary scenarios for water use:

- The IGCC facility is located at the Mohave Site; C-Aquifer water is used for slurry delivery of coal and Colorado River water is used for process and cooling water purposes.
- The IGCC facility is located at the Black Mesa Site; C-Aquifer water is used for slurry delivery of coal and for process purposes. Cooling is provided by an air-cooled condenser to minimize water use.
- The IGCC facility is located at the Black Mesa Site; Dry coal feed gasification (Shell) technology is selected to minimize the water requirements from the C-Aquifer water for process purposes only. Cooling is provided by an air-cooled condenser to minimize water use.

Each of these scenarios was considered for the three carbon removal cases studied, that is, no CO_2 removal, CO_2 removal without shift conversion, and maximum CO_2 removal. The results of the study are summarized in Table 2-7. The data lists the flow rate in gallons per minute (gpm) and acre-ft/yr of instantaneous demand and in acre-ft per year assuming a 100% capacity factor to ascertain maximum water demand.

Table 2-7 — Water Demand for IGCC at Mohave and at the Black Mesa Mine

Based on 100% Capacity Factor	No CO_2 Removal		CO_2 Removal without Shift Conversion		With CO_2 Removal	
	gpm	acre-ft/yr	gpm	acre-ft/yr	gpm	acre-ft/yr
Boiler Feedwater Make-up (1)	175	282	175	282	182	292
Coal Feed Slurry @ Mohave	*1,095*	*1,762*	*1,095*	*1,762*	*1,137*	*1,829*
Coal Feed Slurry @ Black Mesa	*842*	*1,356*	*842*	*1,356*	*874*	*1,407*
Miscellaneous Plant Uses	175	282	182	292	182	292
Cooling Tower Make-up (2)	2,800	4,507	2,800	4,507	2,906	4,678
Total Plant Use Mohave (3)	4,245	6,833	4,252	6,844	4,406	7,093

Based on 100% Capacity Factor	No CO_2 Removal		CO_2 Removal without Shift Conversion		With CO_2 Removal	
	gpm	acre-ft/yr	gpm	acre-ft/yr	gpm	acre-ft/yr
Total Plant Use Black Mesa [(3)]	*1,192*	*1,919*	*1,199*	*1,930*	*1,238*	*1,992*
Total Plant Use Black Mesa (Shell gasifier)	*350*	*563*	*357*	*574*	*363*	*585*

1. Boiler feedwater make-up is assumed to be 1% of main steam flow rate.
2. Cooling tower make-up includes evaporation, drift, and blowdown with four cycles of concentration.
3. Cooling towers used at Mohave; dry cooling used at Black Mesa.
Water use from C-Aquifer in italics.

The feeding of coal as a slurry from the Black Mesa Mine to the Mohave Generating Station typically requires a slurry of about 50% coal in water. This implies that for each pound of coal, a pound of water is required. Gasification prefers that a slurry minimize the amount of water fed to the gasifier to improve efficiency. Slurry concentrations of about 65% to 70% are desired. S&L assumed that slurry will be fed to the gasifier with a slurry concentration of 65% (in the absence of vendor data). This means that for slurry feed to the gasifier, there is 0.53 pound of water for each pound of coal, yielding 1.53 pounds of slurry. For a plant located at Mohave, excess water must be removed before feeding to the gasifier. If a plant is located at the Black Mesa site, slurry could be prepared to meet the gasifier requirements, since pipeline transportation of the fuel is not required. For dry feeding of coal, no slurry water is required.

The quality of the water from the C-Aquifer is unknown at this time. Estimates performed for the gasification plant include a factor for typical water treatment (softening) and for boiler water treatment (demineralization). S&L assumed that this level of treatment imbedded in the cost models is sufficient for the IGCC cost estimate.

Data are provided with capital and operating costs for an IGCC plant at Mohave Station that uses either wet or dry cooling. An analysis of the long-term availability of Colorado River water is beyond S&L's scope for this report. S&L assumes that SCE will evaluate the effect of water availability on the cost and performance of the IGCC facility when they perform their integrated resource plan modeling.

2.2.5 Land Requirements

The land requirements reported in the literature to construct a 550-MW IGCC facility varies from 125 acres to 300 acres. The actual requirements depend on several factors:

- Land required for the process equipment

- Land required for coal unloading, storage, and preparation and duration of storage desired (e.g., 30 days or 6 months.
- Land requirements for ash disposal

Technology developers have indicated in past studies by S&L that the land required for the process equipment is about 100 acres. The area required for coal handling and unloading is typically also about 100 acres. The area required for ash disposal is similarly about 100 acres. The smaller value is the minimum required for minimal coal storage and no ash disposal on site. The larger value accommodates more traditional power plant requirements. S&L has worked on site development projects with about 175 acres that use a minimal storage of coal and very limited storage for ash. For this study, a 200-acre site should be adequate if limited ash storage is required, since a complete coal unloading system is not required at either Mohave or Black Mesa. However, a 300-acre site would provide sufficient space for the plant plus ash storage.

2.2.6 IGCC Performance

The IECM model was used to determine the performance of the IGCC Facility as stated above. The overall output of the plant is reduced with CO_2 removal and compression to deliver gas to sequestration sites via pipeline, and thus, the efficiency is diminished. The key performance parameters are listed in Table 2-8. The initial plant efficiency is somewhat lower than might be expected for a typical IGCC facility. This may be because the IECM model does not capture the full measure of thermal integration that is commonly associated with production of steam and electricity associated with cooling the syngas from the exit of the gasifier down to the sulfur removal cleanup system temperatures. This efficiency is typically about 2%. Also, the IECM does not take into account the benefit of integration of the combustion turbine with the air separation unit (ASU), which can also improve efficiency by reducing the compression power required by the ASU. Typical quoted efficiencies reported for the GE (Texaco)-based IGCC facilities at this scale is about 37%. S&L originally hoped to received vendor data for plant efficiencies to reflect their current design philosophy as applied to Black Mesa coal. Since we did not receive vendor input, the values from the IECM model were not adjusted to maintain the consistent nature of the estimate; however, these adjustments can be made when considering parametric analysis of the results.

Table 2-8 — Study-Predicted IGCC Performance Based on IECM Model

Values at 100% Load and 100% Capacity Factor		No CO_2 Removal		CO_2 Removal without Shift Conversion		90% CO_2 Removal	
		Mohave	Black Mesa	Mohave	Black Mesa	Mohave	Black Mesa
Gross Output	MW	639.6	643.9	639.6	643.9	604.9	608.2
Net output	MW	548.9	554.6	531.1	537.1	481.7	483.9
Heat Rate	Btu/kWh	9,909	9,927	10,402	10,259	11,730	11,758
Overall Efficiency	%	34.4	34.4	32.8	33.3	29.1	29.0
Heat Input	mmBtu/hr	5,439	5,506	5,525	5,506	5,650	5,690
Fuel Consumption	lb/hr	502,056	508,191	509,953	508,191	521,560	525,177
Fuel Consumption	tpy	2,199,007	2,225,878	2,233,595	2,225,878	2,284,432	2,300,277

Assumptions: Mohave: Site elevation approximately 710 ft; average ambient temperature 67°F.
Black Mesa: Site elevation approximately 5,500 ft; average ambient temperature 59°F.

Parametric studies were conducted to determine the relative performance of the IGCC facility at varying temperatures to assist SCE with their resource planning. Figure 2-6 identifies the level of plant output variation and net heat rate associated with ambient temperature predicted by the IECM model at the Mohave Site. The performance of the plant at 108°F is reduced significantly from average conditions. Net output for the three scenarios is: 514, 505, and 448 MW (base case/no-regrets/max CO_2 removal). The heat rate at 108°F increases slightly to: 9,930, 10,421, and 11,781 Btu/kWh.

For the Black Mesa site, three curves were prepared (elevation assumed for the Black Mesa Site is 5,500 feet which is the limit of capability for the IECM model). One provides a similar view of the impact of temperature on net heat rate and output at 5,500 feet elevation, Figure 2-7. Figure 2-8 compares the effect of elevation (if an alternative site is considered at an elevation above 5,500 feet, which is very likely) on net output for two ambient temperatures. Figure 2-9 compares the effect of elevation on the net heat rate for two ambient temperatures. All cost and performance data presented in this report were calculated for the Black Mesa design at 5,500 feet elevation.

Figure 2-6 — Mohave Site Net Output and Heat Rate as a Function of Site Temperature

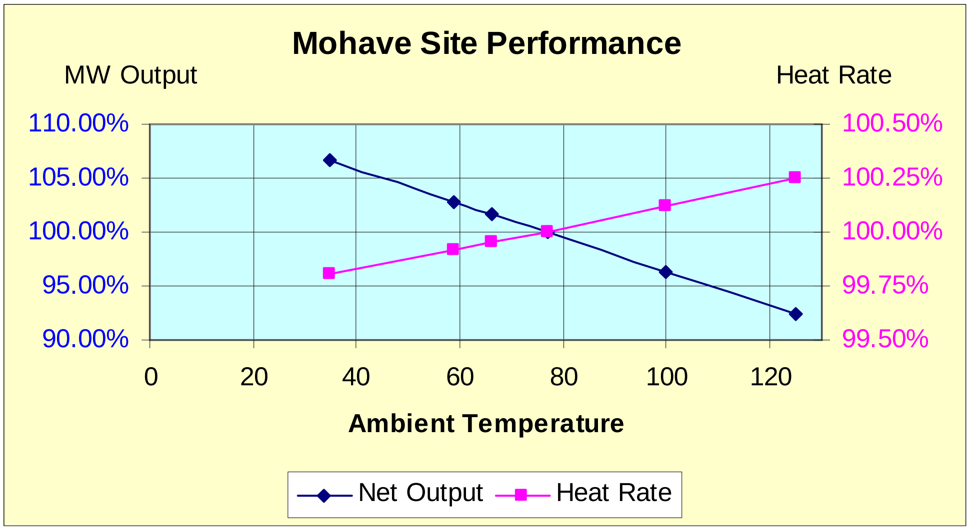


Figure 2-7 — Black Mesa Site Net Output and Heat Rate as a Function of Site Temperature

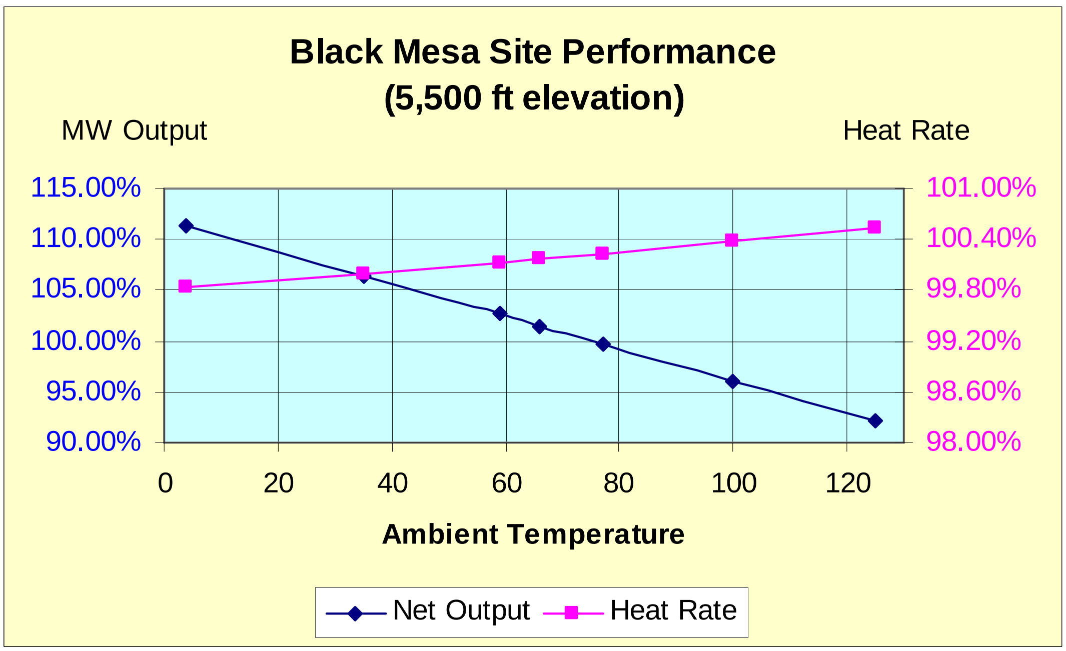


Figure 2-8 — Black Mesa Site Net Output as a Function of Site Elevation

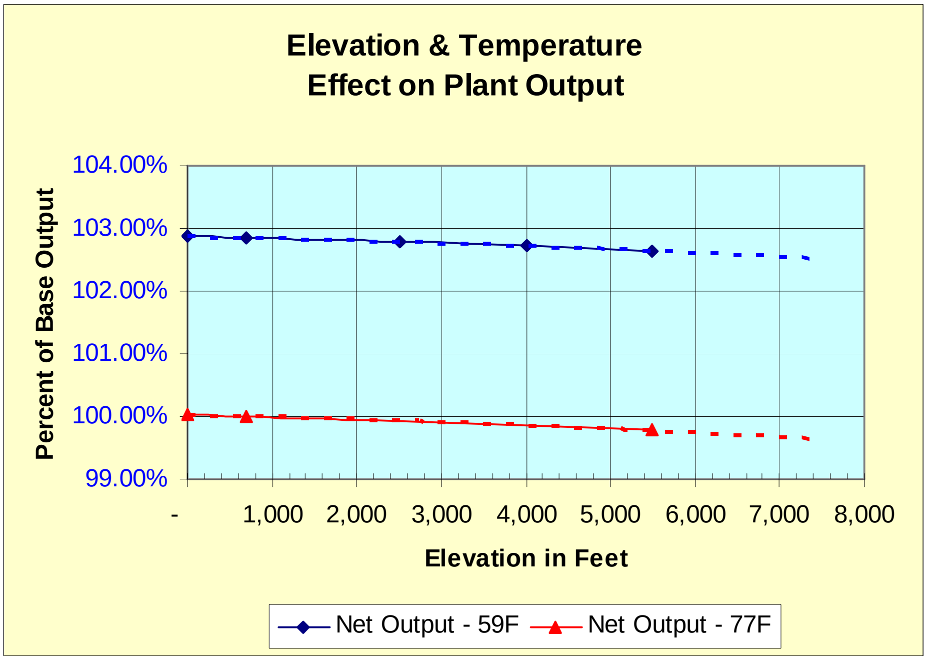
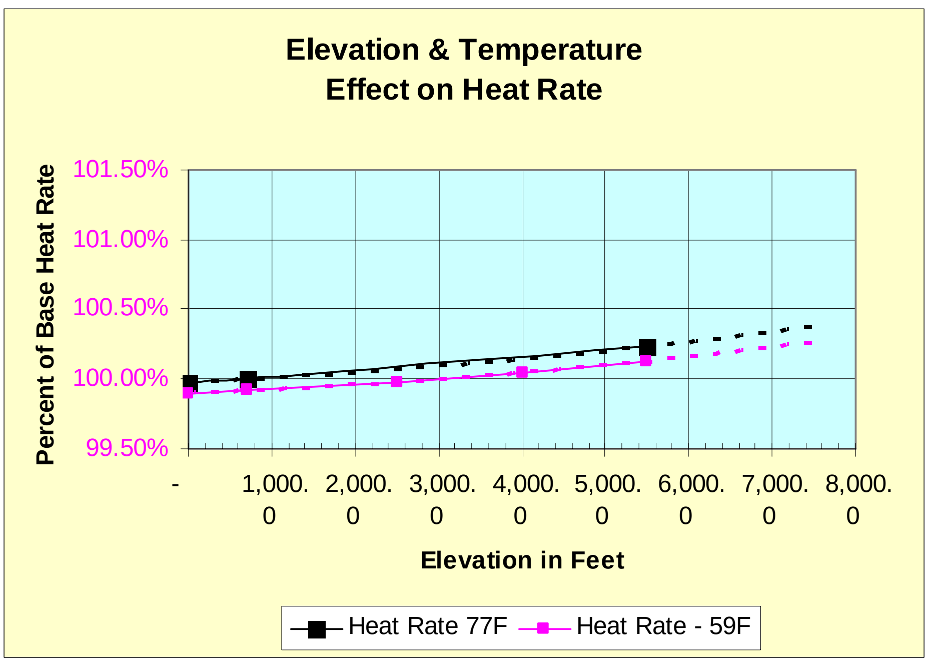
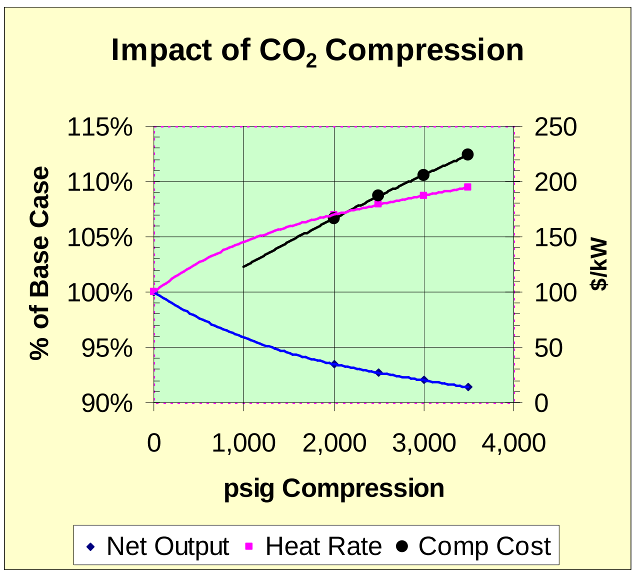


Figure 2-9 — Black Mesa Site Net Heat Rate as a Function of Site Elevation



Examination of the data shows the significant output and heat rate penalty associated with CO_2 recovery and sequestration. A key aspect of sequestration is the compression requirements needed to transport and deliver high-pressure CO_2. This value is highly dependant on distance. S&L exercised the IECM model to ascertain the cost and performance sensitivity of the compression requirements for CO_2 for the maximum removal case facility. This is summarized in Figure 2-10.

Figure 2-10 — Impact of CO_2 Compression on Plant Cost and Performance



2.3 SITE SCREENING

S&L assumed two site locations for this study: the existing Mohave Generating Station and a site near the Black Mesa Coal Mine.

2.3.1 Mohave Generating Station Site

The Mohave Generating Station is located in Laughlin, Nevada. The site elevation is 714 feet above sea level. The area is typical of dry arid desert conditions. Maximum ambient conditions are 125°F with a 79°F wet bulb. The 1% maximum temperature is at 108°F. Minimum ambient temperatures are 20°F. Average conditions considered for the study were 67°F to account for average day-time temperatures during the entire year. The site contains more than sufficient acreage for installation of the facility and for expansion to increase the output from the site if that is desired.

The Mohave Generating Station sits near the Colorado River and uses water from the river for cooling and plant uses. This study assumed that Colorado River water will be used for cooling tower makeup and for process uses. Alternative costs for a dry cooling system were developed in case a reduction in Colorado River water use is considered.

Water from the C-Aquifer will be required for delivering the coal from the Black Mesa mine to Mohave.

The coal will be delivered to the station as a coal-water slurry. It is recommended that slurry-fed gasification technologies provided by either GE (Texaco gasifier) or ConocoPhillips (E-Gas) be considered. The slurry will need to be concentrated from the delivery concentration of about 50% coal to approximately 65% coal before feeding. S&L has assumed that the existing centrifuges would be able to facilitate this. The cost study has credited the installation at the site by reducing the coal handling equipment requirement for rail facilities, coal unloading, and coal storage and reclaim piles.

In case carbon dioxide is removed from the syngas for sequestration, a pipeline of approximately 230 miles to the Bakersfield area was considered.

Since the Mohave site has existing electrical switch yard and transmission access, extension or enhancements of these assets are not required.

2.3.2 Black Mesa Site

The Black Mesa Mine is located on the Navajo Reservation in northern Arizona. The closest town to the site is Kayenta, Arizona. There are vast open areas available for development near the mine, and a specific location was not selected. It is assumed that a suitable location can be identified in case a further, in depth, study is considered. The elevation in the area of the mine varies from about 5,500 to 7,000 feet. For the study, a mine site elevation of 5,500 feet was assumed in the model because that is the limit of altitude adjustment possible. Average ambient temperatures at the site were assumed to be approximately 59°F.

All water for the gasification process was assumed to be derived from the C-Aquifer. For this reason, only dry cooling was considered in the capital cost for this location. In case slurry feed systems are used, it is assumed that the slurry can be prepared with the existing equipment at the mine at the 65% concentration required for feeding the gasifiers. Less water use can be realized if a dry fed gasifier (Shell) is used; however, a higher capital cost to provide for dry grinding and drying of the coal feed would then be needed.

In case carbon dioxide is removed from the syngas for sequestration, a pipeline of approximately 130 miles to the Cortez, Colorado, area was considered.

2.4 ENVIRONMENTAL EMISSIONS ISSUES

The plant emissions are estimated by the IECM model. Additional NO_X removal is calculated to reduce the levels from the CT exhaust to below the anticipated BACT limit. The primary emissions are summarized in Table 2-9. Mercury emissions are not estimated as a part of the IECM model for IGCC facilities. S&L assumed a 90% reduction in mercury, as is predicted by most experts, with the use of activated carbon filters on IGCC plants.

The level of sulfur emissions is significantly reduced on plants that use a two-stage Selexol process for CO_2 removal. This low level is due to the higher degree of H_2S removal that occurs along with the capture of CO_2 from the syngas.

Mercury emissions are shown based on gross generation, to reflect the requirements of the Clean Air Mercury Rule (CAMR) issued in March 2005.

Table 2-9 — Summary of Primary Emissions

Values at 100% Load and 100% Capacity Factor		No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal	Comments
Emissions		**IECM Predicted Performance**			
SO_2	lb/mmBtu	0.13	0.02	0.02	0.15 (Anticipated BACT Limit)
	lb/n-MWh*	1.25	0.21	0.24	
	tpy	2,952	477	495	
NO_X	lb/mmBtu	0.0217	0.0217	0.0214	0.03 (Anticipated BACT Limit)
	lb/n-MWh	0.22	0.22	0.25	
	tpy	510	510	522	
CO_2	lb/mmBtu	200	142	17	
	lb/n-MWh	1,978.16	1,457.45	197.85	
	tpy	4,682,220	3,337,998	410,406	

Values at 100% Load and 100% Capacity Factor		No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal	Comments
Emissions		IECM Predicted Performance			
Particulate	lb/mmBtu	0.012	0.012	0.012	0.012 (Anticipated BACT Limit)
	lb/n-MWh	0.12	0.12	0.14	No IECM Particulate Data
	tpy	282	282	292	
Mercury	lb/TBtu	0.46	0.46	0.46	
	10^{-6} lb/g-MWh*	3.90	3.90	4.28	No IECM Mercury Data; CAMR rule is based on gross output
	oz/yr	344.4	344.4	357.4	

* n-MWh = net megawatt-hour; g-MWh = gross megawatt-hour.

2.5 CARBON SEQUESTRATION

S&L developed the quantities of CO_2 that could be separated from the syngas as characterized by three scenarios. The amount of CO_2 removed for sequestration is listed in Table 2-10. The three scenarios are as follows:

- **No CO_2 removal.** This is technically feasible today with current technology.
- **CO_2 removal without shift conversion.** In this case, 90% of the carbon dioxide generated by the standard syngas production process is removed from the fuel gas. This is technically feasible today.
- **Maximum CO_2 removal.** This assumes that all of the carbon monoxide the syngas is converted to carbon dioxide using a shift reaction and 90% of this CO_2 is removed from the fuel. The shift reaction is technically feasible today. However, a combustion turbine that can use the product syngas is not yet available.

Note that although it is technically possible to remove a high degree of CO_2 from the syngas, it is not likely that such a plant will be technically viable until about the 2020 time frame. This is due to the need to develop a hydrogen-fueled combustion turbine that can reliably generate power and be guaranteed by the turbine vendors.

Burning hydrogen-rich fuels is currently practiced in syngas combustion and in the combustion of assorted waste gases. To meet stringent NO_X emissions, the syngas is diluted with either nitrogen or water to lower peak flame temperatures and also increase the output of the turbine. However, vendors have reported that if burning a fuel where hydrogen is the only fuel component, there are additional issues in design needed to prevent flashback and to ensure proper safeguards. These issues entail extensive design and testing of construction materials and combustion firing configurations. Without such tests, there is considerable risk to both the engine supplier and the power generation company in the deployment of the first such unit.

The U.S. Department of Energy is actively conducting research for development of advanced turbines that will use hydrogen-rich fuels with several turbine vendors. DOE recently awarded a contract to GE for $45.6 million dollars to develop the hydrogen fueled turbine design for an engine that will be tested in the FutureGen project. This is likely to be the first demonstration of a hydrogen-rich fueled engine. Many power generation companies have offered to participate in this project with DOE to ensure its completion. The hydrogen turbine is critical to the ability to commercial CO_2 sequestration moving forward.

Table 2-10 — CO_2 Byproducts for Sequestration

		No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
CO_2	lb/mmBtu	—	57.52	175.41
	lb/n-MWh	—	589.23	2,059.33
	tpy	—	1,349,509	4,271,814

2.6 TRANSMISSION REQUIREMENTS

Direct transmission access costs include the costs of the connection at the plant site, the plant transmission line, and any substation required at the interconnection with the trunk transmission line. For an IGCC plant at the existing site, these costs are assumed to be negligible because the IGCC plant would replace the existing plant if it were built there. At the Black Mesa site, connection of the plant requires a plant switchyard, an approximately 85-mile long transmission line at 500 kV, and interconnection equipment to connect to the existing 500-kV trunk transmission line. These costs are estimated to be approximately $94.6 million.

Direct transmission access costs described here do not include the costs of upgrades to the transmission system that may be required to alleviate congestion or single contingency concerns that result from load flow analyses. Those costs are estimated in Section 12.

2.7 O&M AND CAPITAL COST ESTIMATES

2.7.1 Economic Assumptions

The capital costs for the study assume overnight construction in 2006 dollars. The IECM capital cost data were used as the basis for the plant with adjustments as described in Section 2.1 to meet site requirements and to account for escalation from 2002 at 3%/yr. These values were compared to published capital cost estimates in the literature for reasonableness. The cost of reagents and consumption rates were based on IECM model inputs, except for water costs and for materials not considered in IECM, such as mercury removal and SCR operation.

The costs are shown with the construction labor based on the internal factors assumed within IECM. Productivity adjustments that may be suggested for local conditions in the Laughlin, Nevada, or Black Mesa area are indicated, but are not included in the totals. Sales and property taxes and land lease costs are not included in the cost estimates presented.

2.7.2 Capital Costs

The capital costs determined by the IECM model were developed for the three cases. Costs are shown in total dollars and on a normalized $/kW basis for each case. Costs are shown for both the Mohave Generating Station site (Table 2-11) and the Black Mesa site (Table 2-13). The capital costs for the plant at either site are essentially the same except for specific design differences such as wet or dry cooling or coal slurry feed or dry feed. The normalized costs reported in $/kW will vary based on the changes in net output of the plant due to differences in average ambient temperature and site elevation. There are also differences in performance (heat rate) that affect the operating costs that are site specific due to temperature and elevation. Also, the cost per kilowatt is significantly affected for the cases where carbon dioxide is removed and sequestered. This is the result of the reduced power output from the plant (due to compression requirements to transport CO_2). Thus there are fewer kilowatts for sale and thus the cost per net kilowatt is much higher.

It is assumed that water from the Colorado River will be used for cooling at the Mohave site. If this is not desired, adjustment to the cost for the addition of dry cooling is provided. It is assumed that dry cooling will be necessary at the Black Mesa site to conserve water resources.

The level of emissions, specifically CO_2 emissions, is expected to be about the same for both the Black Mesa and the Mohave sites.

Table 2-11 — Capital Cost Estimate for IGCC Using Black Mesa Coal at Mohave

	No CO_2 Removal		CO_2 Removal without Shift Conversion		90% CO_2 Removal		Comments
Net Output, MW	548.9		531.1		481.7		
Capital Costs	M$	$/kW	M$	$/kW	M$	$/kW	
Costs in Year 2006 Dollars							
Air Separation Unit	199	363	199	375	206	427	
Gasifier Area	295	537	295	555	305	634	Base Cost reduced for Existing Slurry
Sulfur Control	53	97	53	100	53	111	
Mercury Control	4	7	4	8	4	8	
CO_2 Capture	—	—	92	172	233	484	
Power Block	339	617	339	638	337	699	
Dry Cooling Additional Cost	15	27	15	28	15	31	If added for dry cooling reduce makeup water
Post-Combustion NO_X Control	5	10	5	10	5	11	
Total Cost with Wet Cooling	895	1,631	987	1,858	1,143	2,374	
Total Cost with Dry Cooling	910	1,658	1,002	1,886	1,158	2,405	
OT Inefficiency & Premium Pay & Location Adjustment (not included above)							
Owner's Cost							
Owner's Development Costs (6.5%)	59.16	108	65.10	123	75.30	156	Shown for dry cooling
EPC Fees (12.5%)	113.76	207	125.20	236	144.81	301	Shown for dry cooling
Total Expected Costs with Wet Cooling	1,065	1,941	1,174	2,139	1,361	2,479	
Total Expected Costs with Dry Cooling	1,083	2,004	1,192	2,279	1,379	2,911	

Table 2-12 — Capital Cost Estimate for IGCC Using Black Mesa Coal at Black Mesa Site

	No CO_2 Removal		CO_2 Removal without Shift Conversion		90% CO_2 Removal		Comments
Net Output, MW	554.6		537.1		484.9		
Capital Costs	M$	$/kW	M$	$/kW	M$	$/kW	
Costs in Year 2006 Dollars							
Air Separation Unit	199	359	199	371	206	424	
Gasifier Area	295	531	295	549	305	629	Base Cost reduced for Existing Slurry
Sulfur Control	53	96	53	99	53	110	
Mercury Control	4	7	4	7	4	8	
CO_2 Capture	-	-	92	170	233	481	
Power Block	339	611	339	631	337	694	
Dry Cooling Additional Cost	15	27	15	28	15	31	If added for dry cooling reduce makeup water
Post-Combustion NO_X Control	5	10	5	10	5	11	
Total Cost with Wet Cooling	895	1,614	987	1,837	1,143	2,358	
Total Cost with Dry Cooling	910	1,641	1,002	1,865	1,158	2,389	
OT Inefficiency & Premium Pay & Location Adjustment (not included above)							
Owner's Cost							
Owner's Development Costs (6.5%)	59.16	107	65.10	121	75.30	155	Shown for dry cooling
EPC Fees (12.5%)	113.76	205	125.20	233	144.81	299	Shown for dry cooling
Total Expected Costs with Wet Cooling	1,065	1,921	1,174	2,117	1,361	2,454	
Total Expected Costs with Dry Cooling	1,083	1,953	1,192	2,219	1,379	2,843	

2.7.3 Operating and Maintenance Costs

O&M costs are separated into fixed and variable cost categories. Fixed costs include labor and maintenance. Variable costs include chemicals, catalysts, water use, waste disposal and other costs that vary as a function of the annual total production from the plant. A 100% capacity factor was assumed for this study to provide the maximum values for consideration. Adjustments can be performed to the variable cost values for alterative capacity factors. Table 2-13 provides the total O&M cost estimates for the facilities at Mohave. Costs for chemicals, catalyst, etc. are generally developed within IECM, and additional costs not covered by IECM (e.g., activated carbon for mercury control) are added. Water costs were provided, segregated between waters required from the C Aquifer for each site and from the Colorado River, which can be used at the Mohave site. Operating costs for the Black Mesa Site are listed in Table 2-14.

Table 2-13 — Operating and Maintenance Cost Estimate at Mohave

	No CO_2 Removal		CO_2 Removal without Shift Conversion		90% CO_2 Removal	
Net Output, MW	548.9		531.1		481.7	
O&M Costs	M$/yr	$/kW-yr	M$/yr	$/kW-yr	M$/yr	$/kW-yr
Fixed O&M						
Total Plant Labor	14.42	26.27	16.52	31.10	16.52	34.30
Total Maintenance Contract Labor	3.16	5.75	6.56	12.35	6.56	13.62
Total Plant Maintenance Materials	9.22	16.80	12.19	22.95	15.27	31.70
Total Fixed O&M	26.80	48.83	35.27	66.40	38.35	79.62
Variable O&M	M$/yr	$/MWh	M$/yr	$/MWh	M$/yr	$/MWh
Consumable Materials	4.67	0.97	4.73	1.02	5.35	1.27
Process Water from Colorado River	0.33	0.07	0.33	0.07	0.34	0.08
Cooling Water from Colorado River	0.90	0.19	0.90	0.19	0.94	0.22
Slurry Water from C Aquifer	1.76	0.37	1.76	0.38	1.83	0.43
	M$/yr	$/MWh	M$/yr	$/MWh	M$/yr	$/MWh
Mohave Variable O&M with Slurry	7.66	1.59	7.73	1.66	8.46	2.00

Table 2-14 — Operating and Maintenance Cost Estimate at Black Mesa

	No CO_2 Removal		CO_2 Removal without Shift Conversion		90% CO_2 Removal	
Net Output, MW	554.6		537.1		484.9	
O&M Costs	M$/yr	$/kW-yr	M$/yr	$/kW-yr	M$/yr	$/kW-yr
Fixed O&M						
Total Plant Labor	14.42	26.00	16.52	30.76	16.52	34.07
Total Maintenance Contract Labor	3.16	5.70	6.56	12.22	6.56	13.53
Total Plant Maintenance Materials	9.22	16.63	12.19	22.69	15.27	31.49
Total Fixed O&M	26.80	48.33	35.27	65.66	38.35	79.09
Variable O&M	M$/yr	$/MWh	M$/yr	$/MWh	M$/yr	$/MWh
Consumable Materials	4.67	0.96	4.73	1.01	5.35	1.26
	M$/yr	$/MWh	M$/yr	$/MWh	M$/yr	$/MWh
Black Mesa Variable O&M with Slurry	6.14	1.26	6.20	1.32	6.87	1.62

2.7.4 Byproduct Sulfur Production and Operating Credits

Sulfur is a commodity that is widely used for a variety of industrial purposes. One of its primary purposes is the production of sulfuric acid. If a market exists near the IGCC facility for sulfuric acid, capital and operating costs for the facility can be reduced by producing sulfuric acid rather than elemental sulfur. This is done at the Polk County gasification plant in Florida, where the acid is used in fertilizer manufacturing.

For this study, elemental sulfur is produced because it is safer to handle, transport, and store and there are no known larger users of sulfuric acid in the area of the plant sites. Production is shown at a 100% capacity factor basis, and adjustments can be determined for smaller production ratios.

Table 2-15 — IGCC Sulfur Production Estimate for Black Mesa Coal

Values at 100% Load and 100% Capacity Factor		No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
Sulfur	lb/mmBtu	0.34	0.38	0.38
	lb/n-MWh	3.34	3.92	4.49
	tpy	7,913	8,973	9,321
Ash (Slag)	lb/mmBtu	6.17	6.17	6.17
	lb/n-MWh	61.1	63.2	72.4
	tpy	144,709	144,709	150,210
	acres for 30 years (40 ft high)	124		

2.8 PERMITTING ISSUES

The construction of an IGCC plant at the existing Mohave site near Laughlin, Nevada or the Black Mesa mine site will entail a number of permits and approvals before the start of construction. Some permits should be obtained once construction begins, and others should be obtained during commissioning of the plant. The importance of establishing a strict permitting schedule cannot be overstated, as certain procedures (i.e., ambient air quality monitoring and modeling) will require up to two years of lead time. With an adequate knowledge of the applicable regulations and the information required in the various permit applications, SCE can implement an effective permit strategy.

The State of Arizona Department of Environmental Quality (ADEQ) and the U.S. EPA Region IX have designated authority over environmental permitting in Navajo tribal lands to the Navajo Nation EPA (Delegation Agreement #00-0024). This designation affects all air, water, and solid waste permitting issues. There have been some historical disputes between the Navajo Nation and the Hopi Nation over tribal boundaries and control of activities at the Black Mesa Mine; it is not known how these disputes would affect the ability to develop an IGCC plant at the site.

- **Air Quality Construction Permits.** A New Source Review (NSR) / Prevention of Significant Deterioration (PSD) air quality construction permit is the primary approval necessary for the construction of a power plant. The U.S. Environmental Protection Agency (EPA) has delegated authority for the implementation and enforcement of the NSR/PSD regulations to the Nevada Department of Conservation and Natural Resources – Division of Environmental Protection (NV-DEP).

Under NSR, new major stationary sources with the potential to emit "significant" amounts of air pollution are required to obtain approval before commencing construction. Table 2-16 gives the major stationary source thresholds for coal and natural gas-fired power plants. An IGCC plant utilizes coal to great a syngas for running a combustion turbine, so it is not clear which unit configuration in Table 2-16 would apply. Whatever the definition, a 500-MW IGCC plant at either of the two sites would surely be designated as a major stationary source.

Table 2-16 — Definition of Major Stationary Source

Unit Configuration	Is Unit Configuration Included in One of the 28 Source Categories?	Unit is Classified as a Major Stationary Source if it has the Potential to Emit Greater Than….
Coal-Fired Plant with Heat Input >250 mmBtu/hr	Yes	100 tpy
Coal-Fired Plant with Heat Input < 240 mmBtu/hr	No	250 tpy
Natural Gas-Fired Combined-Cycle Plant with HRSG and Heat Input >250 mmBtu/hr	Yes	100 tpy
Natural Gas-Fired Combined-Cycle Plant with HRSG and Heat Input <250 mmBtu/hr	No	250 tpy
Natural Gas-Fired Simple-Cycle Combustion Turbine – any size	No	250 tpy

Construction of a new major stationary source will be subject to NSR review if potential emissions from the new source are "significant." Significant emissions thresholds are defined in terms of annual emissions rates in tons per year (tpy). Table 2-17 lists the pollutants for which significant emission rates have been established.

Table 2-17 — PSD Significant Emission Rates

Pollutant	Significant Emissions Rate (tpy)
CO	100
NO_X	40
SO_2	40
PM_{10}	15
VOC	40
H_2SO_4 mist	7

Source: 40 CFR 52.21 (b) (23)

Major new stationary sources in Nevada are required to submit an Air Use Permit application to the NV-DEP before starting construction. A new source in Navajo County would be required to submit a permit application to the Navajo Nation EPA – Air Quality Control Program. The Air

Use Permit application is used to identify all applicable federal and state regulations. The permit application requires a comprehensive description of the proposed project including—

- Process description
- Regulatory discussion describing all federal, state, and local air pollution control regulations and a discussion of how the proposed process unit complies with each regulation
- Best Available Control Technology analysis
- Emissions summary and calculations
- Stack/vent parameters
- Site description and process equipment location drawings
- Additional supporting information for specific processes and equipment

The Mohave site is located in Clark County, Nevada. Portions of Clark County (the greater Las Vegas metropolitan area) are currently designated as non-attainment for Carbon Monoxide (CO), 8-hour Ozone (O_3), and Particulate Matter less than 10 microns (PM_{10}). Although the Mohave site is not located in the non-attainment area, its close proximity would require that the owners of the proposed plant evaluate its impact on the non-attainment area.

The Black Mesa site is located in Navajo County, Arizona, which is currently in attainment for all criteria pollutants. There are no non-attainment counties near the site that would require an impact assessment or further emissions reductions.

It can take up to two years to obtain a Final Air Quality Construction permit: six to nine months to conduct modeling and prepare the permit application material; one year for the state to review the material and issue a draft permit; and three months for public comment and revisions before issuing the final permit.

- **Ambient Air Monitoring.** The NV-DEP and Arizona DEQ maintain systems of ambient air quality monitors throughout the state. Continuous data is collected for O_3, SO_2, NO_X, CO, PM_{10}, $PM_{2.5}$, and meteorological data. An automated data acquisition system is used to retrieve the data from all monitoring locations onto a central data management system. There are many ambient monitors in Clark County, primarily because of the Las Vegas non-attainment area and the operation of large stationary sources such as the existing Mohave station. The NV-DEP and Arizona DEQ conduct routine maintenance and calibration of these monitors for quality assurance.

  Data from the ambient air quality monitors are used to determine compliance with the National Ambient Air Quality Standards (NAAQS), shown in Table 2-18. The data are used to chart long-term trends in air quality and establish goals. Furthermore, the ambient air quality data are a necessary input for air quality modeling that is used for determining the impact of a proposed power plant.

Table 2-18 — National Ambient Air Quality Standards

Pollutant	Primary Standard 1	Primary Standard 2
PM_{10}	50 µg/m3 (annual mean)	150 µg/m3 (24-hour - 99th percentile)
$PM_{2.5}$	15 µg/m3 (annual mean)	65 µg/m3 (24-hour – 98th percentile)
SO_2	0.03 ppm (annual mean)	0.14 ppm (2nd highest 24-hour)
O_3	0.12 ppm (2nd highest 1-hour)	0.08 ppm (4th highest 8-hour)
CO	9 ppm (8-hour average)	35 ppm (1-hour average)
NO_X	100 µg/m3 (annual mean)	--
Pb	1.5 µg/m3 (quarterly average)	--

- **Air Quality Modeling.** Air quality modeling is used to estimate impacts to ambient air to determine whether the proposed power plant will result in pollutant concentration levels that exceed the applicable ambient air standards. Models allow one to forecast future air quality levels from sources that have not been constructed. Federal law requires that the NV-DEP and Navajo Nation EPA have legally enforceable procedures in place to prevent construction or modification of any source where the emissions from the projected activity would interfere with the attainment and maintenance of the National Ambient Air Quality Standards (NAAQS).

  The primary U.S. EPA modeling guidelines are discussed in *40 CFR Part 51, Appendix W – Guideline on Air Quality Models*. There are two levels of sophistication for air quality models. The first level consists of relatively simple estimation techniques that generally use preset, worst-case meteorological conditions to provide conservative estimates of the air quality impact of a specific source. These are called screening techniques or screening models. The purpose of such techniques is to eliminate the need of more detailed modeling for those sources that clearly will not cause or contribute to ambient concentrations in excess of either the NAAQS or the allowable PSD concentration increments. If a screening technique indicates that the concentration contributed by the source exceeds the PSD increment or the increment remaining to just meet the NAAQS, then the second level of more sophisticated models should be applied.

  The second level consists of those analytical techniques that provide more detailed treatment of physical and chemical atmospheric processes, require more detailed and precise input data, and provide more specialized concentration estimates. As a result, they provide a more refined and, at least theoretically, a more accurate estimate of source impact and the effectiveness of control strategies. These are referred to as refined models.

  The U.S. EPA lists a number of recommended and alternative air quality modeling software. Regardless of the sophistication of the software, the utility of the model largely depends on the availability of good meteorological and ambient air quality data. An applicant for an air quality construction permit in Nevada will need to adequately satisfy the NV-DEP that the air quality in the Las Vegas metropolitan non-attainment area will not be negatively impacted by the project. An applicant for a air quality construction permit in Arizona will need to adequately satisfy the Navajo Nation EPA that the air quality of all neighboring counties remain in attainment with the NAAQS.

- **BACT/LAER Analysis.** The developer of the new plant will need to demonstrate that their planned IGCC plant will be employ the Best Available Control Technology (BACT) for all criteria pollutants. BACT is defined as an emissions limitation based on the maximum degree of reduction which, on a case-by-case basis, is determined to be achievable taking into account energy, environmental, and economic impacts and other costs. Since IGCC power plants are just beginning to be permitted in the U.S., it is unknown whether a SCR system will be required. The close proximity of the Las Vegas 8-hour non-attainment area to the Mohave site may necessitate the use of an SCR to further reduce NO_X emissions. Low-NO_X burners (LNB) are standard for most new combustion turbines; with syngas firing, typical NO_X emission rates will be on the order of 25 ppmvd (at 15% O_2). Recent BACT determinations have required CO emission limits in the 9.0 to 25.0 ppmvd range. Because of the close proximity to the CO non-attainment area in Las Vegas, an oxidation catalyst (OC) may be required to reduce emissions by an additional 70% to 90%. The gasification process will remove most PM_{10}, SO_2 and H_2SO_4 from the syngas, and would be considered BACT.

- **Class I Area Impact Review.** The Clean Air Act Amendments of 1977 gave Federal Land Managers (FLM) an affirmative responsibility to protect the natural and cultural resources of Class I areas from the adverse impacts of air pollution. Class I areas include certain national parks and wilderness areas. FLM responsibilities include the review of air quality permit applications from proposed new major sources near Class I areas. If the FLM determines that emissions from a proposed source will contribute to adverse impacts on the air quality or visibility of a Class I area, then he may recommend to the NV-DEP that the permit be denied, unless the impacts can be mitigated.

  All new emission sources that have the potential to impact visibility in a Class I area will be subject to pre-construction review by the FLM. Visibility impacts are predicted using computer modeling (e.g., CalPUFF), and are generally a function of emissions of SO_2, SO_3, NO_X, PM_{10}, and ammonia. Sources located near a Class I area will be subject to more rigorous review, and if visibility impacts are predicted by the model, the permitting agency may impose more stringent emission requirements.

  The Mohave site is located near numerous Class I areas in California, Utah, and Arizona. Table 2-19 lists the distances between these Class I areas and Laughlin, Nevada.

Table 2-19 — Distances from Laughlin, Nevada, to Class I Areas

Class I Area	Distance (miles)
Domeland Wilderness Area (CA)	202
San Gabriel Wilderness Area (CA)	179

Class I Area	Distance (miles)
Cucamonga Wilderness Area (CA)	184
San Gorgonio Wilderness Area (CA)	139
San Jacinta Wilderness Area (CA)	144
Joshua Tree Wilderness Area (CA)	119
Grand Canyon National Park (AZ)	152
Sycamore Canyon Wilderness Area (AZ)	145
Pine Mountain Wilderness Area (AZ)	174
Mazatzal Wilderness Area (AZ)	195
Zion National Park (UT)	162

The Black Mesa site is located near numerous Class I areas in Arizona, Utah, Colorado, and New Mexico. Table 2-20 lists the distances between these Class I areas and Kayenta, Arizona.

Table 2-20 — Distances from Black Mesa Mine (Kayenta, Arizona) to Class I Areas

Class I Area	Distance (miles)
Grand Canyon National Park (AZ)	116
Sycamore Canyon Wilderness Area (AZ)	141
Pine Mountain Wilderness Area (AZ)	190
Mazatzal Wilderness Area (AZ)	181
Sierra Ancha Wilderness Area (AZ)	205
Petrified Forest National Park (AZ)	122
Zion National Park (UT)	158
Bryce Canyon National Park (UT)	119
Canyonlands National Park (UT)	99
Mesa Verde National Park (CO)	104
Weminuche Wilderness Area (CO)	160
San Pedro Parks Wilderness Area (NM)	188

- **Local Air Quality Permits.** The Clark County Department of Air Quality and Environmental Management (DAQEM) issues permits for all boilers and steam generators in the county. This permit would be applicable to the heat recovery steam generator (HRSG) that is a component of an IGCC plant. The permit application requests basic information, such as the manufacturer name, serial number, boiler rating (in hp), minimum and maximum rating per burner (in ft^3/hr or gal/hr), stack height and diameter, exhaust velocity and temperature, and capacity factor.

The Clark County DAQEM also issues permits for cooling towers. This permit application requests basic information, such as manufacturer name, serial number, circulation rate (in gal/min), maximum TDS (in ppm or mg/L) before purging, drift eliminators and drift loss percentage, and maximum hours of operation per day and per year.

- **Wastewater Discharge Permits.** The existing coal fired power plant (2 x 790 MW) sends its cooling tower blowdown and other plant discharges to a series of lined evaporation ponds. Domestic wastewater from the plant is also treated and sent to evaporation ponds. No plant effluent is discharged to any surface or ground waters of the United States. New IGCC plants at the Mohave or Black Mesa sites would likely use a zero liquid discharge (ZLD) system.

The liquid effluent from a new IGCC plant at the Mohave site would be considerably greater than an NGCC plant, especially if slurry coal were to be used in the gasifier. It is not known whether the existing evaporation ponds could accommodate the additional load or a new evaporation pond will be needed.

Although a traditional National Pollutant Discharge Elimination System (NPDES) permit would not be required, the ZLD system would still require permitting approval from the NV-DEP. The existing permit for Mohave Station (permit #NEV30007) requires leak detection systems for the ponds at the site. Such methods include geophysical survey equipment, visual sump inspections, visual liner inspections, and monitoring wells. There are no flow limitations in the permit, except for the package sewage treatment plant design capacity of 36,000 gallons per day.

There are currently areas of groundwater contamination (high mineral content) on the site from leaking ponds that occurred in the early years of the plant. The existing permit requires an on-going remediation program to bring the groundwater quality to an electrical conductivity below 1,000 microsiemens. The site groundwater is expected to be completely remediated by July 2007.

A new IGCC plant at Mohave would use the existing ZLD system at the site, or it would require the construction of new ponds to accommodate plant effluent. In either case, the permit with the NV-DEP would need to be revised. This revision would require a public comment period and a public hearing before final issuance of the permit. The total time required for this permit revision could range from 6 months to 1 year.

A ZLD system at the Black Mesa site would require permitting approval from the Navajo Nation EPA – Surface and Groundwater Protection Department. The historic mining and water withdrawals (to operate the coal slurry pipeline) at the site have affected the groundwater quality, so any new discharges to the surface or groundwater would require substantial impact modeling. The Navajo Nation EPA issues NPDES permits for discharges to the surface water bodies, and Underground Injection Control permits for discharges into deep wells. The maximum contaminant levels (MCLs) for drinking water must not be exceeded if the IGCC plant discharged to the surface or groundwater.

During construction, the site would require a General Number 2 NPDES permit (storm water discharges from construction activities) from the Nevada DEP or the Navajo Nation EPA. As part of this permit, the construction contractor would need to create a Storm Water Pollution

Prevention Plan (SWPPP), which details the measures for preventing debris from entering local streams. A SWPPP typically performs the following functions:

— Identifies all potential sources of pollution which may reasonably be expected to affect the quality of storm water discharges from the construction site
— Describes practice to reduce and sequester pollutants in the storm water discharges
— Assures compliance with the terms and conditions of the General Number 2 NPDES permit

- **U.S. Army Corps of Engineers Permits.** It is unlikely that there are any jurisdictional wetlands in this arid region of the United States, requiring a permit from the U.S. Army Corps of Engineers. However, if a new natural gas pipeline connection to the site crossed any "waters of the United States," including dry creek beds, then a Nationwide Permit #12 (Utility Line Activities) would be required. This general permit allows installation of a pipeline underneath the river or creek, but requires that the water body be returned to its original condition.

- **Solid Waste Disposal Permits.** At an IGCC plant, the gasification process results in a vitreous coal waste. There may be some recycling options for this waste, although an on-site landfill will be the most likely fate.

  The existing coal-ash landfill at the Mohave site may be able to accommodate the additional load from a new IGCC plant. However, if the landfill would need expansion, then a permit from the Clark County Health District – Office of Solid Waste & Compliance would be required. The height and slope limits of the landfill will be set by the County.

  At the Black Mesa site, the coal waste could potentially be disposed in areas of prior mining, as part of an overall land reclamation process. The permitting of a coal waste landfill is under the auspices of the Navajo Nation Division of Community Development – Solid Waste Management Program. The landfill design would need the appropriate clay and geo-membrane liners, leachate collection systems, groundwater monitoring wells, and other typical requirements. The height and slope limits of the landfill will be set by the Navajo Nation.

  The permit application will request information such as the engineering specifications, environmental monitoring plan, closure plans, and financial assurance documentation. The total time required for a new solid waste landfill permit could range from 6 months to 1 year.

  During construction, hazardous and non-hazardous wastes would be disposed of off-site using a licensed commercial hauler. The plant should make a concerted effort to reuse or recycle construction debris and excavated material.

- **Public Utility Commission of Nevada (PUCN).** Any new power generation facility in the State of Nevada will require a Certificate of Public Convenience and Necessity (CPCN) from the PUCN. To obtain a CPCN, an applicant must demonstrate that there is a public need for a new facility and that the proposed utility is willing to serve and able to fulfill the public need.

- **Arizona Corporation Commission.** The Arizona Corporation Commission (ACC) typically regulates providers of electric service in Arizona and approves the siting of new power plants. They issue Public Convenience and Necessity (CPCN) determinations for investor-owned and cooperative utilities. However, the ACC does not have authority over power plant siting in tribal lands. A new IGCC plant at the Black Mesa Mine site would not require ACC approval.

Any new transmission lines or natural gas pipelines that exit Navajo County may be subject to the ACC regulations.

- **Zoning / Land Use Permits.** The Mohave site is currently zoned for power plant use. It is assumed that a new IGCC power plant could be located entirely within the existing site. While there is no need to obtain a zoning change, the project developers will still need to submit a "Major Project Application: Specific Plan or Land Use & Development Guide" with the Clark County Department of Development Services. This guide costs $1,000 plus $4 per acre (for all acres over 300 acres). The applicant needs only to submit a description of the project and the location of the property (parcel numbers).

  It is possible that some of the landscaping, parking, and fencing requirements have changed since the original plant was built. The Clark County Department of Development Services maintains an Industrial Development Checklist with all of the applicable conditions.

  The Black Mesa Mine site is currently zoned for mining. A new IGCC power plant at the site would require a zoning change from the Navajo Nation Division of Community Development.

- **Building Permits.** For the Mohave site, the Clark County Department of Development Services issues all building and civil design permits. For the Black Mesa site, the Navajo Nation Division of Community Development – Design and Engineering Services issues all building permits. These permits are typically obtained throughout construction, and the applications are submitted in phases. The first permits are for grubbing, grading, and other necessary earthwork. Next are the foundation permits for all buildings, warehouses, equipment skids, cooling towers, and so forth. Structural permits come next, as the building fabrications begin. These are followed by plumbing, mechanical (i.e., HVAC), electrical, and fire protection permits for all occupied buildings. The offices, control room, restrooms, and showers will need to be handicap accessible. There will likely be periodic inspections of the construction site by building inspectors and fire officials.

  Obtaining building permits for a major project, such as a power plant, will require continuous interaction with Clark County or Navajo Nation staff. It is recommended that the project team meet with the appropriate Development Services personnel to establish a submittal schedule and determine how drawings and calculations will be submitted. In some instances a local permit expediter may need to be hired in order to accelerate the permitting process.

- **Other Permits.** A number of minor permits will be required for construction of an IGCC power plant at the Mohave or Black Mesa sites. The delivery of plant equipment in overweight or oversized trucks would require a special use permit from the Nevada Department of Transportation or Arizona Department of Transportation for state highways, or the Navajo Department of Transportation (NDOT) for tribal roads. NDOT also grants archeological clearance for major projects. The construction of a tall stack would require an Obstruction Hazard Determination from the Federal Aviation Administration.

  An IGCC power plant could potentially use fuel oil for startup operations, fire pumps, and emergency generators. Any large petroleum storage tank at the site (>1,100 gallons aboveground, any size below ground) would require a permit from the Clark County Fire Marshall. In addition, the site would need to update its Spill Prevention Control and

Countermeasure (SPCC) plan to account for the new tanks. The SPCC plan (spelled out in 40 CFR Part 112) details how potential spills of petroleum products would be contained.

2.9 CONCEPTUAL PROJECT CONSTRUCTION SCHEDULE

The amount of time required to complete an IGCC facility is about 5 to 6 years from the decision to begin. Actual construction can be accomplished in about 3½ years, which will be followed by a period of about 6 months for startup and commissioning of the plant equipment. The more critical timing aspect is in the front-end decision process and selection of a technology and in the amount of time required to receive permitting and all approvals necessary to begin construction. These periods are shown in the typical schedule shown in Appendix G.

2.10 GENERATION PROFILE AND LOAD DEMAND

The output of the IGCC facility is typical of a baseloaded combined-cycle combustion turbine. The output from the plant will be influenced by the ambient temperatures. In general, power output will improve with decreasing temperatures and decrease with increasing temperatures. The graphs in Section 2.2.6 (Figure 2-6 through Figure 2-10) can be used to assess the variation in output with temperature.

The overall output from the plant is a function of the configuration, that is, a 2 x 2 x 1 combustion turbine, HRSG, and steam turbine of 540 MW in the base case. Lower outputs depend on the extent of carbon dioxide capture desired. The plant can be adjusted in scale by changing the number of combustion turbines installed at the site. The combinations of plant configurations possible and the outputs possible are listed in Table 2-21. It is not possible to select a specific output for an IGCC facility (e.g., 700 MW) since the combustion turbine equipment and associated steam turbine output and auxiliary power demand determine the plant capacity for each configuration.

Table 2-21 — Output for Alternative IGCC Facility Configurations

Configuration	Net output, MW		
	No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
1x1x1	269	260	228
2x2x1	**549**	**531**	**482**
3x3x1	812	786	689

Configuration	Net output, MW		
	No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
4x4x2	1,084	1,049	919
5x5x2	1,356	1,312	1,150

2.11 EMPLOYMENT CHARACTERISTICS

2.11.1 Construction Labor

Table 2-22 provides the anticipated craft labor estimate for the types and duration of skilled workers needed to construct an IGCC facility. The estimated total is 4,110 man-months. Peak work force on site is anticipated to average 120 craft labor workers over about two years. Additional construction supervision, engineering, and site support is required, but was not directly estimated.

Table 2-22 — Construction Labor Estimate

Craft	Man-Months
Insulation Workers	220
Boilermakers	650
Cement Finishers	50
Carpenters	380
Electricians	860
Ironworkers	450
Laborers	390
Millwrights	140
Operating Engineers	200
Painters	80
Pipe Fitters	430
Sheet Metal Workers	100
Surveyors	90
Teamsters	70
Total	4,110
Peak Labor	120

2.11.2 Operations and Maintenance Labor

The labor force required to operate the facility assumes a labor force necessary for performance of all functions of the facility with minimal subcontracting for routine services (such as coal analysis). Assumed total operating staff is based on five shifts. It is assumed that routine labor costs approximately 1/3 of total maintenance cost and is performed by technicians on site because of the relatively remote nature of both sites from areas where industrial trades can be readily called upon to service the plant equipment. Contract labor is assumed for a percentage of maintenance costs that cannot be accommodated by the plant staff. Maintenance material is a percentage of capital equipment, using the IECM factors.

Administration and other staff include shift supervision, engineering, laboratory staff, plant management, and clerical support.

Labor costs are assumed to be $70,000 per year per person averaged across the entire work force. S&L has found that this is a reasonable assumption when estimating aggregate power generation plant budgets for total labor for all persons at the plant in all job categories. For this level of study, it is not necessary to perform a detailed cost analysis for each job description.

The staffing and maintenance costs are summarized in Table 2-23.

Table 2-23 — Labor and Maintenance Cost Estimate for IGCC

	No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
Operating Labor Staff	145	155	155
Onsite Maintenance Staff (1/3 of Maintenance Labor)	20	30	40
Administration and Eng. Other Staff	41	41	41
Total Labor Staff	206	236	236
Total Cost of Labor, M$/yr	$ 14.42	$ 16.52	$ 16.52
Contract Labor, M$/yr	$ 3.16	$ 6.56	$ 6.56
Maintenance Material Costs, M$/yr	$ 9.22	$ 12.19	$ 15.27
Maintenance Labor Costs, M$/yr	$ 4.56	$ 6.54	$ 9.36

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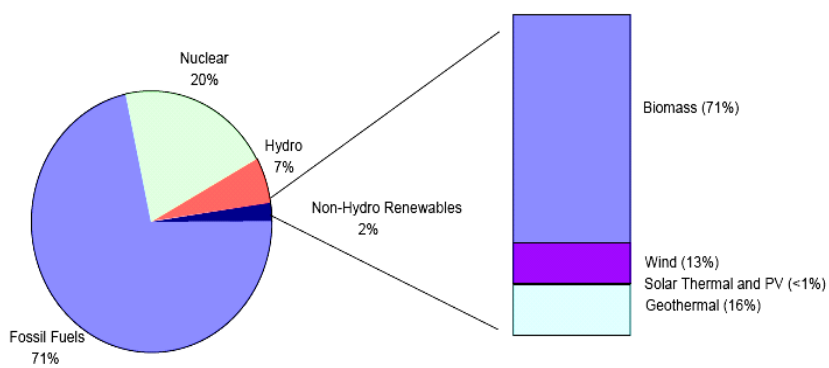
3. SOLAR TECHNOLOGY

In 2003, the United States generated 3,883 billion kilowatt-hours of electricity (Energy Information Administration, *Electric Power Annual*, December 2004). About 71% of United States electricity was generated from fossil fuels, about 20% from nuclear power, another 7% from hydroelectric facilities, and the remaining 2% from other renewables (Figure 3-1). Biomass (71%) was the predominant non-hydro renewable fuel for electricity generation in 2003, followed by geothermal and wind. Solar thermal and photovoltaics together accounted for less than 1% of U.S. non-hydro renewable generation.

Figure 3-1 — United States Electricity Generation, 2003



Source: Energy Information Administration, *Electric Power Annual 2003*, December 2004 and *Electric Power Monthly*, November 2004

The most important law promoting renewable energy in the 1990s was the Energy Policy Act (EPACT) of 1992. EPACT established a 10-year inflation-adjusted production tax credit (PTC) of 1.5 cents per kWh for tax-paying privately and investor-owned wind projects and closed-loop biomass plants brought online between 1994 and 1999. The incentive expired in 1999, but had been renewed twice, in 1999 and 2001, before its expiration at the end of 2003. Late in 2004, it was extended again through 2005. This latest extension increased the number of renewable technologies that are covered by the incentive. While EPACT significantly improved the economics of wind power, another U.S. policy, implemented thus far at a state level, has been more beneficial to the installation of solar photovoltaic generation. This policy is net metering, which allows small producers of renewable energy from selected sources to sell their power back to the grid. The buyback rate is determined by law and is frequently equal to the retail electricity rates, or sometimes slightly less than retail rates. Net metering programs are designed for small electricity customers (residential or small commercial) who produce their own power to bank power on the grid in times of surplus and draw down from the grid in times of need. As of September 2004, net metering was available in 32 states and the District of Columbia (DSIRE, "Rules Regulations and Policies," http://www.dsireusa.org/summarytables/reg1.cfm). Most states set size limits on systems for net metering eligibility with many states having capacity limits of around 25 kW, though limits vary from 10 kW in New Mexico to 1,000 kW in California (DSIRE, "Net Metering Programs," http://www.dsireusa.org/library/docs/ NetMetering_Map.doc).

The limited generation provided by solar thermal and photovoltaics is primarily due to high capital cost, which is partially, but not entirely, offset by lower O&M costs. Dispatchability is another important issue. Besides being more costly than conventional generating sources, concentrating solar power (CSP) electricity generation is also more costly than certain other renewable power generating technologies (notably wind) due primarily to CSP's higher capital cost. CSP cost-competitiveness relative to other renewables is important because CSP will be compared with other renewable technologies in states that have adopted renewable portfolio standards.

3.1 CONCENTRATING SOLAR POWER TECHNOLOGIES

Two types of CSP applications were investigated: dispatchable power systems and distributed power systems. Dispatchable power systems are capable of providing dispatchable intermediate-load generation in the wholesale bulk-power market, such as the Mohave Generating Station. Distributed power systems provide distributed generation, grid support, remote, and village power markets. Distributed energy resources are parallel and stand-alone electric generation units located within the electric distribution system at or near the end user.

There are four CSP technologies being promoted internationally:

- Parabolic trough
- Dish/Stirling engine
- Power tower
- Photovoltaics

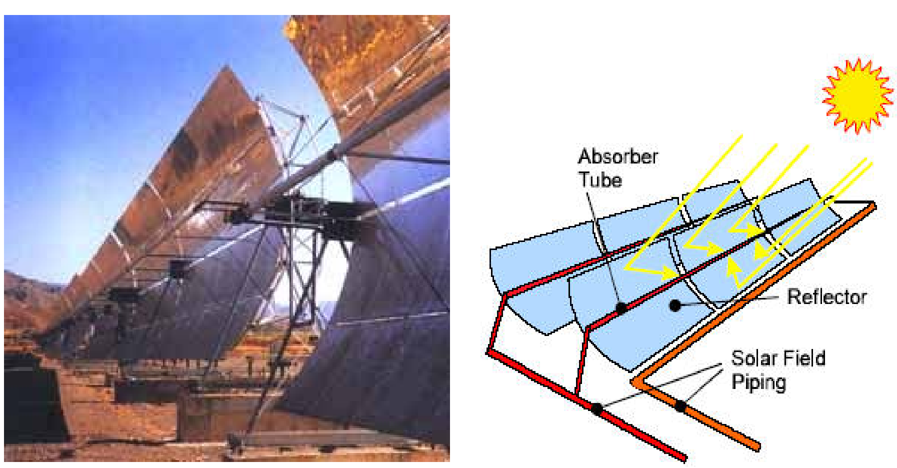
For each of these, there exist several design variations or different configurations. The amount of power generated by a CSP plant depends on the amount of direct sunlight. These technologies use only direct-beam sunlight, rather than diffuse solar radiation.

3.1.1 Parabolic Trough

Parabolic-trough systems concentrate the sun's energy through long rectangular, curved (U-shaped) mirrors. The solar field is modular and is composed of many parallel rows of solar collectors aligned on a north-south horizontal axis. Each solar collector has a linear parabolic-shaped reflector that focuses the sun's direct beam radiation on a linear receiver located at the focus of the parabola. The collectors track the sun from east to west during the day to ensure that the sun is continuously focused on the linear receiver. A heat transfer fluid (HTF) is heated as it circulates through the receiver and returns to a series of heat exchangers in the power block where the fluid is used to generate high-pressure superheated steam. The superheated steam is then fed to a conventional reheat steam turbine-generator to produce electricity. The spent steam from the turbine is condensed in a standard condenser and returned to the heat exchangers via condensate and feedwater pumps to be transformed back into steam. After passing through the HTF side of the solar heat exchangers, the cooled HTF is recirculated through the solar field.

Parabolic trough technology is currently the most proven solar thermal electric technology. This experience is primarily the result of the nine commercial-scale Solar Electric Generating Station (SEGS) solar power plants, the first of which has been operating in the California Mojave Desert since 1984. These plants, which continue to operate daily, range in size from 14 to 80 MW and represent a total of 354 MW of installed electric generating capacity.

Figure 3-2 — Parabolic Trough Concept



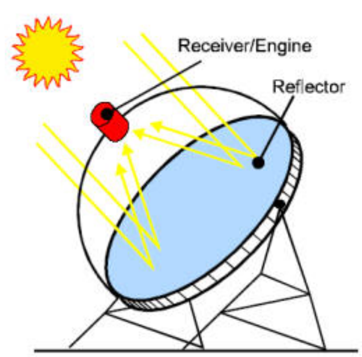
3.1.2 Dish/Stirling engine

A dish/engine system uses a mirrored dish (similar to a very large satellite dish). The dish-shaped surface collects and concentrates the sun's heat onto a receiver, which absorbs the heat and transfers it to a working gas within the engine. The heat causes the gas to expand against a piston or turbine to produce mechanical power. The mechanical power is then used to run a generator or alternator to produce electricity.

Dish/engine systems are characterized by high efficiency, modularity, and autonomous operation. Of all solar technologies, dish/engine systems have demonstrated the highest solar-to-electric conversion efficiency (29.4%) and, therefore, have the potential to become one of the least expensive sources of renewable energy. The modularity of dish/engine systems allows them to be deployed individually for remote applications, or grouped together for small-grid or end-of-line utility applications.

There are no commercial dish-Stirling power plants operating today. Current development in the United States is focused on prototype system of 10 units in active development and testing at Sandia National Laboratories (SNL) under a joint agreement between Stirling Engine Systems (SES) (Phoenix) and Sandia. In early August 2005, Southern California Edison publicly announced the completion of negotiations on a 20-year power purchase agreement with SES for between 500 MW and 850 MW of capacity (producing 1,182 to 2,010 GWh/yr) from the first commercial deployment of this new solar thermal generating technology. SES also signed an agreement for between 300 and 900 MW with San Diego Gas and Electric in September 2005.

Figure 3-3 — Dish/Stirling Engine Concept



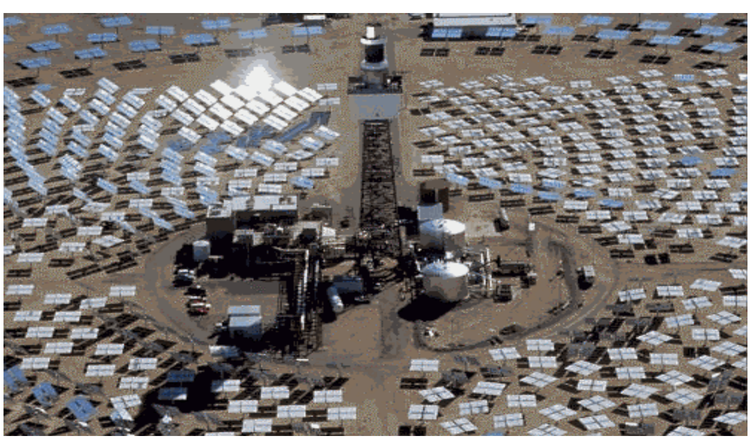
3.1.3 Power Tower

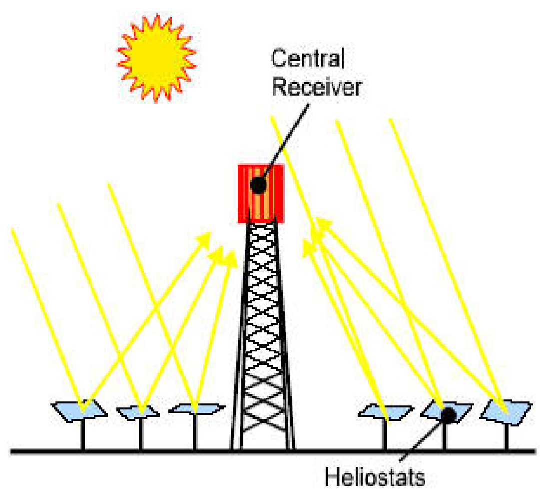
Solar power towers generate electric power from sunlight by focusing concentrated solar radiation on a tower-mounted heat exchanger (receiver). The system uses hundreds to thousands of sun-tracking mirrors called heliostats to reflect the incident sunlight onto the receiver.

In a molten-salt solar power tower, liquid salt at 290ºC (554ºF) is pumped from a ‘cold’ storage tank through the receiver where it is heated to 565ºC (1,049ºF) and then on to a ‘hot’ tank for storage. When power is needed from the plant, hot salt is pumped to a steam generating system that produces superheated steam for a conventional Rankine cycle turbine-generator system, similar to that used in the parabolic-trough system. From the steam generator, the salt is returned to the cold tank where it is stored and eventually reheated in the receiver.

Power tower plants are commercially less mature than parabolic-trough systems, are not modular, and cannot be built in the smaller sizes of dish/Stirling or trough-electric plants and be economically competitive. There are currently no commercial power tower plants in operation. Experimental and prototype systems have been placed in operation in Spain, France, Israel, and the United States, the largest of which were the two 10-MW Solar One and Solar Two plants near Barstow, California.

Figure 3-4 — Power Tower Concept





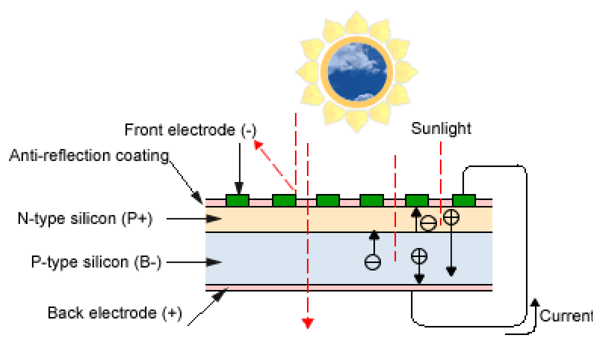
3.1.4 Photovoltaics

Concentrating photovoltaic (CPV) systems use lenses or mirrors to concentrate sunlight onto high-efficiency solar cells. These solar cells are typically more expensive than conventional cells used for flat-plate photovoltaic systems. However, the concentration decreases the required cell area while increasing the cell efficiency.

Photovoltaic output is dc voltage and an inverter is required to convert to ac voltage.

There are no commercial CPV power plants in operation. A series of pre-commercial development systems totaling 500 kW are operating in Arizona under the auspices of Arizona Public Service (APS), and a 200+ kW system is in operation in Australia. Planned deployments in the near future include 5 MW by APS, several megawatts in Australia, and an undetermined level in Europe.

Figure 3-5 — Photovoltaic Concept



3.2 SOLAR RESOURCE

The total amount of convertible solar energy (direct normal insolation) is measured in kilowatt-hours per square meter per day (kWh/m^2/day). At high noon on a clear day, with the sun directly overhead, each square meter receives 1 kilowatt of sun power. If the solar resource in an area is 6 kWh/m^2/day that means the actual power realized in a day is equal to 6 hours of full sun. Insolation values of 8 to 9 kWh/m^2/day are considered premium; values of 7 to 8 kWh/m^2/day, very good; and values of 6 to 7 kWh/m^2/day, good.

An insolation map developed by the U.S. Department of Energy – National Renewable Energy Laboratory (NREL) is provided in Figure 3-6. The majority of the Navajo/Hopi reservations area is shown to have a very good insolation value of 7 to 8 kWh/m^2/day.

Figure 3-6 — CSP Resource Potential

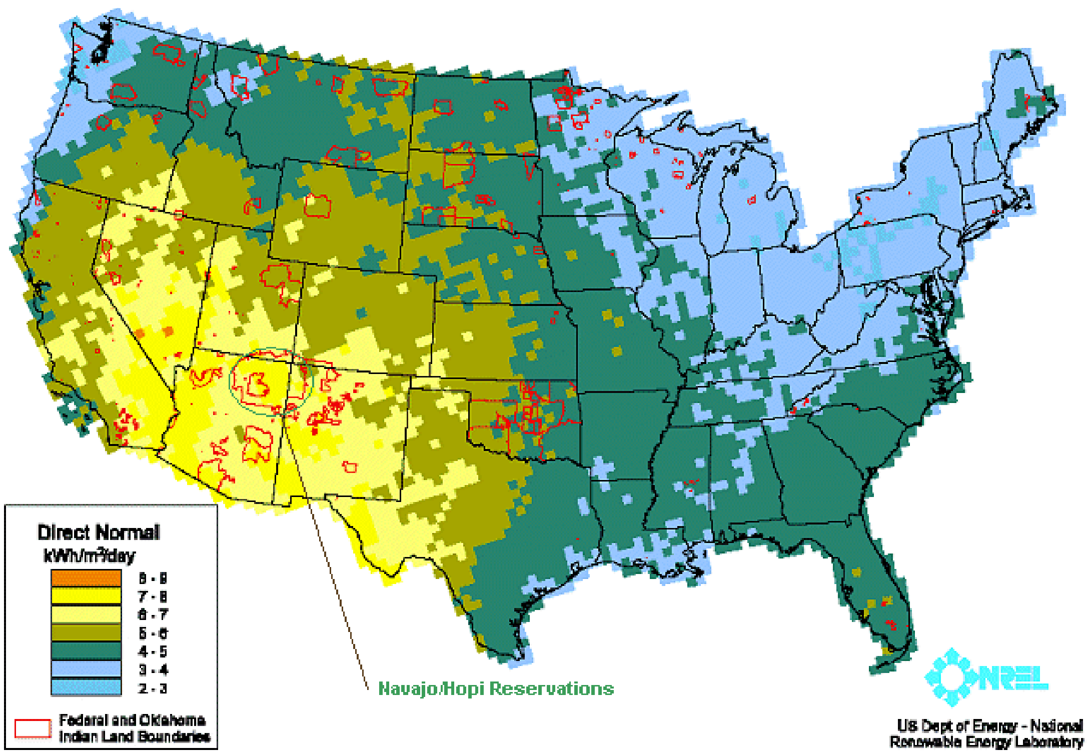
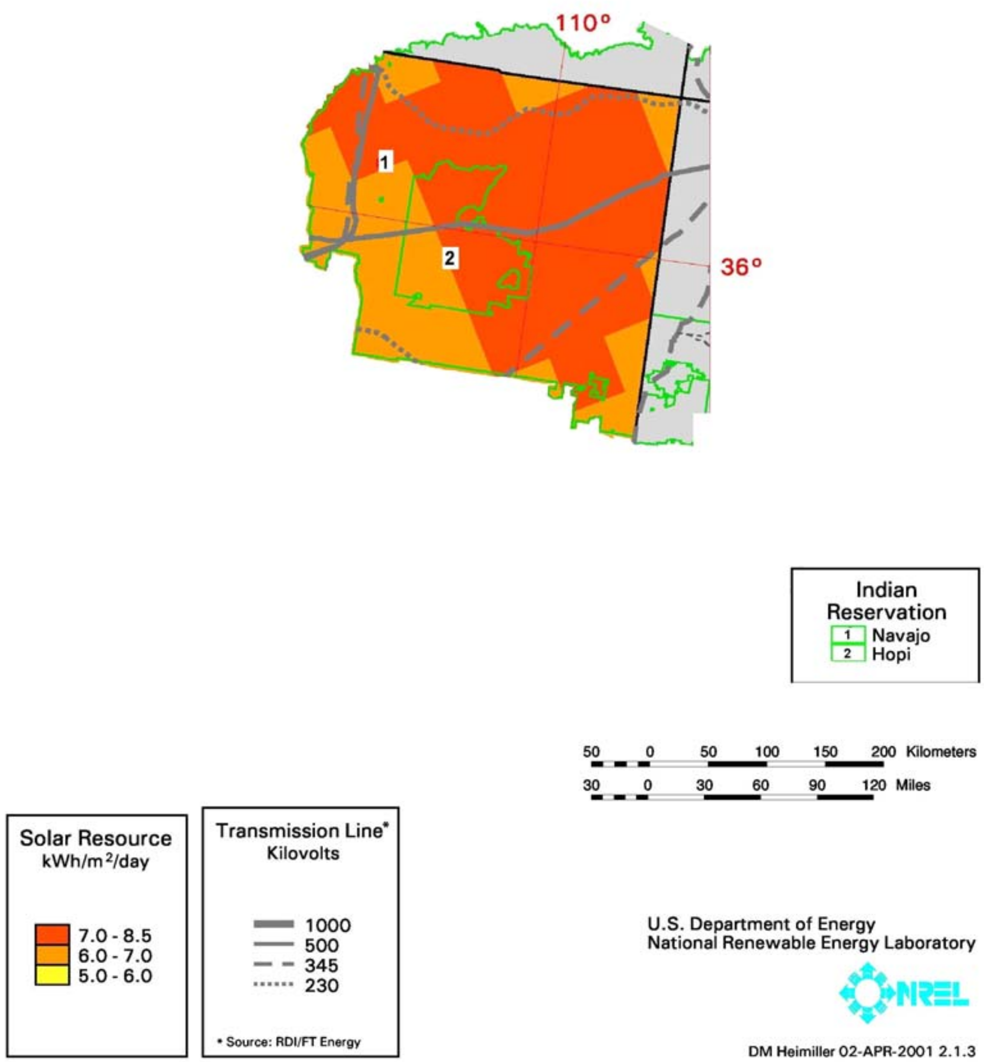


Figure 3-7 presents the NREL CSP resource map for the Arizona reservations area. The majority of the Navajo/Hopi reservations reside in Arizona. Figure 3-7 also indicates that two 1,000-kV, two 345-kV, and one 230-kV transmission lines are within the 7 to 8 kWh/m^2/day insolation area. For dispatchable power systems, location near existing high-voltage transmission lines is desirable to reduce cost. Construction of a transmission line, excluding the electrical substation, can cost between $500,000 and $1,500,000 per mile, depending on voltage, terrain, access, and any required upgrades to the grid.

Figure 3-7 — Arizona CSP Resource Map



3.3 CSP TECHNOLOGY COMPARISON

In this subsection, the four CSP technologies—parabolic trough, dish/Stirling engine, power tower, and concentrating photovoltaics—are compared with respect to the following characteristics:

- Current technology status
- Load profile compatibility
- Capital costs

- O&M costs
- Land area requirements
- Water usage

3.3.1 Current Technology Status

3.3.1.1 Parabolic Trough

Parabolic trough technology is currently the most proven solar thermal electric technology. Nine commercial-scale SEGS solar power plants are operating in the California Mojave Desert, with the first unit operating since 1984. These plants range in size from 14 to 80 MW electric (MWe) and represent a total of 354 MWe of installed electric generating capacity. The primary developers of this technology include Solargenix Energy (USA), Solel Solar Systems (Israel), and Solar Millennium (Germany). Suppliers of components for trough systems include reflector supplier Flabeg (Germany) and receiver suppliers Schott Glass (Germany) and Solel Solar Systems. New commercial projects are either in the planning or active project development stage. At present, there are four new active projects: 50-MW project in Nevada, 1-MW project in Arizona, and two 50-MW projects to be developed in two stages in Spain.

3.3.1.2 Dish/Stirling engine

Solar dish/engine systems are being developed for use in emerging global markets for distributed generation, remote power, and grid-connected applications. Individual units, ranging in size from 10 to 25 kW, can operate independently of power grids. There are no commercial dish/Stirling power plants operating today. Current development in the United States is focused on prototype system of 10 units in active development and testing at Sandia National Laboratories under a joint agreement between Stirling Engine Systems, Phoenix, Arizona, and SNL. Additional prototype systems are planned before implementation of large-scale grid-connected systems. Contracted deployments are as follows:

- SES 25-kW demonstration dish, Eskom, South Africa.
- 10-kW Schlaich Bergermann und Partner (SBP) dish providing power to grid in Spain.

In early August 2005, SCE publicly announced the completion of negotiations on a 20-year power purchase agreement with Stirling Energy Systems for between 500 and 850 MW of capacity (producing 1,182 to 2,010 GWh/year) from the first commercial deployment of a new solar thermal generating technology. According to SES, the commercial, grid-connected dish/engine (Stirling) plant is to begin construction in 2008.

The plant will be located in the Mojave Desert and consist of 20,000 dish/engines. SES also signed an agreement for between 300 and 900 MW with San Diego Gas and Electric in September 2005.

3.3.1.3 Power Tower

Power towers are commercially less mature than parabolic trough systems. The largest power towers built to date are the 10-MWe Solar One and Solar Two demonstration plants in southern California, neither of which is operating at present. The Solar One pilot plant operated from 1982 to 1988. The Solar Two plant was a retrofit of Solar One to demonstrate the advantages of molten salt for heat transfer and thermal storage. Experimental and prototype systems have been placed in operation in Spain, France, Israel, and the United States, the largest of which were the Solar One and Solar Two demonstration plants previously described. There are no definitive power tower projects either contracted or confirmed.

3.3.1.4 Concentrating Photovoltaics

Current technology is characterized by the following:

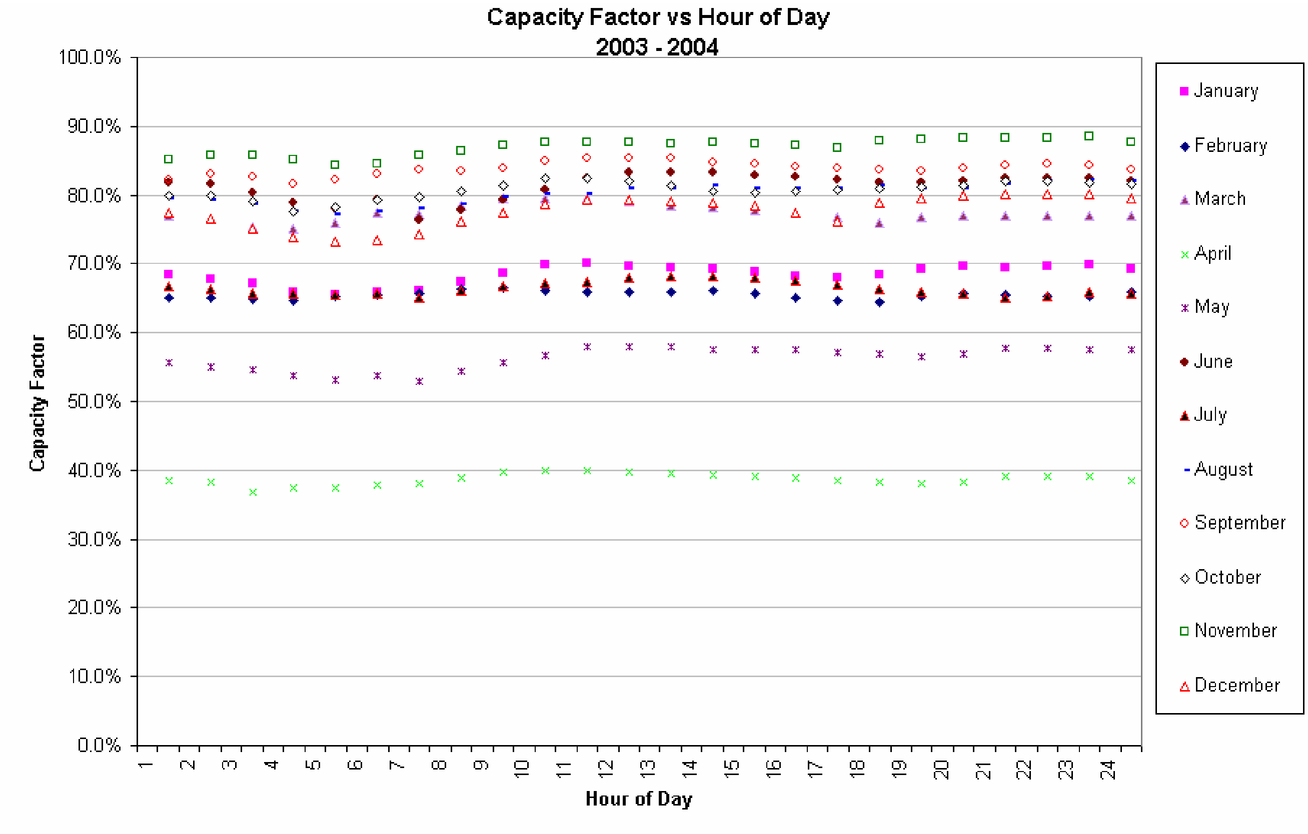
- 25- to 35-kW CPV systems.
- Two-axis tracking structure.
- 350-square-meter concentrator.
- 3M acrylic lens concentrator at 250 times, or parabolic dish with photovoltaics at the focal point.
- Receiver using inexpensive silicon solar cells, or advanced cell multi-junction technology.

There are no commercial CPV power plants in operation. A series of pre-commercial development systems totaling 500 kW are operating in Arizona under the auspices of APS, and a 200+ kW system is in operation in Australia. Planned deployments in the near future include 5 MW by APS, several megawatts in Australia, and an undetermined level in Europe.

3.3.2 Load Profile Compatibility

The load profile, that is, the capacity factor versus hour of the day for a 12-month period, of the Mohave Generating Plant for 2003–2004 is depicted in Figure 3-8. The load profile indicates the Mojave Generating Plant operates in a baseload mode with a relatively constant capacity factor over a 24-hour period for any particular month, with operation at a 60% or greater capacity every month except April (approximately 40%) and May (approximately 55%).

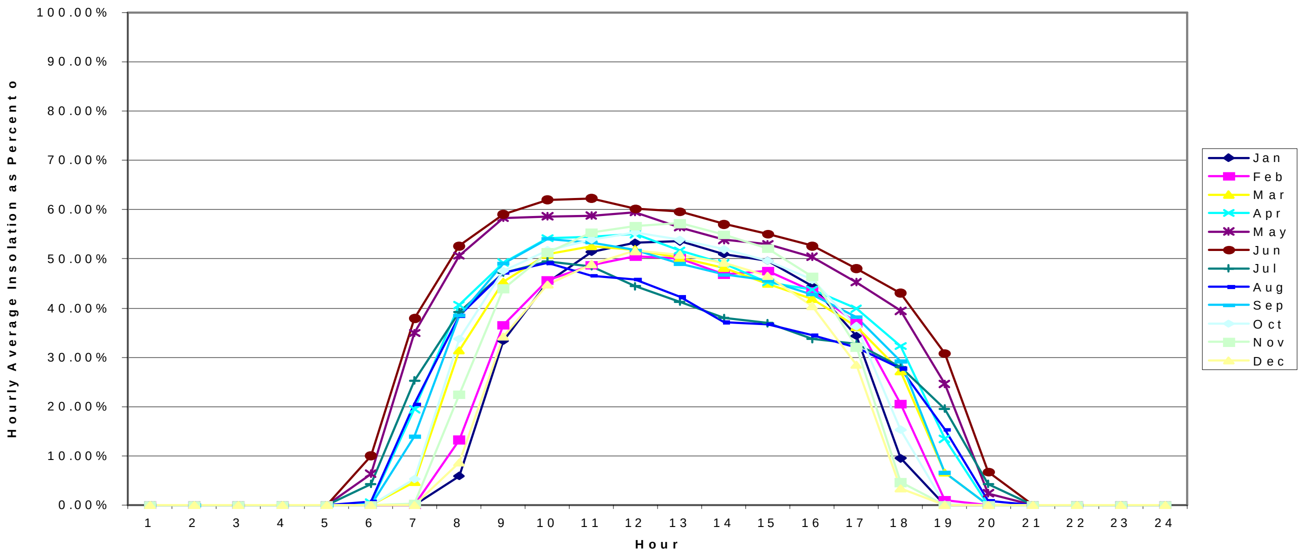
Figure 3-8 — Load Profile for Mojave Generating Plant



NREL data for normal solar insolation at ground level for the period 1981–1990 in the vicinity of Flagstaff, Arizona,[1] were obtained. In order to estimate the output of a solar plant, this information was averaged for each hour of the day for each month of the year. The data were normalized to the maximum insolation value during the 10-year period so that this maximum value of insolation represents 100% output. Results are shown in the following figure.

[1] Data available at http://rredc.nrel.gov/solar/old_data/nsrdb/hourly/

Figure 3-9 — Monthly Average Expected Hourly Output from Solar Technology without Energy Storage



Since all CSP technologies require sunlight to produce power, thermal storage or a hybrid configuration would be necessary to match the existing Mohave Generating Plant load profile.

3.3.2.1 Thermal Storage

Thermal storage stores solar-generated thermal energy for use during non-sunlight periods. As previously noted, the annual average insolation value for the majority of the Navajo/Hopi reservations area is 7 to 8 kWh/m^2/day, equivalent to 7 to 8 hours of full sun. To match the highest capacity factor of approximately 88% of the existing Mohave Generating Plant, the load profile would require approximately 15 to 16 hours of storage.

The first commercial SEGS 14-MWe parabolic-trough CSP plant (1984 vintage) included 3 hours of thermal storage, a simple two-tank storage system that used the plant's HTF for a storage medium. However, the later SEGS plants operated at higher temperatures that precluded the same method due to the higher vapor pressure and high cost of the HTF. No thermal storage technology has been commercially demonstrated for the higher solar field operating temperatures (approximately 400°C) required for the more efficient steam cycles in the later SEGS plants.

The Solar Two power tower CSP plant produced 10 MW of electricity with enough thermal storage, using a two-tank molten-salt storage system, to continue to operate the steam turbine at full capacity for 3 hours after the sun had set. However, the Solar Two 1988 demonstration was only one week of continuous operation.

For parabolic-trough and power-tower CSP technologies, thermal storage costs range from $35 to $70 per kWh. The capital cost for each hour of 885-MW storage ranges from $28,000,000 to $60,000,000. In addition to the cost of storage, the solar field capital cost increases since the solar field has to be larger to provide the heat input to the storage system. For 15 to 16 hours of storage, the solar field would be approximately 4 times larger than without storage. Thus, it is not practical for 15 to 16 hours of 885-MW storage due to the high cost.

Since dish/Stirling engine units are self-contained modules without a circulating medium to transfer heat to a storage system, thermal storage is not considered realistic. The same is true for concentrating photovoltaics; although battery energy storage could be considered, it would be prohibitively expensive and massive.

3.3.2.2 Hybrid Configuration

CSP-fossil hybrid options are possible with a natural gas combined-cycle and coal-fired or oil-fired conventional steam-Rankine power cycle, which would use fossil fuel to supplement the solar output during periods of low solar radiation. All of the SEGS parabolic-trough plants are “hybrids,” utilizing natural gas-fired boilers to generate electricity during low-insolation periods. The SEGS plants are limited, however, to a maximum usage of 25% natural gas on a total heat input basis.

Currently, there are no commercial or prototype hybrid power tower, dish/Stirling engine, or concentrating photovoltaics systems.

To match the existing Mohave Generating Plant load profile, a CSP-fossil hybrid plant would require a 885-MW natural gas combined-cycle, coal-fired or oil-fired conventional steam-Rankine power plant, which defeats the objective of replacing the fossil-fueled plant.

3.4 CAPITAL COSTS

Current capital cost estimates for the CSP technologies are highly speculative since the last commercial-scale CSP plant was built in 1990 (the SEGS IX parabolic-trough plant) and the current dish/engine (Stirling) and concentrating photovoltaics plants are small demonstration plants. The current capital cost estimates presented here are based primarily on NREL data and publicly available CSP technical information. The costs presented below do not include thermal storage for any of the technologies for comparative purposes.

Table 3-1 — Estimated Current Capital Costs for CSP Technologies

2005$	Parabolic-trough	Power Tower	Dish/ Stirling Engine	Concentrating Photovoltaics
Direct Cost, $/kW	$2,500*	$2,800*	$3,000**	$8,000

* 100 MW plant without storage

**Based on Stirling Engine Systems information for first 50 MW deployment

The capital costs for the CSP technologies are notably higher than for a conventional coal-fired plant ($1,600–$1800/kW) or a combined-cycle plant ($600–$800/kW).

3.5 OPERATING AND MAINTENANCE COSTS

Similar to the capital cost estimates, O&M costs for the power tower, dish/Stirling engine, and concentrating photovoltaics plants are highly speculative since current plants are small demonstration plants. The O&M cost estimates presented here for these technologies are based primarily on NREL data. O&M costs for the parabolic-trough plant are based on actual data from the existing SEGS plants. The estimated costs are presented below.

Table 3-2 — Estimated O&M Costs for CSP Technologies

2005$	Parabolic Trough	Power Tower	Dish/Stirling Engine	Concentrating Photovoltaics
Fixed, $/kW-yr	$33	$30	$3	$3
Variable, $/MWh	$30	$30	$11	$5

The higher fixed O&M costs for parabolic trough and power tower reflect the staffing requirements, mainly due to the Rankine-cycle portion of the plant.

3.6 LAND AREA REQUIREMENTS

Approximate plant area requirements for each CSP technology is provided below.

Table 3-3 — Approximate Area Required for CSP Technologies

	Parabolic Trough	Power Tower	Dish/Stirling engine	Concentrating Photovoltaics
Acres per MW	6	5	4	10
For 885 MW				
Acres	5,310	4,425	3,540	8,850
Square Miles	8.3	7.0	5.5	14.0

For comparison, the 1,580-MW Mohave Generating Plant occupies approximately 2,490 acres (1.6 acres per megawatt).

As previously noted, thermal storage will increase the area requirements. For 15 to 16 hours of thermal storage for parabolic trough or power tower, the solar field is approximately 4 times larger than shown in Table 3-3.

3.7 WATER USAGE

Approximate water usage is tabulated in Table 3-4.

Table 3-4 — Approximate Water Usage for CSP Technologies

	Parabolic Trough	Power Tower	Dish/Stirling Engine	Concentrating Photovoltaics
Cooling Tower Makeup (gal/MWh)	700	700	0	0
Rankine-Cycle Makeup (gal/MWh)	16	16	0	0
Mirror Washing (gal/MWh)	2	2	1	1*
Total Gallons per MWh	718	718	1	1

* Based on dish/Stirling engine value.

For an 885-MW plant at 72% capacity factor (equivalent to the Mohave Generating Plant's capacity factor), the estimated water usage per year is shown in Table 3-5.

Table 3-5 — Approximate Water Usage for 885-MW Plant at 72% Capacity Factor

	Parabolic Trough	Power Tower	Dish/Stirling Engine	Concentrating Photovoltaics
Cooling Tower Makeup, (gal/yr)	4,000,000,000 or 0 (with dry cooling)	4,000,000,000 or 0 (with dry cooling)	0	0
Rankine-cycle Makeup, (gal/yr)	90,000,000	90,000,000	0	0
Mirror Washing, (gal/yr)	11,000,000	11,000,000	6,000,000	6,000,000*
Total (gal/yr)	4,101,000,000 or 101,000,000 (with dry cooling)	4,101,000,000 or 101,000,000 (with dry cooling)	6,000,000	6,000,000
Total (acre-ft/yr)	12,585.5 or 310 (with dry cooling)	12,585.5 or 310 (with dry cooling)	18.4	18.4

* Based on dish/Stirling engine value.

For the parabolic trough and power tower Rankine-cycle portion, cooling systems are required to condense the steam at the turbine exhaust and to maintain the design turbine back pressure. The water requirement for the cooling tower is the result of evaporative cooling. This large water usage can be reduced with an air-cooled system. There are two types of air-cooled systems: direct and indirect. Direct systems duct the steam to air-cooled condensers that can be either mechanical or natural draft units. Indirect systems condense the steam in water-cooled surface condensers. The heated water is then pumped to air-cooled heat exchangers, where it is cooled and then re-circulated to the steam condenser. Both systems are commercially available for utility-sized power plants. Air-cooled systems reduce water use at a plant by eliminating the use of water for steam condensation. With an air-cooled system, the capital cost of the plant will increase by approximately 4% to 8%, and power output will be reduced by approximately 5% to 10%. The parabolic-trough and power-tower water requirement would be approximately 101,000,000 gallons per year (18 gallons per MWh, 310 acre-ft per year) for an 88-MW plant at 72% capacity factor with an air-cooled condenser. Since the project is to be located on or near tribal lands, project feasibility depends on water availability from sources on or near tribal lands. Such availability is subject to the desires of the rights holders to negotiate for use of such water.

3.8 CONCLUSIONS OF CSP TECHNOLOGY COMPARISON

3.8.1 Replacement for Mohave Generating Station Generation

Concentrating solar power (CSP) technology, by itself, cannot totally replace the electrical generation of the Mohave Generating Station. This conclusion is based on several factors:

- **Size Limitations.** There is limited CSP technology that is available in commercial (utility) sizes**.** Parabolic trough technology is currently the most proven solar thermal electric technology, with the largest commercial-scale plant of 80 MW. The largest power towers built to date were the 10-MWe Solar One and Solar Two demonstration plants. There are no large-scale (greater than 5 MW) commercial dish/engine (Stirling) or concentrating photovoltaic power plants operating today.
- **Generation Profile Limitations.** Thermal storage or a hybrid configuration would be necessary to match the existing Mohave Generating Plant's load profile. For parabolic-trough and power-tower CSP technologies, the capital cost for each hour of 885-MW storage ranges from $28,000,000 to $60,000,000. In addition to the cost of storage, the solar field capital cost increases since the solar field has to be larger to provide the heat input to the storage system. For 15 to 16 hours of storage, the solar field is approximately 4 times larger than without storage. Since dish/engine (Stirling) units are self-contained modules without a circulating medium to transfer heat to a storage system, thermal storage is not considered realistic. The same is true for concentrating photovoltaics; although battery energy storage could be considered, it would be prohibitively expensive and massive.
- **Lack of Commercial Examples.** Currently, there are no commercial or prototype hybrid power tower, dish/engine (Stirling), or concentrating photovoltaics systems.
- **High Capital Cost.** The capital costs for the CSP technologies are notably higher than for a conventional coal-fired plant or a combined-cycle plant.
- **Large Land Requirements.** An 885-MW CSP plant, without thermal storage, would occupy an area 2 to 3 times greater than the existing 1,580 MW Mohave Generating Plant. With thermal storage, the area requirements approach 8 to 12 times greater.

3.8.2 Complement to Mohave Generating Station Generation

Although CSP technology cannot totally replace the electrical generation of the Mohave Generating Station, it is a potential alternative to replacing or complementing part of the station's electrical generation, both as dispatchable power systems and as distributed power systems. Dispatchable power systems are capable of providing dispatchable intermediate-load generation in the wholesale bulk-power market, such as the Mohave Generating Station. Distributed power systems provide distributed generation, grid support, remote, and village power markets. The majority of the Navajo/Hopi reservations area is shown to have a very good insolation value of 7 to 8 kWh/m^2/day. Two 345-kV and one 230-kV transmission lines are within the 7 to 8 kWh/m^2/day insolation area. Furthermore, much of the far northeast of Arizona is barren, with wide empty valleys interspersed with low, scrub-covered mesas.

Of the four CSP technologies, the parabolic trough and dish/Stirling engine are considered the best selections for complementing electrical generation of the Mohave Generating Station. This conclusion is based on the following rationales:

- **Technology Risk.** Parabolic-trough technology is currently the most proven solar thermal electric technology. A 50- to 100-MW parabolic-trough plant is readily available for near-term deployment. Parabolic-trough plants would operate as dispatchable power systems, as is currently being done at the SEGS Plants.
- **Solar Energy Conversion Efficiency.** Of all solar technologies, dish/engine systems have demonstrated the highest solar-to-electric conversion efficiency (29.4%), and therefore have the potential to become one of the least expensive sources of renewable energy. The modularity of dish/engine systems allows them to be deployed individually for remote applications, or grouped together for small-grid or end-of-line utility applications. The ability to prove the technology on a small scale can be used to eliminate much of the financial risk associated with the technology risk of this technology. With the technology proven at a small scale, the technology's modularity may allow large combinations of the generating units to provide power quantities similar to those provided by existing large utility plants, at least during periods of optimum insolation.

3.9 CSP TECHNOLOGY PLANT CONFIGURATIONS

In order to estimate reasonable unit sizes for the CSP technologies described above, recent Renewable Portfolio Standards (RPS) requirements in the area were evaluated. Arizona currently has an RPS (called an Environmental Portfolio Standard, or EPS, in Arizona) that requires the state's investor-owned utilities (IOUs) and cooperatives to generate or procure renewable energy supplies totaling 1.1% of total retail sales by 2006. To date, the standard has been more or less on a voluntary basis without specific legal and financial penalties for non-compliance. However, given considerably higher standards in neighboring states and Arizonans interest in supporting higher levels of renewables, the Arizona Corporation Commission (ACC) has been exploring expanding the EPS for over a year. In July 2005, the ACC voted to increase the EPS to 5% by 2015 and 15% by 2025. Rules to implement the order are being considered, including various compliance mechanisms and penalties. The final order was expected later in 2005.

The amount of energy corresponding to the production of Mohave Generating Station that must come from renewable sources was estimated. The unit sizes for each technology that could provide this energy were estimated, based on estimated capacity factors for each technology.

Per RPS, in the years 2007–2012, regulated utilities in Arizona are required to generate 1.1% of their electricity with renewable energy of which 60% is solar-electric power. California retail sellers of electricity are required to increase their procurement of eligible renewable energy resources such that 20% of their retail sales (on a megawatt-hour basis) are procured from eligible renewable energy resources by 2017.

An 885-MW plant at 72% capacity factor (equivalent to Mohave Generating Plant capacity factor) produces approximately 5,600,000 MWh of electricity per year. If all the generation is procured by California, 1,120,000 MWh will theoretically have to come from renewable energy resources by the year 2017. The 1,120,000 MWh represents 180 MW of power at 72% capacity factor.

3.9.1 Parabolic-Trough Configuration

The parabolic-trough capacity factor capability, without thermal storage, is approximately 30%. In order to produce 1,120,000 MWh, a unit size of 425 MW is required.

However, in order to reduce the plant size, provide better load profile match, and eliminate the need for a conventional steam-Rankine power plant for backup, thermal storage of six hours can be considered in the parabolic-trough plant configuration. This is consistent with the design of the parabolic-trough plants in Spain, with both plants having six hours of storage using the Nexant/Sandia indirect two-tank thermal storage technology. With six hours of thermal storage, the capacity factor capability is approximately 43%, which for 1,120,000 MWh corresponds to 300 MW of installed power.

Three plants of 100 MW each are used for the configuration based on the size of current parabolic-trough technology of the 80-MW SEGS VIII and IX plants. Use of current technology-size plants minimizes technology risks associated with efficiency and technology improvements and large scale-up factors and allows suppliers to rely more on initial production volume to reduce costs.

3.9.1.1 Costs

Three 100-MW parabolic-trough plants would provide 300 MW. The estimated capital cost is based on actual costs for the SEGS VIII and IX solar plants with scale-up cost reduction. There are recognized scale-up cost reductions for increasing the plant size:

$$C_B = C_A \left(\frac{A_{MW}}{B_{MW}} \right)^{f_s}$$

where:

C_B = Cost of Plant B

C_A = Cost of Plant A

B_{MW} = MW size of Plant B

A_{MW} = MW size of Plant A

f_s = Scale-up factor

Based on the cost data provided by the SEGS Plant, an average scale-up factor of 0.7 was attained: SEGS I to SEGS II, 0.6 scale-up factor; SEGS II to SEGS III, 0.8 scale-up factor; and SEGS V to SEGS VII, 0.7 scale-up factor. The actual cost for each of the 80-MW SEGS VIII and IX plant was $2875/kW. Neither plant has thermal storage.

For each 100-MW plant, without thermal storage, the scale-up equation is

$\$2,460/kW = \$2,875/kW \times (80\ MW/100\ MW)^{0.7}$

Increases in the plant cost for various factors are estimated as follows:

- **Physical Storage Cost.** Using thermal storage cost of $50 per kWh, based on the Nexant/Sandia indirect two-tank thermal storage technology design of the parabolic-trough plants in Spain. With six hours storage at $50/kWh, the additional storage costs $300/kW.
- **Increased Solar Field Size.** Thermal storage requires that the solar field size be increased to obtain solar energy for storage. The solar field is defined by the collector area in square meters, which can be estimated by the following simplified equation:

$$C = \left(\frac{kW_d \times f_c \times h}{\eta \times I} \right)$$

where:

C = Collector area square meters (m^2)

kW_d = Electric generation design capacity, kilowatts = 100,000 kW

f_c = Capacity factor = 30% without storage; 43% with 6 hours storage

h = Hours per year (8,760)

η = Net annual efficiency, Solar to Electric = 14%

I = Annual insolation = 8 kWh/m^2/ day x 365 days) = 2,920 kWh/m^2

Without thermal storage the solar field size is

(100,000 kW x 30% x 8,760) / (14% x 2,920 kWh/m^2) = 643,000 square meters

With 6 hours thermal storage the solar field size is

(100,000 kW x 43% x 8760) / (14% x 2920 kWh/m^2) = 921,000 square meters

The breakdown cost in \$/m^2 for the solar field is shown below.

Table 3-6 — Cost Breakdown for Solar Field

Receivers	43 \$/m^2
Mirrors	40
Concentrator Structure	47
Concentrator Erection	14
Drive	13
Interconnection Piping	10
Electronics & control	14
Header piping	7
Foundations/Other Civil	18
Other (Spares, HTF)	14
Total	220 \$/m^2

Thus, the increase in capital cost due to the larger solar field is

[\$220/m^2 x (921,000 m2 - 643,000 m^2)] / 100,000 kW = \$600 /kW

- **Air-Cooled Condenser System.** To reduce the water requirement, an air-cooled system was considered in lieu of an evaporative cooling tower. An air-cooled system will increase the base cost by approximately 8%.

The total estimated capital cost for three 100-MW parabolic-trough plants with 6 hours indirect two-tank thermal storage is as follows:

Table 3-7 — Total Estimated Cost for Three 100-MW Parabolic-Trough Plants

Base Cost	$2,460/kW
Thermal Storage	$ 300/kW
Increased Solar Field Size	$ 600/kW
Air-Cooled Condenser System	$ 200/kW
Total	$3,560/kW

Costs breakdowns are shown below.

Table 3-8 — Cost Breakdowns for Parabolic-Trough System

Capital Cost Estimate

Category Description	% of Total	Category Breakdown	
		Material	Labor
Siteworks & Infrastructure	2.0%		
General siteworks & infrastructure			
Roads, warehouse, fence			
Watersupply infrastructure			100%
Solar Field	67.0%	83%	17%
HCE			
Mirror			
Metal support structure			
Drive			
Interconnection Piping			
Electronics & control			
Header piping			
Pylon Foundations			
Other Civil Works			
HTF Fluid			
Spares			
Heat Transfer Fluid (HTF) System	2.7%	86%	14%
HTF vessels & HXs			
Pumps			
Field Erection			
Thermal Energy Storage	12.8%	78%	22%
Heat Exchangers & Mech			
Tanks & Vessels			
Nitrate Salt			
Piping, Instr, Electrical			
Civil & Structural			
Power Block	9.8%	66%	34%
Steam turbine & generator			
Electric auxiliaries			
Balance of Plant (BOP)	5.7%	43%	57%
General BOP & cooling			
Water treatment			
Fuel handling & treatment			
Flue gas treatment			
Electrical			
Instrumentation & control			
Other civil works & erection			
Total Direct Cost	**100%**	**77%**	**23%**

The fixed O&M costs are projected to be $33/kW-yr, with variable O&M costs of $30/MWh. The O&M costs for the parabolic-trough plant are based on actual data from the existing SEGS plants.

Costs do not include sales or property taxes or land lease costs.

3.9.1.2 Construction

The estimated construction period for a 100-MW parabolic trough CSP plant is 15 months with a manpower requirement of 1,000 personnel. The labor skills required to build the plant are non-supervisory (75%), supervisory (17%), administrative (5%), and engineering (3%). The construction period is 15 months, and the construction rate is S-shaped, with 23% completed in the first 6 months, 57% completed in 9 months, and 90% completed in 12 months.

The preceding information is based on actual SEGS data and information from the University of New Mexico Bureau of Business and Economic Research study, which evaluated the economic and fiscal impact of building CSP plants in New Mexico (*The Economic Impact of Concentrating Solar Power in New Mexico*, December 2004.) The construction estimates are consistent with the two 50-MW AndaSol project in Spain, which projects a 15-month construction period with a peak labor demand of up to 1,000 workers.

3.9.1.3 Land Requirements

Each 100-MW parabolic-trough solar plant with 6 hours of thermal storage will require approximately 870 acres (1.4 square miles) of area.

3.9.1.4 Water Usage

Use of an air-cooled system in lieu of an evaporative cooling tower reduces the water requirements to the Rankine-cycle makeup and mirror washing. The Rankine-cycle makeup averages 16 gallons per MWh, and mirror washing averages 2 gallons per MWh. For each 100-MW parabolic-trough solar plant, the average annual water requirement is as shown in the following table.

Table 3-9 — Water Usage for Each 100-MW Plant with Air-Cooled Condensers

	Average Amount
Rankine-Cycle Makeup, gal/yr	6,000,000
Mirror Washing, gal/yr	800,000
Total, gal/yr	6,800,000
Total, acre-ft/yr	20.9

3.9.1.5 Staffing

The expected staffing for each plant is presented below in Table 3-10. The expected staffing if the three plants were combined in one site with a common control room is also shown in Table 3-10.

Table 3-10 — Expected Staffing for Parabolic Trough Plant

	Stand-Alone 100-MW Plant	Three 100-MW Plants on Common Site
Administrative	6	6
Technical Services	4	4
Operations	16	24
Maintenance	36	54
Total	62	88

3.9.2 Dish/Stirling Engine

The current dish/Stirling engine technology of 25-kW size modules was used for the configuration. The modularity of dish/engine systems allows them to be deployed individually for remote applications, or grouped together for small-grid or end-of-line utility applications. The dish/engine is an excellent application for remote regions and areas with scarce water resources. The dish/engine capacity factor capability, without thermal storage, is approximately 30%, which for 1,120,000 MWh (same generation as considered for the parabolic-trough technology) corresponds to 425 MW of power. Since dish/engine units are self-contained modules without a circulating medium to transfer heat to a storage system, thermal storage is not considered practical.

In early August 2005, SCE publicly announced the completion of negotiations on a 20-year power purchase agreement with Stirling Energy Systems for between 500 and 850 MW of capacity (producing 1,182 to

2,010 GWh/yr) from the first commercial deployment of a new solar thermal generating technology. According to SES, the commercial, grid-connected dish/engine (Stirling) plant is to begin construction in 2008. The plant will be located in the Mojave Desert and consist of 20,000 dish/engines. SES also signed an agreement for between 300 and 900 MW with San Diego Gas and Electric in September 2005.

For 425 MW of power, a total of 17,000 dish/engines would be required.

3.9.2.1 Costs

The capital cost for dish/engines is approximately \$3,000/kW based on SES information for first 50-MW deployment. The \$3,000/kW is consistent with current cost of \$5,000/kW with reduced unit costs to \$3,000/kW as a result of increased product volume of 2,000 dish/engines for 50 MW of power.

The estimated capital cost of \$3,000 is expected to be less for an application of a 425-MW dish/engine plant based on reduced unit costs as a result of increased product volume. The experience curve describes how unit costs decline with cumulative production, with a specific characteristic that cost declines by a constant percentage with each doubling of the total number of units produced (Lena Neij, "Use of Experience Curves to Analyze the Prospects for Diffusion and Adoption of Renewable Energy Technology," *Energy Policy*, Vol. 23, No. 13, 1997).

The experience curve formula is as follows:

$$C(t) = C_0 Q(t)^b$$

where:

C(t) = Cost per unit as a function of output

C_0 = Cost of the first unit produced

Q(t) = Cumulative production over time

B = Experience index

For each doubling of production, the cost reduction is

$$\frac{C_{CUM_1} - C_{CUM_2}}{C_{CUM_1}} = \frac{C_0 Q_1{}^b - C_0 Q_2{}^b}{C_0 Q_1{}^b} = 1 - \frac{C_0 (2Q_1)^b}{C_0 Q_1{}^b} = 1 - 2^b$$

The value (2^b) is called the progress ratio, denoted ϕ. The progress ratio is used to express the progress of cost reductions for different technologies.

The formula is simplified for use as follows:

$$\phi = \left(\frac{C_2}{C_1} \right)^{\frac{1}{n}}$$

$$n = \frac{1}{\ln 2} \ln \frac{Q_2}{Q_1}$$

where:

C_1 = Cost of initial unit produced

Q_1 = Production quantity for the initial unit cost

C_2 = Desired cost of unit produced

Q_2 = Cumulative production quantity for desired unit cost

ϕ = Progress Ratio

n = Number of doublings of cumulative production

The progress ratio, ϕ, is used to express the progress of cost reductions for different technologies. The lower the value of ϕ, the higher the cost reduction realized. The cost reductions refer to the total costs (labor, capital, administration, research, etc.). The use of experience curves is not an established method, but a correlation that has been observed for several different technologies. A progress ratio of 0.82 for development of wind energy (1980 to 1995) has been identified by the International Energy Agency. The studies on learning curves suggest that a progress ratio of the order of 0.8 to 0.82 have been observed for installed photovoltaics. The Enermodal Study (Enermodal Engineering Limited, Cost Reduction Study for Solar Thermal Power Plant) shows a ϕ range between 0.85 and 0.92 for the installed capital cost of a trough power plant. Arguably, for the highly automated manufactured components, such as the support structure and mirrors, a ϕ of 0.80, as used in the Neij literature, may be more representative based on manufacturing experience. The projected cost estimate is based on progress ratio of 0.85.

The estimated capital cost for a 425-MW plant consisting of 17,000 dish/engines as a result of increased product volume is $1,500/kW. The fixed O&M costs are projected to be $3/kW-yr; the variable O&M costs are projected to be $11/MWh ($0.011/kWh). Costs do not include sales or property taxes or land lease costs.

Both Stirling Energy Systems and Southern California Edison were contacted regarding cost information related to their recently announced power purchase agreement. Both entities indicated that such information was confidential and could not be released for use.

3.9.2.2 Area Requirement

A dish/Stirling engine plant requires approximately one acre per eight 25-kW dish engines. For 17,000 dish/engines, approximately 2,125 acres (3.3 square miles) of area would be required.

3.9.2.3 Water Usage

The only water use required is for mirror washing. Approximately 14 gallons per dish per month is necessary for mirror washing, which converts to 2,856,000 gallons per year (8.8 acre-ft per year) for 17,000 dish/engines.

3.9.2.4 Staffing

The expected staffing for a 425-MW dish/engine plant is presented below in Table 3-11.

Table 3-11 — Expected Staffing for Dish/Stirling Engine Plant

	425-MW Dish/Stirling Engine Plant
Administrative	4
Technical Services	2
Operations	12
Maintenance	100
Total	118

3.10 TRANSMISSION REQUIREMENTS

Direct transmission access costs include the costs of the connection at the plant site, the plant transmission line, and any substation required at the interconnection with the trunk transmission line. For the solar plants, costs are summarized in the following table:

Table 3-12 — Transmission Requirements for Solar Plants

	Dish/Stirling		Trough	
Net Output, MW	425	425	300	300
Connection Voltage, kV	500	230	500	230
Interconnection Cost, $ millions	106.83	73.1	94.6	66.2

Direct transmission access costs shown here do not include the costs of upgrades to the transmission system that may be required to alleviate congestion or single contingency concerns that result from load flow analyses. Those costs are estimated in Section 12.

3.11 SUMMARY

Concentrating solar power technology is not a logical alternative to totally replace the electrical generation of the Mohave Generating Station based on the following considerations:

- There is limited CSP technology that is available in commercial (utility) sizes.
- Thermal storage or a hybrid configuration would be necessary to match the existing Mohave Generating Plant load profile.

The current capital costs for the CSP technologies are notably higher than for a conventional coal-fired plant or a combined-cycle plant.

An 885-MW CSP plant, without thermal storage, would occupy 2 to 3 times the area of the existing 1,580-MW Mohave Generating Plant. With thermal storage, the area requirements approach 8 to 12 times greater.

However, CSP technology is a potential element of a portfolio that could replace or complement the electrical generation of the Mohave Generating Station, both as dispatchable power systems and as distributed power systems. Of the four CSP technologies, the parabolic-trough and dish/Stirling engine are considered the best selections for complementing electrical generation of the Mohave Generating Station.

The parabolic-trough technology was selected because it is the most proven solar technology for the generation of electricity. A 50- to 100-MW parabolic-trough plant is readily available for near-term deployment. Parabolic-trough plants would operate as dispatchable power systems, as is currently being done at the SEGS plants.

The dish/Stirling engine system was selected because such systems have demonstrated the highest solar-to-electric conversion efficiency (29.4%). They have the potential, therefore, to become one of the least expensive sources of renewable energy. The modularity of dish/engine systems allows them to be deployed individually for remote applications, or grouped together for grid or end-of-line utility applications. Furthermore, scale-up from a few dish/engines to utility-scale installations is, at least conceptually, very straightforward.

The two technologies are compared in Table 3-13.

Table 3-13 — Comparison of Parabolic Trough and Dish/Stirling Engine

	Parabolic Trough	Dish/Stirling Engine
Plant Size	300,000 kW	425,000 kW
Number of Units	3	17,000
Unit Size	100,000 kW	25 kW
Thermal Storage	Yes – 6 hours	No
Annual Capacity Factor	43%	30%
Annual Generation	1,120,000 MWh	1,120,000 MWh
Capital Cost	$3,560/kW	$1,400/kW
O&M Cost	$33/kW-yr fixed $30/MWh variable	$3/kW-yr fixed $11/MWh variable
Area Requirement	870 acres per unit	2,125 acres
Water Requirement	6,800,000 gal/yr/unit	2,856,000 gal/yr
Total Staffing	62 per unit (stand alone units) 88 total (combined units)	118

The parabolic-trough technology presents the lower risk of the two CSP technologies based on the nine commercial-scale SEGS solar power plants, which continue to operate daily. While the Stirling engine itself is a well-established technology, the dish/engine CSP technology is currently at a high $/kW capital cost level and there are no large-scale commercial dish/engine power plants operating today in the size contemplated. There is the risk that any or all of the projected cost reductions for the dish/engine CSP technology as a result of increased product volume will not be realized. Since the dish/engines are modular, scale-up cost reductions for increasing the plant size will not be realized.

Parabolic-trough technology, dish/engine technology, or a combination of the two can, in conjunction with other generation technologies, replace or complement the electrical generation of the Mohave Generating Station.

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4. WIND TECHNOLOGY

4.1 WIND ENERGY TECHNICAL FEASIBILITY AND MAXIMUM CAPACITY

Four wind energy sites were evaluated for this study. All four are located in the state of Arizona on or near lands owned by the Navajo and Hopi tribal nations. That portion of Arizona's wind resource equivalent to Class 4 wind or better is estimated to be 2,600 MW by Northern Arizona University. Estimates of technical resources for the state are as high as 20,000 MW; however, economic resources of Class 3 wind or better, suitable for utility scale development, are likely in the 3,000 to 5,000 MW range. Please refer to the 50-meter and 70-meter Arizona wind resource maps developed by AWS Truewinds included as Figures 1 and 2 in Appendix H.

The initial capacity under development on the four sites on near Navajo and Hopi lands with Class 3 or better wind is estimated to be 685 MW, with moderate to higher levels of expansion possible. Three of the sites evaluated are Class 3+ or better. There are also additional sites on or near Navajo and Hopi lands not evaluated in this study that could probably be commercially developed.

All four sites evaluated are technically feasible, and several of these sites are exemplary wind sites with Class 4 to 7 wind resources. With regard to timing of electric generation power sales from these sites, only about 60 MW could possibly be constructed in 2006, and another 75 to 175 MW in 2007. The remainder would likely be phased in through 100-150 MW tranches in 2008, 2009, and 2010.

The four wind energy sites evaluated are Gray Mountain, Aubrey Cliffs, Clear Creek, and Sunshine Wind Park.

The Gray Mountain site is located on the Navajo reservation near Cameron, Arizona, and is about 10 miles away from the Moenkopi Substation. The site has a potential of 150 MW by 2008 and at least 450 MW by 2010, and is currently under development by the Navajo Tribal Utility Authority (NTUA). Please refer to Figure 4-1 and Figure 4-2 below.

Figure 4-1 — Gray Mountain Project Site Map

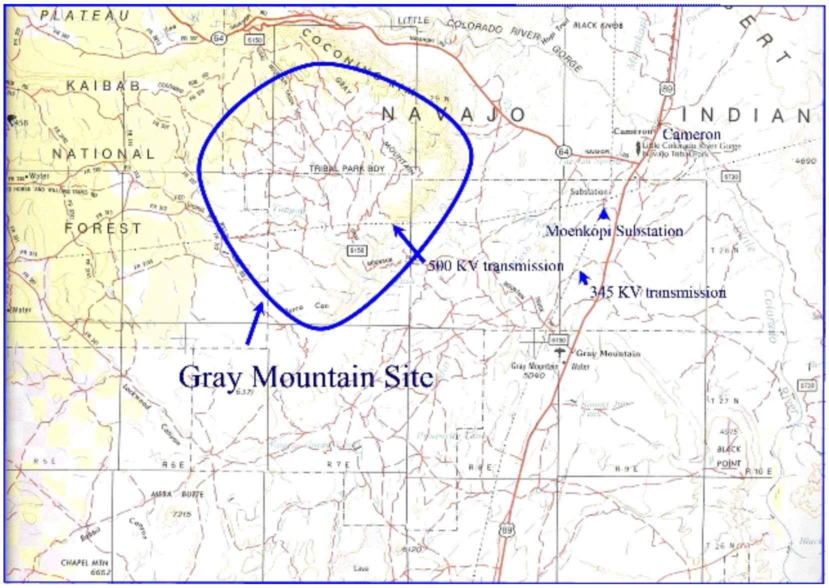
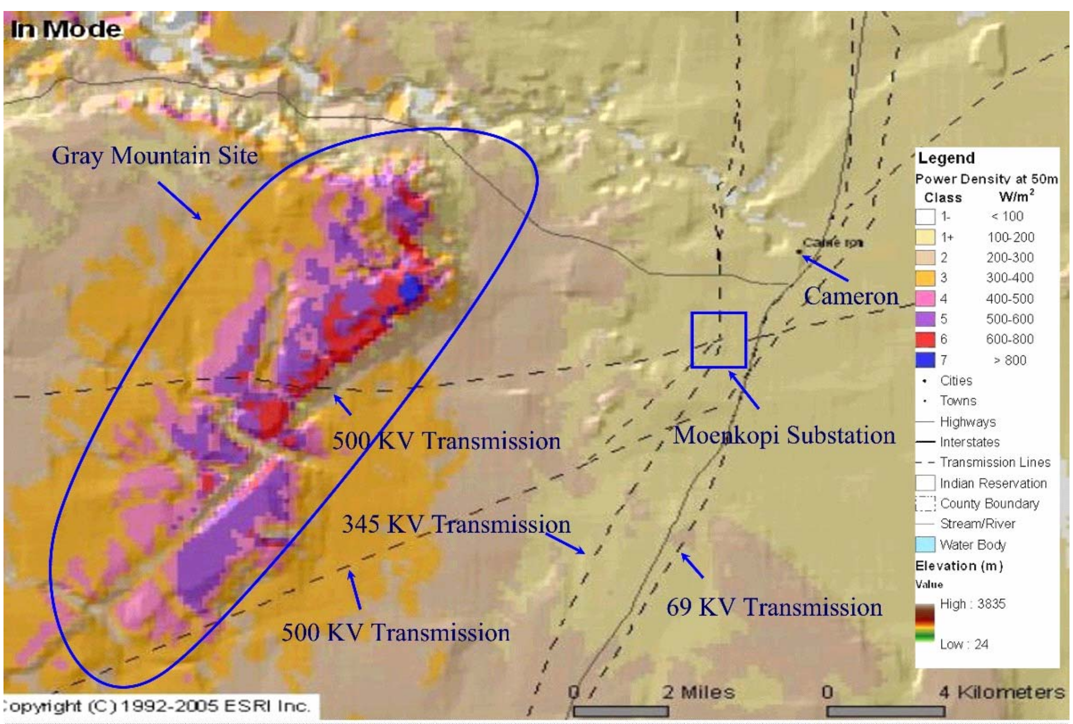


Figure 4-2 — Gray Mountain Site Wind Resource Map



The Aubrey Cliffs site is located on Navajo fee and State Trust lands just northwest of Seligman, Arizona. The site has a potential 100 MW by 2007–2008 with upside development potential, and is currently under development by Foresight Wind Energy, NTUA, and Department of Natural Resources (DNR) of the Navajo Nation. Site information is provided in Figure 4-3 and Figure 4-4 below.

Figure 4-3 — Aubrey Cliffs Project Location Map

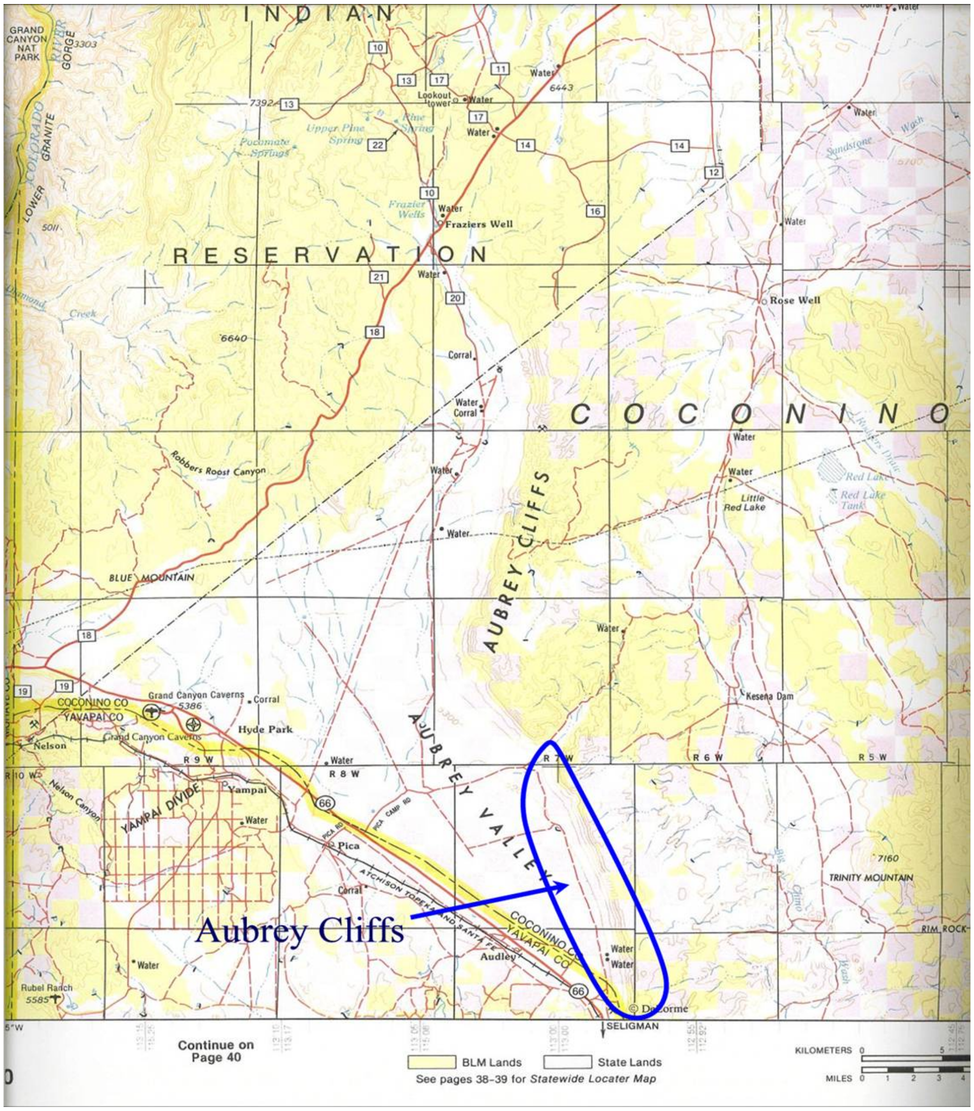
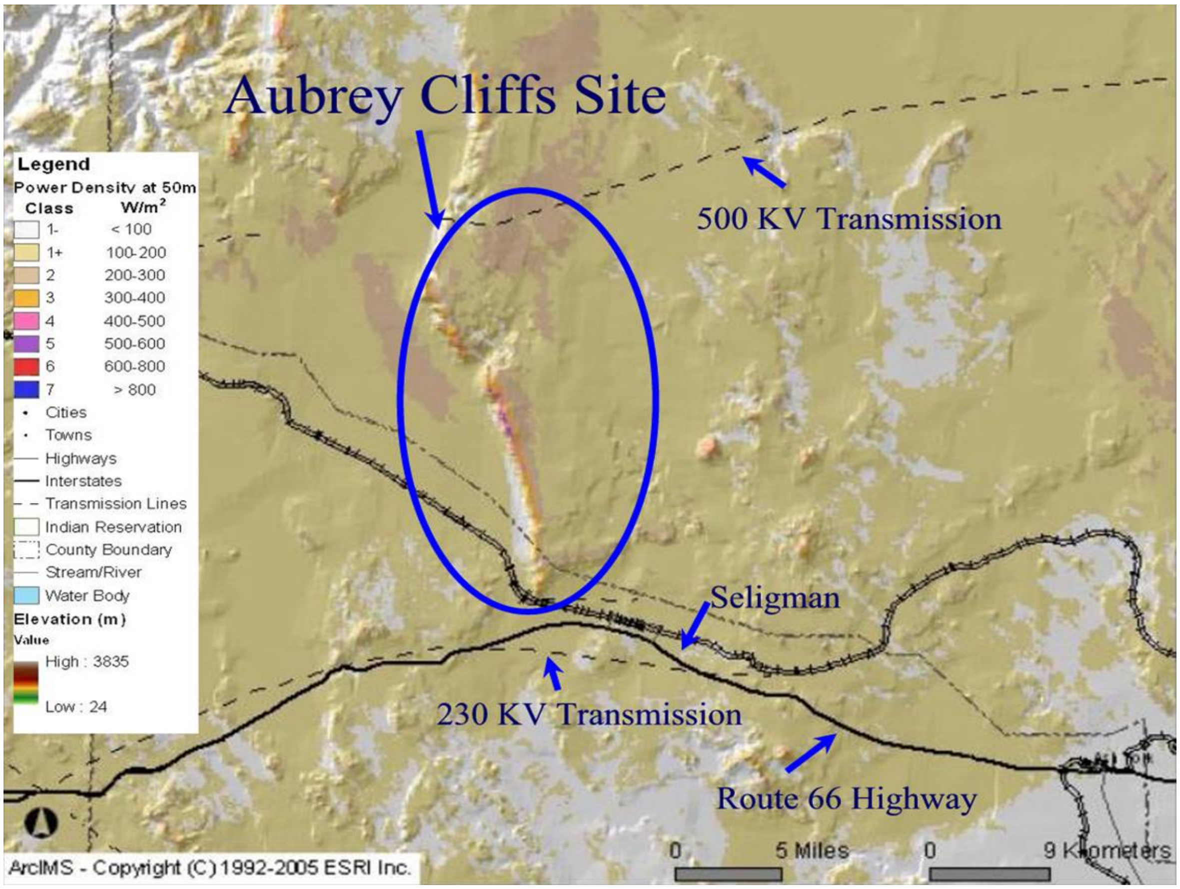


Figure 4-4 — Aubrey Cliffs Site Wind Resource Map



The Clear Creek site is located on Hopi fee and State Trust lands southwest of Winslow and has a potential to provide 75 MW in 2007. The site is currently under development by Foresight Wind Energy and the Hopi Nation. Foresight Wind Energy, LLC (Foresight), a major wind developer focused regionally in the southwestern United States, is a professional and competent wind energy development company. The principals have over 30 years of energy industry experience and have served in lead roles in development and operation of over 250 MW of wind energy projects in the western United States.

The Sunshine Wind Park is located on Hopi fee and private ranch lands owned by two other landowners. The site is 35 miles east of Flagstaff on I-40 near the Meteor Crater and west of Winslow, and has the potential to provide 60 MW by 2006. The site is currently under development by Foresight Wind Energy and the Hopi Nation. Figure 4-5 shows a general map of the area of the Clear Creek and Sunshine areas. Figure 4-6 and Figure 4-7 depict the wind resources available for the sites.

Figure 4-5 — Clear Creek and Sunshine Wind Park Project Location Map

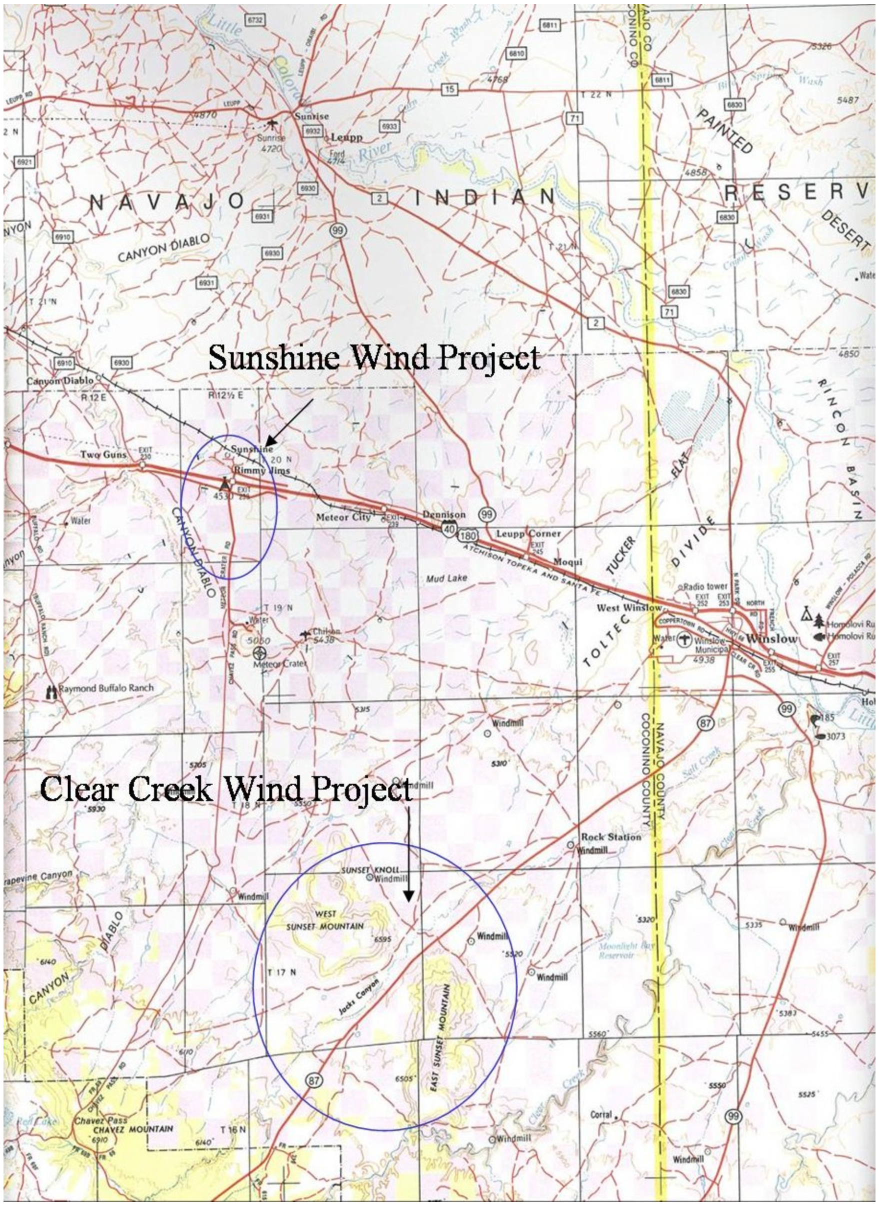


Figure 4-6 — Clear Creek and Sunshine Wind Resource Overview Map

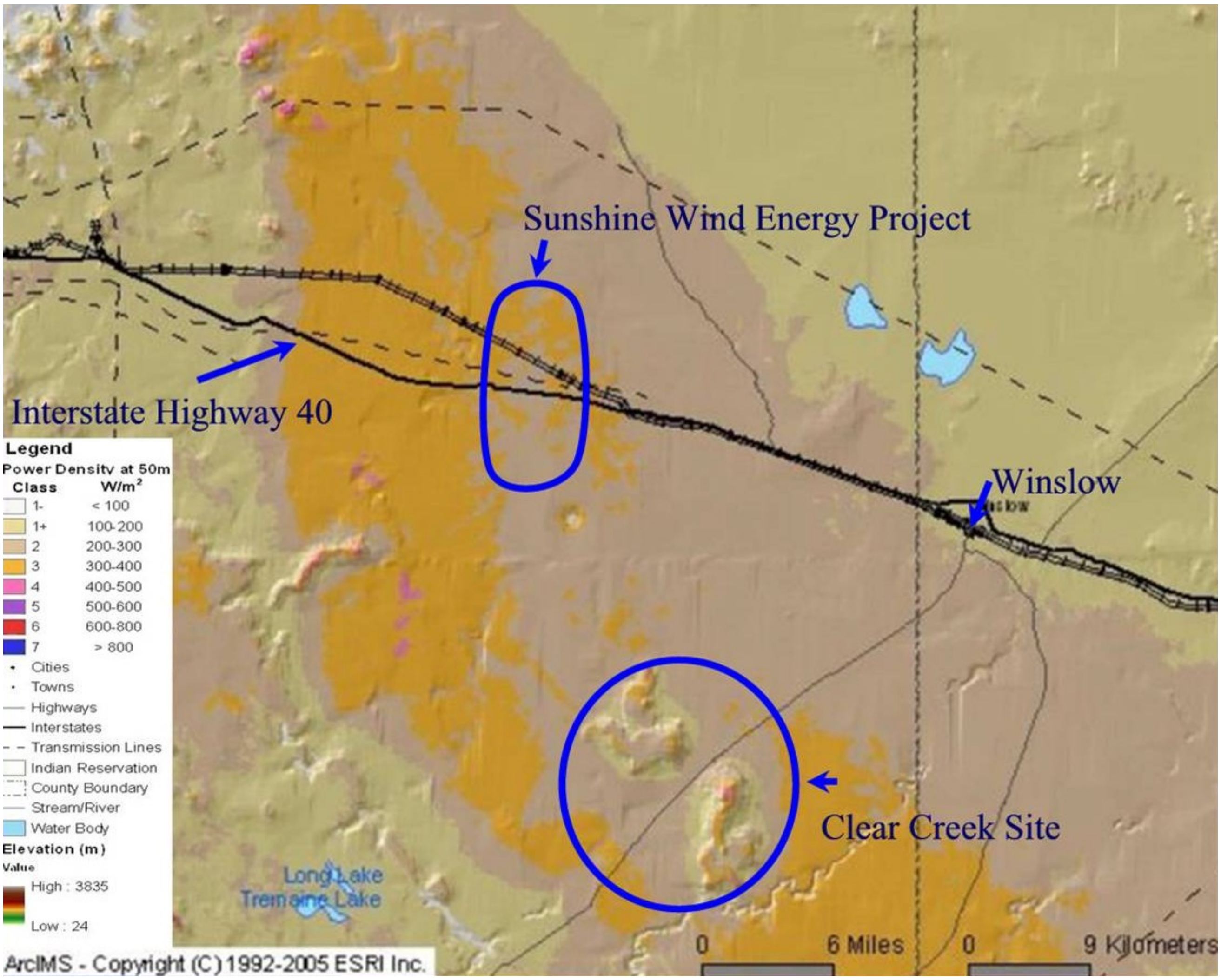
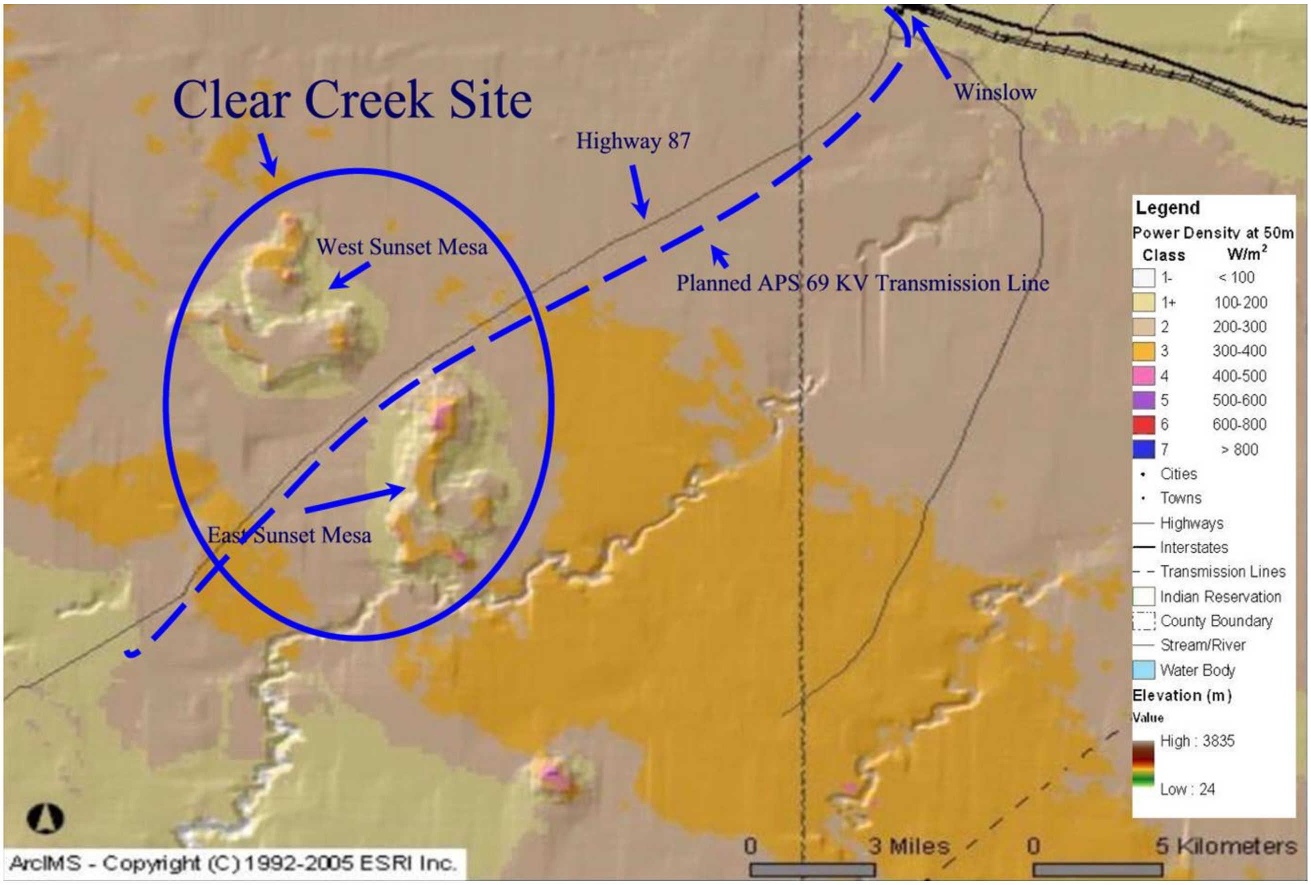


Figure 4-7 — Clear Creek Wind Resource Map



The characteristics of the projects identified are presented in the table below.

Table 4-1 — Wind Project Characteristics

Site	Developer	Wind Class at 80 m	MW	Timing
Gray Mountain	NTUA	4 to 7	450	2008–2010
Aubrey Cliffs	Foresight	3+ to 5	100	2007–2008
Clear Creek	Foresight	3+ to 4	75	2007
Sunshine	Foresight	3	60	2006

All four of these wind energy project sites are located within the State of Arizona. Arizona currently has a Renewable Portfolio Standard (RPS) (called an Environmental Portfolio Standard, or EPS, in Arizona) that requires the state's investor-owned utilities (IOUs) and cooperatives to generate or procure renewable energy supplies totaling 1.1% of total retail sales by 2006. To date, the standard has been more or less on a voluntary basis without specific legal and financial penalties for non-compliance. However, given considerably higher standards in neighboring states and Arizonans interest in supporting higher levels of renewables, the Arizona Corporation Commission (ACC) has been exploring expanding the EPS for over a year. In July 2005, the ACC voted to increase the EPS to 5% by 2015 and 15% by 2025. Rules to implement the order are being considered, including various compliance mechanisms and penalties. The final order was expected later in 2005. Final approval of this standard, even with a rather slow ramp up in percentage requirement in the early years, is expected to support considerable expansion in wind energy development activity in Arizona similar to that seen in states such as Texas, California, Minnesota, Wisconsin, New York, Colorado, and others that have adopted an RPS or legal order mandating utilities in those states to purchase renewable energy supplies. Twenty states in the U.S. have now adopted RPS standards.

4.1.1 Design Basis Technical Assumptions

Design basis technical assumptions for wind generation are summarized in the table below:

Table 4-2 — Design Basis Assumptions

Site	Net Capacity Factor (%)	Wind Class at 80 m	Wind Turbine
Gray Mountain	40	4 to 7	V-82 1.65 MW
Aubrey Cliffs	34	3+ to 5	V-82 1.65 MW
Clear Creek	32	3+ to 4	V-82 1.65 MW
Sunshine	25	3	V-82 1.65 MW

4.1.2 Feasible Capacity Ranges

4.1.2.1 Gray Mountain

The DOE has estimated that Gray Mountain has total wind resource potential of up to 800 MW; however, this estimate may not take into account physical limitations, transmission capacity, economic resources versus technical resources, or other constraints at the site. An estimate to build out to 450 MW over a three-year phased development program of 150 MW per phase seems feasible at this time. The site may have upside potential to this estimate; however, additional study, and some actual permitting, construction, and verification of wind resource data via wind test towers, would be needed to determine the upside potential beyond 450 MW.

4.1.2.2 Aubrey Cliffs

Aubrey Cliffs is initially being developed to a size of 100 MW, but could potentially be built out to 200 MW, depending on the degree to which the wind resource drops off further from the mesa edge and the transmission capacity available on the targeted 230-kV transmission system where interconnection will occur south of Chino Point and Route 66 near Seligman.

4.1.2.3 Clear Creek

Clear Creek is initially being developed to a size of 75 MW. There does not appear to be sufficient planned transmission capacity at this site over the near and intermediate term to exceed 75 MW, but over the long run, it might eventually support 150 MW, depending on transmission capacity. The transmission system at this site is only a 69-kV system, which may prove to be more of a limiting factor than the land area available or the wind resource at this site.

4.1.2.4 Sunshine Wind Park

The Sunshine Wind Park is being developed to a size of 60 MW to fully utilize the available transmission capacity on the 69-kV APS line into which the project would interconnect. Accordingly, the project cannot be expanded easily beyond this size. The planned location of turbines at the site already makes good use of the sandstone outcrops and hill features in order to get the wind resource to a Class 3 level at the 80-meter elevation; however, even though the project has 8,000 acres of land, some of the land at the lower elevations off the ridges, hills, and outcrops may be a Class 2 resource and not economic given today’s capital costs for wind turbines.

4.1.3 Fuel Requirements

There are no fuel requirements since the generation equipment is powered by the wind; however, there will need to be electric station service provided to each project from the local electric retail franchise provider in whose territory the projects are located. The projects will need a small amount of electricity to power utilities when the wind is not blowing and to keep automation systems and utilities on.

4.1.4 Water Requirements

Other than drinking water for facility employees or water associated with a sewage system at a field office, there are no ongoing requirements for water associated with a wind energy facility, and the only water usage for the projects will be on a one-time basis for construction of foundations or dust control as required.

4.1.5 Land Requirements

4.1.5.1 Gray Mountain

The Gray Mountain site has between 23,000 and 34,000 acres (35.9 to 53.1 sq. mi.) on which to site wind turbines. Assuming an average of eight turbines per section of land, the number of turbines that could be sited (assuming 1.65 MW turbines) would be 287 turbines, with the potential to site as many as 425 wind turbines. Building 450 MW at this site would equate to 272 turbines using 1.65 MW turbines. If larger turbines are used, somewhat fewer turbines can provide the same number of megawatts.

All of the land at the Gray Mountain site is on the Navajo Reservation and in the jurisdiction of the Cameron Chapter. The elevation at this site is about 6,400 feet above sea level and overlooks the Moenkopi Substation about 10 miles away.

4.1.5.2 Aubrey Cliffs

The Aubrey Cliffs site is an elevated ridgeline or cliff running about 10 miles in length and overlooking Aubrey Valley. This site is very similar in its appearance to many sites developed around McCamey, Texas, along high mesas and ridgelines. The elevation at this site is about 6,300 feet above sea level. If the site is limited to one or two rows of turbines sited along the length of the ridge, this site would consist of about 5,200 acres (8.1 sq. mi.). Assuming a spacing of 750 feet between turbines, about 56 turbines and 92 MW can be sited per row along the ridgeline. It is important to note that the land ownership at this site is a checkerboard of State Trust land and Navajo fee land. Therefore, both the Arizona State Land Department and the Navajo Nation would need to participate to allow this project to proceed as envisioned.

4.1.5.3 Clear Creek

At the Clear Creek site, Foresight Wind Energy is evaluating two mesas. Both sites will have wind studies conducted with wind test towers; however, Foresight plans to proceed with development on only one of the mesas at this time. The two mesas are known as East and West Sunset mountains, located approximately 18 miles southwest of Winslow, Arizona, on both sides of Highway 87. East Sunset appears to have about 4,320 acres (6.8 sq. mi.) across its top, and West Sunset appears to have about 5,760 (9.0 sq. mi.) acres across its top. The elevation of these mesas ranges between 6,100 and 6,500 feet above sea level. Foresight is planning a project of about 75 MW on one of these mesas using 40 to 50 turbines in the 1.5- to 1.65-MW size range. This site would entail leases from both the Arizona State Land Department and the Hopi Tribe as it is a "checker-boarded" site. The Hopi lands at this site are fee simple land holdings.

4.1.5.4 Sunshine Wind Park

Foresight Wind Energy has already leased 8,000 acres (12.5 sq. mi.) north and south of the I-40 interstate highway for the Sunshine Wind Park. The topography is flat plains with some outcropping sandstone hills. The elevation at this site is about 5,400 feet above sea level. The project is laid out in such a way that the turbines will follow ridgelines and hilltops to take advantage of any extra elevation which will be needed to access Class 3 wind at this site. Foresight is planning to use 35 to 40 turbines in the 1.5- to 1.65-MW size range that are suited for low-wind-speed application at this site. The site is leased from three landowners including Hopi fee lands.

4.1.6 General Design Concept

4.1.6.1 Gray Mountain

The layout at Gray Mountain would likely be in rows and columns north to south and east to west but with some interruption and adjustment of the pattern for ravines and low areas and to take advantage of terrain features offering elevation and added wind shear. There is a large amount of land to work with on top of the mountain in a mesa or flat plateau ranging between 23,000 and 34,000 acres. In areas where there is a Class 7 wind resource, the design may need to incorporate vertical axis wind technology in lieu of traditional three-bladed wind turbines. Horizontal axis wind turbines would be used throughout the areas of the mountain with Class 4–6 wind, but may not have a normal 20- to 30-year useful life or survive the wind shear of the Class 7 area of the mountain.

This site would need to have about 15 miles of access road improvements, and a 10-mile transmission system feeder of 34.5-kV line (for each 150-MW project phase) run into Moenkopi Substation. For construction, a cement batch plant would need to be constructed on top of the mountain, since there are no nearby facilities from which cement can be hauled in a timely manner onto the site.

4.1.6.2 Aubrey Cliffs

The layout at this site will be in one or possibly two rows of wind turbines running along the rim or ridgeline of the cliff running generally from north-northwest to south-southeast. The turbines would be sited on the far west side of the feature, sitting back from the cliffs several hundred feet to reduce turbulence and facing Kingman, Arizona. The turbines would likely be spaced about 750 to 900 feet apart along this ridgeline.

This site would need to have 10 to 12 miles of access road improvements, and a 5-mile power collection system feeder of 34.5-kV line run south under or over Route 66 to the 230-kV system south of Chino Point. Cement for foundations can probably be hauled in from Seligman, Kingman, or another nearby city using Route 66.

4.1.6.3 Clear Creek

The layout at this site will likely resemble that of Aubrey Cliffs with one or two rows of turbines sited 750 to 900 feet apart along the ridgeline of the mesas overlooking Highway 87 and Jacks Canyon. Due to limited transmission capacity, even after the planned APS 69-kV extension in the near to intermediate term, Foresight plans to develop only one of the mesas. There will need to be 8 to 10 miles of access road upgrades at this site.

Interconnection will be via a new 4-mile power collection system feeder to the APS 69-kV planned transmission system extension due to be built in 2006. Cement for foundation work can be transported from Winslow or possibly Flagstaff via Highway 87.

4.1.6.4 Sunshine Wind Park

The project and project layout has already secured a conditional use permit (CUP) granted by Coconino County. The layout generally runs from west-northwest to east-southeast along sandstone hill outcrop features, and there appear to be up to four rows of turbines on four separate outcrops. Each row will have from 7 to 12 wind turbines per row. Most of the turbines will be located south of I-40. There is an existing 69-kV transmission line and an existing 69-kV substation on the site for making an interconnection. Foresight has already substantially completed its required capacity and facilities studies with APS at this site for interconnection. Cement for foundation work can be transported from Flagstaff or Winslow on I-40.

4.1.7 Off-Site Facility Requirements

4.1.7.1 Gray Mountain

At Gray Mountain, one 10-mile 34.5-kV transmission line per 150-MW phase will need to be constructed from the project area on top of the mountain to the Moenkopi Substation in order to interconnect with the 500-kV system there. It is likely that telephone lines, fiber optic data communication lines, and electric station service will all need to be run into the project area on top of the mountain as well. A field office with central computer servers, O&M facilities, and office space will also need to be constructed either on the site or at the bottom of the mountain. Approximately 15 miles of access road upgrades with some blasting on sharp corners will need to be made to transport the blades, the generation sets, and the tower sections into the construction site.

4.1.7.2 Aubrey Cliffs

At Aubrey Cliffs, a 5-mile 34.5-kV transmission line from the project area on top of the ridge will need to be constructed underneath Route 66 and south of Route 66 and Chino Point to interconnect with the 230-kV system. A new 230-kV substation would likely be built at the point of interconnection with the 230-kV transmission line south of Route 66. It is likely that telephone lines, fiber optic data communication lines, and electric station service will all need to be run into the project area on top of the mountain as well. A field office with central computer servers, O&M facilities, and office space will also need to be constructed either on the site or at the bottom of the ridge. Approximately 10 to 12 miles of access road upgrades will need to be made to transport the blades, the generation sets, and the tower sections into the construction site.

4.1.7.3 Clear Creek

At Clear Creek, a 4-mile 34.5-kV transmission line will need to be constructed from the project area on top of the ridge towards Highway 87 to interconnect with the 69-kV system there. A small substation would likely be built at the point of interconnection. It is likely that telephone lines, fiber optic data communication lines, and electric station service will all need to be run into the project area on top of the mesa as well. A field office with central computer servers, O&M facilities, and office space will also need to be constructed either on the site or at the bottom of the mesa. Approximately 10 to 12 miles of access road upgrades will need to be made in order to transport the blades, the generation sets, and the tower sections into the construction site.

4.1.7.4 Sunshine Wind Park

At the Sunshine Wind Park, telephone lines, and electric station service will need to be run into the project area.

4.1.8 Site Screening

The sites chosen for evaluation were selected based on four factors:

- Location on or near Navajo or Hopi lands
- Cultural acceptance and sensitivity
- Wind resource potential of Class 3+ or better

- Transmission access

Although there are some excellent wind resource sites in northeastern Arizona on the Navajo lands in the Chuska Mountains, the cultural sensitivity and elevation of those sites made them lower on the priority list. From a technical perspective, the higher elevation in the Chuska Mountains also implies a lower air density, and thus a more degraded power curve output. Blue Canyon and Black Mesa were also initially selected for site visit and evaluation, but were not evaluated due to lack of tribal interest as well as time and prioritization. After some follow up discussion, it is believed these sites may have potential, but are probably not as promising as Gray Mountain or Aubrey Cliffs.

4.2 ENVIRONMENTAL EMISSIONS ISSUES

There are no emissions created in the generation of wind energy.

4.3 CAPITAL AND O&M COST ESTIMATES

Capital and O&M costs for the four projects identified are summarized in the following table.

Table 4-3 — Capital and O&M Cost Estimates

Project Size and Capital Costs	Gray Mountain 3 Phases	Gray Mountain Phase 1	Aubrey Cliffs	Clear Creek	Sunshine
Net MW	450	150	100	75	60
Project Costs $2006	755,017,000	258,031,000	169,196,000	126,570,000	99,671,000
Project Costs per kW, $/kW	1,678	1,740	1,692	1,688	1,661
Fixed O&M, $/kW-yr	23.73	23.73	24.24	24.94	27.08
Variable O&M, $/MWh	0.195	0.195	0.223	0.244	0.279

Please note that variable O&M expenses include consumable materials. Fixed O&M expenses include field operation labor, long-term service agreement expenses, insurance, lenders agency fees, letters of credit (LOC) fees or costs. Property taxes, sales taxes, and land lease or royalty payments are not included in the costs.

4.3.1 Gray Mountain

The “all in” capital costs in un-inflated 2006 dollars for Gray Mountain, excluding all direct transmission access and system upgrade costs, are estimated to be as follows:

Table 4-4 — Gray Mountain Capital Costs

Phases	$	$/Net kW
Phase 1 - 150 MW	258,031,000	1,720
Phase 2 - 150 MW	248,493,000	1,657
Phase 3 - 150 MW	248,493,000	1,657
Total Cost for 450 MW	755,017,000	1,678

The cost of Gray Mountain is higher than the other projects due to three main factors:

- **Access Roads.** 15 miles of access roads are required. Work on the access road will include some blasting on sharp turns in the existing road. This will increase its construction costs relative to the other projects.
- **Depot Facilities.** There are no nearby cities with depot facilities from which cement can timely be hauled to the top of the mountain; therefore, a batch plant will likely need to be constructed atop the mountain to make cement on location for the turbine foundations.
- **Interconnection.** The interconnection into the Moenkopi Substation 10 miles away is quite costly.

The capital costs for Phase I of Gray Mountain assume turbine costs of $1,113/kW in 2006 dollars, for delivery in 2008 and beyond, a substation/transmission-related cost of $26.32 million, and access road upgrade costs of $7.5 million. Because Phase I carries the burden of access roads and substation interconnection costs, even with inflation, Phase 2 costs would be slightly less, and Phase 3 costs only slightly more than Phase 1. All-in capital costs include costs of project financing, a 5% project contingency. Costs do not include sales and local taxes. O&M costs do not include sales and local taxes, property taxes, or land lease fees.

Therefore, even though the wind resource at Gray Mountain is better than the other projects, the expense of Phase 1 of Gray Mountain will likely offset some of its wind resource advantages. Subsequent phases of Gray Mountain should attain some economies of scale and potentially better power price competitiveness relative to Phase I.

4.3.2 Aubrey Cliffs

The capital costs for Aubrey Cliffs assume turbine costs of $1,113/kW in 2005 dollars, for delivery in 2007, and access road upgrade costs of $5 million. All-in capital costs include costs of project financing, a 5% project contingency.

4.3.3 Clear Creek

The capital costs for Clear Creek assume turbine costs of $1,113/kW in 2006 dollars, for delivery in 2007, a substation/transmission-related cost of $6.89 million, and access road upgrade costs of $5 million. All-in capital costs include costs of project financing, a 5% project contingency.

4.3.4 Sunshine Wind Park

The capital costs for the Sunshine Wind Energy Project assume turbine costs of $1,113 /kW in 2006 dollars, for delivery in 2006, and access road upgrade costs of $500,000. All-in capital costs include costs of project financing, a 5% project contingency.

4.4 TRANSMISSION ACCESS REQUIREMENTS

Direct transmission access requirements for the wind sites are described as follows:

- **Gray Mountain.** At Gray Mountain, a 34.5-kV power collection system for each 150-MW project phase will be run 10 miles into the Moenkopi Substation near Cameron to interconnect with the 500-kV transmission system.
- **Aubrey Cliffs.** At Aubrey Cliffs, a 34.5-kV power collection system will be run 5 miles south of Chino Point underneath Route 66, to interconnect with the 230-kV transmission system near Seligman. A substation will need to be constructed at the location of the 230-kV tie.
- **Clear Creek.** At Clear Creek, a 34.5-kV power collection system will be run 4 miles to interconnect with the planned APS 69-kV system upgrade to be constructed in 2006. A substation will need to be constructed at the location of the 69-kV tie.
- **Sunshine Wind Park.** The existing Sunshine APS substation will be substantially upgraded and expanded at Sunshine, and the project will interconnect at 69 kV onsite at this substation.

Cost estimates associated with direct transmission access for each wind site are as follows:

Table 4-5 — Direct Transmission Access Cost Estimates for Wind Sites

	Gray Mountain 3 Phases	Gray Mountain Phase 1	Aubrey Cliffs	Clear Creek	Sunshine
Net Output, MW	450	150	100	75	60
Direct Transmission Access Cost, $ millions	37.5	12.8	12.6	6.89	5.80
Estimated Cost per kW, $/kW	83.3	85.2	126.2	91.9	96.7

4.5 NET OUTPUT ASSUMPTIONS

In order to properly characterize the net output of the plant given the observed available wind resources at the various sites, the following assumptions regarding net output were made:

Table 4-6 — Net Output Assumptions

	Gray Mountain (each phase)	Aubrey Cliffs	Clear Creek	Sunshine
Gross Wind Generation, kWh/yr	584,878,952	341,179,388	229,364,295	164,568,882
Net Wind Generation, kWh/yr (12% array loss)	522,213,349	304,624,454	204,789,549	146,936,501
Net Wind Generation/turbine, kWh/yr	5,119,739	4,479,771	4,095,791	3,583,817
Annual Capacity Factor, %	40	34	32	25

These assumptions result in the net capacities shown for each project.

4.6 ROYALTIES, TAXES, AND OTHER ITEMS

Certain other costs and credits should be taken into account in the performance of integrated resource planning studies that are not included in the capital and O&M costs shown above. These include property taxes, sales and use taxes, income tax, production tax credits, and land lease payments. The parameters used in estimates of these quantities are discussed below and in Section 9 of this report.

4.6.1 Property Tax

For the three project sites within Coconino County, it was assumed that Foresight will obtain similar property tax treatment as for the Sunshine Wind Project. For the Gray Mountain Project on the Navajo Reservation, the normal property tax, which takes the form of the Possessory Interest Tax (PIT), is normally 3%. This would be a fairly high rate of property tax for a wind project and investment of the scale being considered at Gray Mountain versus the customary or industry standards in other states of the U.S.

4.6.2 Sales and Use Tax

Most states allow an industrial machinery sales tax exemption for wind energy projects covering all of the wind turbines, substation, and other facilities and equipment, and the services and labor used to install the equipment. Normally, exemptions cover 85% to 90% of the total capital costs of a project. Since Arizona has not had experience with wind energy projects and since Foresight is still investigating a tax opinion and securing this exemption for Sunshine Wind Project. Arizona State and county sales tax in Coconino County runs 6.525% and is referred to as the Transaction Privilege Tax (TPT).

For the Gray Mountain Project, the tax that is analogous to sales and use tax under Navajo Law is the Business Activity Tax (BAT). This tax is 5%.

Sales and use taxes are not included in the capital and O&M cost estimates shown in this section.

4.6.3 State of Arizona Corporate Income Tax

The State of Arizona has a 6.968% income tax on corporate profits. This tax is applied to federally taxable income to approximate its effect on the three projects which are within the state's jurisdiction. This tax is not included in any cost estimates included in this report.

4.6.4 Federal Production Tax Credit

The U.S. federal production tax credit is a very important assumption that must be considered in the economics of these projects. This credit, under Section 45 of the federal tax code, is set to expire on December 31, 2007. However, it may be extended beyond that date. The credit amounts to an "after tax" benefit of 1.9 cents/kWh for each kilowatt-hour produced for the initial 10-year period of each project. In general, this tax credit is worth up to 1/3 of the net present value of each project, and the viability of any of these projects would need to be re-evaluated if the credit is not available in 2008 and beyond. Any integrated resource plan process that is considering wind resources must take this production tax credit and its possible extension into account.

4.6.5 Lease Payments

Estimates of certain lease payments that would be paid to the Navajo and Hopi nations are shown below. The lease payments are representative of other wind projects in the United States.

Table 4-7 — Lease Payment Summary

Project	Gray Mountain (3 Phases)	Aubrey Cliffs	Clear Creek	Sunshine	Totals
Plant Output, MW	450	100	75	60	
Annual Lease Payments, $	1,530,000	272,000	185,000	135,300	2,122,300

4.7 PERMITTING ISSUES

4.7.1 Gray Mountain

The Navajo Nation internal siting and zoning process will probably require one to two years and has not yet been started for this large-scale project. This process, in general, is as follows:

- Review and consensus by the local Cameron Chapter of the Navajo Nation, resulting in a Chapter Resolution
- Referral to the Tribal Land Administration Resources Office for review and approval
- Review by the Office of the President of the Navajo Nation
- Review by the Legislative Branch –Resources Committee of the Navajo Nation
- Possible review by the Department of the Interior of the U.S.

Since Gray Mountain is on the Navajo Reservation, Coconino County does not have jurisdiction for this project, except perhaps for transportation coordination. It is likely that in the process of forming a resolution approving the project, the Cameron Chapter will want to follow a site permit process similar to that of Coconino County in issuing a Conditional Use Permit. In addition, a building permit is likely to be required from the appropriate local Cameron Chapter Office.

Gray Mountain has already had an initial National Environmental Policy Act (NEPA) study made by NTUA. There do not at this time appear to be any obvious flight path issues with military operational areas (MOAs) or with the Federal Aviation Administration (FAA); however, additional due diligence will be required. Each turbine and each wind measurement tower taller than 200 feet will require an individual FAA permit.

Likely a storm water pollution prevention plan (SWPPP) permit for the construction period will need to be filed with the Department of Natural Resources (DNR) for the Navajo Nation, and some permits from the DNR of the Navajo Nation concerning fish and wildlife, archeological, and historical and cultural clearance will also be required. Additional biological and avian survey studies need to be done at this site. This project seems to have the initial support of the Cameron Chapter of the Navajo, and an initial archeological, historical, and cultural clearance has already been obtained by NTUA in order to install a meteorological wind testing tower.

Since the project would interconnect into and sell its power into the Federal Energy Regulatory Commission (FERC) -regulated high-voltage transmission system at Moenkopi Substation, the project would likely need an Exempt Wholesale Generator (EWG) certificate from FERC. It is not known whether a Certificate of

Convenience and Necessity (CCN) hearing for transmission system tie-in would be needed for building any new transmission feeder to Moenkopi Substation, and this would be a due diligence action item. A CCN determination is usually a state level public utility commission function, especially if there is a need for condemnation or, in some cases, a need to allow for public notice and comment.

The project will likely want to secure an EWG declaration from FERC. In addition, there could be wholesale exemptions needed under Arizona law for the Transaction Privilege Tax.

Additional due diligence would be needed to determine whether there are any waters of the U.S., State of Arizona, or the Navajo Nation affected by the project either at or adjacent to the site or downstream of the site. No obvious waters of the U.S., of the State of Arizona, or of the Navajo were observed on the mountain, or in the path of the transmission line right-of-way to Moenkopi Substation, during the site visit. If a more in-depth environmental due diligence determines that there are affected waters, then there may need to be some Federal, state, or Navajo permits obtained in this regard.

The Kaibab National Forest is located approximately 3 to 6 miles due west of the project site atop Gray Mountain. Some additional due diligence may be needed to determine whether any special permitting or notices will need to be filed with federal authorities or the National Park Service regarding the project.

4.7.2 Aubrey Cliffs

Aubrey Cliffs would be permitted in Coconino County jurisdiction very similar to the site permitting already carried out by Foresight Wind Energy for the Sunshine Wind Park, which has already received a Coconino County Conditional Use Permit. A building permit will be required for construction from Coconino County. Foresight has already done some initial due diligence, and at this time, there does not appear to be any obvious flight path issues with MOAs or FAA problems; however, some additional due diligence is required. Each turbine and each wind measurement tower taller than 200 feet will require an individual FAA permit.

The Navajo Nation internal project approval process will probably take one to two years and has not yet been started. This approval process is believed to be more for approval in lieu of actual permits at this site, as it is off the Navajo Reservation and is fee land owned by the Navajo within Coconino County. It is likely that as a part of the internal Navajo Nation approval process, the DNR for the Navajo Nation will have a significant sign off in the decision making process. The approval and sign off of the NTUA may also be required as the internal Navajo Nation department most involved and knowledgeable about wind energy. While it does not appear that there will be any apparent conflict or compatibility issues, the DNR of the Navajo has been contemplating a residential resort approximately 3 to 5 miles due east of the location of turbines (to be sited along the cliffs on top of the east side of the plateau atop the Aubrey Cliffs feature) and closer to Seligman, Arizona.

Initial screens by the Arizona Game and Fish Department and the U.S. Fish and Wildlife Service (USFWS) have not identified any sensitive species at this site. Additional avian survey work needs to be done and is scheduled to being in the latter half of 2005.

A SWPPP permit will need to be filed with the Department of Environmental Quality for the State of Arizona, and final clearance from the State Game and Fish Department and the USFWS concerning fish and wildlife and, separately, clearances for archeological and historical and cultural will be required. This project seems to have the initial support of the Navajo Nation, and a meteorological wind testing tower has already been installed atop the cliffs to monitor wind data.

Similar to the analysis performed at Sunshine Wind Park, Foresight has had consultants perform initial electronic interference studies to determine whether it can site turbines along the ridgeline in such a manner so as not to interfere with the existing large telecommunications installations at the far south end of Aubrey Cliffs.

Since the project would interconnect into and sell its power into the FERC-regulated 230-kV high-voltage transmission system, the project would likely need an EWG certificate from FERC. It is not known whether a CCN hearing for the transmission system tie-in would be required for building any new transmission feeders to the 230-kV system, and this would be a due diligence action item. The likely location for a substation would be at the point of interconnection with the 230-kV system. Overhead 34.5-kV transmission lines would likely cross Route 66 and run south to an interconnection point with the existing 230-kV transmission system.

The project will likely want to secure an EWG declaration from FERC. In addition, there could be wholesale exemptions needed under Arizona law for the Transaction Privilege Tax.

Additional due diligence will be needed to determine whether there are any waters of the U.S. or State of Arizona affected by the project either at or adjacent to the site or downstream of the site. No obvious waters of the U.S. or waters of the State of Arizona were observed on the site, or in the path of the transmission line easement south of Route 66 during the site visit. If a more in-depth environmental due diligence determines that there are affected waters, then there may need to be some Federal or state permits obtained in this regard.

Foresight is investigating obtaining a State of Arizona Industrial Machinery Sales Tax Exemption for the Aubrey Cliffs Wind Energy Project. Typically, these certifications allow the developer to avoid paying sales tax on a very high percentage of the capital involved in purchasing equipment, services, and labor related to installation of equipment, and most of the personal property and tangibles not classified as real estate that make up a project.

4.7.3 Clear Creek

Clear Creek would be permitted in Coconino County jurisdiction very similar to the site permitting already carried out by Foresight Wind Energy for the Sunshine Wind Park, which has already received a Coconino County Conditional Use Permit. A building permit from Coconino County will be required for construction. Foresight has already done some initial due diligence, and at this time, there does not appear to be any obvious flight path issues with MOAs or FAA problems; however, some additional due diligence is required. Each turbine and each wind measurement tower taller than 200 feet will require an individual FAA permit.

The Hopi Nation will have a significant decision making input and approvals in their internal project approval process, which is being discussed with them by Foresight. This approval process is believed to be more for approval in lieu of actual permits at this site, as it is off the Hopi Reservation and is fee land owned by the Hopi within the Coconino County, State of Arizona, and Federal U.S. jurisdiction.

Phase I biological and avian studies are underway, and Phase II survey work is scheduled to start in the fall of 2005. A SWPPP permit will need to be filed with the Department of Environmental Quality for the State of Arizona, and some permits from the State Department of Game and Fish and USFWS concerning fish and wildlife, archeological, and historical and cultural clearance will also be required. This project seems to have the initial support of the Hopi Nation, and a meteorological wind testing tower has already been installed atop the East Mesa to monitor wind data.

It is believed that no CCN hearing (Certificate of Convenience and Necessity) for transmission system tie-in will be required for building any new transmission feeder to the 69-kV system. The likely location for a substation would be at the point of interconnection with the 69-kV system.

The project will likely want to secure an EWG (Exempt Wholesale Generator) declaration from FERC. In addition, there could be wholesale exemptions needed under Arizona law for the Transaction Privilege Tax. Additional due diligence would be needed to determine whether there are any waters of the U.S. or State of

Arizona affected by the project either at or adjacent to the site or downstream of the site. No obvious waters of the U.S. or waters of the State of Arizona were observed on the site, or in the path of the transmission line easement running from either mesa towards Highway 87 during the site visit. If a more in-depth environmental due diligence determines that there are affected waters, then there may need to be some Federal or state permits obtained in this regard.

Foresight is investigating obtaining a State of Arizona Industrial Machinery Sales Tax Exemption for the Clear Creek Wind Energy Project. Typically these certifications allow the developer to avoid paying sales tax on a very high percentage of the capital involved in purchasing equipment, services, and labor related to installation of equipment and on most of the personal property and tangibles not classified as real estate that make up the Project.

4.7.4 Sunshine Wind Park

Sunshine Wind Park has already been granted its County Conditional Use Permit from Coconino County. A review of the permit application and public outreach materials indicates they are highly professional, quite thorough, and detailed, and that they provide excellent documentation of the due diligence and facts and plans surrounding the project site and its construction and operation. A building permit will be required for construction from Coconino County. Foresight has already done some initial due diligence and at this time, there does not appear to be any obvious flight path issues with MOAs or FAA problems; however, some final micro-siting, surveying, and permitting work is required. Each turbine and each wind measurement tower taller than 200 feet will require an individual FAA permit.

Western EcoSystems Technology, Inc. has completed a Phase I biological assessment of the site and determined there are no endangered species, or critical habitats in the area of the Project. The desert scrub habitat and lack of water and trees limits the concentration of wildlife in the area. The site has received clearance from the Arizona Game and Fish Department and USFWS. Eleven winter migrating bird surveys were conducted in 2004 and 2005 at three sites on or adjacent to the project site. Migratory bird surveys were also conducted in March through May 2005. Fall avian migration studies are currently underway to provide an understanding of the site spanning an entire year. The area is not a migratory fly way, and there do not appear to be any issues or concerns at this time regarding the biological studies conducted to date.

All archeological, cultural, and historical assessments have been completed at this site. There are several telecommunications towers on or adjacent to the site; however, Foresight has already planned for locating the turbines so as to avoid any impact on these telecommunications systems signal paths. Comsearch performed analysis of the worst-case full microwave paths at the project site for Foresight.

The typical SWPPP permit will need to be filed with the Department of Environmental Quality for the State of Arizona. This project seems to have the support of the Hopi Nation, and four meteorological wind testing towers have already been installed at the site to monitor wind data. Two towers are north of I-40 and two towers are south of I-40.

Since the project would interconnect into and sell its power into the FERC-regulated 69-kV high-voltage transmission system, the project would likely need an EWG certificate from FERC. It is believed by Foresight that no CCN hearing for transmission system tie-in is needed since the transmission line and substation are already on the land where the project is located.

The Project will likely want to secure an EWG declaration from FERC. In addition, there could be wholesale exemptions needed under Arizona law for the Transaction Privilege Tax.

No obvious waters of the U.S. or of the State of Arizona were observed on the site during the site visit.

One disaffected landowner adjacent to the project has filed suit against the Coconino County Planning Commission claiming that the County Planning Commission did not have the jurisdiction or legal standing to approve the Sunshine Wind Energy Project. At least at first glance, this lawsuit seems without merit, and baseless in its claim the County did not have jurisdiction or a legal basis for its approval of the Conditional Use Permit. The suit is likely to be either dismissed as baseless or litigated by the County, and should not prevent the Project from proceeding under the Conditional Use Permit it has legally obtained.

Foresight is investigating obtaining a State of Arizona Industrial Machinery Sales Tax Exemption or exemption from the Transaction Privilege Tax for the Sunshine Wind Energy Project. Typically these certifications allow the developer to avoid paying sales tax on a very high percentage of the capital involved in purchasing equipment, services, and labor related to installation of equipment and on most of the personal property and tangibles not classified as real estate that make up the Project.

4.8 CONCEPTUAL PROJECT DEVELOPMENT SCHEDULE

4.8.1 Gray Mountain

Gray Mountain's project development schedule for Phase I of 150 MW is attached in Appendix H. Each of the major project development tasks leading up to construction is shown with start dates, days duration, and finish or completion dates. Given the internal consensus building and the initial approval of the Navajo Cameron Chapter to erect a meteorological tower to measure the wind, the NEPA studies, and archeological clearances already accomplished by NTUA, and assuming a 1- to 2-year internal approval process by the Navajo Nation to develop and approve the construction of the project, it is believed that 150 MW could be constructed starting in the spring of 2008. The likely critical path for this project will not be so much technical or financial as the internal Navajo Nation review and approval process and in working with the Navajo to define an acceptable commercial framework, deal structures that allow for fair and equitable royalties, lease payments, or equity participation or some combination of these financial benefits. Since this type of project will be relatively new to the various departments and branches of the government of the Navajo Nation, some extra time should be anticipated to obtain consensus and approval. The schedule shown is for Phase I only, but it should be feasible to obtain all permits, and to allow flexibility in the contracts to add 150-MW amounts, Phases II and III, in 2009 and 2010. Please note that it is not likely that this project can be constructed in time to capture the Federal Production Tax Credit, which is due to expire December 31, 2007, and that this uncertainty could prove to be a major development risk factor borne by the developer.

4.8.2 Aubrey Cliffs

The project development schedule for Aubrey Cliffs is attached in Appendix H. Each of the major project development tasks leading up to construction is shown with start dates, days duration, and finish or completion dates. Major progress on land leases agreements, environmental due diligence, and Coconino County site permits will need to be made in 2006 for this project to be constructed in 2007. But, assuming progress on these fronts, it seems feasible the project could be constructed starting in the spring of 2007.

Staying on this schedule would have major advantages in ensuring the project will capture the Federal Production Tax Credit for wind due to expire December 31, 2007. This project does have some risk of slipping to 2008 due to the complexity of the checker-boarded land ownership of the State of Arizona and the Navajo Nation at the site and, as shown on its development schedule, is probably slightly less advanced than the Clear Creek Site.

4.8.3 Clear Creek

The Clear Creek project development schedule is attached in Appendix H. Each of the major project development tasks leading up to construction is shown with start dates, days duration, and finish or completion dates. Major progress on land leases agreements, environmental due diligence, and Coconino County site permits will need to be made in 2006 for this project to be constructed in 2007. But, assuming progress on these fronts, it seems feasible the project could be constructed starting in the spring of 2007. Staying on this schedule would have major advantages in ensuring the project will capture the Federal Production Tax Credit for wind due to expire December 31, 2007. The development of this site may proceed a little more quickly than Aubrey Cliffs only because the Hopi Nation has already been involved in the development of the Sunshine Wind Project, and are somewhat familiar with wind energy project development and deal structures. Foresight has also already been discussing the various ways to lease the "checker-boarded" land at the site from either the Hopi or the State of Arizona.

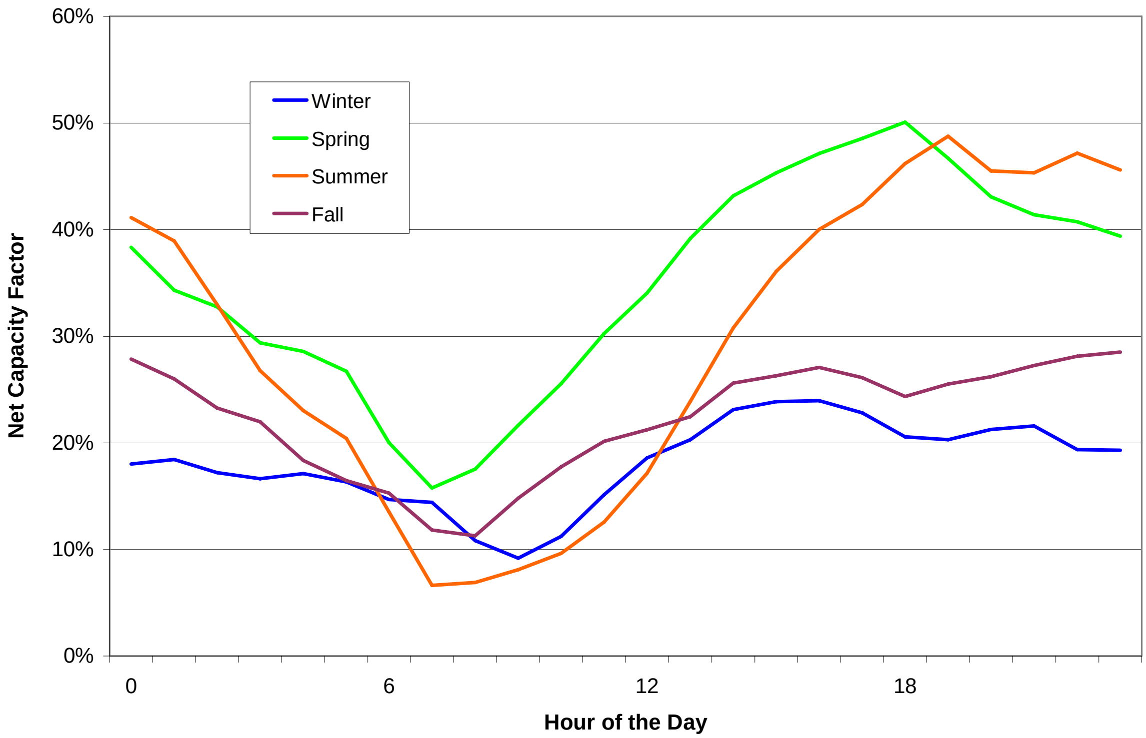
4.8.4 Sunshine Wind Park

The Sunshine Wind Park project development schedule is attached in Appendix H. Each of the major project development tasks leading up to construction is shown with start dates, days duration, and finish or completion dates. The high percentage of complete development tasks and milestones on this project are indicated by the black fill on the schedule bars. Most of this project is in the advanced stages of development with many critical path development milestones complete or nearly complete.

4.9 GENERATION PROFILE AND LOAD DEMAND

For this study, it is assumed that load demand is sufficient to absorb the capacity of these four projects as long as transmission capacity is available. The generation profile for these projects is likely to be more on peak coincident than most wind projects in the U.S. As the figure below indicates, more of the generation will occur in the afternoons, peaking at about 5 to 6 p.m. This situation is likely to make wind generation in Arizona more valuable than wind generation in other parts of the U.S. where, in some instances, the peaks occur well into the evening and night during off-peak periods.

Figure 4-8 — Seasonal-Diurnal Wind Energy Output



4.10 CONSTRUCTION AND OPERATION STAFFING

The major impact on employment for wind energy projects will be during the construction period. On a permanent basis, wind projects typically employ 3 or 4 people per 75 to 100-MW of capacity. The table shown below indicates permanent and construction manpower characteristics for each of the four projects.

Table 4-8 — Manpower Requirements for Wind Projects

Project	MW	Permanent Jobs	Average Construction Jobs	Peak Construction Jobs	Percent Skilled Crafts during Construction
Gray Mountain	450	14	110 (each phase, three phases)	150 (each phase, three phases)	35%
Aubrey Cliffs	100	4	95	130	35%
Clear Creek	100	4	95	130	35%
Sunshine Wind Park	60	3	75	100	30%

Last page of Section 4.

5. NATURAL-GAS COMBINED CYCLE TECHNOLOGY

Natural gas combined-cycle (NGCC) technology was investigated as a potential alternative to replace or complement the electrical generation of the Mohave Generating Station. The Mohave Generating Station is a two-unit 1,580-MW coal-fired power plant located in Laughlin, Nevada, built between 1967 and 1971. The station covers approximately 2,490 acres. This study considered NGCC technology for the Southern California Edison 56% portion (885 MW) of the plant power generation. It is assumed that natural gas fuel can be obtained from natural gas trunk pipelines near the existing Mohave site.

Combined-cycle technology has been used to generate power for a number of years. Combined-cycle technology in the power industry is primarily a combination of the Brayton and Rankine cycles. The combustion turbine operates on the Brayton cycle and the bottoming cycle, which is made up of the heat recovery, steam generator, steam turbine, and related balance-of-plant systems, operates on the Rankine cycle.

The first combined-cycle power plant in the United States using combustion turbines was installed in 1957 for the West Texas Utilities Company. This unit was rated at approximately 38 MW. Over the years, advancements in combustion turbine design have been numerous, leading to increased capacity, performance, and reliability. The advancements in the combustion turbines have lead to increased combined-cycle plant sizes, performance, and reliability.

Combined-cycle plants generally come in discreet sizes. These discreet sizes are a function of the combustion turbine size. Unlike traditional power plants where the plant size is determined by the steam turbine, the combined-cycle power plant size is primarily a function of the combustion turbine. A general rule of thumb for combined-cycle plants that use industrial combustion turbines is that for every 2 MW of combustion turbine power generated, the steam turbine will generate approximately 1 MW of power. Today, combustion turbines have ISO capacity ratings over 250 MW for 60 Hz applications. Therefore, there are combined-cycle plants in 60 Hz applications, utilizing a single combustion turbine, which generate approximately 400 MW of power.

To achieve a power output of approximately 885 MW, the plant configuration for this study will be made up of two nominal 500-MW combined-cycle power blocks. Each 500-MW power block has a 2 x 2 x 1 configuration. The 2 x 2 x 1 designation refers to two combustion turbines, two heat recovery steam generators, and one steam turbine. This configuration and size were selected due to the vast industry experience and to be capable of achieving 885 MW of power.

5.1 NGCC TECHNOLOGY DESCRIPTION

For a combined-cycle power plant, the combination of multiple power cycles is performed to improve the overall efficiency of the total power plant. In general, a simple-cycle combustion turbine (i.e., Brayton cycle) has an efficiency in the range of 19% to 38% on a higher heating value basis. The efficiency range is quite broad due to the firing temperature of the combustion turbine, the pressure ratio, and the blade and component design of the machine. The Rankine-cycle power plant efficiency is typically in the range of 32% to 39% on a higher heating value basis. The Rankine-cycle efficiency is generally a function of the cycle configuration, the steam conditions, the equipment design, and the cooling source. The combination of these two power cycles, representing the combined-cycle power plant, generally provides efficiencies in the range of 48% to 52% on a higher heating value basis.

5.1.1 Combustion Turbine

Typically, combustion turbines used for combined-cycle plants are industrial-frame units (sometimes referred to as heavy-duty units). An industrial-frame combustion turbine is generally designated as such because it is larger, heavier, operates at slower speeds (i.e., typically 3,600 rpm) and is generally considered more rugged. The other classification of combustion turbines is aeroderivative. An aeroderivative combustion turbine is so named because they are modeled after jet engines used in airplanes. These engines are generally smaller, lighter, operate at higher speeds and can require specialized maintenance personnel due to more technical, complex components.

The combustion turbine included in this study is the F-Class, industrial-frame unit. The F-Class unit designation is given to the machine due to the firing temperature. Generally, the F-Class combustion turbine has a firing temperature of approximately 2,350°F to 2,400°F. Most F-Class combustion turbines for 60-Hz applications have an ISO rating in the range of 170 MW to 200 MW depending on the manufacturer. In particular, the F-Class combustion turbine selected for this study is the General Electric PG7241(FA), which is typically called the 7FA. This combustion turbine has an ISO rating of 171,700 kW, a lower heating value heat rate of 9,360 Btu/kWh (36.5%), a pressure ratio of 16, and a speed of 3,600 rpm. Other manufacturers of F-Class combustion turbines, including, but not limited to, Siemens, Alstom, and Mitsubishi Heavy Industries, could also provide machines that would work in this application.

There will be two GE 7FA combustion turbines per nominal 500-MW power block. Therefore, there will be a total of four combustion turbines for the site. The combustion turbines will be designed to fire natural gas as the primary fuel and No. 2 fuel oil as emergency backup. The combustion turbines will be equipped with dry low NO_X burner technology to limit the NO_X emissions from the combustion turbine to 9 ppmvd at 15% O_2 or less when operating on natural gas. Water injection will be used to control the NO_X to 42 ppmvd at 15% O_2 when operating on No. 2 fuel oil.

The combustion turbines will be equipped with an inlet filtration system to protect it from airborne dirt and particles. A pulse-type self-cleaning inlet air filtering system was selected. Evaporative coolers were also selected to lower the combustion turbine inlet air temperature during warm weather operation to enhance the combustion turbine's performance. An inlet silencer is included to reduce the noise emitted from the combustion turbine compressor inlet.

The air enters the compressor section of the combustion turbine through the inlet bellmouth. The air is compressed in the axial compressor through multiple compressor stages. The compressed air leaves the compressor section and is routed to the combustor where fuel is admitted for combustion. The hot combustion gases are directed into the turbine section of the combustion turbine where they are expanded. The turbine section of the combustion turbine drives the combustion turbine compressor and the generator. After expansion in the turbine section, the hot exhaust gases leave the turbine section through the diffuser and are directed to the heat recovery steam generator through the exhaust duct.

A combustion turbine is a constant-volume machine. Therefore, the more mass that goes through the turbine, the greater the output from the turbine. Based on this principle, the performance of the combustion turbine is highly dependent on ambient conditions. As the inlet air temperature is lowered, more inlet air mass will be ingested into the machine and the machine will generate more power output. Similarly, higher atmospheric pressures cause more air to be ingested into the machine, leading to greater output. Therefore, as the site elevation increases, the potential power output of the plant will be less than it would be at sea level.

5.1.2 Heat Recovery Steam Generator

The HRSG is used to generate steam by recovering the wasted energy from the combustion turbine hot exhaust gases. Heat recovery steam generators are typically classified as horizontal or vertical units. Horizontal units have vertical heat exchanger tubes with the exhaust gas flowing horizontally through the unit. These units are widely used in the United States. Vertical units have horizontal heat exchanger tubes with the exhaust gas flowing vertically through the unit across the tubes. The majority of these units are forced circulation units. These units are more widely used in European countries where available space is limited, typically, due to a smaller footprint.

Each combustion turbine exhausts into a dedicated HRSG; therefore, for the two 500-MW combined-cycle power blocks proposed in this study, there will be a total of four HRSGs required. Each HRSG will be three-pressure level, reheat, natural circulation, drum-type units. High-pressure steam will be generated at 1,800 psig and 1,050°F to be used as main steam to the steam turbine. The intermediate-pressure steam will be blended with the cold reheat steam before entering the reheat section of the HRSG. The reheat steam will be generated at 1,050°F and will be routed to the intermediate (reheat) turbine. The low-pressure section of the HRSG will be used for deaeration, and superheated steam from the low-pressure superheater will be sent to the low-pressure steam turbine to generate additional power.

The HRSG will comprise heat exchange sections including superheater(s), evaporator, and economizer(s) for each pressure level of steam generated. In a combined-cycle unit, the condensate is typically heated with the low-pressure economizer section of the HRSG rather than via feedwater heaters that take extraction steam from the steam turbine. This is done to recover as much waste heat from the combustion turbines as possible and to allow as much steam to pass through the steam turbine to generate power and to improve the overall efficiency of the unit. The low-pressure section of the HRSG incorporates an integral deaerator, and the low-pressure drum acts as the deaerator storage tank. Condensate is fed from the low-pressure drum to the boiler feedwater pump(s), where it is pumped to the intermediate- and high-pressure sections of the HRSG.

The design point of the HRSG will be based on the combustion turbine performance at the average ambient conditions. The performance will incorporate 15°F pinch point temperatures and a 20°F evaporator approach temperatures. The HRSG will also be designed for a 2°F temperature drop in the duct between the combustion turbine and the first heat transfer section of the HRSG. A 1% thermal loss is included to account for radiation losses, convection losses, and leakage from the HRSG to the atmosphere. A 5°F temperature drop is included in the steam lines between the HRSGs and the steam turbine. For natural gas operation, the stack temperature is generally kept above 180°F, and for No. 2 fuel oil, the stack temperature is typically maintained above 280°F.

Blowdown systems are included for the HRSG steam drum to remove suspended solids. The blowdown from each HRSG will be routed to a blowdown tank. A continuous blowdown rate of 1% will be used for normal operation.

The HRSGs will be shop-fabricated and assembled to the maximum extent possible permitted by shipping regulations. The HRSGs will be erected on site and set on a concrete slab with foundations designed to withstand the full-of-water loads. The HRSGs will be located outdoors. Each HRSG will have a separate stack with continuous emissions monitoring.

5.1.3 Steam Turbine

There will be one steam turbine for each 500-MW combined-cycle power block. Therefore, there will be two steam turbines required for the site. The steam turbines will be reheat condensing units. Each steam turbine will generate nominally 175 MW of power. High-pressure steam from the HRSG will be sent to the steam turbine as main steam. Cold reheat steam from the steam turbine will be routed to the reheat section of the HRSG. A 10% pressure drop is allocated for steam pressure drop in the cold reheat piping, HRSG reheater, and hot reheat piping. The hot reheat steam is directed to the intermediate or reheat steam turbine. Low-pressure superheated steam from the HRSG is routed to the low-pressure section of the steam turbine.

The steam turbine is a condensing unit where the low-pressure steam exhausts from the steam turbine into either a wet surface condenser or an air-cooled condenser. The unit will include generator and auxiliaries, main steam control and stop valves, reheat stop and pilot valves, turbine control system, casing drains, and so forth. In addition, the unit will include all auxiliary systems associated with the proper operation of the steam turbine including, but not limited to, steam seal, exhaust hood sprays, lube oil, seal oil, and cooling system. The unit will operate at 3,600 rpm and be designed for outdoor installation.

5.1.4 Balance-of-Plant System Descriptions

Brief descriptions of the majority of balance-of-plant systems follow.

5.1.4.1 Mechanical Systems

Mechanical systems include the following:

- **Steam Systems.** The steam systems consist of the main steam, hot and cold reheat steam, intermediate-pressure steam, low-pressure steam, and bypass steam systems. The main steam system includes the main steam piping and components from the heat recovery steam generator superheater outlet to the high-pressure steam turbine control valves. The cold reheat steam system includes the piping and components from the high-pressure turbine exhaust to the HRSG reheat inlet. The intermediate-pressure steam system includes piping and components from the intermediate-pressure superheater outlet to the cold reheat piping connection. The HRSG supplier typically provides this system. The hot reheat steam system includes the piping and components from the final HRSG reheater to the steam turbine reheat stop valve. The low-pressure steam system includes the piping and components from the low-pressure HRSG superheater outlet to the admission point at the low-pressure steam turbine. The steam turbine bypass steam system will be used for startup and for trips, and involves bypassing the steam either to the condenser for the hot reheat and low-pressure bypass systems, or routing the steam from main steam to cold reheat for the high-pressure steam system. The steam piping will generally be routed on a system of pipe racks.

- **Condensate System.** The condensate system will be used to transfer the condensate from the condenser (i.e., either wet surface condenser or air-cooled condenser) hotwell to the low-pressure economizer section of the HRSG. The condensate system will include pumps, piping, and components. The condensate system will also include connections for water sampling and chemical feed.

- **Feedwater System.** The feedwater system will be used to transfer water from the low-pressure drum to the intermediate-pressure and high-pressure economizer sections of the HRSG. The feedwater system will include motor-driven boiler feed pumps, piping, control valves, and components. The feedwater control valves will be used to control the flow of feedwater to the high-pressure and intermediate-pressure systems.

- **Cooling Water System.** The circulating water system will be incorporated in the configuration that includes a wet mechanical draft cooling tower with wet surface condenser. The mechanical draft cooling tower will be designed for the summer ambient conditions. There will be one mechanical draft cooling tower per steam turbine. Therefore, two towers will be installed. The cooling water will be circulated to the wet surface condenser and back to the cooling tower via circulating water pumps. The vertical circulating water pumps will take suction from the cooling tower basin. The circulating water pumps will also supply water to the closed cooling water heat exchanger. The closed cooling water system will be a closed system and circulate cooling water to all of the equipment heat exchangers located throughout the plant.

- **Fuel System.** A new fuel system will be required for the combined-cycle units. The primary fuel will be natural gas with No. 2 fuel oil for emergency backup. The natural gas system will require a new pipeline, fuel gas compressors, fuel gas conditioning and performance heating system, and fuel gas metering system. The No. 2 fuel oil system will require storage and a fuel forwarding system.

- **Inlet Air System.** As discussed in the description of the combustion turbine, an inlet air system will be required for the combined-cycle combustion turbines. A pulse-type inlet air system will be used to filter the ambient air entering the combustion turbine compressor. Filtering the air is required to minimize the effects of erosion, corrosion, plugging, and fouling on the combustion turbine compressor and turbine blades. The pulse-type inlet air system uses cartridges to filter the air. These cartridges are periodically cleaned with a pulse of air from the reverse direction.

  The inlet air system also incorporates evaporative coolers. The evaporative coolers will be installed in the inlet air system to cool the inlet air during warm weather operation. The evaporative coolers use potable quality water to saturate a membrane in the air stream. The inlet air passes through the membrane lowering the air temperature through evaporation of the water. The inlet air system will also include silencing.

- **Flue Gas System.** Each CT/HRSG train will incorporate a flue gas system. Each flue gas system will consist of the ducting from the combustion turbine to the HRSG, the selective catalytic reduction system, the ducting from the HRSG to the stack, the continuous emissions monitoring system (CEMS), and the stack.

  It is anticipated that a selective catalytic control (SCR) system will be required to reduce the nitrogen oxides (NO_X) found in the exhaust gas of the combustion turbine. The combustion turbine is designed for a NO_X emission level of 9 ppmvd at 15% O_2 when firing natural gas. It is anticipated that the NO_X requirements for the Mohave Generating Station will be on the order of 3 to 5 ppmvd at 15% O_2. At this time, it is anticipate that the SCR system will use aqueous ammonia with a catalyst placed in the HRSG. The ammonia is injected in the exhaust gas upstream of the catalyst. The ammonia mixes with the exhaust gas, and the NO_X breaks down into N_2 and O_2 when it comes in contact with the catalyst. Each HRSG will have a dedicated stack with a CEMS located as required to obtain accurate readings.

- **Fire Protection System.** A fire protection system will be required for the combined-cycle power blocks. The system will include detection, alarming, and suppression systems. The fire protection alarming system will be located in the control room. This system will include fire extinguishers, sprinkler system (as required), dry suppression system (as required), piping, pumps, and hydrants to protect the facility.

- **Waste Water System.** A new process waste water system will be required for the combined-cycle facility. The process waste water system will be used to collect and neutralize waste water before discharging to the city. The process waste water system will incorporate piping, neutralization equipment, and components. In addition, combustion turbine water wash drains tanks will be required. These tanks collect water that has drained from the combustion turbines after an off line water wash. This water will be stored in the drains tank until a licensed waste hauler pumps the waste water out of the tank for proper off site disposal.

- **Station and Instrument Air System.** A station and instrument air system will be required for the combined-cycle facility. A separate system will be installed for each 500-MW power block. Each system will include two 100% centrifugal air compressors providing both instrument and station air. The system will also include filters, dryers, receiver, and piping. The system will deliver 125 psig compressed air.

5.1.4.2 Electrical and Control Systems

The electrical systems will provide a source of ac and dc power for the combined-cycle plant auxiliaries. The electrical system will consist of the generation system, medium-voltage system, low-voltage system, uninterruptible power supply (UPS) and dc systems, and motors, new switchyard breakers, generators and generator breakers, auxiliary and main power transformers, and plant electrical auxiliary systems. Electrical systems are described as follows:

- **Generation System.** The generation system will consist of the generators, excitation system, generator buses, generator breakers, and the main power transformers. For this study, each combustion turbine and steam turbine will have a generator (18 kV rated), exciter, generator bus (ISO-phase), generator breaker, and main power transformer (two winding).

- **Medium-Voltage System.** Each 500-MW combined-cycle power block will have a medium-voltage system. The medium-voltage auxiliary system provides feed to motors, other medium-voltage loads and low-voltage unit substations. The medium-voltage system distributes power to the combustion turbine, HRSG, and steam turbine 4,160-V electrical auxiliaries during normal operation, startup, and shutdown. The system will consist of two 100% unit auxiliary transformers (i.e., station service transformers) and associated switchgear.
- **Low-Voltage System.** Each 500-MW combined-cycle power block will have a low-voltage system. The low-voltage system distributes power to the combustion turbine, HRSG, and steam turbine low-voltage electrical auxiliaries during normal operation, startup, and shutdown. The main components are the power center transformers, 480-V power centers, and motor control centers.
- **Uninterruptible Power Supply and DC Systems.** The UPS and dc systems provide highly reliable sources of power for dc protective equipment, instrumentation, control, computers, and electronic circuits that require reliable sources of power. The UPS system provides 120 Vac, single-phase, 60-Hz power to these critical loads. The dc system provides a reliable source of power for the UPS system and critical control and power functions. The dc system will be operated ungrounded except through high-resistance ground detectors and instruments.
- **Motors.** All motors will be designed for across-the-line starting and will not exceed a class B insulation system temperature rise as defined by ANSI C50.41. All motors 25 hp and above will be provided with motor space heaters. Motors will be of the highest efficiency available for the specified application. Motors will be according to NEMA Standard MG-1. All stator windings will be copper.
- **Distributed Control System.** A distributed control system will be used to control the facility. The combustion turbines will come with their own control system. This control system will be tied to the plant controls. However, the primary control system will be by the combustion turbine supplier. The control system will provide coordinated control of steam generation, combustion turbine power generation, and steam turbine power generation. The control system will also provide control of plant systems and data acquisition in the main control room, and interfaces with the combustion turbine generator control system. The operators will be able to start/stop and load the combustion turbines, steam turbine, and all auxiliary equipment from the control room. The combustion turbine controls will be connected to the main control room by a data highway. Local control will also be provided at the combustion turbines and plant auxiliaries.

5.2 PLANT PERFORMANCE

Performance of the major NGCC equipment is provided individually and the overall performance is summarized below. The performance is based on a per 500-MW combined-cycle power block. The overall plant performance (i.e., nominally 1,000 MW) is also provided.

5.2.1 Combustion Turbine Performance

Combustion turbine performance depends on ambient conditions, the combustion characteristics including the type of nitrogen oxide (NO_X) control and the type of fuel being burned, the inlet pressure losses, and the turbine backpressure. The design basis information is as follows:

Table 5-1 — Design Basis Information

Ambient Temperature (dry bulb/wet bulb)		
- Winter	20°F / 20°F	
- Summer	125°F / 79°F	
- Average ambient	67°F / 50°F	
Elevation	714 feet above mean sea level	
Primary Fuel/Secondary Fuel	Natural gas / No. 2 fuel oil	
NO_X Emission Control	Primary Fuel	Secondary Fuel
- Control Type	Dry, low NO_X combustion	Water injection
- Emission Level from Turbines	9 ppmvd at 15% O_2	42 ppmvd at 15% O_2
Inlet Pressure Loss	4 in. H_2O	
Exhaust Pressure Loss	16 in. H_2O	

The GE 7FA combustion turbine is GE’s nominal 170-MW F-Class machine. The estimated full-load performance data for the GE 7FA combustion turbine, operating in combined-cycle service with natural gas is as follows:

Table 5-2 — Combustion Turbine Performance Data

Ambient Temperature	20°F	67°F	108°F	125°F
Generator Output, kW	176,950	166,950	149,500	147,350
LHV Heat Input, mmBtu/hr	1,669	1,583	1,459	1,442
HHV Heat Input, mmBtu/hr	1,853	1,757	1,619	1,601
Exhaust Temperature, °F	1,089	1,120	1,141	1,143
Exhaust Flow, klb/hr	3,678	3,482	3,276	3,252

Note: Evaporative coolers are in service for 67°F, 108°F, and 125°F cases.

5.2.2 Heat Recover Steam Generator Performance

The performance of a HRSG is dependent upon the configuration of the surface area within the HRSG, the amount of energy available in the form of hot combustion turbine exhaust gas, the temperature and pressure of the steam being generated, the inlet feedwater conditions, and the HRSG heat losses.

The HRSGs have the following characteristics:

- **Surface Area Impacts.** The greatest impacts on HRSG surface areas are defined by the pinch point temperature difference and the steam drum approach temperature difference. These characteristics were set as follows:
  - 15°F Pinch Point Temperature: Pinch point temperature is defined as the temperature difference between the constant evaporation temperature on the tube side of the HRSG evaporator and the exhaust gas leaving the evaporator section.
  - 20°F Steam Drum Approach Temperature: The steam drum approach temperature is defined as the temperature difference between the subcooled water leaving the economizer outlet and the saturation temperature of the steam drum.
- **Combustion Turbine Backpressure.** The amount of allowable pressure drop through the HRSG impacts the combustion turbine performance and the exhaust temperature entering the HRSG. For this study, a pressure loss of 16 inches water column from the combustion turbine outlet through the HRSG stack was used. This pressure drop also accounts for the pressure loss of the SCR catalyst.
- **Heat Losses.** The amount of heat lost from the HRSG and steam cycle impacts the quantity of steam generated. The HRSG losses were estimated as follows:
  - Radiation and Convection: 1% heat loss from the HRSG due to radiation and convective heat transfer and exhaust gas leakage to the atmosphere.
  - Transition Piece Temperature Loss: 2°F temperature loss through the transition duct work from the combustion turbine exhaust flange through the HRSG inlet.
  - Blowdown: 1% steam drum blowdown for the removal of dissolved solids.
- **Steam Conditions.** The design basis steam conditions are as follows:
  - 1,850 psig/1055°F high-pressure superheater outlet steam
  - 427 psia/1005°F reheater outlet steam
  - 79 psia/462°F low-pressure superheater outlet steam

5.2.3 Steam Turbine Performance

The steam turbine performance depends on the cycle type, the steam conditions entering the steam turbine, and the steam turbine backpressure. For this study, the cycle type that was selected was the reheat cycle. The primary reason for the reheat cycle is to improve the efficiency of the steam turbine. The reheat cycle allows the efficiency to improve through increased steam inlet temperatures. The steam conditions also affect the performance of the steam turbine. The steam turbine performance improves with higher steam pressures and temperatures. However, as the steam conditions are increased, the amount of steam generated is decreased due to the limited energy from the combustion turbine exhaust gases. Therefore, a balance between the improved performance of the steam turbine due to increased steam conditions and the amount of steam generated to make power is necessary. Finally, the steam turbine backpressure affects the amount of power generated by the steam turbine. As the backpressure is increased, the power generated by the steam turbine is decreased.

The design basis steam conditions to the steam turbine are as follows:

- 1,800 psig/1,050°F high-pressure steam (i.e. main steam)
- 410 psia/1,000°F hot reheat steam
- 75 psia/460°F low-pressure admission steam

For this study, two types of cooling were evaluated. The base case was a mechanical draft cooling tower with a wet surface condenser. For this case, the steam backpressures could be maintained relatively low for all ambient conditions. For the average ambient condition, the backpressure was 2.5 inches of mercury absolute (inHgA). The other cooling method was an air-cooled condenser. The air-cooled condenser is a function of the dry bulb temperature. While lower steam turbine backpressures are possible at lower ambient temperatures, high backpressures occur at the high ambient temperatures, which negatively affect the performance. For the average ambient condition, the air-cooled condenser backpressure was 2.5 inHgA.

5.2.4 Plant Performance

The overall plant performance was estimated for the Mohave site. The performance was estimated for the 2 x 2 x 1 500-MW combined-cycle power block operating on natural gas at the site average ambient conditions. To obtain the total site performance estimate (i.e., nominal 1,000-MW facility), the performance estimate for the single 500-MW power block was doubled.

The full-load estimated plant performance while operating on natural gas with a mechanical draft cooling tower is as follows:

Table 5-3 — Plant Performance Data with Cooling Towers

Ambient Temperature	20°F	67°F	108°F	125°F
Gross Generator Output, MW	1,063	1,016	928	917
HHV Heat Input, mmBtu/hr	7,412	7,028	6,476	6,404
Auxiliary Power Estimate, MW	23	22	21	21
Net Generator Output, MW	1,040	994	907	896
Net Plant Heat Rate, Btu/kWh HHV	7,130	7,070	7,140	7,150

The full load estimated plant performance while operating on natural gas with an air-cooled condenser is as follows:

Table 5-4 — Plant Performance Data with Air-Cooled Condensers

Ambient Temperature	20°F	67°F	108°F	125°F
Gross Generator Output, MW	1,063	1,017	902	880
HHV Heat Input, mmBtu/hr	7,412	7,028	6,478	6,404
Auxiliary Power Estimate, MW	23	23	22	21
Net Generator Output, MW	1,040	994	880	859
Net Plant Heat Rate, Btu/kWh HHV	7,130	7,070	7,355	7,460

As part of this study, CO_2 sequestration is being evaluated. Based on information from the Department of Energy's computer program IECM, the performance of the combined-cycle facility is affected by the addition of CO_2 sequestration. From the program, the performance impact is approximately 15% less output and approximately 18% higher heat rate at the average ambient conditions.

5.2.5 Long-Term Performance

During the course of operating a power plant, the power output generally decreases from the new and clean condition due to degradation of the equipment. This degradation causes an increase in the plant heat rate and increases the operating cost for the plant. The primary contributors to the combined-cycle power plant degradation are the combustion turbines and, to a lesser extent, the steam turbine. The combustion turbine and steam turbine degradation can be classified into two categories, recoverable and non-recoverable degradation. The following table summarizes the causes for degradation and identifies which causes are recoverable:

Table 5-5 — Combustion Turbine and Steam Turbine Degradation

Degradation Type	Combustion Turbine	Steam Turbine
Recoverable	Compressor Fouling	Condenser Fouling Reduction in steam supply due to combustion turbine fouling.
Non-recoverable	Blade leakage, erosion, shaft seal leakage, compressor residual fouling	Blade leakage, erosion, shaft seal leakage, blade fouling

The combustion turbine performance will degrade as the compressor fouls from the inlet air and the compressor and turbine blades wear. Most of the compressor fouling impacts can be recovered by frequent on-line and off-line compressor washes. Most of the combustion turbine and steam turbine performance losses due to wear can be recovered with major equipment overhauls. However, these overhauls require outages that, depending on the type of overhaul, could cause a significant amount of down time. Major overhauls are generally recommended every 6 to 8 years depending upon the number of hours of equivalent operation. Predictions for the average amount of degradation have been developed. The performance degradation impact is typically on the order of 3% to 6% reduction in output and 2% to 4% increase in heat rate.

5.2.6 Start-Up Characteristics

The start-up of the combined-cycle plant depends on the condition of the plant before start-up. Generally, start-ups are classified as cold starts, warm starts, and hot starts. The definition of each of these depends on metal temperatures for the steam turbine rotor, HRSG drums, and the combustion turbine rotor with the steam turbine typically being the limiting factor. The estimated times for start-up are as follows:

- Estimated Hot Start-up Time 1 - 2 hours
- Estimated Warm Start-up Time 2 - 3 hours
- Estimated Cold Start-up Time 3 - 5 hours

5.3 COST ESTIMATES

Capital, fixed O&M, and variable O&M cost estimates were developed for the combined-cycle technology. The cost estimates were based on S&L's in-house database of similar projects. Sales and property taxes and land lease costs are not included in the costs presented.

5.3.1 Capital Costs

Current capital cost estimates for the NGCC technology were developed using S&L's in-house database. A single 2 x 2 x 1 500-MW combined-cycle power block cost estimate was developed for each of two different cooling methods. The first case was for a plant with a mechanical draft (MD) cooling tower with a wet surface condenser. The second case was for a plant with an air-cooled condenser. The capital cost estimates are based on current dollars, are based on zero liquid discharge, are based on labor rates commensurate with the Laughlin, Nevada area, and do not include costs associated with demolition of existing structures and equipment on the Mohave site. The capital cost estimates are as follows:

Table 5-6 — Capital Cost Estimates

Configuration	Estimated Capital Cost	Capital Cost per Installed kW*
Single 2x2x1 500-MW Combined-Cycle Power Block with MD Cooling Tower	$300,000,000	604
Two 2x2x1 500-MW Combined-Cycle Power Blocks with MD Cooling Tower	$540,000,000	544
Single 2x2x1 500-MW Combined-Cycle Power Block with Air-Cooled Condenser	$306,000,000	616
Two 2x2x1 500-MW Combined-Cycle Power Blocks with Air-Cooled Condenser	$551,000,000	555

* Based on net power at average ambient conditions

In addition to the costs that were developed for the two cooling methods, a cost estimate was developed for CO_2 sequestration. This estimate is based on the DOE IECM program data. The estimated capital cost for CO_2 sequestration is approximately $350/kW to $400/kW higher than the capital cost estimates provided above. Therefore, for a nominal 1,000-MW combined-cycle plant with mechanical draft cooling towers, the estimated capital cost with CO_2 sequestration is approximately $894/kW to $944/kW. Similarly, for a nominal 1,000-MW combined-cycle plant with air-cooled condensers, the estimated capital cost with CO_2 sequestration is approximately $905/kW to $955/kW.

5.3.2 Operating and Maintenance Costs

The fixed and variable O&M costs were estimated for the natural gas combined-cycle technology.

The fixed O&M costs are those spent regardless of how much the plant operates. The fixed O&M costs include costs for direct and indirect labor for operations and maintenance staff that are permanently employed at the plant site, as well as home office support costs allocable to the plant. In addition, the fixed costs include O&M contract services and materials and power purchased for in-house plant needs during plant outages.

The variable O&M costs are those costs that change with the amount of power generated. The variable O&M costs include chemicals and consumables, catalyst replacement and major maintenance of the combustion turbines, steam turbines, HRSG, and balance-of-plant. The estimate was derived on the basis of an 80% capacity factor and approximately 50 starts per year. On the basis of this duty cycle, the combustion turbines will require a combustion inspection every year, a hot gas path inspection every three years, and a major inspection every six years.

The fixed and variable O&M costs for the natural gas combined-cycle power plant for each of the two cooling methods studied in this report are presented in the following table.

Table 5-7 — Estimated O&M Costs

Current $	MD Cooling Tower with Wet Surface Condenser	Air-Cooled Condenser
Fixed, $/kW-yr	$5.47	$5.47
Variable, $/MWh	$1.97	$1.77

CO_2 sequestration O&M costs were also estimated for this study. The fixed and variable O&M costs were estimated based on the DOE IECM program. The estimated fixed and variable O&M costs for the combined-cycle plant with mechanical draft cooling towers and with CO_2 sequestration are $6.45/kW-yr and $2.32/MWh respectively. The estimated fixed and variable O&M costs for the combined-cycle plant with air-cooled condensers and with CO_2 sequestration are $6.45/kW-yr and $2.08/MWh respectively.

5.4 LAND AREA REQUIREMENTS

Approximate plant land area requirements for the natural gas combined-cycle facility are presented in the following table. The table represents the estimated land requirements for two 500-MW combined-cycle power blocks. In addition, the table provides the approximate area required based on the method of cooling (i.e., mechanical draft cooling towers with wet surface condensers versus air-cooled condensers).

Table 5-8 — Approximate Land Area Required for 1,000-MW NGCC Facility

	MD Cooling Tower with Wet Surface Condenser	Air-Cooled Condenser
Acres without CO_2 Sequestration	30	42
Acres with CO_2 Sequestration	34	46

5.5 WATER USAGE

Approximate water usage for the natural gas combined-cycle facility is provided in the following table.

Table 5-9 — Approximate Water Usage for 1,000-MW NGCC Facility

	MD Cooling Tower with Wet Surface Condenser		Air-Cooled Condenser	
	gpm	acre-ft/yr	gpm	acre-ft/yr
Cooling Tower Makeup Peak / Average	3,500 / 2,300	5,650 / 3,710	0 / 0	0 / 0
Cycle Makeup Peak / Average	66 / 44	110 / 70	66 / 44	110 / 70
Miscellaneous Peak / Average	76 / 76	120 / 120	76 / 76	120 / 120
Total Water Makeup Peak / Average	3,642 / 2,420	5,870 / 3,900	142 / 120	230 / 190

Water availability depends on securing the rights to use the water that is currently being used at the Mohave site. Currently water rights are, in large part, tied to use of coal from the Black Mesa mine. This may impede development of an NGCC plant at the existing site.

5.6 PERMITTING ISSUES

The construction of a NGCC plant at the existing Mohave site near Laughlin, Nevada, will entail a number of permits and approvals before the start of construction. Some permits should be obtained once construction begins, and others should be obtained during commissioning of the plant. The importance of establishing a strict permitting schedule cannot be overstated, as certain procedures (e.g., ambient air quality monitoring and modeling) will require up to two years of lead time. With an adequate knowledge of the applicable regulations and the information required in the various permit applications, SCE can implement an effective permit strategy. A listing of possible permitting issues is provided below:

- **Air Quality Construction Permits.** A New Source Review (NSR) / Prevention of Significant Deterioration (PSD) air quality construction permit is the primary approval necessary for the construction of a power plant. The U.S. EPA has delegated authority for the implementation and enforcement of the NSR/PSD regulations to the Nevada Department of Conservation and Natural Resources – Division of Environmental Protection (NV-DEP).

  Under NSR, new major stationary sources with the potential to emit "significant" amounts of air pollution are required to obtain approval before commencing construction. Table 5-10 gives the major stationary source thresholds for NGCC plants. A 500-MW NGCC plant at the Mohave site would be designated as a major stationary source.

Table 5-10 — Definition of Major Stationary Source

Unit Configuration	Is Unit Configuration Included in One of the 28 Source Categories?	Unit is Classified as a Major Stationary Source if it has the Potential to Emit Greater Than….
Natural Gas Fired Combined Cycle Plant with HRSG and Heat Input >250 mmBtu/hr	Yes	100 tpy
Natural Gas Fired Combined Cycle Plant with HRSG and Heat Input <250 mmBtu/hr	No	250 tpy
Natural Gas Fired Simple Cycle Combustion Turbine – any size	No	250 tpy

Construction of a new major stationary source will be subject to NSR review if potential emissions from the new source are "significant." Significant emissions thresholds are defined in terms of annual emissions rates (tpy). Table 5-11 lists the pollutants for which significant emission rates have been established.

Table 5-11 — PSD Significant Emission Rates

Pollutant	Significant Emissions Rate (tpy)
CO	100
NO_X	40
SO_2	40
PM_{10}	15
VOC	40
H_2SO_4 mist	7

Source: 40 CFR 52.21 (b) (23).

Major new stationary sources in Nevada are required to submit an Air Use Permit application to the NV-DEP before starting construction. The Air Use Permit application is used to identify all applicable federal and state regulations. The permit application requires a comprehensive description of the proposed project, including the following:

- Process description
- Regulatory discussion describing all federal, state, and local air pollution control regulations and a discussion of how the proposed process unit complies with each regulation
- Best Available Control Technology analysis
- Emissions summary and calculations
- Stack/vent parameters
- Site description and process equipment location drawings

— Additional supporting information for specific processes and equipment

The Mohave site is located in Clark County, Nevada. Portions of Clark County (the greater Las Vegas metropolitan area) are currently designated as non-attainment for carbon monoxide (CO), 8-hour ozone (O_3), and particulate matter less than 10 microns (PM_{10}). Although the Mohave site is not located in the non-attainment area, the close proximity would require that the owners of the proposed plant evaluate its impact on the non-attainment area.

It can take up to two years to obtain a Final Air Quality Construction permit: six to nine months to conduct modeling and prepare the permit application material; one year for the state to review the material and issue a draft permit; and three months for public comment and revisions before issuing the final permit.

- **Ambient Air Monitoring.** The NV-DEP maintains a system of ambient air quality monitors throughout the state. Continuous data are collected for O_3, SO_2, NO_X, CO, PM_{10}, $PM_{2.5}$, and meteorological data. An automated data acquisition system is used to retrieve the data from all monitoring locations onto a central data management system. There are a large number of ambient monitors in Clark County, primarily because of the Las Vegas non-attainment area and the operation of large stationary sources such as the existing Mohave station. The NV-DEP conducts routine maintenance and calibration of these monitors for quality assurance.

  Data from the ambient air quality monitors are used to determine compliance with the NAAQS, shown in Table 5-12. The data are used to chart long-term trends in air quality and establish goals. Furthermore, the ambient air quality data is a necessary input for air quality modeling that is used for determining the impact of a proposed power plant.

Table 5-12 — National Ambient Air Quality Standards

Pollutant	Primary Standard 1	Primary Standard 2
PM_{10}	50 µg/m3 (annual mean)	150 µg/m3 (24-hour - 99th percentile)
$PM_{2.5}$	15 µg/m3 (annual mean)	65 µg/m3 (24-hour – 98th percentile)
SO_2	0.03 ppm (annual mean)	0.14 ppm (2nd highest 24-hour)
O_3	0.12 ppm (2nd highest 1-hour)	0.08 ppm (4th highest 8-hour)
CO	9 ppm (8-hour average)	35 ppm (1-hour average)
NO_X	100 µg/m3 (annual mean)	—
Pb	1.5 µg/m3 (quarterly average)	—

- **Air Quality Modeling.** Air quality modeling is used to estimate impacts to ambient air to determine whether the proposed power plant will result in pollutant concentration levels that exceed the applicable ambient air standards. Models allow one to forecast future air quality levels from sources that have not been constructed. Federal law requires that the NV-DEP have legally enforceable procedures in place to prevent construction or modification of any source where the emissions from the projected activity would interfere with the attainment and maintenance of the NAAQS.

  The primary U.S. EPA modeling guidelines are discussed in *40 CFR Part 51, Appendix W – Guideline on Air Quality Models*. There are two levels of sophistication for air quality models. The first level consists of relatively simple estimation techniques that generally use preset, worst-case meteorological conditions to provide conservative estimates of the air quality impact of a specific source. These are called screening techniques or screening models. The purpose of such techniques is to eliminate the need of more detailed modeling for those sources that clearly will not cause or contribute to ambient concentrations in excess of either the NAAQS or the allowable PSD concentration increments. If a screening technique indicates that the concentration contributed by the source exceeds the PSD increment or the increment remaining to just meet the NAAQS, then the second level of more sophisticated models should be applied.

  The second level consists of those analytical techniques that provide more detailed treatment of physical and chemical atmospheric processes, require more detailed and precise input data, and provide more specialized concentration estimates. As a result, they provide a more refined and, at least theoretically, a more accurate estimate of source impact and the effectiveness of control strategies. These are referred to as refined models.

  The U.S. EPA lists a number of recommended and alternative air quality modeling software. Regardless of the sophistication of the software, the utility of the model largely depends on the availability of good meteorological and ambient air quality data. An applicant for an air quality construction permit in Nevada will need to adequately satisfy the NV-DEP that the air quality in the Las Vegas metropolitan non-attainment area will not be negatively impacted by the project.

- **BACT/LAER Analysis.** Southern California Edison will need to demonstrate that their planned NGCC plant will be employ the Best Available Control Technology (BACT) for NO_X, CO, and PM_{10}. BACT is defined as an emissions limitation based on the maximum degree of reduction which, on a case-by-case basis, is determined to be achievable taking into account energy, environmental, and economic impacts and other costs. A typical new NGCC plant will require a SCR system with low-NO_X burners (LNB), in order to achieve a NO_X emission rate of 3.5 to 4.5 ppmvd (at 15% O_2). In addition, an oxidation catalyst (OC) may be required to reduce emission of CO, because of the close proximity of the site to the CO non-attainment area in Las Vegas. Recent BACT determinations have required CO emission limits in the 9.0 to 25.0 ppmvd range; an oxidation catalyst would further reduce these emissions by approximately 70% to 90%. Pipeline quality natural gas is generally considered BACT for PM_{10}, SO_2 and H_2SO_4 emissions, without further controls.

- **Class I Area Impact Review.** The Clean Air Act Amendments of 1977 gave Federal Land Managers (FLM) an affirmative responsibility to protect the natural and cultural resources of Class I areas from the adverse impacts of air pollution. Class I areas include certain national parks and wilderness areas. FLM responsibilities include the review of air quality permit applications from proposed new major sources near Class I areas. If the FLM determines that emissions from a proposed source will contribute to adverse impacts on the air quality or visibility of a Class I area, then he may recommend to the NV-DEP that the permit be denied, unless the impacts can be mitigated.

All new emission sources that have the potential to impact visibility in a Class I area will be subject to pre-construction review by the FLM. Visibility impacts are predicted using computer modeling (e.g., CalPUFF), and are generally a function of emissions of SO_2, SO_3, NO_X, PM_{10}, and ammonia. Sources located near a Class I area will be subject to more rigorous review, and if visibility impacts are predicted by the model, the permitting agency may impose more stringent emission requirements.

The Mohave site is located near numerous Class I areas in California, Utah, and Arizona. Table 5-13 lists the distances between these Class I areas and Laughlin, Nevada.

Table 5-13 — Distances from Laughlin, Nevada, to Class I Areas

Class I area	Distance (miles)
Domeland Wilderness Area (CA)	202
San Gabriel Wilderness Area (CA)	179
Cucamonga Wilderness Area (CA)	184
San Gorgonio Wilderness Area (CA)	139
San Jacinta Wilderness Area (CA)	144
Joshua Tree Wilderness Area (CA)	119
Grand Canyon National Park (AZ)	152
Sycamore Canyon Wilderness Area (AZ)	145
Pine Mountain Wilderness Area (AZ)	174
Mazatzal Wilderness Area (AZ)	195
Zion National Park (UT)	162

- **Local Air Quality Permits.** The Clark County Department of Air Quality and Environmental Management (DAQEM) issues permits for all boilers and steam generators in the county. This permit would be applicable to the HRSG that is a component of a NGCC plant. The permit application requests basic information, such as the manufacturer name, serial number, boiler rating (in hp), minimum and maximum rating per burner (in ft^3/hr or gal/hr), stack height and diameter, exhaust velocity and temperature, and capacity factor.

  The Clark County DAQEM also issues permits for cooling towers. This permit application requests basic information, such as manufacturer name, serial number, circulation rate (in gal/min), maximum TDS (in ppm or mg/L) before purging, drift eliminators and drift loss percentage, and maximum hours of operation per day and per year.

- **Wastewater Discharge Permits.** The existing coal fired power plant (2 x 790 MW) sends its cooling tower blowdown and other plant discharges to a series of lined evaporation ponds. Domestic wastewater from the plant is also treated and sent to evaporation ponds. No plant effluent is discharged to any surface or ground waters of the United States. A new NGCC plant at the Mohave site would likely use a zero liquid discharge (ZLD) system. It is not known whether the existing evaporation ponds could accommodate the additional load or a new evaporation pond will be needed.

  Although a traditional NPDES permit would not be required, the ZLD system would still require permitting approval from the NV-DEP. The existing permit for Mohave Station (permit #NEV30007) requires leak detection systems for the ponds at the site. Such methods include geophysical survey equipment, visual sump inspections, visual liner inspections, and monitoring wells. There are no flow limitations in the permit, except for the package sewage treatment plant design capacity of 36,000 gallons per day.

  There are currently areas of groundwater contamination (high mineral content) on the site from leaking ponds that occurred in the early years of the plant. The existing permit requires an on-going remediation program to bring the groundwater quality to an electrical conductivity below 1,000 microsiemens. The site groundwater is expected to be completely remediated by July 2007.

  A new NGCC plant at Mohave would use the existing ZLD system at the site, or it would require the construction of new ponds to accommodate plant effluent. In either case, the permit with the NV-DEP would need to be revised. This revision would require a public comment period and a public hearing before final issuance of the permit. The total time required for this permit revision could range from 6 months to 1 year.

  During construction, the site would require a General Number 2 NPDES permit (storm water discharges from construction activities) from the Nevada DEP. These permits are issued instantaneously, with only a notification to the state that construction has started. As part of this permit, the construction contractor would need to create a Storm Water Pollution Prevention Plan (SWPPP), which details the measures for preventing debris from entering local streams. The SWPPP typically performs the following functions:

  — Identifies all potential sources of pollution which may reasonably be expected to affect the quality of storm water discharges from the construction site

  — Describes practice to reduce and sequester pollutants in the storm water discharges

  — Assures compliance with the terms and conditions of the General Number 2 NPDES permit

- **U.S. Army Corps of Engineers Permits.** It is unlikely that there are any jurisdictional wetlands in this arid region of the United States requiring a permit from the U.S. Army Corps of Engineers. However, if a new natural gas pipeline connection to the site crossed any "waters of the United States," including dry creek beds, then a Nationwide Permit #12 (Utility Line Activities) would be required. This general permit allows installation of a pipeline underneath the river or creek, but requires that the water body be returned to its original condition.

- **Solid Waste Disposal Permits.** A NGCC plant would not create any solid waste during operation, outside of household trash and shop wastes. These would be disposed of off-site using a licensed commercial hauler. During construction, hazardous and non-hazardous wastes would likewise be disposed of off-site using a licensed commercial hauler. The plant should make a concerted effort to reuse or recycle construction debris and excavated material. There would be no need for an onsite landfill for an NGCC plant.

- **Public Utility Commission of Nevada (PUCN).** Any new power generation facility in the Nevada will require a Certificate of Public Convenience and Necessity (CPCN) from the PUCN. To obtain a CPCN, an applicant must demonstrate that there is a public need for a new facility and that the proposed utility is willing to serve and able to fulfill the public need.

- **Zoning / Land Use Permits.** The Mohave site is currently zoned for power plant use. It is assumed that a new NGCC power plant could be located entirely within the existing site. While there is no need to obtain a zoning change, the project developers will still need to submit a "Major Project Application: Specific Plan or Land Use & Development Guide" with the Clark County Department of Development Services. This guide costs $1,000 plus $4 per acre (for all acres over 300 acres). The applicant needs only to submit a description of the project and the location of the property (parcel numbers).

  It is possible that some of the landscaping, parking, and fencing requirements have changed since the original plant was built. The Clark County Department of Development Services maintains an Industrial Development Checklist with all of the applicable conditions.

- **Building Permits.** The Clark County Department of Development Services issues all building and civil design permits. These permits are typically obtained throughout construction, and the applications are submitted in phases. The first permits are for grubbing, grading, and other necessary earthwork. Next are the foundation permits for all buildings, warehouses, equipment skids, cooling towers, and so forth. Structural permits come next, as the building fabrications begin. These are followed by plumbing, mechanical (e.g., HVAC), electrical, and fire protection permits for all occupied buildings. The offices, control room, restrooms, and showers will need to be handicap accessible. There will likely be inspections of the construction site by building inspectors and fire officials.

  Obtaining building permits for a major project, such as a power plant, will require continuous interaction with Clark County staff. It is recommended that the project team meet with the appropriate Development Services personnel to establish a submittal schedule and determine how drawings and calculations will be submitted. In some instances, a local permit expediter may need to be hired in order to accelerate the permitting process.

- **Other Permits.** A number of secondary permits will be required for construction of an NGCC power plant at the Mohave site. The delivery of plant equipment in overweight or oversized trucks will require a special use permit from the Nevada Department of Transportation for state roads and the Clark County Department of Transportation for county roads. The construction of a tall stack will require an Obstruction Hazard Determination from the Federal Aviation Administration.

  An NGCC power plant could potentially use fuel oil for startup operations, fire pumps, and emergency generators. Any large petroleum storage tank at the site (>1,100 gallons above ground, any size below ground) will require a permit from the Clark County Fire Marshall. In addition, the site would need to update its Spill Prevention Control and Countermeasure (SPCC) plan to account for the new tanks. The SPCC plan (spelled out in 40 CFR Part 112) details how potential spills of petroleum products are to be contained.

The installation of ammonia storage tanks (either anhydrous or aqueous) for an SCR would not require any permits. However, information on ammonia and other hazardous chemicals will need to be shared with the local Emergency Planning Commission (EPC). Since Mohave Station already participates with the EPC, the list of on-site chemicals would only need to be updated.

5.7 SCHEDULE

A level one schedule was developed for the 1,000-MW natural gas combined-cycle power plant. The total duration from initiation of permit development through commercial operation for the two 2 x 2 x 1 500-MW combined-cycle power blocks is estimated to be 36 months. A breakdown of the major activities is as follows:

- Permitting – 12 months
- Engineering – 26 months
- Procurement – 28 months
- Construction – 18 months
- Start-up and Commissioning – 10 months
- Performance Testing – 2 months

Last page of Section 5.

6. DEMAND-SIDE MANAGEMENT/ENERGY EFFICIENCY TECHNOLOGY

6.1 ENERGY EFFICIENCY RESOURCE AVAILABILITY

6.1.1 Overview and Description of Concept

Southern California Edison's "Final Study Plan" for Mohave Alternatives and Complements includes evaluation of demand-side management (DSM) resource alternatives located outside the state of California. As noted in SCE's filing:[1]

> Based upon D.04-12-016 and stakeholders' comments, the Study will encompass all of the following [(1) through (4), generation alternatives] …
>
> (5) Study of energy efficiency that might be achieved in western U.S. states outside of California with SCE financing, by means of power purchase arrangements under which the resultant available power would be purchased by SCE.

This evaluation was conducted by performing the following:

- Evaluating energy efficiency resource potential in states outside of California
- Examining the institutional and regulatory issues associated with the concept of procuring a DSM resource outside of SCE's territory
- Discussing with a potential utility partner the commercial and regulatory aspects of implementing a DSM resource coupled with a power purchase agreement
- Describing the factors that would influence the price of any commercial arrangement for "DSM transfer" and developing a simple quantitative model to illustrate the way in which DSM resource procurement might work

Ultimately, the pricing arrangements for procurement of DSM resources coupled with a power purchase contract would be subject to negotiation between SCE and any potential utility partners or to the outcome of a competitive solicitation process.

This concept is based on the assumption that there are considerable low-cost efficiency resources in states neighboring California, and that SCE may be willing or directed to procure such resources (through DSM implementation coupled with a power purchase contract) depending on the overall costs in comparison to other alternatives. In doing so, SCE could create, for example, a 10-year power purchase agreement (PPA) with a

[1] Southern California Edison Company Final Study Plan for the Study of Potential Mohave Alternative/Complementary Resources, Docket R.04-04-003, submitted pursuant to CPUC Decision 04-12-016, Ordering Paragraph 3. March 21, 2005. Page 6.

neighboring utility at a price below its avoided costs, yet still high enough to entice the neighboring utility to implement the DSM. The DSM resource would be that available beyond what is already being pursued by the neighboring utility or state.

It is important to note that this mechanism for purchasing energy efficiency resources from another state or another utility is an innovative approach and has not (to our knowledge) been implemented anywhere in the U.S.[2], at least not on the scale considered as part of this study. As such, it required some investigation as to the institutional and contractual arrangements necessary to make it feasible and practical.

6.1.2 Methodology

The scope of work at the outset of the study was as follows:

- Assess the states and utilities in the region that would be appropriate sellers of energy efficiency resources. This includes Arizona, New Mexico, Nevada, Utah, and Colorado.
- Develop an estimate of the technical and economic potential for energy efficiency resources from the candidate states. This estimate would rely heavily upon existing studies, such as *The New Mother Lode: the Potential for More Efficient Electricity Use in the Southwest*, recently prepared by the Southwest Energy Efficiency Project.
- Define more clearly the conceptual mechanism for purchasing energy efficiency resources from other states and other utilities.
  - What types of energy efficiency measures would be eligible?
  - Who would be responsible for ensuring that the energy efficiency measures are installed and the efficiency savings are achieved?
  - What type of efficiency programs (e.g., rebates, shared savings, audits, other) would be used to achieve the savings? Does this issue need to be addressed, or can it be left up to the seller of the efficiency savings?
  - How would the "resultant available power" be determined and would it have to be linked to specific energy efficiency savings?
  - What time periods would the power be provided on (peak, off-peak, seasonal, daily), and would the power necessarily have to be linked to specific energy efficiency savings during those periods?
  - Would the energy efficiency savings have to be monitored and verified, and if so, how?
- Develop an estimate of the amount of economic potential for energy efficiency in the neighboring states that could be sold to SCE through power purchase arrangements. This would include consideration of the extent to which energy efficiency in the neighboring states is being

[2] A "Conservation Transfer Agreement" of a smaller scale was implemented in 1990 between Bonneville Power Administration (BPA) and the Snohomish, Mason and Lewis Public Utility Districts (PUDs) in Washington State, which allowed for saved energy to be delivered to Puget Sound Energy from BPA due to the measures installed in the PUDs.

developed for internal purposes. It would also include consideration of energy efficiency policy developments that would affect the potential for exports, such as the Nevada policy to allow energy efficiency to be used for complying with that state's renewable portfolio standard.

- Assess the economics of the mechanism for purchasing energy efficiency resources from other states and other utilities. What price should SCE be willing to pay to purchase energy efficiency resources? What price should neighboring utilities be willing to accept to sell such energy efficiency resources?
- Identify the contractual arrangements necessary for purchasing energy efficiency resources from other states and other utilities. What duration would the contracts be for? What sort of terms and conditions would be necessary to protect both parties to the contract?
- Assess the institutional challenges for purchasing energy efficiency resources from other states and other utilities. What incentives would other states and utilities have to sell such power? Would energy efficiency programs implemented for this purpose conflict with energy efficiency programs already being implemented by neighboring states and utilities? How would the costs and revenues from the energy efficiency sales be treated in the neighboring utility's rates? Would lost revenues create a problem for the neighboring utility?
- Use the results of the analyses described above to develop a recommendation for the extent to which this sort of energy efficiency purchase can represent an alternative (or partial alternative) to Mohave. To the extent possible, the recommendation will include an estimate of the costs of such a purchase and the amount of efficiency that could potentially be obtained from such a purchase.

6.2 POTENTIAL ENERGY EFFICIENCY RESOURCE AVAILABLE IN THE REGION

6.2.1 Southwest States as the Primary Source of Efficiency Resources

In evaluating out-of-state energy efficiency resources that might be purchased to offset SCE's share of the Mohave generating plant, the study focused on energy efficiency resources available in the southwestern states. While it may also be possible to purchase energy efficiency resources from states in the Northwest (Oregon, Washington, Idaho, and Montana), these states have not been included in this analysis. This analytical choice was made primarily because energy efficiency programs, often very aggressive, in the Pacific Northwest have been underway for some years, resulting in significant electricity savings over the past two decades[3]. These accumulated savings, plus the fact that building energy codes (for example) have generally been more robust in the Northwest than in the Southwest, coupled with the rapid growth of population in several southwestern states, lead us to believe that the remaining unaddressed energy efficiency opportunities in the Northwest are likely to

[3] The results of over two decades of energy efficiency programs in the Northwest are summarized in several documents, available from http://www.nwcouncil.org/energy/rtf/consreport/2004/Default.asp, that comprise the Northwest Power Planning Council's Utility Conservation Achievements Reports: 2004 Survey. This survey, for example, estimates that "[s]ince 1978, regional electricity conservation programs have saved about 2,925 [average] megawatts, more than enough electricity for two cities the size of Seattle".

be not as significant or, probably, as cost-effective to tap as those in other states within easy transmission reach of southern California.

This is not to say that all of the available energy efficiency resources in the northwest have been exhausted; the Energy Trust of Oregon, for example, is launching a re-assessment of remaining energy efficiency opportunities in Oregon, and the Energy Trust and many other northwest jurisdictions have very active energy efficiency programs at present. It is understood, however, that the magnitude of the opportunities available in the Southwest is much greater than those in the Northwest, and that efficiency resources in the Southwest will be available at lower cost. Another factor, for Oregon, is that the efficiency opportunities in the service territories of the state's two large investor-owned utilities are addressed by the Energy Trust, which is an independent, non-utility entity that does not buy or sell power. This means that the utility-to-utility efficiency resource/power transfer arrangement described here would not apply as such in most of Oregon, since power purchases from a third party would be needed to complete the trading arrangement.

Among the southwestern states that could potentially sell energy efficiency resources into southern California, this analysis focuses on Arizona, New Mexico, and Nevada. Colorado, Utah, and Wyoming were excluded, because (a) it may be more difficult to transmit power into southern California from these states, (b) there may be somewhat less energy efficiency potential in these states, and (c) the exclusion simplifies the analysis. To the extent that there are opportunities to sell energy efficiency resources from these states (particularly Colorado with its larger customer base), the study's estimates of energy efficiency potential will be conservative.

6.2.2 SWEEP Study of Energy Efficiency Potential in the Region

The study's analysis began with a review of a recent study by the Southwest Energy Efficiency Project (SWEEP) of the economic potential for energy efficiency in the Southwest (SWEEP 2002). The SWEEP study provides a detailed and comprehensive assessment of the efficiency potential in six southwestern states (Arizona, Nevada, New Mexico, Colorado, Utah, and Wyoming), and provides a useful starting point for the analysis. This section discusses the assumptions and conclusions of the SWEEP study, and the following section describes how those assumptions were used to estimate the amount of efficiency resources that might be readily available for SCE.

The SWEEP study consists of four major analyses, which were conducted for each state in the Southwest. First, it analyzed energy efficiency potentials by establishing baseline consumption and identifying energy savings potential relative to this baseline. The second analysis estimated the costs and benefits of the high efficiency measures, as well as the environmental impacts. The third analysis estimated macro-economic impacts from the high efficiency scenario, such as job impacts and income effects. Finally, the study identified policies necessary to achieve identified saving potentials.

The SWEEP study began by developing a base-case scenario electricity demand forecast by residential, commercial and industrial sectors, and by state, through the year 2020. It then developed a high-efficiency scenario by sector and state through 2020. This scenario assumed widespread adoption of cost-effective, commercially available energy efficiency measures during 2003–2020.

Some of the key assumptions in the analysis include the following:

- Any measures whose costs are below the retail electricity price are deemed cost-effective.
- For measures such as high-efficiency appliances or air conditioners, the "cost" of the measure is assumed to be the incremental cost for greater energy efficiency at the time of equipment replacement or purchase for a new building.
- Installed costs of measures are increased by 10% to account for the costs of policy and program implementation.

The study also made assumptions regarding the implementation rates necessary to realize the maximum potential efficiency savings. For existing buildings, the study assumed that 4.4% of the potential efficiency measures could be implemented per year and would reach 80% by 2020. For new buildings, the study assumed that 50% of the potential efficiency measures are installed as of 2003, and the percentage of implementation would increase steadily over time until it reached 100% implementation in 2010.

The SWEEP study notes that the high-efficiency scenario is conservative in two ways. First "miscellaneous" end-use appliances for residential buildings were not included in this analysis. This category accounts for approximately 35% of electricity use in housing and includes such appliances as active-mode consumption of TVs, VCRs, computers, and other electronic devices, evaporative coolers, and water pumps. Second, the analysis did not include new energy efficiency measures beyond the measures identified as cost-effective today.

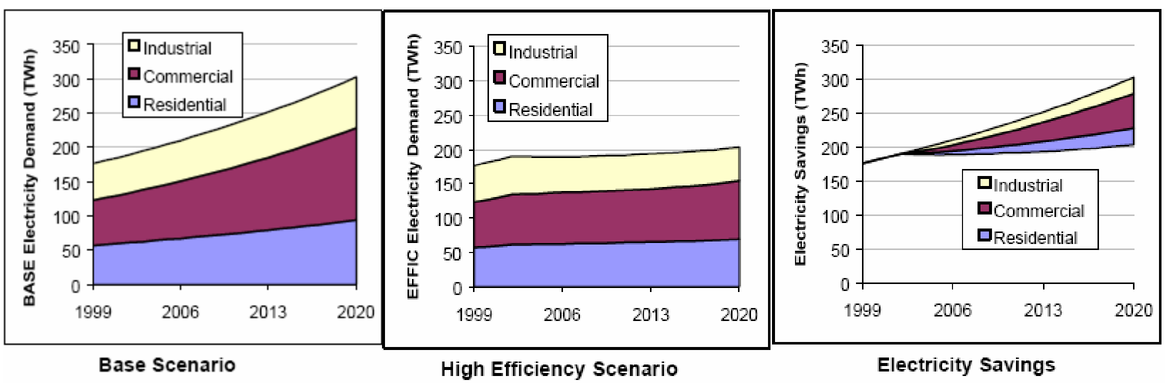
The results of the SWEEP analysis are summarized in Table 6-1 and Figure 6-1 below. The table indicates that the states in the region could reduce total electricity consumption by roughly 17% to 19% by 2010, and that by as much as 31% to 35% by 2020. The figure presents the potential efficiency savings by sector, and indicates that the total amount of efficiency savings is enough to reduce future load growth to nearly zero.

Table 6-1 — SWEEP Estimates of Energy Efficiency Potential – All Sectors

Year 2010		Region	AZ	CO	NV	NM	UT	WY
Baseline Consumption	GWh	232,658	79,755	54,516	34,797	21,229	28,702	13,657
Savings Potential	GWh	41,437	14,690	9,074	6,130	4,070	4,825	2,648
Savings Potential	%	17.8	18.4	16.6	17.6	19.2	16.8	19.4

Year 2020		Region	AZ	CO	NV	NM	UT	WY
Baseline Consumption	GWh	302,380	107,791	71,680	45,522	24,871	36,885	15,634
Savings Potential	GWh	99,038	36,585	22,352	14,155	8,897	11,500	5,552
Savings Potential	%	32.8	33.9	31.2	31.1	35.8	31.2	35.5

Figure 6-1 — SWEEP Estimates of Energy Efficiency Potential – By Sector



The SWEEP study estimated the net economic benefits of energy efficiency by comparing the incremental cost of the energy efficiency measures with the benefits of the reduced costs (i.e., avoided costs) for electricity supply. The avoided costs include the costs of power plant construction, fuel, O&M, transmission, distribution, and purchased power. In addition, consumers and businesses receive benefits from reduced natural gas prices influenced by reduced demand for natural gas for power plants. The SWEEP study did not include the economic benefits of reducing air emissions from power plants.[4]

Table 6-2 and Figure 6-2 present a summary of the economic benefits of the SWEEP energy efficiency potential. They indicate that by 2020 the energy efficiency could reduce electricity costs in the region by as much as $28 billion. The

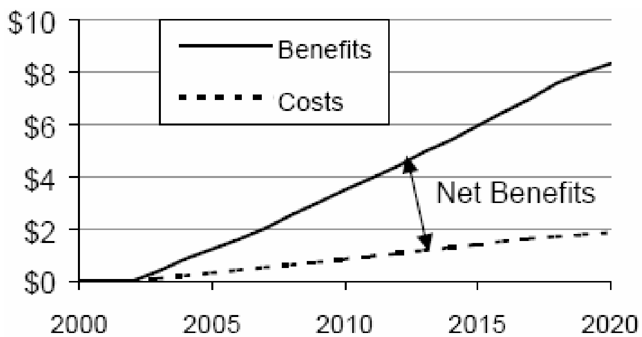
[4] Note that in its 2006-2008 energy efficiency portfolio, Southern California Edison regarded emissions reduction as economic benefits to energy efficiency measures (SCE 2005).

benefit cost ratio is 4.2, which suggests that for every dollar spent on energy efficiency, total electricity costs will be reduced by roughly four dollars.

Table 6-2 — Costs and Benefits of the High Efficiency Scenario by 2020 (billion cumulative present value dollars, in year 2000 dollars)

Sector	Energy Efficiency Costs	Overall Benefits	Net Benefits	Benefit-Cost Ratio
Commercial	3.0	17.7	14.7	5.8
Residential	3.2	9.3	6.1	2.9
Industrial	2.6	10.1	7.5	3.9
Total	**8.8**	**37.1**	**28.2**	**4.2**

Figure 6-2 — Costs and Benefits of the High Efficiency Scenario by 2020 (billion present value dollars, in year 2000 dollars)



Finally, the SWEEP study called for implementing seven different policies and programs with which states in the southwest can capture the energy efficiency potentials identified in the analysis. Those policies and programs include the following:

- System benefit charge or other mechanisms for funding utility (or state-based) energy efficiency programs,
- Utility rate reform,
- Building energy codes,
- Appliance efficiency standards,
- Tax incentives for innovative energy-efficient technologies,
- Public sector investment in energy efficiency,
- Market transformation effect.

The study identified ranges of percentages representing the potential savings which these policies or programs can contribute to energy savings. These are presented in Table 6-3. The ranges of the percentage in savings are mainly based on experiences from past energy efficiency policies and programs in various states. The upper ranges represent the aggressive implementation of policies and programs.

Table 6-3 — Potential Electricity Savings from Different Policy Options

Policy or program	Electricity savings potential in 2020 (%)
SBC-based Energy Efficiency Programs	10 – 15
Utility Rate Reform	3 – 6
Building Codes	4 – 8
Appliance Standards	4
Tax Incentives	1 – 2
Public Sector Investment	1 – 2
Market Transformation Effect	5 – 10
Total	**28 – 47**

6.2.3 Readily Available Energy Efficiency Potential in Arizona, Nevada, and New Mexico

The SWEEP study provides a useful indication of the *total* potential for cost-effective energy efficiency in the region. However, the electric utilities in Arizona, Nevada, and New Mexico would not be able to implement this level of energy efficiency savings for the purpose of selling power to SCE for several reasons. First, among all the policies listed in Table 6-3 above, electric utilities would only be able to implement the first set of policies: SBC-Based Energy Efficiency Programs.[5] Second, the SWEEP study assumed very aggressive implementation activities, and electric utilities might not have the interest or the capacity to pursue energy efficiency resources at this very aggressive level. Third, the utilities in these three states are already undertaking energy efficiency activities for their own customers, and thus have fewer efficiency resources available for selling to other utilities.

The SWEEP energy efficiency estimates, therefore, were adjusted to account for these three factors, and to develop an estimate of the "readily available utility efficiency," i.e., the amount of efficiency that a utility could implement — using standard industry energy efficiency programs — for the purpose of selling power to SCE. This analysis is presented in Table 6-4 below. Note that the energy savings in Table 6-4 (in GWh) are based on

[5] There is also precedent for electric utilities implementing substantial market transformation programs, often at very low cost per unit savings. This potential is not included in this report. Electric utilities might be able to undertake activities to implement the other policies listed in Table 6-3. However, they are less able to have a direct influence on these policies, and thus they have been left out of our analysis.

cumulative efficiency activities from all the previous years. For example, the savings in 2010 are a result of the efficiency investments from 2006 through the end of 2010.

For each state, the top row in Table 6-4 presents the estimates from the SWEEP study of the total electricity efficiency savings potential in each state. The next row presents a rough estimate of the portion of that total potential that can be obtained through utility-run energy efficiency programs. This estimate is derived by simply taking one-third of the total efficiency potential, based on Table 6-3 above, which indicates that the SBC policies will result in anywhere from 32% to 36% of the total efficiency savings.

Table 6-4 — Readily Available Utility Efficiency Potential in Arizona, Nevada, and New Mexico (GWh)

Arizona	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
SWEEP Total Efficiency Potential	7,253	9,104	10,961	12,822	14,690	16,792	18,900	21,014	23,134	25,260
SWEEP Utility Efficiency Potential	2,393	3,004	3,617	4,231	4,848	5,541	6,237	6,935	7,634	8,336
Easily Acheivable Utility Efficiency	1,197	1,502	1,808	2,116	2,424	2,771	3,119	3,467	3,817	4,168
Current Utility Efficiency Practices	221	328	436	543	651	759	866	974	1,081	1,189
Readily Available Utility Efficiency	976	1,174	1,373	1,572	1,773	2,012	2,252	2,494	2,736	2,979
Nevada	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
SWEEP Total Efficiency Potential	3,251	3,967	4,686	5,407	6,131	6,910	7,692	8,477	9,264	10,054
SWEEP Utility Efficiency Potential	1,073	1,309	1,546	1,784	2,023	2,280	2,538	2,797	3,057	3,318
Easily Acheivable Utility Efficiency	536	655	773	892	1,012	1,140	1,269	1,399	1,529	1,659
Current Utility Efficiency Practices	449	682	691	933	945	1,216	1,250	1,541	1,582	1,803
Readily Available Utility Efficiency	88	-27	82	-41	67	-75	19	-142	-53	-144
New Mexico	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
SWEEP Total Efficiency Potential	2,173	2,650	3,125	3,598	4,069	4,561	5,052	5,541	6,028	6,513
SWEEP Utility Efficiency Potential	717	875	1,031	1,187	1,343	1,505	1,667	1,829	1,989	2,149
Easily Acheivable Utility Efficiency	359	437	516	594	671	753	834	914	995	1,075
Current Utility Efficiency Practices	27	33	40	47	53	60	67	73	80	87
Readily Available Utility Efficiency	332	404	476	547	618	693	767	841	915	988
Total: AZ+NV+NM (GWh)	1,396	1,551	1,931	2,078	2,457	2,629	3,039	3,192	3,597	3,823
Total: AZ+NM (GWh)	1,308	1,578	1,848	2,119	2,391	2,705	3,019	3,335	3,650	3,967
Total: AZ+NM (MW)	223	269	315	361	407	461	514	568	622	676

The third row for each state presents the "easily achievable" utility efficiency potential. This represents the portion of the total utility potential that could be achieved with moderate, as opposed to aggressive, investment and activity levels. It accounts for the fact that utilities might not have the interest or capacity to obtain all the cost-effective energy efficiency savings that are achievable, and that some efficiency measures are more difficult to implement in practice than to assess in theory. This analysis assumes that the easily achievable utility efficiency potential will be one-half of the SWEEP estimate of the total utility efficiency potential. In other words, the savings in the third row are equal to one-half of the savings in the second row.

The fourth row for each state presents an estimate of the amount of energy efficiency savings that is likely to be developed as a result of utility and regulatory policies in place today.

In Arizona, Arizona Public Service Company (APS) recently prepared a DSM Program Portfolio Plan that is expected to result in an average of $16 million per year of investment for 2005–2007 (APS 2005). The cumulative efficiency savings from APS by 2010 is estimated to reach roughly 651 GWh.[6]

In Nevada, a law was recently passed that allows electric utilities in the state to use energy efficiency savings to comply with the Portfolio Energy Standard (PES). The standard requires a certain portion of the companies' portfolio to consist of either energy efficiency, renewable resources, or both. Efficiency can be used to meet up to 25% of the PES, and of the efficiency that is used, one half of it must be from the residential sector. The efficiency portion of the PES is multiplied by the companies' recent load forecast to estimate the amount of energy efficiency that is expected to be developed by the electric companies as a result of this new policy.[7]

In New Mexico, there is much less energy efficiency activity than in the other two states assessed here. Utilities in New Mexico have a budget of roughly $2 million per year to implement energy efficiency programs. (SWEEP 2005) In the absence of a forecast of the amount of efficiency savings expected from these investments, we have developed a rough estimate for this study. It is assumed that the utilities in New Mexico will be able to achieve energy efficiency savings for an average cost of roughly $20/MWh, where the MWh are equal to the savings over the entire life of the efficiency measures.[8] It is also assumed that the efficiency measure installed have an operating life of 15 years on average. Under these assumptions, it is estimated that the $2 million dollars per year invested in New Mexico will result in roughly 7 GWh of energy efficiency savings per year.[9]

The fifth row for each state in Table 6-4 presents the estimate of the readily available utility efficiency savings. It is derived by subtracting the savings of the existing utility efficiency policies from the readily achievable

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[6] This estimate includes actual efficiency saving from 2003 and 2004, because the potential savings estimates in the SWEEP study are based on load and efficiency data as of 2002.

[7] The PES law does not *require* utilities to implement this level of energy efficiency. Instead, it *allows* them to implement this amount of efficiency as an alternative to developing renewable resources. Given the current economic advantage of energy efficiency over renewable generation, it is safe to assume that the electric companies in Nevada will be pursuing as much of this energy efficiency option as possible.

[8] See the following section for a discussion of the cost of saved energy for typical utility energy efficiency programs. While it may cost more to achieve the efficiency savings in New Mexico, we use this assumption to be conservative, i.e., to avoid overstating the readily available efficiency potential.

[9] The estimates in Table 6.4 include actual efficiency saving from 2003 and 2004, because the potential savings estimates in the SWEEP study are based on load and efficiency data as of 2002.

utility efficiency. This estimate provides a rough indication of the amount of efficiency that could be developed by electric utilities and sold to SCE.

Note that Arizona has, by far, the largest potential for readily available utility efficiency savings. This is because Arizona has the largest amount of electricity consumption, and thus the largest amount of efficiency potential.

Also, note that the readily available efficiency potential in Nevada is relatively low, and in some years negative, under these assumptions. This is because the Portfolio Energy Standard will be encouraging the two electric utilities there to develop a large amount of energy efficiency savings, leaving very little, or no, efficiency left to be sold to SCE. This finding is consistent with the general understanding among utility efficiency stakeholders in Nevada; that it will be challenging for the utilities to meet the efficiency portion of the PES.[10] For this reason, Nevada has been removed entirely from the estimate of the potential for efficiency resources that could be sold to SCE.[11]

The next-to-the-last row in Table 6-4 presents the estimate of the amount of energy efficiency savings (in GWh) in Arizona and New Mexico that could readily be made available for sale to SCE. The final row presents the amount of capacity (in MW) that this level of savings might represent. This level of capacity is estimated using the results of the SWEEP study, which found that in the entire Southwest region 99,038 GWh of energy would result in 16.9 GW of capacity. This same relationship of capacity to energy is used to estimate the capacity savings in Table 6-4.[12]

In summary, by 2010, there are at least 2,394 GWh of energy and 408 MW of capacity available from Arizona and New Mexico. To put this in perspective, SCE's share of the Mohave generation is roughly 5,700 GWh per year, and its share of the Mohave capacity is 885 MW. Thus, by 2010, energy efficiency from Arizona and New Mexico could replace over 40% of the energy and over 45% of the capacity from the Mohave plant. This is a very conservative estimate of the potential to replace Mohave with efficiency resources, as a result of the

[10] Synapse Energy Economics is representing the Nevada Bureau of Consumer Protection in the Nevada Demand-Side Management Collaborative, and this statement is based on recent informal comments of several parties within the Collaborative, particularly representatives for Nevada Power Company and Sierra Pacific Power Company.

[11] Note that the Nevada utilities are likely to have more energy efficiency opportunities from the commercial and industrial sectors than from the residential sector. Thus, the 50% residential requirement is likely to mean that some commercial and industrial energy efficiency will be available above and beyond the PES. However, we have chosen not to include this potential in our estimates.

[12] The capacity savings may well be considerably higher than this if sufficient emphasis is placed on efficiency measures that save energy during peak periods.

adjustments made above. A highly motivated utility could obtain more than the easily achievable efficiency savings identified here.

Furthermore, although Nevada, Colorado, Utah, Wyoming, and the Northwest states were excluded from the analysis, efficiency might also be purchasable from those states. This report focused on Arizona and New Mexico, however, because these states are likely to have the most efficiency potential that is easiest to sell to SCE. If SCE were interested in purchasing more efficiency than identified above in Table 6-4, then it should look to these other states in the region.

6.2.4 Approximate Cost of Energy Efficiency in the Region

In order to demonstrate the economics of SCE purchasing energy efficiency from another utility, a rough estimate of the likely cost of developing energy efficiency resources in the region was developed. A more detailed analysis would be beyond the scope of this analysis. Nonetheless, it is possible to use estimates of the cost of saved energy in several other states to provide examples of what efficiency might cost.

Table 6-5 below presents a summary of the cost of saved energy for six states that implement relatively large energy efficiency programs. The cost of saved energy (in $/MWh) is calculated by dividing the initial costs of implementing an energy efficiency measure in any one year (including administration costs), by the cumulative energy savings over the total lifetime of the efficiency measure. Thus, the cost of saved energy can be compared directly with the cost of generation from a power plant, or the cost of purchasing power through a contract or the spot market. Table 6-5 indicates that the cost of saved energy for these states has ranged from $23/MWh to $44/MWh in the past.

Table 6-5 — Cost of Saved Energy from Selected States

State	Cost of Saved Energy ($/MWh)
California	30
Connecticut	23
Massachusetts	40
New Jersey	30
New York	44
Vermont	30

Source: ACEEE 2004, page 30, Table 5.

Table 6-6 below presents additional information on the cost of saved energy for states and utilities relevant to the Southwest region. In its recent DSM Program Portfolio Plan, APS estimated that its energy efficiency activities in 2005–2007 will cost $18/MWh on average. Nevada Power (NVP) recently submitted an Annual DSM Report detailing the historical efficiency activities of NVP and Sierra Pacific Power (SPP) in 2004, which indicates that the cost of saved energy was roughly $13/MWh.[13] SCE's own energy efficiency plan assumed that it will spend roughly $37/MWh to achieve the energy efficiency savings. Finally, the SWEEP study assumed that the energy efficiency savings identified in the study will cost roughly $20/MWh.[14]

Table 6-6 — Cost of Saved Energy in the Southwest Region

State	Cost of Saved Energy ($/MWh)	Source
Arizona Public Service Co.	18	APS 2005, page 4
Nevada Power and Sierra Pacific Power	13	NVP 2005, Exhibit B, Table 1
Southern California Edison	37	SCE 2005
SWEEP Study	20	SWEEP 2003

In practice, the cost of saved energy can vary widely depending upon the particular efficiency measure, the sector being served, the utility, the delivery costs, and other factors. For example, lighting programs tend to cost less than those addressing other measures, commercial and industrial customers are typically less costly to serve than residential customers, and utilities that tend to address measures comprehensively (as opposed to cream-skimming) tend to spend more money to achieve efficiency savings.

Costs in Table 6-5 and Table 6-6 are provided merely to illustrate the typical range of the cost of saved energy from a variety of efficiency programs. Based on this range, it is assumed that the amount of readily available efficiency savings presented in Table 6-4 can be achieved for a cost of $40/MWh or less. A high estimate was chosen in order to be conservative. APS is one of the best sources of efficiency purchases for SCE, and they estimate that efficiency costs them only $18/MWh. On the other hand, it may cost more for APS to go above and beyond the efficiency opportunities that they are already planning to pursue.

[13] The companies spent $10.6 million to save 78,300 MWh per year. We assume that the average measure life is 10 years, in order to estimate the cost of saved energy for lifetime energy savings. This average measure life is relatively short because most of the NVP and SPP savings are from commercial programs which we assume to include mostly lighting measures.

[14] This cost is for the efficiency associated with all types of policies, not just the utility-run energy efficiency programs. Other policies (e.g., appliance standards and building codes) tend to have relatively low costs to implement, and thus might be responsible for lowering this average cost figure.

Also, this cost of saved energy is assumed to include the cost incurred by the electric company implementing the efficiency programs, as well as any costs incurred by the customer participating in the programs. In other words, it is based on the Total Resource Cost test, which requires accounting for both utility and customer costs. In very rough terms, approximately $30/MWh would be incurred by the utility, and the remaining $10/MWh would be incurred by the customer. The costs incurred by the utility would include all the program administration costs, marketing and delivery costs, monitoring and verification costs, and the utility portion of the cost of the measure itself.

6.2.5 References for this Subsection

- American Council for an Energy Efficient Economy (ACEEE) 2004. *Five Years In: An Examination of the First Half-Decade of Public Benefits Energy Efficiency Policies*, Martin Kushler, Dan York and Pattie White, April.
- Arizona Public Service Company (APS) 2005. *APS Demand-Side Management Program Portfolio Plan: 2005-2007*, July 1.
- Nevada Power Company (NVP) 2005. *Integrated Resource Plan 2003, Ninth Amendment to the Action Plan*, Submitted to the Nevada Public Utilities Commission, August 15.
- Southern California Edison, 2005, *Testimony Of Southern California Edison Company In Support Of Its Application for Approval of Its 2006-08 Energy Efficiency Programs and Public Goods Charge and Procurement Funding Requests*, before the California Public Utilities Commission, June 1, 2005.
- Southwest Energy Efficiency Project (SWEEP) 2005. *Utility Energy Efficiency Policies and Programs in the Southwest*, Howard Geller, Presentation to the Energy Efficiency Task Force Meeting, Santa Fe, New Mexico, March.
- SWEEP 2004. *Utility Energy Efficiency Policies and Programs in the Southwest*, Howard Geller, September 17.
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6.3 PURCHASE POWER ARRANGEMENTS WITH NEIGHBORING UTILITIES

To investigate the feasibility and practicality of the DSM resource / power purchase alternative/complement, discussions were held with PNM Resources of New Mexico. Initial attempts to discuss the issue with Arizona Corporation Commission staff and Arizona Public Service personnel have yet to result in substantive discussions. The aim of these conversations was to obtain feedback on the willingness of parties to participate in the DSM resource procurement, and to determine the key issues facing potential utility partners considering a

DSM/power purchase arrangement with SCE.[15] In particular, Synapse sought to obtain information on the regulatory and institutional concerns or barriers that may exist, and to determine the commercial factors that would influence the pricing arrangements that would accompany the DSM implementation/power purchase alternative. Another goal was to determine the likely range of prices or at least the driving factors in price determination before completion of the final report.

The discussions with PNM sought to answer the following questions:

- Is this a concept that PNM would consider seriously?
- What types of questions would need to be clarified in order to actually make this happen?
- What might pricing arrangements look like between PNM and SCE?
- Is there a pricing concept PNM could convey to us that would allow us to create some practical examples?
- Would SCE be the right company for PNM to make such an arrangement with, or would PNM be better off forging such a relationship with a different company?
- What particular New Mexico regulatory issues should we be aware of?
- Would PNM be willing to try this sort of DSM/power purchase contract agreement even though the concept is not well proven?
- How would environmental credits associated with a DSM resource, if any, be treated?

The conversations did not result in confirmation of any particular commercially acceptable pricing arrangements or price bounds. However, PNM did maintain an expression of interest in the concept. The conversations did reveal that a major concern existed concerning the manner in which the New Mexico Public Service Commission might view any arrangements that did not allow for freed-up generation capacity to remain available to New Mexico jurisdictional ratepayers. Based on this perspective, the DSM resource illustrative example provided in this chapter presumes significant retention of "freed-up" peaking capacity for the host utility in the neighboring state.

6.3.1 Approach to Analyzing the DSM Resource

The approach used to analyze the DSM resource first determined the range of DSM implementation costs and then considered the interaction between the DSM resource and the power purchase contract that must be coupled

[15] Synapse thanks the PNM personnel for the time taken to speak with us on the issues. PNM was aware that all discussions were focused on establishing a "proof of concept," or disproving such a concept, and that no commercial implications are to be taken from any of the information provided in the example

with the resource in order to physically flow the resulting "freed up" energy to SCE territory. A simple spreadsheet model was developed to test the assumptions used. The model allowed for an analysis of the way in which DSM peak shaving benefits would provide value to any potential partnering utilities. It was determined that the simplest and most effective demonstration of the DSM technology option concept would be to construct a power purchase arrangement that flowed "flat" or baseload power to SCE equivalent to the total annual energy saved by the DSM measures installed in the partnering utility's service territory, while simultaneously allowing for all incremental peak load reduction benefits to accrue to the partnering utility. This was determined after first investigating alternative models that "flowed" the DSM savings profile directly to SCE.

Table 6-7 below lists stakeholder objectives and sample approaches to reach those objectives when considering the DSM technology option.

SCE customers will be made better off, or at least will not be harmed, if the DSM technology option is no more expensive than the next available alternative, accounting for the value of the power over peak and off-peak periods. In the example used to illustrate the DSM technology option, the DSM contract price was set equal to \$70/MWh, for a 24 x 7 flat "baseload" product flowed into SCE territory from the Palo Verde hub; this is somewhat less than existing estimates for SCE avoided costs[16], and less than the costs for some of the other supply alternatives. Thus, SCE customers remain at least neutral to the DSM option if a partnering utility is willing to receive \$70/MWh for a 24 x 7 product. As the example shows, the peak reduction benefits together with the revenues received from a contract price of \$70/MWh appear to be adequate to provide enough incentive to a partnering utility to consider the transaction.

The partnering utility's customers who directly participate in the DSM program offerings will be made better off through bill savings resulting from DSM measure installation. Those partnering utility customers who choose not to participate in any installation program will not see any rate impact, as long as the way in which benefits flow to the partnering utility allows them to offset the lost revenues from the DSM installations. The partnering utility's management and shareholders will consider the DSM technology option as long as the lost revenues arising from the DSM installations are at least offset by the wholesale sale (i.e., the 24 x 7 product flowed to SCE) revenues (net of DSM costs) and the net production cost savings associated with peak load reduction.

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in this section.

The example illustrated in the following section purposefully considered a conservative allocation of the DSM benefits by keeping the partnering utility customers "held harmless," i.e., there was no rate impact assumed on the partnering utility side. As indicated in Table 6-7 and in the example to follow, the partnering utility's "participating" customers receive considerable benefit through direct bill reduction resulting from the DSM measures.

Table 6-7 — DSM Technology Option – Analysis of Stakeholder Interests

Stakeholder	Stakeholder Objectives	Sample Approaches to Meeting Stakeholder Objectives
SCE Customer	No rate increase relative to other technology options.	Purchase power/DSM costs to SCE must be less than or equal to— –Other technology options; –SCE avoided costs; or –Mohave costs after retrofit.
SCE Shareholder	Fair earnings compensation.	To be determined by CPUC.
Partnering Utility – All Customers and Shareholders	Reduced cost of electric service; improved reliability; improved fuel diversity; reduced environmental impacts; improved economic development; minimize future capacity and energy costs.	Implementation of cost-effective DSM in general results in these system-wide benefits.
Partnering Utility Customer Direct Participant in DSM Program	Reduced bills from installed DSM measures.	Customers elect to participate in program; customer contribution less than total savings.
Partnering Utility Customer So-Called "Non-Participant"	No change in near-term rates.	Flow sufficient benefits to partnering utility so that all its customers benefit.
Partnering Utility Shareholder	Compensated for lost revenue; fair earnings compensation.	Partnering utility retains near-term peak-load reduction benefits (reduced total costs to generate, reduced losses, no change in rates).

Note: Tribal stakeholder benefits of the DSM resource are not directly addressed in the DSM illustrative example. Some direct DSM measure benefit could occur depending on DSM program structure, if DSM measures are made available for installation on the reservations or are delivered near the reservations by enterprises based on the reservations or employing tribal members. Tribal indirect impacts are addressed in Chapter 9 of the report.

[16]Based on an examination of material included in "Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs," October 25, 2004, by Energy and Environmental Economics, Inc.; a review of the "Comparative Cost of California Central Station Electricity Generation Technologies," August 2003 by the staff of the California Energy Commission; and considering increased natural gas price trends.

6.3.2 Demand-Side Management as a Peaking Resource

In general, DSM resources have the potential to reduce peak load requirements in the service territories in which they are implemented, in addition to providing energy savings during shoulder and off-peak periods. For areas outside the Desert Southwest, there is considerable data available describing “DSM load shapes” and providing, among other details, annual load factors and coincident factors for DSM technologies.[17] However, the SWEEP study examined for the Desert Southwest region contained only an aggregate representation of the way in which DSM implementation will result in peak benefits. The actual DSM resource being evaluated is thus not defined with specificity. In particular, there is no list of the exact measures to be installed or of the technologies or behavioral changes to be promoted. Thus, there is no concrete set of DSM load shapes to evaluate for the DSM technology option. But that does not imply that the benefits of peak load reduction seen with DSM cannot be accounted for in the analysis undertaken for the DSM resource; the SWEEP study’s aggregate “DSM load shape” can be used to approximate the peak load reduction benefit accruing to the “partnering” utility implementing the DSM measures. The example below accounts for the peak-load reducing benefits of DSM by recognizing the higher value of energy saved during peaking periods.

6.3.3 Example of DSM Implementation / Purchase Power Agreement

The following simplified example illustrates how the economics behind the DSM implementation / power purchase agreement might work. Conceptually, the DSM alternative represents procurement of a resource that is less expensive, or at least no more expensive, than other supply options facing SCE. Simultaneously, the DSM technology option allows a partnering utility (for example, PNM or another southwest region utility) to sell additional energy at wholesale; that is, energy that is only freed up and available for sale because of the DSM procurement. Thus, the arrangement could become a “win-win” approach because of the existence of (1) low DSM resource costs; (2) higher SCE avoided costs, or higher SCE costs based on a comparison to other options; and (3) value to the partnering utility in the form of peak period benefits, if the power purchase contract is not “shaped” to reflect the actual DSM savings “load” profile. The example uses a flat 24 x 7 power purchase product coupled with DSM implementation and retention of DSM peaking benefits by the partnering utility. It illustrates one way to ensure that all stakeholders are at least neutral and some are made better off by the adoption of the DSM option. The example does not directly illustrate certain temporal aspects of the DSM

[17] For example, the Northwest Power and Conservation Council posts publicly available savings and shape data on a wide array of DSM measures. These can be found at http://www.nwcouncil.org/energy/rtf/supportingdata/.

resource, such as front-loaded costs and savings seen over the life of the DSM measures; it uses levelized total resource costs (TRC) to represent the costs associated with a given megawatt-hour of energy savings.

The study scope for the DSM alternative does not include a detailed examination of the rate impacts affecting the neighboring utility ratepayers. In the example below, zero rate impact is assumed, when in reality there could be beneficial rate impacts if the savings associated with the use of the less expensive resource are shared not only between SCE and the partnering utility, but between SCE, the partnering utility, and the partnering utility's regulated ratepayers.[18]

The example uses the information gleaned from the SWEEP study to posit a DSM total resource cost of $40/MWh, and a utility cost of $30/MWh, assuming a customer contribution of $10/MWh. The total annual contract quantity of 300 GWh/yr is based on an assumption that the DSM resource could ramp up to such a level of implementation over the course of five years. This quantity is a somewhat arbitrary amount chosen to illustrate the workings of the contract; it is considerably below the energy efficiency potential identified in the earlier section of this report; and it can be scaled up linearly at least to the "readily available utility efficiency" identified in Table 6-4.

This assumption of 300 GWh/yr is not meant to be limiting in any way; it merely allows for a snapshot analysis of savings during a single year that are equivalent to the total energy flowing to SCE in the power purchase component of the transaction. If the DSM resource were employed up to the "readily available utility efficiency" seen in Table 6-4, it could conservatively replace approximately 42% of the annual energy and 45% of the capacity of SCE's share of the Mohave plant. The 300 GWh/year leads to a peak savings of 51 MW, based on the peak savings to annual energy savings ratio found in the SWEEP study.

The example shows the assumed, negotiated contract particulars for the power purchase / DSM resource procurement. The postulated contract price of $70 per MWh would depend on resource cost assumptions: the DSM implementation cost itself, SCE's avoided costs, and the partnering utility's cost structures with and without the presence of the DSM savings. The value chosen for the example is based on a minimum level of revenues required by the partnering utility to compensate for production costs and lost retail revenues while simultaneously reflecting an estimate of the benefits the partnering utility gains from peak load reductions and associated reduction in generation production cost to serve its retail load.

[18] The timing of forthcoming rate cases, and the existence of policies related to "decoupling" of utility profits from utility sales will also affect rate impacts. We address institutional "decoupling" issues in a subsequent section.

The example illustrates the tradeoffs between losing retail sales due to DSM installation and gaining wholesale sales through the power purchase component of the contract. In this instance, a retail price of $73/MWh has been used to demonstrate the effect of lost retail revenues. The current rate structure in the PNM service territory includes a retail rate of approximately $73/MWh or 7.3 cents/kWh. At a contract price of $70/MWh, the partnering utility would see a revenue increase (to partially offset the retail revenue loss) of $21 million per year.

The example includes an estimate of the peak load reduction benefit seen by the partnering utility. The peak benefit arises from three interacting effects: (1) the wholesale power purchase flows physical power equal to 34 MW for all hours of the year, while the DSM savings include 51 MW on average during peak times; (2) the partnering utility's overall system load profile is flattened (its annual load factor increases) due to the peak shaving effect of the DSM measures; and (3) the line loss benefits accrue directly to the partnering utility, which does not have to generate to compensate for the distribution system losses. Additional transmission level loss savings are likely (given the location of the "freed up" power closer to SCE's load center, at Palo Verde), but have not been quantified; nor have any additional beneficial effects associated with potential reduced distribution investment. For the 300-GWh transfer, the partnering utility offsets the lost retail revenue of $21.9 million per year with $21 million per year from SCE, and with $3.1 million per year in net DSM peak reduction benefit, arising from production cost savings, for a net gain of $2.3 million per year.

Lastly, the effect of the DSM measures on the partnering utility participating customer is shown below. In this example, the vast majority of the benefits accrue to these customers, for a total of $18.9 million net savings per year for the 300-GWh/yr quantities. The allocation of the vast majority of benefits to participating customers of the partnering utility reflects an approach that minimizes the regulatory risk of interregional DSM transfers by ensuring that partnering utility ratepayers are held harmless when "freed up" power is used to meet out-of-state loads. This does not imply that such a benefits allocation is the only way to effect a DSM transfer; alternative allocation strategies are possible (e.g., increase the customer contribution) that retain the viability of the DSM option while possibly lowering the costs to SCE.

Table 6-8 — Illustrative Example of DSM Implementation / Purchased Power Arrangement

Contract Particulars and Assumptions			Comments/Definitions
Total Cost (TRC) of DSM (Cost of Saved Energy)	40	$/MWh	Levelized TRC - High end of range of observed costs
Customer Contribution	10	$/MWh	Estimate
Net Utility Cost of DSM	30	$/MWh	
DSM Resource Qty / Purchased Power Qty	300	GWh/year	Contract Quantity
DSM Resource Qty - Peak Savings	51	MW	Based on aggregate peak impact factor from SWEEP
Negotiated or RFP-based Contract Price	70	$/MWh	Negotiated Contract Price or Result of RFP
Average MW Flow to SCE	34	MW	Average MW Flat Flow at 300 GWh per Year
Power Purchase Shape	24 x 7	Hrs/Week	Flat, Constant Power Flow All Year
Estimate of SCE Avoided Cost to Compute SCE Benefits	70	$/MWh	Estimate - to assume neutral impact on SCE
Average Annual SCE Impact (Customers and Shareholders)			
Resource Savings			
Avoided Costs	70	$/MWh	
Total Contract Price	70	$/MWh	
Price Difference, Avoided Costs - Contract Price	0	$/MWh	
Annual Quantity of Savings	300	GWh/year	
Net Savings	-	$/Year	Equal to Price Difference x Resource amount
Estimate of Average Annual PNM Shareholder Impact			
Revenue Loss Impact Before Peak Reduction Benefit			
Payment from SCE	70	$/MWh	Contract Price
Quantity Wholesale Sale to SCE	300	GWh/year	Contract Quantity
Total Revenue Increase from Purchased Power Contract	21,000,000	$/Year	Contract price x quantity flowed / saved
Retail Rate	73	$/MWh	Approximate based on current rates
Quantity Lost Retail Sales	300	GWh/year	
Lost Retail Revenues from Effect of DSM	21,900,000	$/Year	Contract quantity x retail price
Revenue Loss Impact Before DSM Peak Reduction Benefit	(900,000)	$/Year	Revenue increase from PP minus lost retail revenues
Estimate of DSM Peak Reduction Benefit			
On Peak Costs of Generation	80	$/MWh	Estimate based on PV Market
Off Peak Costs of Generation	35	$/MWh	Estimate
Share of DSM Savings Occuring During Peak Periods	67.0%		Estimate
Share of System Load On-Peak without DSM	70.0%		Estimate
Share of System Load On-Peak with DSM	69.3%		Estmate based on DSM Savings % On-Peak Periods
Share of Power Purchase Contract Flow On-Peak	57.0%		Based on 6X16 on-peak definition, 52 weeks/year
System Size	30	10^6 MWh/Yr	Base to allow DSM GWH at 1% of retail load
T&D Loss Savings as % of Retail Load	5.0%		Estimate
Total Production Cost Savings Including Loss Effect	12,154,778	$/Year	Based on On and Off Peak Costs - See Model
Total Utility DSM Costs	9,000,000	$/Year	Utility Costs x Resource Quantity
Net DSM Peak Reduction Benefit	3,154,778	$/Year	Delta Production Costs incl. T&D Loss Effect
Net Impact Including Peak Reduction Benefit	2,254,778	$/Year	Net Peak Benefit Less Revenue Loss Impact
Estimate of Average Annual PNM Participant Impact			
DSM Savings	300	GWh/year	
Retail Rate	73	$/MWh	
Gross Savings to Participating Customers	21,900,000	$/Year	Quantity x Retail Rate
Customer Contribution	3,000,000	$/Year	Per Unit Customer Contribution x Quantity
Net Savings to Participating Customers	18,900,000	$/Year	

6.3.4 Barriers to Implementation

The barriers to implementation of the DSM technology option include the following:

- Actual or perceived economics of the transaction from the perspective of the partnering utility
- Uncertainties with regulatory reception in the neighboring states
- Increasing local efforts to undertake DSM opportunities
- Lack of experience with interregional DSM resource transfers

The primary barrier to implementation is likely the perceived economics of the transaction from the partnering utility's perspective. To make up retail lost revenues, the partner must be persuaded that the magnitude of peak savings effects is adequate to offset the portion of retail lost revenues not recouped through wholesale sales, while ensuring an adequate financial incentive for shareholders. The economics of the DSM option as illustrated in the example above are sensitive to peak and off-peak power costs and the ratio of those costs; to the negotiated price for the transfer; to the load shape of the DSM measures; to the estimated distribution loss savings; and to the level of customer contribution. All of these driving factors must be given careful attention by the potential partnering utility in determining whether the incentive is large enough to consider the DSM transfer.

Regulatory barriers to implementation include the revenue risks partnering utilities face from home state utility commissions. The DSM technology option involves reduced retail sales and increased wholesale sales, with different revenue streams associated with each. Also, the retention of benefits associated with peak load reduction could flow through to ratepayers as a means of keeping the "freed up" capacity, or a portion of it, in the home state. This could reduce the effective shareholder incentive available to partnering utilities. The DSM transfer would also compete with existing neighboring state utility DSM efforts; at this time, the potential DSM savings far outstrips the efforts currently underway in Arizona, New Mexico, or Nevada, but local efforts could increase the cost of DSM measures incremental to those being captured by the home state itself.

6.4 INSTITUTIONAL AND REGULATORY SUPPORT FOR DSM PROCUREMENT

The example provided in the previous section uses retail lost revenues in estimating the benefits to the partnering utility for the DSM resource procurement / power purchase agreement. It is possible that under different forms of regulation in New Mexico (or other states that might be involved in potential DSM resource procurements), the existence of a rate-making structure that "decouples" a utility's profits from its regulated retail sales may help to reduce the lost margin often associated with lost revenues, and subsequently lower the contract price for the DSM resource (by lowering the risk of revenue recovery for the partnering utility). In this example, the retail lost revenues are mostly recouped through wholesale gained revenues. However, there may be circumstances in which the existence of a "decoupling" framework could help to put downward pressure on the price otherwise required to enter into a "DSM transfer" such as is contemplated herein. The remainder of this section describes the relationship between decoupling and the prospects for DSM procurement in other states.

6.4.1 Relationship between Regulatory "Decoupling" and Prospects for External Purchase of Efficiency Resources

The incentive for utilities to participate in agreements to implement energy efficiency programs in the states neighboring California in general, and to implement energy efficiency programs to enable power transfers to southern California in particular, is, not surprisingly, directly related to the effect those programs are likely to have on corporate profits. Under traditional utility ratemaking, if sales are higher than forecasted in a utility's rate case, the utility accrues higher profits. Correspondingly, when sales fail to meet forecasts levels—including as a result of energy efficiency programs—utility profits decline. Of the various methods open to utility regulators for reducing or eliminating this disincentive to pursue energy efficiency programs, the "decoupling" of utility profits from the level of sales is a concept that has been implemented or is under discussion in many states. A very brief review of the concept of decoupling is provided below. The status and apparent direction of decoupling-related initiatives in Arizona, Colorado, Nevada, New Mexico, Utah, and Oregon are then summarized. These are the states where it is most likely to be technically feasible to transfer energy efficiency resources to SCE. The reason for this is that these states have available to them both considerable and untapped efficiency resources and appropriate electricity transmission infrastructure allowing sales of power to southern California.

The status of decoupling discussions in the states that are candidates for "energy efficiency resource trading" of the type described here is germane because of its effect on incentives for the utility in whose service territory the efficiency resources are located. Although most jurisdictions allow recovery of funds spent on DSM programs, and many offer some form of shareholder incentives for efficiency programs mounted by the utilities, it is far less likely that a utility commission would approve utility incentives toward participation in energy efficiency programs not paid for by the utility itself. The utility with an energy efficiency resource to "sell" is likely, therefore, to suffer loss of sales and loss of margins if its service territory hosts successful DSM programs underwritten by other parties. Indeed, this is one of the concerns expressed in conversations with PNM. If utility profits and sales are decoupled, however, the utility's financial disincentive to participate in an energy efficiency resource trading arrangement will be substantially reduced. Thus, the status of decoupling and similar disincentive-removal policy discussions in the states around California bears watching. This is not to say that decoupling is necessarily *essential* to a successful energy efficiency resource trading arrangement; a combination of financially attractive terms for power exported to southern California, assistance with mounting more aggressive DSM programs in its own territory (in part, perhaps, to address regulatory and public pressure to do so), and perhaps environmental considerations (reduced greenhouse gas emissions, for example) may make such trading sufficiently attractive to garner utility participation even in the absence of decoupling. The decoupling of utility profits from sales, however, is likely to lower the barriers to utility participation in a trading arrangement.

6.4.2 Decoupling: Concept and Proposed Mechanisms

A recent review of decoupling of utility profits from sales includes the following summary description:[19]

> Traditional electric and gas utility ratemaking mechanisms unintentionally include very strong financial disincentives for utilities to support or implement EE [Energy efficiency] and DG [Distributed Generation]. More so than any other issue, this fundamental 'throughput disincentive'….discourages utilities from promoting EE/DG that lowers customer costs. The net effect of the disincentive is that utilities' management interests are misaligned with a public interest in least-cost electric and gas energy service. This misalignment is somewhat arbitrary; but it can be directly remedied through 'decoupling' utility profits from sales or instituting similarly effective regulatory approaches.
>
> Decoupling involves regular adjustment (downward or upward) of utility rates to account for actual sales volume, rather than waiting until the next rate case to evaluate revenue requirements and adjust rates. This type of balancing mechanism is known as an Electric Revenue Adjustment Mechanism ('ERAM'). Some utilities have used an alternative approach, adopting a Lost Revenue Adjustment Mechanism (or LRAM). An LRAM can help reduce the throughput disincentive, but it fails to address the underlying problem.

The same review goes on to note:

> A large majority of electric utility costs are fixed, to pay for capital-intensive equipment such as wires, poles, transformers and generators. Utilities recover most of these fixed costs through volumetric-based rates, which change every 3-5 years with each so-called major 'rate case', the traditional and dominant form of utility ratemaking. But between rate cases, utilities have an implicit incentive to maximize their retail sales of electricity (relative to forecast levels, which set 'base' rates); i.e., to maximize the "throughput" of electricity across their wires, in order to ensure recovery of fixed costs and maximize allowable earnings (recovery of variable costs is

[19] The information is taken from a review conducted by Synapse Energy Economics on behalf of the U.S. Environmental Protection Agency. The U.S. EPA has not yet issued its final report and it may contain changes to the language initially provided by Synapse.

> assured through regular – e.g., quarterly - adjustments such as for fuel, and thus doesn't impose analogous disincentives.)
>
> With traditional ratemaking, there is no mechanism to prevent 'over-recovery' of these fixed costs, which occurs if sales are higher than projected; and no way to prevent 'under-recovery', which can happen if forecast sales are too optimistic (such as when weather or regional economic conditions deviate from forecast or 'normal'). This dynamic creates an automatic disincentive for utilities to promote energy efficiency or distributed generation, because those actions – even if clearly established and agreed-upon as less expensive means to meet customer needs - will reduce the amount of money the utility can recover towards payment for fixed costs.

In concept, decoupling severs the relationship between utility revenues and the volumes of sales per customers. In one form of decoupling, regulators set an allowable return per customer, and rates are periodically adjusted so reflect changes in revenue per customer as sales increase or decrease[20]. In this method, differences between revenues allowed by regulators and actual revenues received in each year following a rate case are tracked, and any differences are taken into account in adjusting customer rates (either up or down) in the following year. With this mechanism in place, utilities' economic disincentives to pursue energy efficiency are reduced, since any increase or decrease in sales per customer will be compensated for fairly promptly by rate adjustments. Decoupling does place a limit on "upside" net revenues by a utility, but also limits the "downside" effect of reduced sales related to either energy efficiency or a weather-related decrease in consumption.[21]

6.4.3 Consideration of Decoupling Policies in Southwest States and in Oregon

The following brief survey summarizes the status, and in some cases some of the history, of formal and informal discussions regarding implementing the decoupling of utility profits and sales in six western states. As such, these summaries provide one indicator of which states are more likely, at least from an incentives/disincentives regulatory perspective, to be the first hosts of efficiency resource trading arrangements (for example, New Mexico and Utah), and which may be less likely to host such arrangements in the short term.

6.4.3.1 Arizona

The concept of decoupling of utility profits from sales has received limited attention in Arizona. One of the two major gas utilities operating in the state, Southwest Gas, did propose to the Arizona Corporation Commission a decoupling mechanism, but that proposal was rejected by the Commission. A 2005 Commission Staff report on DSM policy did touch upon the issue of lost net revenue recovery by utilities, noting arguments for and against

[20] See, for example, Wayne Shirley, *Barriers to Energy Efficiency*. Presentation prepared for the Regulatory Assistance Project, June, 2005.

the concept as expressed by parties to a 2003/2004 workshop process to discuss DSM policy in Arizona. There is no discussion of decoupling in the Commission Staff's document. The staff ultimately took no position on lost net revenue recovery, noting that the Commission would decide the issue on a case-by-case basis.[22] Looking forward, a Commission Staff member indicated that decoupling was "not recommended" by the staff, and that while it is expected that the issue will be brought up again in the context of the next gas utility rate case, the idea has yet to be considered for electric utilities in Arizona, and there are no current plans to do so.

6.4.3.2 Colorado

A considerable effort by energy efficiency advocates was mounted in the 1990s to establish decoupling of utility sales and net revenues as Public Service Commission policy in Colorado. These efforts, however, proved unsuccessful. This year, Colorado House Bill 05-1133, "Concerning measures to promote energy efficiency," initially included text instructing the Commission to "[a]dopt a procedure for decoupling a gas distribution utility's sales and revenues," though the version of the bill ultimately forwarded to the governor for signature was not as explicit, instructing the Commission only to "identify barriers that financially penalize gas distribution utilities if they implement cost-effective energy efficiency programs for their customers."[23] In early June, however, Governor Owens vetoed the bill out of concerns that residential customers would be burdened unfairly with costs for gas energy efficiency programs (the bills exempted commercial and industrial customers from the application of cost-adjustment mechanisms that would allow gas utilities to recover energy efficiency program costs).[24] Some energy efficiency advocates familiar with the Colorado situation rate the prospects of adopting decoupling mechanisms under the current Commission as very unlikely.

6.4.3.3 Nevada

The State of Nevada, guided by what is now the Public Utilities Commission of Nevada, was an early leader in the movement to implement integrated resource planning (IRP), adopting what was then called "least-cost utility

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[21] The application of decoupling to smooth weather-related consumption variations is particularly of interest for gas utilities.

[22] The Commission Staff's First Draft of Proposed DSM Rules in DSM Rulemaking Docket No. RE-00000C-05-0230, dated April 15, 2005, is available in two volumes: Draft Demand-Side Management Rules (http://www.cc.state.az.us/utility/electric/DSM-Exhibit1.pdf), and Staff Report on DSM Policy for the Generic Proceeding Concerning Electric Restructuring Issues, Et Al (Docket Nos. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069), (http://www.cc.state.az.us/utility/electric/DSM-Exhibit2.pdf).

[23] See HOUSE BILL 05-1133, available as http://www.swenergy.org/legislative/2005/colorado/HB%201133%20Bill%20Language%20to%20Governor.pdf

[24] See Governor's Office press release dated June 3, 2005 at http://www.colorado.gov/governor/press/june05/hb1133.html.

planning" in 1983.[25] The IRP process led the two large private electric utilities in the state to pursue moderately successful DSM programs through the mid-1990s. At that time, a move toward a restructured and competitive utility environment in Nevada caused the utilities to substantially drop their DSM programs.

In 2001, however, the move toward restructuring was reversed, and the utilities began offering DSM programs again. At present, utilities receive an adder equal to a 5% return on equity to encourage demand-side management, but rewards for DSM are linked to expenditures, not performance, and there remains little incentive to mount DSM programs that do not build rate base. Decoupling of utility revenues from sales was recently proposed by a gas utility in a recent rate case, but the request was denied by the Commission.[26] One of the Commissioners, speaking in a national forum on energy efficiency and renewable energy, indicated that it was not clear to him "whether we have statutory authority to specifically implement either lost revenue or decoupling," though he indicated that the passage of Senate Bill 188 (the central provisions of which were ultimately included in Assembly Bill 03, which was signed into law in June of 2005[27]) might cause the Commission to "to take another look at the whole incentive structure for DSM and EE programs and make sure that programs are coherent as a whole"[28].

6.4.3.4 New Mexico

Considerable recent activity in the energy efficiency and renewable energy policy areas has helped to put active consideration of decoupling of utility net revenues and sales on a fast track in New Mexico. Governor Richardson's "Clean Energy Executive Order and Task Forces," established under Executive Order 2004-019, includes a Task Force on Utility Energy Efficiency. This includes among other duties consideration of "[r]ate issues like decoupling and treatment of utility program costs"[29]. In addition, and probably of more immediate relevance to policy implementation, the New Mexico Public Regulation Commission (NMPRC) has an active proceeding on energy efficiency rulemaking that will in the coming months, probably within 2005 or 2006, draft a set of general rules for decoupling of net revenues and sales for both electric and gas utilities. The rules will be

[25] Robert Balzar, Howard Geller, and Jon Wellinghoff (2004?), The Rebirth of Utility DSM Programs in Nevada. Available as http://www.swenergy.org/programs/nevada/127.pdf.

[26] From http://www.swenergy.org/pubs/Nevada_Energy_Efficiency_Strategy.pdf, in "Order in Docket No. 04-3011. Public Utilities Commission of Nevada. Aug. 26, 2004," "PUCN denied Southwest Gas's request to decouple gas sales and revenues in a recent rate case decision."

[27] See description in 2005 Nevada Legislative Effort by the Southwest Energy Efficiency Project (SWEEP), at http://www.swenergy.org/legislative/nevada/.

[28] Notes on DSM Incentives in Nevada, dated 5/19/05, and provided as background to a presentation by Nevada PUC Commissioner Carl Linvill to the State Technical Forum on EE/RE, organized by the Keystone Center for the USEPA.

[29] Jon T. Brock, New Mexico Eyes Clean Energy and Efficiency. From http://www.electricenergyonline.com/IndustryNews.asp?m=1&id=32109, dated February, 2005.

drafted by a group including representatives of the Commission staff, utilities, non-governmental organizations, and consumer groups. The general rules ultimately agreed to by this group will then be used to develop utility-specific decoupling mechanisms in the context of the next rate cases for the gas and electric utilities operating in the state.

6.4.3.5 Oregon

A number of different mechanisms for alleviating utility disincentives to pursue DSM were tried during the 1990s for electric utilities, including lost revenue adjustments, shared savings, and decoupling. Oregon's investor-owned utilities no longer run DSM programs themselves, but rather collect a 3% "public purpose charge," which is spent on DSM programs through the independent non-profit Energy Trust of Oregon, which began operation in 2002. As a result, decoupling and related mechanisms are no longer in use for electric utilities in Oregon. In 2001, a decoupling mechanism covering 90% of the difference between actual and expected weather-normalized revenue per customer was adopted by the Public Utilities Commission for Northwest Natural Gas. The mechanism for Northwest Natural Gas, and for the electric-utility mechanisms formerly in use, was designed largely through a consensus process, with only "general guidance" from the Commission[30].

6.4.3.6 Utah

The concept of decoupling utility profits from sales was discussed in Utah at least as early as 1991–1992, when it was raised by a party to PacifiCorp's integrated resource plan review.[31] At the time, the Utah Public Service Commission directed that an existing or new task force study decoupling and associated issues related to incentives and disincentives for the acquisition of demand-side resources, and to report back to the Commission. This process ultimately did not result in the adoption of a decoupling rule. The issue surfaced again in the mid-1990s, when a decoupling rule was proposed by a party in the context of an electric utility proceeding, but the proposal was ultimately abandoned. In the last year or so (2004–2005), tentative and informal discussions have begun with Questar Gas, the major gas utility in Utah, regarding the possibility of decoupling profits from sales, with an eye toward removing utility disincentives toward DSM as well as addressing some other problems, such as declining sales per customer, faced by the utility. It is, as yet, unclear whether this process will lead to a

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[30] Notes on Oregon - Decoupling Natural Gas Sales, dated 5/19/05, and provided as background to a presentation by Oregon PUC Head of Utility Division Lee Sparling to the State Technical Forum on EE/RE, organized by the Keystone Center for the USEPA.

[31] Public Service Commission of Utah, Docket No. 90-2035-01, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order on Standards and Guidelines. Issued June 18, 1992.

proposal for addressing disincentives, or whether such a proposal, if offered, will include decoupling. Mindful that whatever ruling is accepted with regard to the gas utility will likely result in consideration of similar measures for the electric utilities in Utah, the state agency, utility, and other representatives involved in the discussion intend to proceed very carefully and deliberately in looking at decoupling and other options. In any case, the presence of these discussions would seem to be a clear indication of interest in the decoupling idea in Utah.

6.5 TRANSMISSION REQUIREMENTS

Because of the existence of supply resources owned by neighboring utilities (for example, by both PNM and APS) at the Palo Verde hub point at the California border, specific transmission assessments for the DSM alternative have not been conducted,. Unlike the alternative and complementary supply resources in the Study Area, the DSM resource will not require transshipment across Arizona/Nevada because its source point is already at the California border.

6.6 CONCLUSIONS

The following conclusions can be drawn from the analysis of the DSM resource alternative/complement:

- A sufficient amount of cost-effective DSM resource potential exists in the states neighboring California for this resource to be considered as a potentially viable technology option for SCE. In particular, relatively untapped, cost-effective DSM potential exists in Arizona, New Mexico, and Nevada.
- The overall economics of the transaction appear attractive based on a set of reasonable and, in some ways, conservative assumptions made in the analysis of the resource. It is important to consider all of the benefits arising from the DSM alternative, given the existence of retail lost revenues and their effect on pricing requirements. For example, distribution system loss avoidance is a considerable benefit and should not be underestimated. The allocation of the benefits between utility customers and utility shareholders will affect the economics and could prove decisive to the viability of the DSM technology option.
- The proximity of the Palo Verde hub to the SCE territory, and the relative liquidity of wholesale power supply at the hub, makes it easier for utility companies located in the Southwest states to consider a commercial arrangement with SCE. In these instances, there is no need to secure transmission to deliver the DSM resource from the actual service territory of the partnering utility.
- The uncertain regulatory environment in partnering utility states and the relative inexperience with interregional DSM transfers increase the risk associated with the DSM alternative when compared to more standard DSM implementation considerations.

Last page of Section 6.

7. OTHER RENEWABLE ENERGY TECHNOLOGY

Other renewable power technologies were investigated as a potential alternative to replace or complement the electrical generation of the Mohave Generating Station. This study considers geothermal and biomass technology for SCE's 56% portion (885 MW) of the plant power generation. Two types of renewable technologies were investigated: geothermal and biomass.

The total renewable generation for geothermal and biomass as compared to other renewable sources in the four state area (Arizona, Colorado, New Mexico, and Utah) area is shown in Table 7-1.

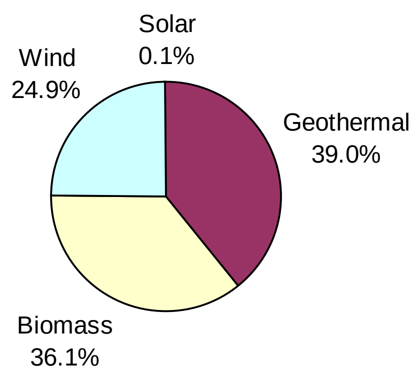
Table 7-1 — Total Renewable Net Generation: Four-State Area

Total Renewable Net Generation in 2002 (thousand Kilowatthours)

	Hydro	Geothermal	Biomass	Solar	Wind	Total
Arizona	7,427,180	0	141,060	459	0	7,568,699
Colorado	1,209,007	0	29,834		139,006	1,377,847
New Mexico	264,591	0	19,408	0	0	283,999
Utah	457,732	217,651	11,197	0	0	686,580
Total	9,358,510	217,651	201,499	459	139,006	9,917,125

Source: DOE/EIA Renewable Energy Trends with Preliminary Data for 2003

Figure 7-1 — Renewable Percentage (without Hydro): Four-State Area

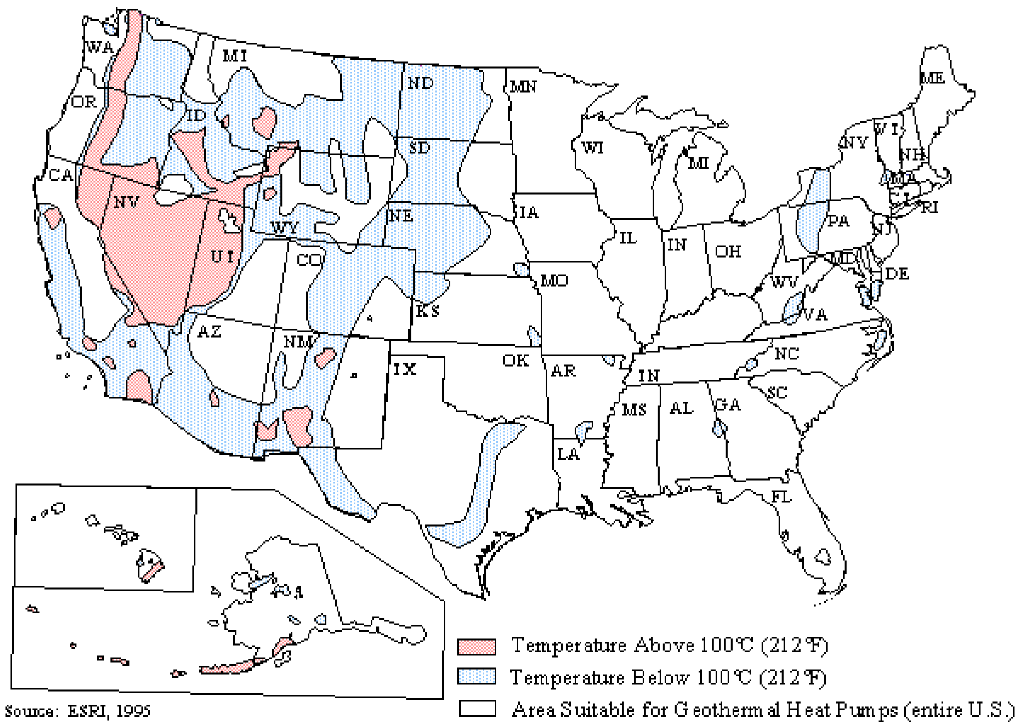


DOE/EIA Renewble Energy not including hydro trends with prelimimary data for 2003

7.1 GEOTHERMAL

Geothermal power plant technology consists of three types: flashed, dry steam, and binary. The map showing areas suitable for geothermal power plants is shown in Figure 7-2.

Figure 7-2 — Geothermal Resources

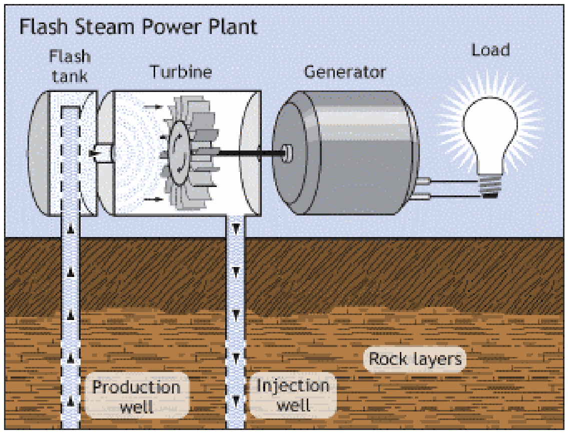


7.1.1 Technology

7.1.1.1 Flashed Steam Plants

Most geothermal power plants operating today are “flashed steam” power plants. Hot water at temperatures greater than 360°F (182°C) are pumped under high pressure to generation equipment at the surface. The hot water is passed through one or two separators where, released from the pressure of the deep reservoir, part of it flashes (explosively boils) to steam as shown in Figure 7-3. The force of the steam is used to spin the turbine generator. To conserve the water and maintain reservoir pressure, the geothermal water and condensed steam is generally redirected down an injection well back into the periphery of the reservoir, to be reheated and recycled.

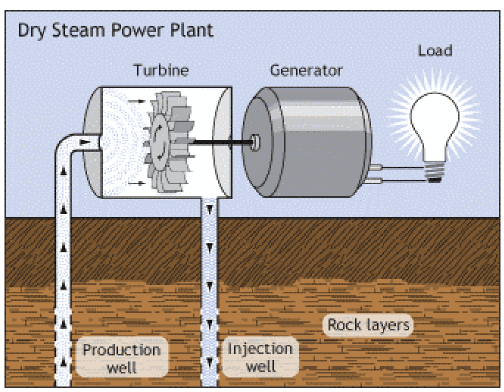
Figure 7-3 — Flashed Steam Plant



7.1.1.2 Dry Steam Plants

A few geothermal reservoirs produce mostly steam and very little water. Here, the steam shoots directly through a rock-catcher and into the turbine as shown in Figure 7-4. The Geysers dry steam reservoir in northern California has been producing electricity since 1960. It is the largest known dry steam field in the world and, after 40 years, still produces enough electricity to supply a city the size of San Francisco.

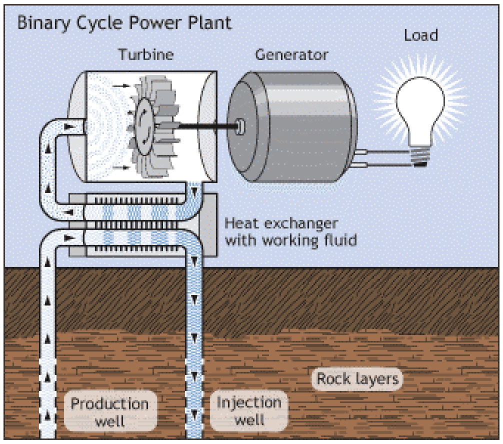
Figure 7-4 — Dry Steam Plant



7.1.1.3 Binary Power Plants

In a binary power plant, the geothermal water is passed through one side of a heat exchanger, where its heat is transferred to a second (binary) liquid, called a working fluid, in an adjacent separate pipe loop as shown in Figure 7-5. The working fluid boils to vapor which, like steam, powers the turbine generator. It is then condensed back to a liquid and used over and over again. The geothermal water passes only through the heat exchanger and is immediately recycled back into the reservoir. The advantage of the binary cycle is that it can operate with water from 225°F (107°C) to 360°F (182°C).

Figure 7-5 — Binary Power Plant



Although binary power plants are generally more expensive to build than steam-driven plants, they have several advantages:

- The working fluid (usually isobutane or isopentane) boils and flashes to a vapor at a lower temperature than does water, so electricity can be generated from reservoirs with lower temperatures. This increases the number of geothermal reservoirs in the world with electricity-generating potential.
- The binary system uses the reservoir water more efficiently. Since the hot water travels through an entirely closed system, it results in less heat loss and almost no water loss.
- Binary power plants have virtually no emissions.

7.1.2 Current Technology Status – Geothermal

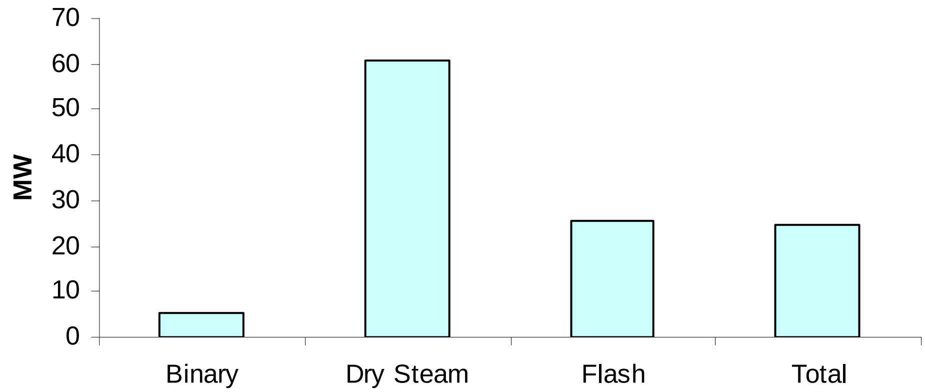
In 2003, geothermal contributed 16% of the non-hydro renewable electricity produced in the United States. The technology is mature and proven to be a reliable source of electricity. There are 113 geothermal power plants in operation in the southwest region area (California, Nevada, and Utah) with a total net capacity of 1,613 MW (see Table 7-2).

Table 7-2 — Geothermal Plants in Southwest Region

		Location				
Type	Data	Califorinia	Nevada	Utah	Grand Total	Percent
Binary	Sum of Nameplate Capacity (MW)	184	89	2	276	
	Sum of # of Units	20	30	3	53	
	Sum of Annual Avg Gross Capacity (MW)	131	63	7	201	
	Sum of Annual Avg Net Capacity (MW)	173	46	4	222	14%
Dry Steam	Sum of Nameplate Capacity (MW)	1635		9	1644	
	Sum of # of Units	26		1	27	
	Sum of Annual Avg Gross Capacity (MW)	932		7	939	
	Sum of Annual Avg Net Capacity (MW)	878		4	882	55%
Flash	Sum of Nameplate Capacity (MW)	669	151	26	846	
	Sum of # of Units	24	8	1	33	
	Sum of Annual Avg Gross Capacity (MW)	590	148	26	764	
	Sum of Annual Avg Net Capacity (MW)	357	129	23	509	32%
Total Sum of Nameplate Capacity (MW)		2488	240	37	2765	
Total Sum of # of Units		70	38	5	113	
Total Sum of Annual Avg Gross Capacity (MW)		1653	211	39	1903	
Total Sum of Annual Avg Net Capacity (MW)		1408	174	31	1613	100%
Average Capacity (MW)						
	Binary				5	
	Dry Steam				61	
	Flash				26	
	Total				24	
Average Net Capacity Factor(%)						
	Binary				80.5%	
	Dry Steam				53.7%	
	Flash				60.1%	
	Total				58.3%	

The average size plant for the three types is 24 MW, with dry steam being the largest and binary the smallest, as shown in Figure 7-6. Dry steam is the largest plant and the geological reservoirs are mainly found in California, with some in Utah.

Figure 7-6 — Geothermal Power Plants – Average Capacity



7.1.3 Potential Geothermal Technology for the Mohave Study

Available information on geothermal resources published by the Idaho National Engineering and Environmental Laboratory (INEEL) for the Department of Energy (DOE) was reviewed. INEEL produced resource maps of 13 western states. An overview of the results of the study for the four-state area along with the results by state are shown in Appendix I.

The available geological information indicate that thermal wells and springs within tribal lands range from 20°C (68°F) to 50°C (122°F) with the exception of two wells greater than 50°C (122°F). The water from thermal wells needs to be greater than 225°F (107°C) for generation of electricity. Hot water from geothermal wells in the low to moderate temperature range (30°C [86°F] to 150°C [302°F]) have applications for building heating, greenhouses, fish farming, and a wide variety of other uses.

The location of wells greater than 50°C within or near tribal lands in New Mexico is as follows:

- Northwest edge of Cibola National Forest near Fort Wingate (near tribal lands)
- Six miles west of Bisti Wilderness Area (within tribal lands)

The well near Bisti could potentially support a binary geothermal power plant. Without a detailed feasibility study of the wells potential, it is assumed that the size plant would be between 2.5 and 5 MW.

7.1.4 Capital Cost

The cost for small geothermal power plants depends on the power plant, drilling cost, and resource quality. Capital cost for the power plant is similar to small conventional power plants. The cost exploration, drilling, and resource quality depends on the well.

Resource quality is evaluated as follows:

- **High Quality.** Resource has a high temperature (> 250°C), with good field-wide permeability, and is likely to be a dry steam or two-phase reservoir, with low gas content and benign chemistry.
- **Medium Quality.** Resource has a temperature between 150°C and 250°C.
- **Low Quality.** Reservoir has a temperature below 150°C or a resource that, although it has a higher temperature, has poor permeability, high gas content, and difficult chemistry.

Without a detailed feasibility study and because the surrounding wells have lower temperatures, it must be assumed that the well is low to medium quality and will be in the range of 1.25 to 2.5 MW gross capacity. Capital cost for small geothermal power plants range from $1,800 to $3,400 per kilowatt based on studies done by NREL and the World Bank. The studies are shown in Table 7-3 to Table 7-5.

The well at Bisti would be similar to plants in the NREL study and, as such, would have a gross capacity of as much as 2.5 MW with a estimated capital cost of $3,400 per kilowatt.

Table 7-3 — Geothermal Direct Capital Costs

		High Quality Resource	Medium Quality Resource	Low Quality Resource
		$/kW	$/kW	$/kW
Small Plants (< 5 MW)	Exploration	400 – 800	400 – 1000	400 – 1000
	Steam Field	100 – 200	300 – 600	500 – 900
	Power Plant	1100 – 1300	1100 – 1400	1100 – 1800
	Total	**1600 – 2300**	**1800 – 3000**	**2000 – 3700**
Medium Plants (5-30 MW)	Exploration	250 – 400	250 - 600	
	Steam Field	200 – 500	400 – 700	
	Power Plant	850 – 1200	950 – 1200	
	Total	**1300 – 2100**	**1600 – 2500**	**Not Suitable**

		High Quality Resource	Medium Quality Resource	Low Quality Resource
		$/kW	$/kW	$/kW
Large Plants (>30 MW)	Exploration	100 – 200	100 – 400	
	Steam Field	300 – 450	400 – 700	
	Power Plant	750 – 1100	850 – 1100	
	Total	**1150 – 1750**	**1350 – 2200**	**Not Suitable**

Exploration costs are assumed to be made up of geoscientific surface exploration (US$600,000) and one (small plant development) to five exploration wells, each well costing about US$1.5 million.

Table 7-4 — Geothermal Binary Power Plant Capital Cost ($2000)

Plant	Resource		Gross Capacity	Net Capacity	Auxiliary Power	Capital Cost		Remarks
	°C	L/min	kW	kW	kW	$	$/kW	
Empire, Nevada	118	4,500	1,200	1,000	200	2,585,000	2,155	Existing 1,800-ft well/air-cooled condenser
Exergy/AmericCulture, New Mexico	116-118	3,800	1,420	1,000	420	3,370,000	2,373	Existing 400-ft well/exit heat for fish hatchery
Milgro-Newcastle, Nevada	127		945	750	195	2,550,000	2,698	Exit heat to green house/well cost $400,000 (included)
Ormat/LDG, New Mexico	150-160	2,900	1,300	900	400	2,870,000	2,207	Existing 1,300 ft well/ air-cooled condenser
Vulcan, New Mexico	112	7,600	1,260	1,000	260	2,200,000	1,746	Existing well

Source: NREL/CP-550-30275

Table 7-5 — Geothermal Binary Power Plant Capital Cost ($2000) – Summary

	Plant Cost ($/kW)	Field Cost ($/kW)	Well Cost ($/kW)	Total Cost ($/kW)
Empire, Nevada	2,089	256	0	2,585
Exergy/Americulture, New Mexico	2,600	185	30	3,370
Milgro-Newcastle, Nevada	2,495	165	333	3,400

Source: NREL/CP-550-30275

7.1.5 Operating and Maintenance Costs

The O&M cost will be about 1.4 ¢/kWh based on a plant load factor of 80% based on two small geothermal plants in New Mexico (see Table 7-6).

Table 7-6 — Geothermal Binary Power Plant O&M Cost ($2000)

Plant	Annual O&M Cost		Cost of Energy
	($/kW)	(¢/kWh)	(¢/kWh)
Empire, Nevada	$80	1.37	8.8
Exergy/AmeriCulture, New Mexico	$70	1.42	6.4
Milgro-Newcastle, Nevada	$30	0.54	6.2

Source: NREL/CP-550-30275.
Assumptions: Cost of Energy (COE) includes all costs (capital and O&M).
Plant Load Factor is 80%.

7.1.6 Cost of Energy

The cost of energy (COE) is between 6.2 and 10.5 ¢/kWh based on information from World Bank (Table 7-7). This is comparable with the 2000 study by NREL of the top eight locations (Gawlink and Kutscher) with a range of 7 to 9 ¢/kWh.

Table 7-7 — Geothermal Cost of Energy

	High Quality Resource ($/MWh)	Medium Quality Resource ($/MWh)	Low Quality Resource ($/MWh)
Small Plants (< 5 MW)	50 – 70	55 – 85	60 – 105
Medium Plants (5-30 MW)	40 – 60	45 – 70	Normally not suitable
Large Plants (> 30 MW)	25 – 50	40 – 60	Normally not suitable

Discount rate of 10% and capacity factor of 90% are assumed.
Source: World Bank

7.1.7 Water Usage

Binary geothermal technology requires approximately the same water resource as a conventional power plant. A closed-loop binary-cycle geothermal plant requires 1,300 to 1,500 gallons per minute (gpm) to generate 1 MW with a 300°F fluid temperature and air temperature of 60°F and 45 to 75 gpm of cooling tower make-up. The proposed 2.5 MW binary geothermal power plant at Bisti would require 8.8 to 10.3 acre-feet of water per day

(3,210 to 3,759 acre feet per year) at a plant load factor of 80% as shown in Table 7-8. Dry cooling will reduce the water usage to 8.5 to 9.8 acre-feet per day (3,103 to 3,580 acre-feet per year) but will result in capital costs about 3% to 6% higher and an 8% to 9% loss in plant performance.

Table 7-8 — Water Usage

	gpm per MW		gal per day		acre-ft per day		acre-ft per year	
	Min	Max	Min	Max	Min	Max	Min	Max
Closed Loop Cycle								
300°F fluid	450	600	958,776	1,278,367	2.94	3.92	1,074	1,432
210°F fluid	1,300	1,500	2,769,796	3,195,918	8.50	9.81	3,103	3,580
Cooling Tower Make-up	45	75	95,878	159,796	0.29	0.49	107	179
Total Flow Requirements								
300°F fluid			1,054,653	1,438,163	3.24	4.41	1,181	1,611
210°F fluid			2,865,673	3,355,714	8.79	10.30	3,210	3,759

Assumptions: Air Temperature = 60°F
Plant Capacity = 2.5 MW
Net Capacity = 1.85 MW
Plant Load Factor = 80%
1 acre foot = 325,851 gal

7.1.8 Conclusion

The geological information shows that all the known thermal wells and springs on the tribal lands are low to moderate temperature with the exception of one well in New Mexico near Bisti. The temperature for the low to moderate wells is not high enough to generate electricity. The well near Bisti could potentially support a binary power plant of at most 2.5 MW.

7.2 BIOMASS

Biomass power plants (biopower) use agricultural residues, residues from forestry and wood processing, and energy crops (fast growing trees) as fuel to power direct combustion and gasification. Biomass consists of plant material such as the following

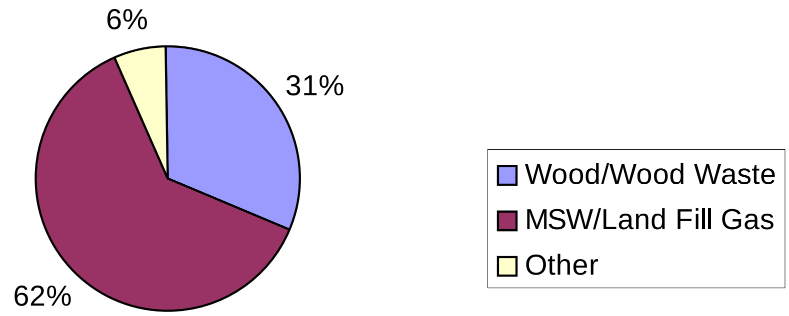
- Fast growing trees and grasses, like hybrid poplars or switchgrass
- Agricultural residues, like corn stover, rice straw, wheat straw or used vegetable oils

- Wood waste, such as sawdust and tree prunings, paper trash, and yard clippings.

Next to hydropower, more electricity is produced from biomass than any other renewable energy resource in the United States.

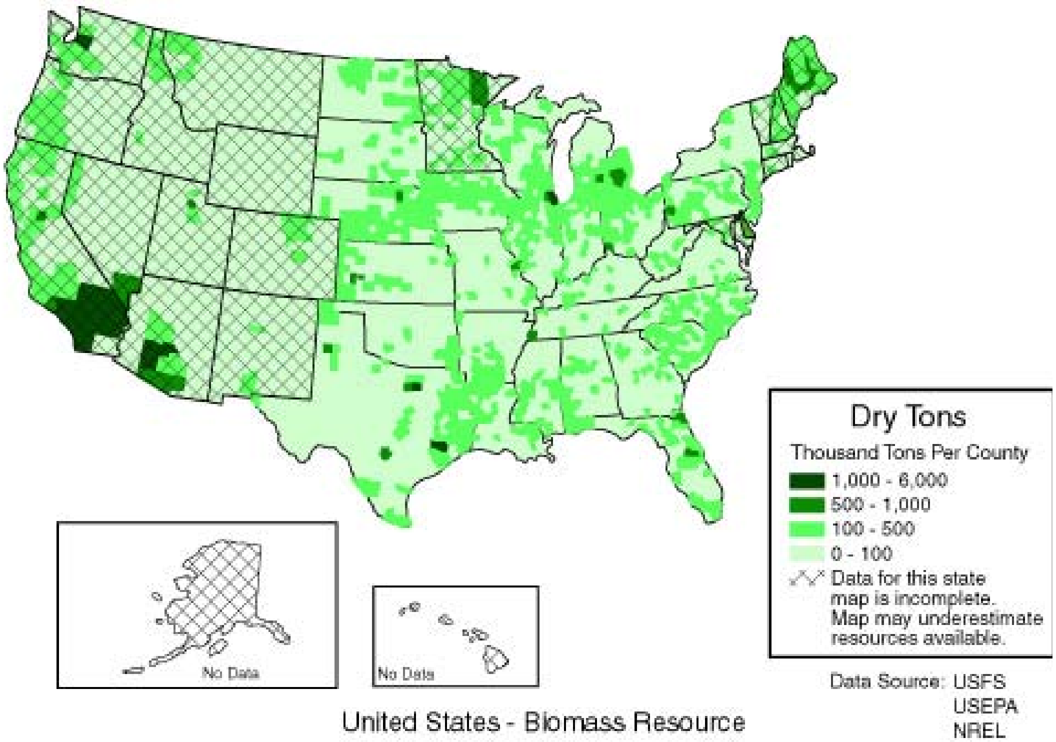
- U.S. generation of electricity from biomass is ~ 7,800 MW
- 60 million tons per year, most of which is clean wood and agricultural waste
- Approximately 80% is generated in the industrial sector, primarily in pulp and paper industry

Figure 7-7 — Biomass for Electric Generation[a]



(a) Electric utilities and Independent Power Producers
Source: DOE/EIA Renewable Energy Trends 2003 with Preliminary Data for 2003

Figure 7-8 — Biomass Resources in the United States



7.2.1 Technology

7.2.1.1 Direct Combustion

Most biopower facilities operating today are direct combustion power plants. The biomass product is burned in the boiler, which converts water to steam and drives a turbine generator. The process is the same as conventional coal-fired power plants. Virtually all biomass electric power plants use conventional boilers and steam turbines.

7.2.1.2 Gasification

The gasification process converts a solid biomass to a gas that can be burned in a combustion turbine, co-fired with coal or used in a fuel cell. This technology is still in the demonstration stage of development.

7.2.1.3 Co-Firing

Biomass can be co-fired with coal, displacing up to 15% of the coal feedstock.

7.2.2 Current Technology Status – Biomass

Biopower is a proven technology and a reliable source of production of electricity. There is about 10 GW of installed capacity: 7 GW from the forest and agricultural industry, 2.5 GW of municipal solid waste and 0.5 GW of other capacity (such as landfill gas). The net generation from biomass in the four-state area was 201,499 kWh, which is 2% of the total renewable generation as shown in Table 7-9.

Table 7-9 — Biomass Net Generation in the Four-State Area in 2002

	Wood/ Wood Waste (MWh)	Biomass MSW/ Landfill Gas (MWh)	Other Biomass (MWh)	Total (MWh)	Percent of Total Renewable
Arizona	0	49,604	91,456	141,060	1.9%
Colorado	0	0	29,834	29,834	2.2%
New Mexico	0	0	19,408	19,408	6.8%
Utah	0	11,197	0	11,197	1.6%
Total	0	60,801	140,698	201,499	2.0%

Source: DOE/EIA Renewable Energy Trends with Preliminary Data for 2003
MSW – Municipal Solid Waste
Other – Agriculture byproducts/crops, sludge waste, tires, and othe biomass solids, liquids, and gases

The largest traditional biomass capacity is from using wood or wood by-product. There are more than 500 such facilities in operation throughout the country. A group of 16 biomass power plants using wood products, industry leaders in North America, shows that the average net capacity is 43 MW, the largest plant is 79.5 MW, and the average net capacity factor is 68% as shown in Table 7-10.

Table 7-10 — Biomass Industry Leaders

Plant	Location	Online	Capacity	Capacity Factor
	State	Year	Mwe	%
Bay Front	Wisconsin	1979	30	62%
Kettle Falls	Washington	1983	46	82%
McNeil	Vermont	1984	50	35%
Shasta	Califorinia	1987	50	96%
Stratton	Maine	1989	45	90%
Tracy	Califorinia	1990	18.5	80%
Tacoma (co-fire)	Washington		12	27%
Colmac	Califorinia	1992	49	90%
Grayling	Michigan	1992	36.2	63%
Williams Lake	British Columbia	1993	60	106%
Multitrade	Viriginia	1994	79.5	19%
Ridge	Florida	1994	40	57%
Greenidge (co-fire)	New York	1994	10.8	80%
Camas (cogen)	Washington	1995	38	65%
Snohomish (cogen)	Washington	1996	43	60%
Okeelanta (cogen)	Florida	1997	74	70%
Total			682	
Average			43	68%

Source: NREL/SR-570-26946, Lessons Learned from Existing Biomass Power Plants.

All of this biomass capacity is from direct-combustion boiler/steam technology.

There is a large fuel supply throughout the United States, but there is a lack of infrastructure to obtain and transport the fuels. Princeton University research shows that of the total biomass available, only half can be economically used as fuel, with one-third from agricultural waste and two thirds from forestry product residue. For biomass to be economical as a fuel for generating electricity, the source needs to be close (less than 100 miles) to the point of use.

7.2.3 Potential Biomass Technology for the Mohave Study

Available information on biomass resources published by NREL and the State of Arizona was reviewed. The results of the study for the four-state area are shown in Appendix J.

7.2.3.1 Arizona

Arizona does not produce a large volume of agricultural crops of forest residue. Currently there is about 5 MW of electricity produced from landfill gas and animal waste. Generation potential estimated by the *Renewable Energy Atlas of the West* is 1 million MWh/yr.

7.2.3.2 New Mexico

New Mexico is arid and as such has less potential for agricultural and forest residue for production of fuels for biomass energy. Generation potential estimated by the *Renewable Energy Atlas of the West* is 1 million MWh/yr.

7.2.3.3 Utah

Utah is arid and as such has less potential for agricultural and forest residue for production of fuels for biomass energy. Generation potential estimated by the *Renewable Energy Atlas of the West* is 1 million MWh/yr.

7.2.3.4 Colorado

Colorado has significant agricultural crops, which could be used for biomass. The Colorado Office of Energy Management and Conservation is working on a demonstration project using methane produced by hog farms. Generation potential estimated by the *Renewable Energy Atlas of the West* is 4 million MWh/yr.

7.2.4 Capital Cost

The capital investment for biomass fueled direct fire combustion power plant is about $2,000 per kW installed as shown in Table 7-11. Oak Ridge National Laboratory estimates the same capital cost.

Table 7-11 — Wood Biomass Costs

Capacity	Fuel Use	Capital Cost			O&M Cost	
MW	green tpy	million $	$/kW$_{installed}$	$/kWh	million $	$/kWh
10	100,000	20	2,000	0.2854	2	0.0285
75	800,000	150	2,000	0.2854	15	0.0285

Source: USDA Techline Wood Biomass for Energy

Assumptions: Plant Load Factor 80%
Auxiliary Power Usage 4%
Plant Efficiency - 18 to 24%

7.2.5 Operating and Maintenance Costs: Biomass

O&M costs are presented in the table below:

Table 7-12 — Operating and Maintenance Costs

Plant Type	$/MWh
Typical coal-fired power plant	23
Cofiring biomass	21
Direct fire biomass power plant	52 to 67
Electricity from Landgas	29 to 36

Source: From Oregon Department of Energy

7.2.6 Water Usage: Biomass

Biopower technology requires approximately the same water resource as a conventional power plant. Using the average plant size of 20 MW, the approximate water usage would be as follows.

Table 7-13 — Approximate Plant Water Usage

	Gallons per year	Acre-ft per year
Rankine-cycle make-up	2,100,000 (demineralized)	6.44
Cooling Tower make-up	32,000,000	98.2

Dry cooling would eliminate the cooling tower make-up water usage but would result in capital costs approximately 3% to 6% higher and would result in an 8% to 9% loss in output.

7.2.7 Conclusion

Production of electricity in the quantities significant enough to be considered as part of a replacement of or complement to the existing Mohave plant from other renewable resources would require a feedstock of municipal solid waste and/or forestry residue.

Power generation from municipal solid waste requires a large source (population) and the ability to sort and provide combustible solid waste as a fuel source. The expansive area and lack of large population concentrations in tribal lands make this a complex option. However, municipal solid waste is not considered biomass. Biomass plants in the U.S. only use uncontaminated feedstock, which contains no toxic chemicals. Potentially hazardous materials (such as creosote-wood and batteries) would have to be removed from municipal solid waste at additional cost to be considered true biomass.

Tribal lands have large forests and the potential to support a forestry industry, but this is not a likely option in the near future. In the late 1950s, the Bureau of Indian Affairs and the Navajo Tribal Council created the Navajo Forest Products Industries (NFPI). From 1962 to 1992, NFPI cut and processed an average of 40 million boardfeet of lumber each year, creating thousands of jobs and tribal revenue. Unfortunately, this program was carried out with little concern for how these activities affected Navajo subsistence and the spiritual use of the forests. In the early 1990s an intra-tribal conflict arose over the use of the forests. This conflict resulted in closure of the sawmill in 1995.

Power generation from methane produced from animal waste is currently only in the demonstration stage and, as such, would not be considered as a proven reliable source of energy.

The use of fast-growing crops to provide fuel for biomass is in an early stage of development within the United States. Additional research is required to modify direct-firing equipment to burn the agricultural crops efficiently and meet environmental standards. Oak Ridge National Laboratory (ORNL) and INEEL scientists are working to gather experimental and operational data to validate the supply chain for fast-growing crops to overcome the technical barrier of lack of sustainable supply of biomass. Factors involving cost, environmental impact, social impact and economic impact are being researched.

Therefore, the potential for developing feedstock for a biomass power plant within tribal lands within the next few years of a size large enough to play a significant role in replacing or complementing lost generation from the Mohave Project is extremely low.

Last page of Section 7.

8. CO_2 SEQUESTRATION

8.1 OVERVIEW OF GEOLOGIC SEQUESTRATION OF CARBON

Carbon sequestration is the "capture and secure storage of carbon that would otherwise be emitted or remain in the atmosphere."[1] In this study, we reviewed geological methods of carbon sequestration, that is, the capture, transport and storage of carbon dioxide, produced by power plants and other point sources, in underground formations. Carbon dioxide may also be sequestered by pumping it to the deep ocean floor or by improving upon natural processes that sequester carbon dioxide, e.g., forestation projects. While these methods for carbon sequestration may be technologically and economically feasible, they are beyond the scope of this report. However, we do explore five types of geologic sequestration: enhanced oil recovery, enhanced gas recovery, sequestration in unminable coal seams, sequestration in deep saline aquifers, and sequestration in natural CO_2 domes.

8.1.1 Enhanced Oil Recovery Using Carbon Dioxide

Enhanced oil recovery (EOR) using carbon dioxide (CO_2-EOR) involves the injection of carbon dioxide in order to improve pressure in the reservoir and, thereby, the flow of oil.[2] There are approximately 74 CO_2-EOR projects worldwide.[3] Most of these are in the United States, in the Permian Basin of West Texas and southeastern New Mexico.

While domestic production of oil is approximately 6 million barrels per day, less than 700,000 barrels per day are currently produced using enhanced oil recovery. Approximately half of these barrels were produced via CO_2-EOR, primarily using CO_2 pumped from natural CO_2 domes in the Southwest. Tertiary EOR techniques,[4] such as CO_2-EOR, could increase the percentage of original oil in place (OOIP) that is ultimately recovered from 10% under primary recovery to 30 to 60%.[5]

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[1] Herzog, Howard and Dan Golomb, 2004. "Carbon Capture and Storage from Fossil Fuel Use," in C.J. Cleveland (ed.), *Encyclopedia of Energy*, Elsevier Science Inc., New York, pp 277-287, 2004. Available at http://sequestration.mit.edu/pdf/enclyclopedia_of_energy_article.pdf.

[2] Schlumberger Oilfield Glossary, 2005. Available at http://www.glossary.oilfield.slb.com/Display.cfm?Term=enhanced%20oil%20recovery.

[3] Baker, Richard, 2004. "What is Important in the Reservoir for CO_2 EOR/EGR and Sequestration?" For *APEGGA Annual Conference on GHG Opportunities: Small and Large Technologies*, April 22-24, 2004. Available at http://www.apegga.org/Members/ProfDev/Presentations/Baker.ppt.

[4] Primary oil recovery is the recovery of oil without aid of a drive fluid such as water or gas. Secondary oil recovery involves the injection of gas or water to produce oil. Tertiary oil recovery techniques stimulate flow of oil that was not extracted during the primary or secondary phases of recovery using other gases (such as carbon dioxide), steam or chemicals.

[5] U.S. DOE, "Enhanced Oil Recovery/CO_2 Injection, 2005. Available at http://www.fe.doe.gov/programs/oilgas/eor/.

While the technology for enhanced oil recovery using CO_2 is commercial, most CO_2-EOR projects are not intended to sequester carbon dioxide and as such perform a "blowing down" of the reservoir during decommissioning. Blow down, which releases some of the pressure in the reservoir by releasing some of the CO_2 injected over the life of the project, is intended to maximize oil recovery and recover CO_2 gas that is recycled for use in another CO_2-EOR project. As such, CO_2-EOR projects, as they are implemented currently, do not provide permanent sequestration of CO_2.

Current CO_2-EOR technology is divided into miscible and immiscible technologies. Two liquids are said to be "miscible" if they can be mixed together. Under miscible CO_2-EOR, the CO_2 is injected at high pressure and at such a temperature that it forms a supercritical fluid. Miscible CO_2-EOR is the most widely used CO_2-EOR technology and is more appropriate for recovery of light oil. Immiscible CO_2-EOR, while less common, can be used to recover heavy oils.[6]

The Weyburn CO_2-EOR project in Saskatchewan, Canada is one of a few CO_2-EOR projects using an anthropogenic source of carbon dioxide and is the only one specifically designed to monitor the reservoir's ability to store carbon dioxide. As such, no blow down phase is planned for Weyburn. Unless they were also designed for carbon sequestration, it is unlikely that future CO_2-EOR projects would similarly *not* have a blow down phase.

Weyburn purchases CO_2 from a coal gasification plant in Beulah, North Dakota. The project has been in operation since September 2000. As of February 2004, 98 billion cubic feet of CO_2 had been injected into Weyburn and approximately 5,500 metric tons (tonnes) of CO_2 per day was purchased. The gas injected into Weyburn is 95% pure carbon dioxide. Resulting incremental production is estimated to be 7,000 to 9,000 bbl/day over normal unit production of 22,400 bbl/day.[7]

While 5 years is, geologically-speaking, a very short time to determine the risk of CO_2 migration, the risk assessment modeling performed to date predicts that there may be limited migration of CO_2 from the reservoir to

[6] For more on how miscible and immiscible CO_2-EOR technologies work see Section 3 of "Basin Oriented Strategies for CO_2Enhanced Oil Recovery: Onshore California Oil Basins." Prepared by Advanced Resources International, Inc. for the U.S. Department of Energy, March 2005. Available at http://www.fe.doe.gov/programs/oilgas/publications/eor_co2/California_CO2-EOR_Report_web.pdf.

[7] Petroleum Technology Research Centre, "History/Background." Available at http://www.ptrc.ca/access/DesktopDefault.aspx?tabindex=0&tabid=111.

surrounding geologic formations, but no leaks to the surface.[8] The modeling was performed to predict storage performance over the 5,000 years following the end of the EOR project.

8.1.2 Carbon Sequestration with Enhanced Gas Recovery

Carbon dioxide could also be used in enhanced gas recovery (CSEGR) projects. While still a theoretical undertaking, it is thought that CO_2 injected at a well some distance from the gas-producing well will cause increased production of natural gas. CSEGR is untested because of the cost of CO_2 and because there is a concern that the CO_2 will rapidly mix with the natural gas, degrading the resource. Nonetheless, CSEGR is a natural option for carbon sequestration, since the formations in which natural gas is held are proven to have sequestered a gas for many years. Indeed, both depleted oil and gas reservoirs could store carbon dioxide regardless of whether such storage revives hydrocarbon production.

8.1.3 Enhanced Coal Bed Methane Recovery

Similarly, carbon dioxide could be stored in unminable coal seams. It is common knowledge that methane can be found in coal seams. The production of coal bed methane, while still less common than traditional sources of methane, is a growing source of natural gas. Enhanced coal bed methane recovery using carbon dioxide (ECBM) is being explored through existing R&D projects such as COAL-SEQ, which are experimenting with the injection of CO_2 into these seams for long-term storage and enhanced recovery of methane.[9] A unique aspect of the COAL-SEQ project is that injection of CO_2 is accompanied by N_2, a primary component of power plant flue gases. If both gases can successfully displace methane, it may no longer be necessary to separate the CO_2 from the flue gas, lowering the overall cost of sequestration.

8.1.4 Sequestration in Deep Saline Aquifers

Carbon dioxide may also be sequestered in deep saline aquifers. Saline aquifers are porous sandstone or sand formations sealed by low permeability rock formations. The geology of individual saline aquifers is likely to be less well understood, since they are not employed in the production of commodities such as gas and oil. However, saline aquifers have been used as storage for natural gas to accommodate seasonal changes in demand, and the technology does exist to evaluate saline aquifers for this purpose.

[8] Petroleum Technology Research Centre, "Results." Available at http://www.ptrc.ca/access/DesktopDefault.aspx?tabindex=0&tabid=115.

[9] More information on COAL-SEQ is available at http://www.coal-seq.com/Proceedings2004/ProjectFactSheet.pdf.

The world's first commercial-scale carbon sequestration project in a saline aquifer has been operating successfully since 1996.[10] Statoil, the Norwegian owner of the Sleipner natural gas field, decided to invest in the project because of the high cost of carbon dioxide emissions; Norway had imposed a tax of about $40/tonne in the 1990s. The natural gas coming from the field contains more CO_2 than is allowed under commercial and pipeline specifications and as such must be removed before transport, so Statoil was faced with the prospect of paying the tax for the release of these CO_2 emissions. The CO_2 is captured from the natural gas and injected into the Utsira formation, a vast aquifer of sand and salt water.[11]

8.1.5 Sequestration in Natural CO_2 Domes

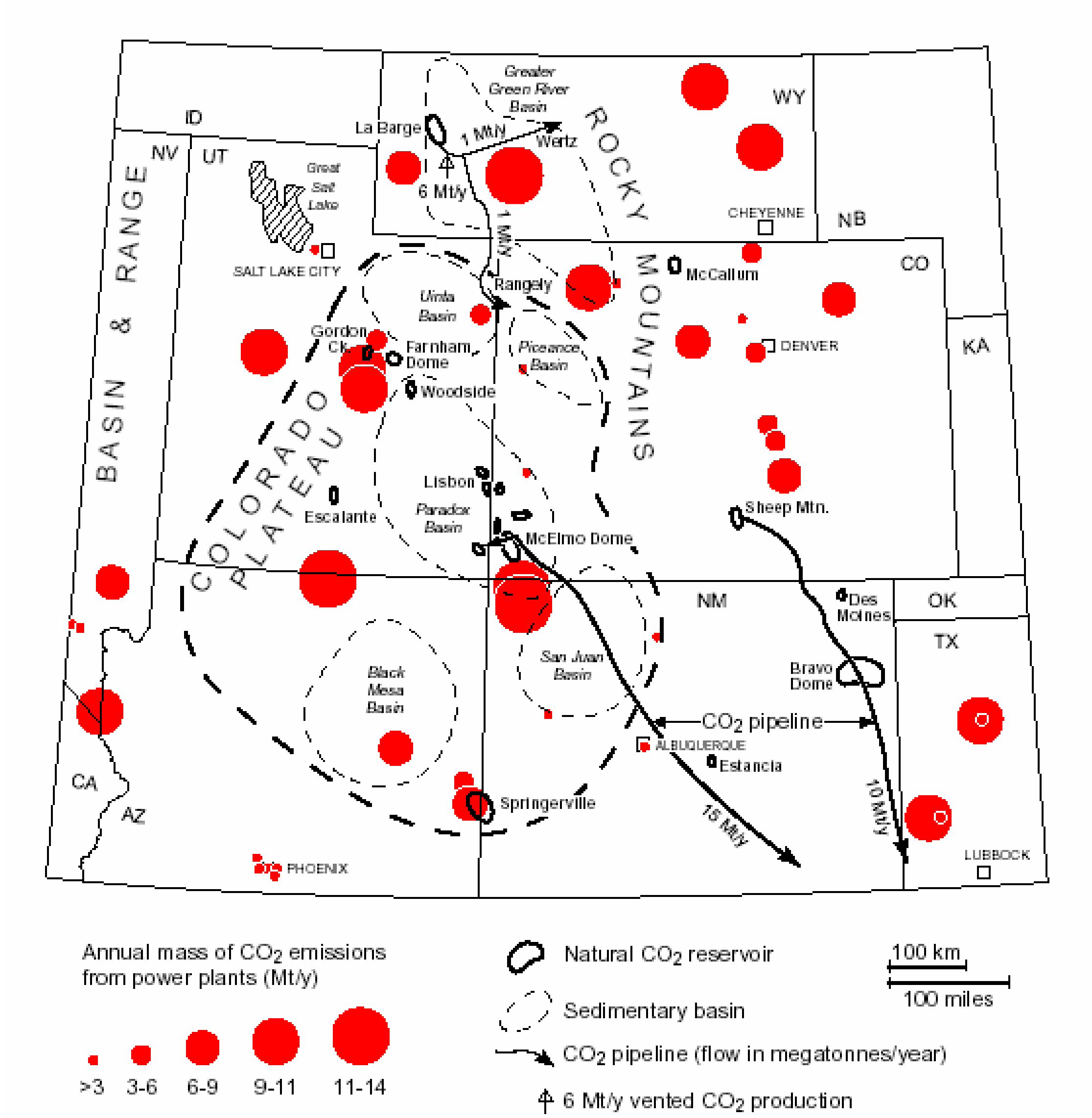
Natural CO_2 domes or reservoirs are an obvious analog for carbon sequestration. These domes have proven their ability to store CO_2 gas over long periods of time. Previously, these reservoirs were the lowest cost source for CO_2 for industrial uses such as enhanced oil recovery and dry ice. Now they are being examined as possible candidates for CO_2 storage themselves.[12] A study led by the Utah Geological Survey (UGS) and funded by the DOE, suggests that CO_2 from coal-fired power plants could replace the CO_2 already extracted from the natural domes. Figure 8-1 shows the relative concentration of CO_2 emissions from coal-fired power plants along with the CO_2 domes that have been in production.

[10] Torp, Tore A. and Ken R. Brown, 2004. "CO_2 Underground Storage Costs as Experienced at Sleipner and Weyburn." *Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies*, September 5-9, 2004. Available at http://uregina.ca/ghgt7/PDF/papers/peer/436.pdf.

[11] Torp, Tore A. and Ken R. Brown. 2004.

[12] Allis, R., et al. "Natural CO_2 Reservoirs on the Colorado Plateau and Southern Rocky Mountains: Candidates for CO_2 Sequestration," 2001, *Proceedings of the First National Conference on Carbon Sequestration*, Washington DC, May 2001, pp. 19. Available at http://geology.utah.gov/emp/co2sequest/pdf/reservoirs.pdf.

Figure 8-1 — Natural CO_2 Domes, Carbon Emissions from Power Plants, and CO_2 Pipelines



Source: Allis, R., et al.,2001.

If a 1,000 MW coal-fired power plant emits 9 million tonnes per year of CO_2, then, UGS estimates, "the volume of CO_2 at standard temperature and pressure after 20 years is 3.6 Tcf." This is similar to the quantity of CO_2 withdrawn from the McElmo dome for the period 1982–2001. While it appears technically feasible, it is not clear under what circumstances the owners of these domes, e.g., Kinder Morgan, would be willing to accept CO_2 rather than sell it.

8.1.6 Industrial Uses for CO_2

Finally, there are many uses for carbon dioxide in industry, for example, in the production of dry ice, as a refrigerant, for carbonation of beverages, as a compressed gas or in fire extinguishers. However, none of these uses requires significant amounts of CO_2 and, ultimately, do not provide long-term sequestration of CO_2.

8.2 FEASIBILITY OF GEOLOGICAL CARBON SEQUESTRATION

While the sequestration of carbon can be motivated by the economic benefits of enhanced hydrocarbon production (oil and gas), the primary motivator for the advancement of the technology is the expectation that anthropogenic carbon dioxide emissions will have to be controlled in order to mitigate global climate change. International scientific consensus holds that the world is warming, the climate system is changing, and that most of the warming observed over the past 50 years is due to human activities (primarily fossil fuel combustion).[13] Increasingly, there is interest in climate mitigation activities such as carbon sequestration.

While carbon sequestration will not be the sole solution to climate change, the worldwide capacity for storing carbon is predicted to be substantial. Worldwide capacity for geological sequestration of carbon is outlined in Table 8-1.

Table 8-1 — Worldwide Capacity for Geologic Carbon Sequestration

Sequestration Option	Capacity[a,b]	
	CO_2 (gigatonnes)	Carbon (gigatonnes)
Depleted oil and gas reservoirs	360 – 3,600	100 – 1,000
Deep saline formations	360 – 36,000	100 – 10,000
Coal seams	36 – 360	10 – 100

Source: Adapted from Herzog, Howard and Dan Golomb, 2004. “Carbon Capture and Storage from Fossil Fuel Use.” *Encyclopedia of Energy*, 2004. Available at http://sequestration.mit.edu/pdf/enclyclopedia_of_energy_article.pdf.

a Worldwide anthropogenic carbon emissions are approximately 7 gigatonnes C per year

b Orders of magnitude estimates

Domestic capacity in the United States is shown in Table 8-2.

[13] Y. Ding, J.T. Houghton, et al. editors, 2001. Climate Change 2001: The Scientific Basis (Contribution of Working Group I to the Third Assessment Report of the IPCC). Intergovernmental Panel on Climate Change. 2001. Available at: http://www.grida.no/climate/ipcc_tar/wg1/index.htm

Table 8-2 — Domestic Storage Capacity for Carbon Dioxide

Sequestration Option	Capacity[a]	
	CO_2 (million tonnes)	Carbon (million tonnes)
Depleting Oil Reservoirs	50,000	15,000
Depleting Gas Reservoirs	100,000	30,000
Unmineable Coal Beds	50,000	15,000
Saline Aquifers	Large	Large

Source: Beecy, David, 2003. "Recent Developments in Carbon Management at DOE." From *Proceedings of COAL-SEQ II*, Washington D.C. 2003. Available at http://www.coal-seq.com/Proceedings2003/Beecy.pdf.

a. U.S. anthropogenic carbon emissions are approximately 1,600 million tonnes C per year.

Saline aquifers have a very large potential carbon dioxide storage capacity; however, these formations tend to be less well characterized because they are not generally employed for industrial or commercial uses.

The geologic feasibility of carbon sequestration through EOR at the Bakersfield oil fields, for emissions from a plant at the existing Mohave site, and through sequestration in natural formations for a plant located near the Black Mesa mine, respectively are treated in Appendix C.

8.3 POLICY AND LIABILITY BARRIERS TO CARBON SEQUESTRATION

Both technological and policy barriers confront the widespread application of carbon sequestration. First, the cost of capture technologies, compression and transport to the sequestration site is significant.[14] Specifically, the removal of carbon dioxide from flue gas streams or before combustion during the gasification process exacts an "energy penalty" that creates a cost in addition to the capital and operating costs associated with the capture and transport infrastructure. In some cases, i.e. for enhanced oil and gas recovery, that cost can be made up, in whole or in part, by selling the carbon dioxide. In general, however, widespread deployment of carbon sequestration will need to be motivated by a governmental policy. Greenhouse gas regulation that allows for offsets from carbon sequestration is the most logical policy. Projections of the prices of such offsets are provided in Appendix D.

[14] This discussion assumes that the source of carbon dioxide will be from an industrial facility such as an IGCC coal plant or a coal gasification facility. This discussion makes no judgment as to whether an electrical generating station is more economic than an on-site coal gasification plant at the Black Mesa mine, but simply recognizes that both options have the technical potential to capture and sequester their carbon dioxide emissions.

Second, carbon sequestration faces liability issues. Figueiredo, et al.,[15] terms these liabilities: operational liability, climate liability and *in situ* liability. Operational liability applies to the potential risks associated with the transport of carbon dioxide to the sequestration site. These are the risks of a well or pipeline failure and are quite familiar to the gas and oil industry. Because carbon dioxide is non-toxic and non-flammable, leaks from a CO_2 pipeline present less public and environmental health issues than leaks from a natural gas or oil pipeline. The risk posed by CO_2 leaks is that the gas will not be able to diffuse to a concentration that is breathable, causing asphyxiation. Such a situation could occur in depressions or bowls since CO_2 is heavier than air.

Climate liability will be an issue if regulations are in place to control greenhouse gases, and as such, a penalty is associated with the release of carbon dioxide. If geologic sequestration is an eligible method to reduce carbon dioxide emissions, there would be a certain level of risk and associated liability arising from leaks, whether during transport or because the injection well does not properly function.

Furthermore, *in situ* liability is associated with the actual storage of carbon dioxide. As mentioned above, at high enough concentrations, carbon dioxide can cause asphyxiation. While the probability that such a situation would occur is small, it is a risk that must be considered when designing carbon sequestration sites. Another example of *in situ* risk is the possibility that leakage of carbon dioxide could lead to "soil acidification or suppression of respiration in the root zone."[16] The risk that carbon dioxide would contaminate drinking water is very slight. Formations used for carbon sequestration are at depths far below those of most drinking water aquifers and, in the case of hydrocarbon reservoirs, would probably have already contaminated the water source if there were a connection between the reservoir and the aquifer.

Since few, if any, states have an existing and clear regulatory framework to govern carbon sequestration, there is some concern that this uncertainty will limit carbon sequestration projects. There is, however, the possibility that an insurance solution will be available to tackle this issue.[17] Requests for more information were not answered, but it appears that Swiss Re, the world's largest reinsurance company, has expressed interest in developing an insurance product specifically for carbon sequestration projects. Though the details are not available, such a product could potentially resolve many, if not all, of these liability issues.

[15] de Figueiredo, M.A., D.M. Reiner and H.J. Herzog, 2005. "Framing the Long-Term In Situ Liability Issue for Geologic Carbon Storage in the United States." Accepted by *Mitigation and Adaptation Strategies for Global Change*, 2005. Available at http://sequestration.mit.edu/pdf/Liability_Issue.pdf.

[16] de Figueiredo, M.A., D.M. Reiner and H.J. Herzog, 2005.

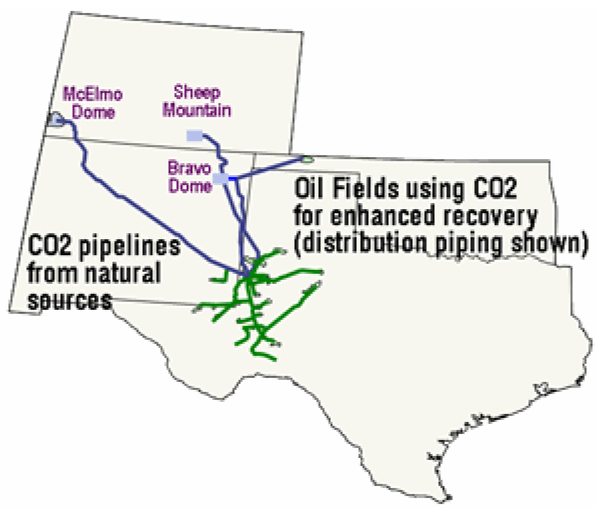
[17] Presentation by Ian Duncan, Ph.D of the Texas Bureau of Economic Geology at the 2005 Gasification Technologies Conference in San Francisco, California on October 11, 2005.

8.4 ECONOMICS OF CARBON SEQUESTRATION

8.4.1 Market for CO_2 Gas in Enhanced Oil Recovery

There is already an existing market for CO_2 gas (as opposed to the Kyoto-inspired emissions allowances). The CO_2 market is largely concentrated in West Texas. A series of pipelines from natural CO_2 domes in Colorado and New Mexico carries CO_2 to West Texas for use in enhanced oil recovery. Figure 8-2 below shows this infrastructure.

Figure 8-2 — Existing CO_2 Pipelines and Sources



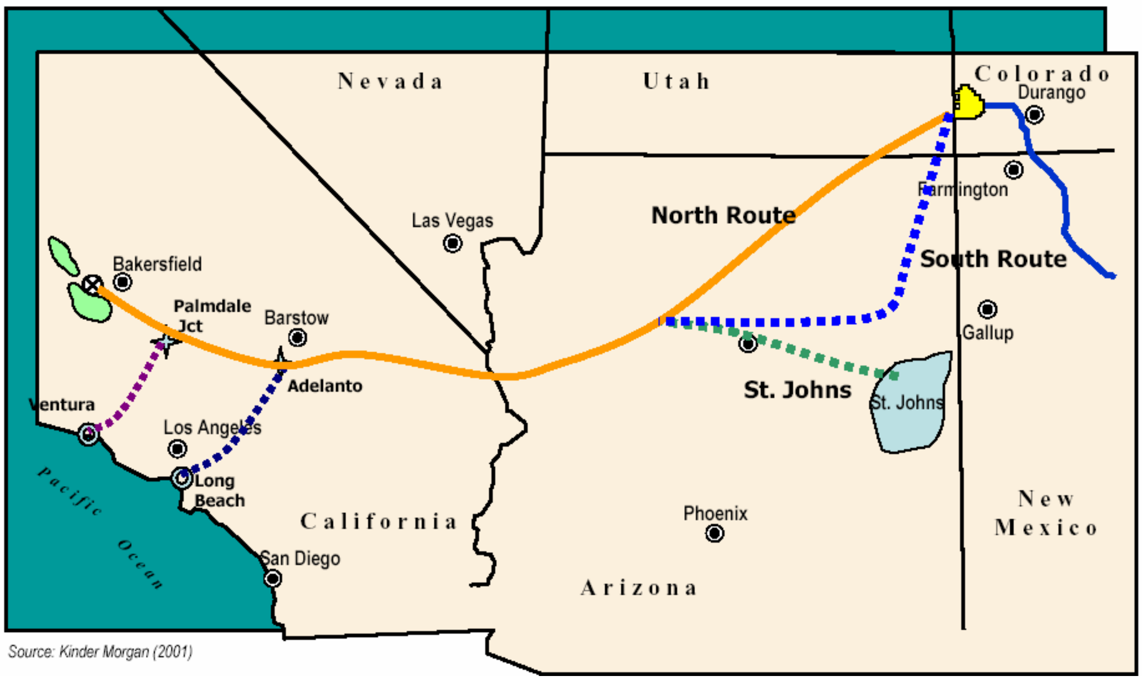
Source: WESTCARB, http://www.westcarb.org/transport.htm

As recently as 2002,[18] Kinder Morgan CO_2 Company and Ridgeway Petroleum were discussing the possibility of developing a 600-mile pipeline to California to serve demand for CO_2 in the state (a possible route for the pipeline is shown in Figure 8-3). Kinder Morgan is the owner of the McElmo CO_2 dome, shown just west of Durango, Colorado, in Figure 8-3, and Ridgeway Petroleum owns the St. Johns formation in Arizona. No information on more recent developments on the pipeline is available. The owners confront a number of large obstacles in building the pipeline. The first is the length and mountainous terrain over which the pipeline must travel. The second is the relative uncertainty regarding the market for CO_2 in California. Limited information is available on the price of CO_2 gas that could be expected in California. The most recent CO_2-EOR project in

[18] Billingsley, Eric, 2002. "CO_2 Project Brewing in Western New Mexico." *New Mexico Business Weekly*, 27 December 2002.

California at the Lost Hills reservoir trucked CO_2 gas over 120 miles at a cost of about \$3.50/Mcf[19] or over \$61/ton, but other, local sources could potentially provide CO_2 at a cheaper price. Calls to Ridgeway and Kinder Morgan requesting an update on the status of the pipeline were not returned and there is some indication that it will not be built because refineries in the Los Angeles area can provide CO_2 at a lower cost.[20]

Figure 8-3 — Proposed CO_2 Pipeline to Bakersfield, California



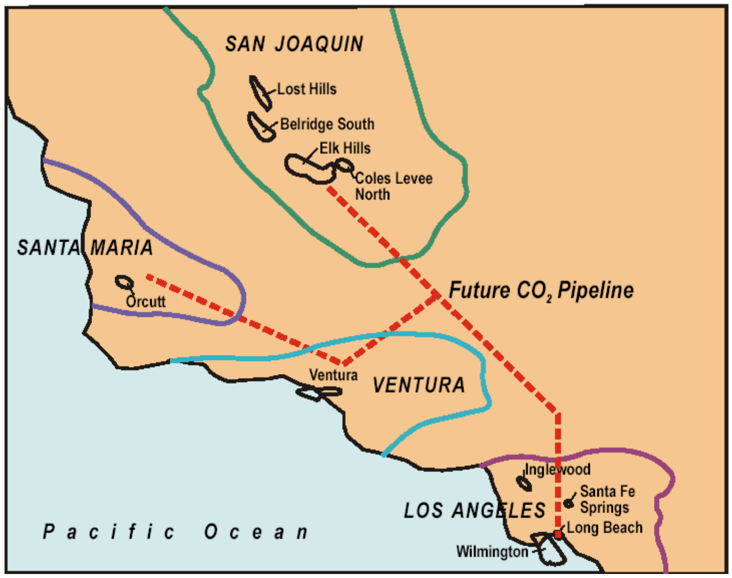
The ability of the Mohave Generating Station to access the pipeline, should it be built, in order to sell its own CO_2 (assuming it installs a capture system) will be determined not just by the cost to access the pipeline, but also by the willingness of Kinder Morgan and Ridgeway to allow other parties to use the pipeline. That degree of willingness is currently an unknown.

The potential market for CO_2 gas in California is thought to be significant because of the potential for CO_2 -EOR in California's onshore oil fields. The major onshore basins and oil fields are shown in Figure 8-4, along with a conceptual pipeline route to bring CO_2 from the hydrogen plants at the oil refinery complex at the Wilmington Oil field.

[19] Ruether, John, et al., 2002. "Gasification-based Power Generation with CO_2 Production for Enhanced Oil Recovery." For the *2002 Pittsburgh Coal Conference.* Available at http://www.netl.doe.gov/coal/gasification/pubs/pdf/35.pdf.

[20] Personal Communication with Julio Friedmann, Lawrence Livermore National Laboratory. October 12, 2005.

Figure 8-4 — California On-Shore Basins and Reservoirs



Source: Taken from Advanced Resources International, 2005. "Basin Oriented Strategies for CO2 Enhanced Oil Recovery: Onshore California Oil Basins." Prepared by Advanced Resources International, Inc. (ARI) for the U.S. Department of Energy, March 2005. Available at http://www.fe.doe.gov/programs/oilgas/publications/eor_co2/California_CO2-EOR_Report_web.pdf.

In the past, some CO_2 injection at California oil fields has occurred, primarily during the 1980s, but current CO_2 -EOR activities in California are virtually non-existent, largely because of a lack of CO_2 supply.[21]

California is the fourth largest oil-producing state in the nation, behind Louisiana, Texas, and Alaska, respectively.[22] Advanced Resources International recently published a study evaluating the potential to recover California's "stranded oil" through CO_2-EOR. California's onshore oil reservoirs originally held 83 billion barrels (Original Oil in Place or OOIP). To date, 26 billion barrels have been recovered or proved.[23] This leaves 57 billion barrels of oil stranded (Remaining Oil in Place or ROIP). Table 8-3 shows the ROIP amenable to CO_2-EOR.

[21] Advanced Resources International, 2005.

[22] Advanced Resources International, 2005.

[23] Advanced Resources International, 2005.

Table 8-3 — Stranded Oil Amenable to CO_2 -EOR in California

Basin	Number of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves (Billion Bbls)	ROIP (Billion Bbls)
San Joaquin	29	11.9	3.8	8.1
Los Angeles	36	14.1	4.2	9.9
Coastal	23	5.9	1.8	4.1
Total	88	31.9	9.8	22.1

Source: Advanced Resources International, 2005.

The economically recoverable oil resource using miscible CO_2-EOR, Table 8-4, is much lower. It is limited to 50 million barrels in just the San Joaquin Basin; the basin that incorporates the Bakersfield area. These estimates were developed assuming an oil price of $25 per barrel, a CO_2 cost of 5% of the oil price and a rate of return (ROR) hurdle rate of 25% (before tax).

Table 8-4 — Economically Recoverable Resources Using Miscible CO_2-EOR

Basin	Number of Reservoirs	OOIP (Million Bbls)	Technically Recoverable (Million Bbls)	Economically Recoverable (Million Bbls)
San Joaquin	24	8,900	860	50
Los Angeles	15	7,830	470	—
Coastal	20	4,690	450	—
Total	59	21,420	1,780	50

Clearly, the price of oil, as it refers to the price of West Texas Intermediate (WTI), a light, sweet crude, is much higher than the price of oil used in the Advanced Resources International (ARI) study. As of September 21, 2005, WTI crude oil futures were trading at over $60 per barrel on NYMEX through 2011. WTI oil can be expected to trade at a slight premium to other, less-desirable light oils and to heavy crudes found in California reservoirs, though these crudes are still trading at prices much higher than $25/barrel. Though it is not feasible to re-do ARI's analysis for this study, as a general trend, higher oil prices would be expected to make more CO_2-EOR projects economically feasible.

Under alternative scenarios outlined below in Table 8-5, additional oil resources would become economically recoverable, including oil in the Los Angeles and Coastal Basins.

Table 8-5 — Additional Recoverable Resources under Various Scenarios

Basin	Scenario 2: "State of the Art"[a] (Million Bbls)	Scenario 3: "Risk Mitigation"[b] (Million Bbls)	Scenario 4: "Ample Supplies of CO_2"[c] (million Bbls)
San Joaquin	1,060	1,380	1,780
Los Angeles	700	1,290	1,370
Coastal	70	830	830
Total	1,830	3,500	3,980

a. Scenario assumes oil price of $25 per barrel, a CO_2 cost of 5% of the oil price, and an ROR hurdle rate of 15% (before tax).

b. Scenario assumes oil price of $35 per barrel, a CO_2 cost of 5% of the oil price, and an ROR hurdle rate of 15% (before tax).

c. Scenario assumes oil price of $35 per barrel, a CO_2 cost of 2% of the oil price, and an ROR hurdle rate of 15% (before tax).

The "State of the Art" scenario assumes use of miscible CO_2-EOR technology at deep, light oil reservoirs, immiscible CO_2-EOR at deep, heavy oil reservoirs and much higher volumes of CO_2 injection over what is traditionally injected. A total of 1,830 million barrels are recoverable in this scenario.

The "Risk Mitigation" scenario assumes an increase "in the EOR investment tax credit, reduced State production taxes and Federal and State royalty relief (for projects on Federal and State lands)" providing an equivalent increase in the price of oil of $10 per barrel. A total of 3,500 million barrels are recoverable under this scenario. Any other change that led to a similar price increase could be expected to have the same effect.

The "Ample Supplies of CO_2" scenario assumes a generous supply of EOR-ready CO_2 at a lower cost. A total of 3,980 million barrels are recoverable under this scenario.

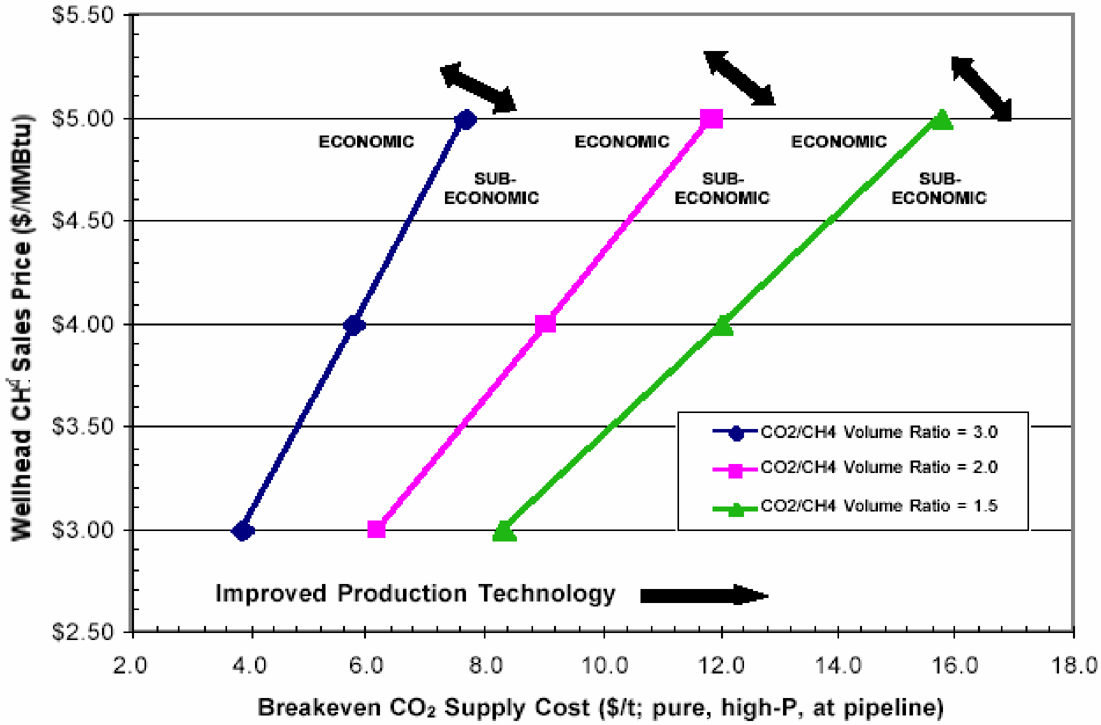
The volumes of CO_2 needed to recover these barrels are significant. ARI projects that the market for CO_2 in California could reach 18 Tcf, plus 40+ Tcf of recycled CO_2. Over 1 billion tons of CO_2 could potentially be stored.[24] As a matter of practicality, however, CO_2-EOR will only occur if the CO_2 supply to the point of use is economical. At this point, is it is not possible to conclude that the provision of CO_2 from power plants outside of California, such as Mohave, would be economical. As noted above, it is quite possible that CO_2 would be more economically provided from hydrogen plants at the Wilmington Oil field.

[24] Advanced Resources International, 2005.

8.4.2 Market for CO_2 Gas in Enhanced Gas Recovery

Despite its theoretical status, there has been some effort to evaluate the economics of carbon sequestration for enhanced gas recovery (CSEGR).[25] The analysis by Oldenburg, et al., found that CSEGR could be economical at a CO_2 cost of \$10/ton, a cost comparable to that of natural CO_2, but below the costs of capture from power plants.[26] This analysis was performed without consideration for the effect that a climate change policy would have on this decision-making, which one would expect to positively affect the decision to pursue CSEGR using anthropogenic carbon dioxide.

Figure 8-5 — Economic Analysis of CSEGR at California Depleting Gas Field



Source: Ernest Orlando Lawrence Berkeley National Laboratory, 2004.

The analysis performed was specific to the Rio Vista gas field in California, but the same dynamics could be expected at other gas fields; that is, that the results were highly dependent on the cost of CO_2, the cost of natural gas, and the ratio of CO_2 injected to natural gas produced. Logically, higher gas prices mean that operators can

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[25] Oldenburg, C.M., S.H. Stevens and S.M. Benson, 2003. "Economic Feasibility of Carbon Sequestration with Enhanced Gas Recovery (CSEGR)." Berkeley Lab Report LBNL-49762, 2003. Available at http://www-esd.lbl.gov/GEOSEQ/pdf/oldenburg_etal138.pdf.

tolerate higher CO_2 costs, as Figure 8-5 demonstrates. As with oil prices, higher natural gas prices would tend to make more CSEGR projects economically feasible. As of September 21, 2005, Henry Hub NYMEX natural gas futures were trading at or above $7/mmBtu through the end of 2010 (note that the wellhead price in Figure 8-5 is shown, not the Henry Hub price).

8.5 CAPITAL COSTS ASSOCIATED WITH GENERATION ALTERNATIVES

Capital costs were developed for the 282.5-mile pipeline from the existing Mohave site to the Bakersfield area. The results of these analyses are shown in the following tables:

Table 8-6 — CO_2 Pipeline and Compression Costs for Mohave Site

		IGCC CO_2 Removal without Shift Conversion	IGCC 90% CO_2 Removal	NGCC 90% CO_2 Removal*
Corresponding Plant Net Output	MW	522.9	473.6	423
CO2 Removal Rate	ton/hr	155	490	185
Pipeline Nominal Diameter	inches	14	18	14
Pipeline and Compression Cost	$ millions (2006)	370.8	542.2	370.8
	$/kW	709.1	1,144.8	876.6

* Pipeline costs are assumed equal for the IGCC CO2 Removal without Shift Conversion and the NGCC 90% CO2 Removal since pipeline diameters are equal and the increased flow would be handled by a slight increase in compressor size. Total compressor cost is less than 3% of the pipeline cost.

A suitable deep saline aquifer site for an IGCC plant at the Black Mesa mine site is identified in Appendix C at a distance of approximately 45 miles south of the mine site. The capital costs estimated for the Mohave site were adapted to estimate the cost for a pipeline of this length. The results of this estimate are as follows:

[26] Ernest Orlando Lawrence Berkeley National Laboratory, 2004. "GEO-SEQ Best Practices Manual, Geologic Carbon Dioxide Sequestration: Site Evaluation to Implementation." September 30, 2004. Available at http://www.netl.doe.gov/coal/Carbon%20Sequestration/pubs/GEO-SEQ_BestPract_Rev1-1.pdf

Table 8-7 — CO_2 Pipeline and Compression Costs for Black Mesa Site

		IGCC CO_2 Removal without Shift Conversion	IGCC 90% CO_2 Removal
Corresponding Plant Net Output	MW	537.1	483.9
CO2 Removal Rate	ton/hr	155	490
Pipeline Nominal Diameter	inches	14	18
Pipeline and Compression Cost	$ millions (2006)	49.2	86.4
	$/kW	91.6	178.5

A natural gas-fired combined-cycle (NGCC) plant was not contemplated at the Black Mesa site.

It can be seen that pipeline costs are very high, indicating that, economically, their use can likely be justified only if they can generate a rate of return from the product shipped. However, the proximity of the sequestration location to the Black Mesa mine reduces pipeline costs significantly.

8.6 PERMITTING ISSUES

The installation of a new CO_2 pipelines from the Mohave site to Bakersfield, California or from the Black Mesa site to a sequestration site will entail a number of permits and approvals before the start of construction.

- **Environmental Impact Statement.** Since the pipelines will cover at least two adjacent states and may need to traverse federal lands, and Environmental Impact Statement (EIS) will most likely be necessary. The National Environmental Policy Act (NEPA) requires an EIS for all such projects that have a federal scope. An EIS is a full disclosure document that details the process through which a project was developed, includes consideration of a range of reasonable alternatives, analyzes the potential impacts resulting from the alternatives, and demonstrates compliance with other applicable environmental laws and executive orders. The EIS process in completed in the following ordered steps: Notice of Intent (NOI), draft EIS, final EIS, and record of decision (ROD). A properly prepared EIS will include the following sections:
  - **Purpose and Need.** The Purpose and Need Section of an EIS is one of the most important. The purpose and need discussion drives the development of the range of alternatives. This section will need to demonstrate that utilizing CO_2 gas for oil field recovery and CO_2 sequestration are the best uses of the gas. The environmental benefit of sequestration over emission of the greenhouse gas must be shown.
  - **Alternatives.** The Alternatives Section describes the process that was used to develop, evaluate, and eliminate potential alternatives based on the purpose and need of the project. The discussion should include how alternatives were selected for detailed study, the reasons why some alternatives were eliminated from consideration, and describe how the alternatives meet the need for the project and avoid or minimize environmental harm. For

developing alternative routes for a CO_2 pipeline, the requirements of 23 CFR 771.111(f) state that projects must connect logical termini, have independent utility, and not restrict the consideration of future transmission alternatives. The “no-build” alternative is always included as a benchmark against which the impacts of the other alternatives can be compared.

- **Affected Environment.** This section provides information on the existing resources and the condition of the environment. It should focus on the import issues in order to provide an understanding of the project area relative to the impacts of the alternatives. The affected environment should discuss the existing social, economic, and environmental settings surrounding the project. It should also identify environmentally sensitive features in the project corridor.
- **Environmental Consequences.** This section describes the impacts of the project alternatives on the environment and documents the methodologies used in evaluating these impacts. Information in this section is used to compare project alternatives and their impacts. This section should describe in detail both the impacts of the proposed action and the potential measures that could be taken to mitigate these impacts. Mitigation must be considered for all impacts, regardless of their significance. Environmental impacts should be discussed in terms of their context and intensity.
- **Comments and Coordination**. The EIS must summarize the scoping process and list any comments received during public meetings. Between the draft and the final EIS, the preparer must consider and respond to all substantive comments received. The final EIS must include copies of the comments and responses.

- **Public Utility Commission of Nevada.** Any new linear pipeline in the state of Nevada will require a Certificate of Public Convenience and Necessity (CPCN) from the Public Utility Commission of Nevada. To obtain a CPCN, an applicant must demonstrate that there is a public need for the CO_2 pipeline and that the proposed utility is willing to serve and able to fulfill the public need. An EIS, described above, may be a necessary component of the CPCN process.

- **California Public Utility Commission.** Any new linear pipeline in the state of California will require a CPCN from the California Public Utility Commission. To obtain a CPCN, an applicant must demonstrate that there is a public need for the CO_2 pipeline and that the proposed utility is willing to serve and able to fulfill the public need.

- **Arizona Corporation Commission.** The Arizona Corporation Commission (ACC) typically regulates the siting of transmission lines, pipelines, and other linear utilities. They issue Public Convenience and Necessity (CPCN) determinations for investor-owned and cooperative utilities. However, the ACC does not have authority over power plant siting in tribal lands. A CO_2 pipeline from the Black Mesa Mine to Cortez, Colorado, would not fall under the jurisdiction of the ACC. Since Navajo County borders New Mexico, the pipeline would not traverse any parts of Arizona outside of tribal lands.

- **New Mexico Public Regulation Commission.** Any new CO_2 pipeline in the state of New Mexico will require a Certificate of Public Convenience and Necessity (CPCN) from the New Mexico Public Regulation Commission. There is no indication that tribal land in New Mexico is exempt from jurisdiction by the Public Regulation Commission. To obtain a CPCN, an applicant must demonstrate that there is a public need for the CO_2 pipeline and that the proposed utility is willing to serve and able to fulfill the public need.

- **Colorado Public Utility Commission.** Any new CO_2 pipeline in the state of Colorado will require a CPCN from the Colorado Public Utility Commission. To obtain a CPCN, an applicant must demonstrate that there is a public need for the CO_2 pipeline and that the proposed utility is willing to serve and able to fulfill the public need.

- **Underground Injection Well Permit.** Injection of CO_2 into the oil fields in Bakersfield, California would require permitting under the U.S. EPA's Underground Injection Control (UIC) program. The UIC program classified injection wells into five classes. This project would be considered a Class II well, which is defined by injection of fluids associated with oil and natural gas recovery. In California, Class II well permits are issued by the California Department of Conservation – Division of Oil and Gas Recovery. Their office is in Bakersfield, and they have permitted numerous Class II wells in the area. This permit would require public notification in a local newspaper, but would only require a public hearing if there were significant interest in the project.

  Injection of CO_2 into a sequestration location at a saline aquifer would also require permitting under the U.S. EPA's UIC program. Injection wells typically require a state permit. This permit typically requires public notification in a local newspaper, but typically only requires a public hearing if there were significant interest in the project.

- **U.S. Army Corps of Engineers Permit.** It is possible that there are some jurisdictional wetlands in the path of the CO_2 pipeline; if any would require filling, then the developer must seek an U.S. Army Corps of Engineers permit. If the CO_2 pipeline will cross any "waters of the United States," including dry creek beds, then a Nationwide Permit #12 (Utility Line Activities) would be required. This general permit allows installation of a pipeline underneath the river or creek, but requires that the water body be returned to its original condition. A permit would be issued for each crossing, provided that they meet the criteria for Nationwide Permit #12. One permit officer from the U.S. Army Corps of Engineers would be assigned to the entire project. Typical permit review times could take up to one year.

- **Zoning / Land Use Permits.** Each county along the right-of-way will need to grant approval for the CO_2 pipeline.

- **Building Permits.** At various points along the CO_2 pipeline, compression stations will need to be installed. At each station, a building permit from the local municipality or county will need to be obtained. Since these structures will not be regularly occupied, the design requirements are not as strict.

- **Other Issues.** It is recommended that the project developers seek concurrence from the State Historical Preservation Officers (SHPO) in both Nevada and California or in Arizona, New Mexico, and Colorado, as necessary, to determine that no known historical or archeological features are in the path of the CO_2 pipeline. There is no permit that would need to be obtained, nor does the SHPO have authority to stop a project. Still, obtaining concurrence would be sound planning. Similarly, the Nevada Natural Heritage Program (part of the Department of Conservation and Natural Resources) and the California Department of Fish and Game should be consulted to determine whether there are any known threatened or endangered species along the path of the CO_2 pipeline.

8.7 CONCLUSION

There is limited experience worldwide with carbon dioxide injection projects dedicated to long-term carbon storage. A number of policy, economic, and technical barriers confront geologic sequestration to varying degrees. As research and development projects progress and policies such as carbon dioxide regulations are put into place, we may see more activity in carbon sequestration.

The available evidence appears to demonstrate that there is a potentially significant market for CO_2 gas. However, the ability to tap into that market is constrained by lack of supply and uncertainties about the technical feasibility of enhanced gas recovery. Any carbon dioxide producing power plant at the Mohave site would need to perform further economic analyses to justify the transport of its CO_2 to a gas or oil field in California.

It is also important to keep in mind that while enhanced hydrocarbon recovery can potentially be an economically feasible endeavor without subsidy or assistance, it is not a net-zero method to sequester anthropogenic carbon dioxide. The oil and gas produced will also result in the release of CO_2 when burned. It is worth noting however, if CO_2 captured from an IGCC plant were used in EOR *instead* of natural CO_2 that would otherwise have been newly extracted from a dome and the resulting oil production was no more than would otherwise have occurred, then there would be a net positive climate change benefit to using CO_2 from the IGCC plant. However, in a regulatory or legislative setting, this argument might be problematic. Furthermore, without greenhouse gas (GHG) regulation, it is not clear what incentive there would be to substitute more expensive anthropogenic CO_2 for cheaper natural CO_2, particularly when pipelines from CO_2 domes to oil fields already exist.

Last page of Section 8.

9. TRIBAL ISSUES

9.1 SCOPE OF STUDY

The scope of work at the outset of the study included investigating the following areas:

- Employment impacts for certain technology options;
- Estimates of royalties, taxes and other costs assumed to be paid to the tribes in the course of implementing certain technology options;
- Costs of land, water, and Black Mesa Mine coal;
- Requirements and likelihood of permitting for generation plants, new or renewed coal mining operations, and right of way (ROW) permitting for power lines, roads and pipelines;
- Acceptability of development on Hopi and Navajo lands for certain technology options;

Employment impacts and estimates of tax liabilities for the various technology options were developed and are presented in this report. Due to their complexity and confidential nature, it was agreed by the stakeholders that issues of royalties, as well as land, water, and coal costs, permitting, and acceptability, were not to be developed further. Therefore, these issues are discussed only briefly.

Economic benefits would flow to the tribes—as governmental entities—from the initial investment in and operation and maintenance of any of the technology options. Those economic benefits would take the form of tax revenues on investments in the construction and operation of the option; royalties, fees, and similar payments; and taxes paid by employees of the businesses operating those technology options, along with any similar taxes and payments from secondary economic activity flowing from the technology option. Tribes would likely see additional expenses in some areas from government services provided and reduced expenses in other areas. Royalties, land rents, and similar revenue would be due to the tribes for many of the options studied in this report and would form an important part of the quantitative benefits to the tribes. However, since critical data were not available due to the confidentiality restrictions mentioned above, no quantitative estimates of those benefits were possible. Tax revenues to the tribes from investment, operation and maintenance outlays, and direct employment were estimated, but tax revenues from expenditures by employees and secondary business activity were not estimated as part of this study. However, the amount of employment in those secondary business activities on the reservations and adjacent counties was estimated and is included in the totals shown in Section 9.4. A critical factor in estimating employment impacts for these technology options would be the effect of tribal employment preference requirements. As only limited information on the effects of those requirements was available, employment impacts had to be based on certain assumptions about preferences.

Section 9.2 begins with a review of land tenure and of approval issues. Section 9.3 presents estimates of the taxes that would be payable to the Navajo Nation by technology options on tribal land.[1] Finally, Section 9.4 presents estimates of the direct and indirect employment benefits expected from a selection of technology options under study.

9.2 TRIBAL ISSUES IN CONTEXT

Any discussion of the above issues or the processes by which they are addressed, even a cursory one, depends critically on a clear understanding of the varieties of land tenure that occur in and around tribal lands. Therefore, this section begins with a review of those categories and then reviews a few of their implications relevant to energy development projects. That discussion necessarily includes various complexities and identifies certain potential barriers to development. They are potential barriers in the sense that if they arise, they would need to be overcome. Overcoming such barriers can be time-consuming and complex in some cases. In other cases, especially when all relevant parties are in accord, addressing approvals and permitting may be less complex and more streamlined.

As detailed in Chapter 10 of this report, there are numerous financial benefits that can be available to the owners of energy projects on tribal land and to the tribes involved. In addition to the tax benefits and other financial incentives outlined in Chapter 10, there are certain other advantages and simplifications that may flow from siting energy projects on tribal land. For example, tribes may now negotiate energy development leases with third parties without obtaining U.S. government approval.[2] Also, certain federal laws provide preferential standing for purchases from certain businesses located on Indian reservations.[3] Another preference exists for purchases from businesses owned by Native Americans.[4]

[1] No taxes have been enacted by the Hopi Tribe at this time.

[2] EPACT 2005, Section 2604. This could be valuable in relation to the technology options of non-tribal ownership of IGCC at Black Mesa, wind development at Gray Mountain and, possibly, other sites, and both solar energy sites under consideration.

[3] HUBZone Act of 1997, Public Law 105-135 expanded by P.L. 106-554.

[4] Small Business Act, Public Laws 85-536 and 95-507, Sec. 8(a).

Of course, there can be substantial benefits to tribes that host energy projects. Among those that flow directly to the tribes are tax revenue, royalties, and land lease revenue. Benefits that flow to tribal members and their families include direct employment and training opportunities that stem from the project, indirect employment in businesses that support the project (contractors for maintenance and other services, vendors of supplies and other goods, and so on), and further employment supported by re-spending of personal or business income from direct and indirect employment. In addition, there can be social benefits to communities that benefit from these economic impacts. Depending on the nature of the project, there may also be other effects on the community, the environment, and the local economy, but the balancing of all these consequences is an important part of determining which energy projects best suit the tribes.

This study does not intend to convey the impression that energy projects cannot or should not be developed on tribal lands; many such developments have occurred and, no doubt, more will occur. Indeed, numerous advantages, financial and otherwise, may ease the way for such developments, depending on project and site qualifications. However, it is important to begin with a clear understanding of the potential issues that might confront potential owners, developers, tribes and other stakeholders.

9.2.1 Land Tenure Issues and Their Relation to Approval and Permitting

A technology option's physical location affects its permitting, approvals, taxation, land ownership or leasing, and other factors. For example, type of land ownership and the nature of the approvals for business activity that a type of land ownership mandates are important and can be a "gating" item for proposed enterprises. Although, as is explained below, some of the above subtasks are not being pursued to completion, an informational summary of the types of locations and certain permitting issues that might be relevant to the study or to subsequent consideration by the stakeholders is provided below.

An *Indian reservation* is a geographic territory over which a particular form of governmental jurisdiction has been created by action of federal law. Within a given reservation, there may be one or many of the following forms of land ownership:

- **Land can be held in trust by the U.S. for a tribe.** The consent process for business activities on such land involves approvals from both the tribe and the federal government. Because federal approval is required, certain federal laws—such as the National Environmental Policy Act (NEPA), which may require the federal government to draft an environmental impact statement regarding a new proposed activity—may make the process of getting projects approved on land held in trust by the U.S. for a tribe a cumbersome task.

- **Land can be held by the U.S. in trust for individual tribal members.** Typically, over time, such lands have been passed down from one original owner to many heirs—often through several generations. The consequence is that a large number of individual owners may hold a fractional undivided interest in the land's title. These lands are referred to as "fractionated" allotments. Activities on such lands generally require the consent both of the federal government and of at least 50% of the allotment owners.[5] While such approvals are certainly possible, the multiple ownership scenario of this type of land and the approval process represents a large degree of complication for potential business activities.
- **Land can be owned by the tribe.** This scenario is less complicated, as federal approval of business activities on such pieces of land are eliminated. However, the tribal government must still approve use.
- **Land can be owned by the U.S. in trust for joint use by more than one tribe.** Approval of business activities on joint lands requires approvals from multiple tribal governments as well as by the U.S. government. This may represent some significant issues for potential businesses.
- **Land can be owned by a non-tribal business entity.** In this scenario, the U.S. government does not need to approve use of the land.
- **Land can be owned by non-tribal individuals.** In this situation, again, federal approval of use of land is not required.

Lands that fall under these latter two ownership scenarios sometimes are known as "checkerboard lands." Such lands often were originally owned by the tribes or tribal members, but then were sold to private, non-trial owners. An example of checkerboard land follows:

> The 1830 Treaty of Rabbit Creek [sic] called for the removal of the Choctaw from their ancestral homeland in the Carolinas, Mississippi, and Tennessee to Oklahoma Territory.[6] Subsequently, 104,320 acres in Mississippi were awarded to the 5,000 Choctaw who remained on the traditional lands. Fraudulent land sales fueled the checkerboarding of the reservation. Today, 8,400 members live on 29,000 checkerboard acres in seven communities. Using the profits generated by tribal business, the tribe is purchasing reservation land to consolidate and fill in the checkerboard areas within each of the communities. The goal is to simplify jurisdictional and development issues for the tribe and for the state of Mississippi.[7]

In addition to the above reservation ownership scenarios, the U.S. can hold land for tribes or tribal members outside of a reservation. Such land has the same approval-of-use issues as those lands held by the U.S. within a

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[5] See 25 Part 162 (Leasing and Permitting) C.F.R. section 162.605(b)

[6] The treaty more usually called "The Treaty of Dancing Rabbit Creek." The complete title given in the treaty, itself, is "A treaty of perpetual, friendship, cession and limits, entered into by John H. Eaton and John Coffee, for and in behalf of the Government of the United States, and the Mingoes, Chiefs, Captains and Warriors of the Choctaw Nation, begun and held at Dancing Rabbit Creek, on the fifteenth of September, in the year eighteen hundred and thirty." Charles J. Kappler, *Indian Affairs: Laws and Treaties*, Washington: U.S. Govt. Printing Office, 1904, vol. II, p. 310 ff.

[7] The Urban Institute, Inc., 2004.

reservation boundary. Finally, land can be owned by the tribe outside of the reservation. This type of land is known as “tribal fee land.” The tribe owns such land, because it purchased it outright. For such parcels of land, the tribe likely does not exercise governmental authority; but as the land’s owner, the tribe can control activities on such lands.

Table 9-1 summarizes the various technology options, their proposed locations, and ownership issues.

Table 9-1 — Technology and Land Use Approval Issues

Technology	Proposed Location	Land Owner Type	Requires Tribal Approval?	Requires Federal Approval?
IGCC	Laughlin, NV	Private	No	No
IGCC	Black Mesa, AZ	No specific site has been identified, but the general area surrounding the Black Mesa mine is land held in trust by the U.S. for the Navajo Nation with the subsurface (mineral) estate held in trust by the U.S. jointly for the Navajo Nation and the Hopi Tribe	Yes	Yes
NGCC	Laughlin, NV	Private	No	No
Solar	Northeast of Black Mesa Coal Mine, AZ	No specific site has been identified, but the general area is land held in trust by the U.S. for the Navajo Nation	Yes	Yes
Solar	East of Tuba City, AZ	No specific site has been identified, but the general area is land held in trust by the U.S. for the Hopi Tribe	Yes	Yes
Wind	Gray Mountain	Land held in trust by the U.S. for the Navajo Nation	Yes	Yes
Wind	Clear Creek (southwest of Winslow, AZ)	On Hopi fee and Arizona State lands	Yes	Not as to trust issues
Wind	Aubrey Cliff (northwest of Seligman, AZ)	Navajo fee and Arizona State lands	Yes	Not as to trust issues
Wind	Sunshine (located 35 miles east of Flagstaff on I-40 near the Meteor Crater and west of Winslow)	Hopi fee and private ranch lands owned by two other landowners,	Yes	Not as to trust issues
Biomass	Unspecified	N/A	N/A	N/A
Geothermal	Unspecified	N/A	N/A	N/A

In summary, numerous issues connected with approvals for land use can arise for potential business operations, and various approval processes may apply, depending on the circumstances. To the extent that more land is required for the business activities and this increased land requirement involves additional tracts under new and different ownership statuses, the potential for approval difficulties increases significantly.[8] Specifically, additional owners may be affected, additional approval processes may be triggered, or both. As a result, those generating technologies mentioned in this study that require use on land held by the U.S. or on land held by multiple owners may present business challenges.[9] On the other hand, when all relevant parties are in accord, addressing approvals and permitting may be less complex and more streamlined.

Furthermore, as explained in Chapter 10 of this report, there are numerous financial benefits that can be available to the owners of energy projects on tribal land and to the tribes involved, and certain other advantages and simplifications may exist, such as purchase preferences. The substantial benefits to tribes and the communities that host energy projects may justify approval. Balancing all these consequences is an important part of determining which energy projects are best suited to the tribes.

9.2.2 Acceptance and Permitting, Royalties, and Other Payments to Tribes

Examples of aspects of a project proposal that would affect acceptance and permitting for projects include royalties and other payments, compensation provisions for individuals and communities that are affected, and effects on land, air and water, on employment, and on other uses of land.

Most of the specific technology options under consideration for siting on or near tribal land, including an IGCC facility at Black Mesa, wind, and solar, would face exceedingly complex water rights issues and aquifer studies currently under way, highly confidential royalty negotiations also under way, and numerous other issues not in the public domain. To a large extent, even the historical values and issues relating to some of these types of matters lie outside the public domain. However, it should be kept in mind that life extension or renewal of the existing Mohave Generating Station would also raise such issues.

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[8] It is important to note that members of tribes can own land outside of a reservation. These owners are not required to obtain tribal or federal approval for business activities on their lands. Such lands would be subject to generally applicable state and federal laws, but not to any laws unique to Indians or Indian tribes.

[9] This does not mean that a larger size of the leasehold, *per se*, makes approval more difficult. Rather, if increased land requirements lead to a need for lands that are under different and additional types of ownership or trusteeship, this could trigger additional types of approval requirements and could add to the complexity of approval. In addition, even a project located on land under a single type of ownership or trusteeship may require acquisition or use of land under additional types of ownership or trusteeship for ancillary uses, such as access roads or transmission lines.

9.3 TAXES

9.3.1 Overview of Applicable Taxes

Tribes have the authority to levy taxes on business activity conducted on tribal land in a manner analogous to the authority of states. Among the most significant benefits for development of the various technology options is their potential as tax revenue sources. The technology options under consideration would be subject to such taxes if their operations were conducted on tribal land.

The Navajo Nation (NN) has enacted three taxes that would be applicable to businesses conducted on its tribal land:

- **Possessory Interest Tax**, which applies to the property rights under a lease, including the rights to use or possess tribal lands, to lease premises, rights-of-way, and rights to underlying natural resources; 24 N.N.C. § 204 (A) and (C). Under the Navajo Nation Code (N.N.C.), projects on leased tribal land that generate electricity or transmit electricity at voltages above 14.5-kV would be classified as "Class two possessory interest." This would appear to apply to the IGCC technology option at Black Mesa Mine, the Solar 1 and Solar 2 sites, and some or all of the wind sites identified elsewhere in this study; 24 N.N.C. § 204 (J). It is possible that other renewable options would also fall under that classification if proposed locations have been identified. The valuation of such an interest would be determined by the fair market value, the present value of projected net income over the life of the lease, or such other method as is adopted by the Office of the Navajo Tax Commission; 24 N.N.C. § 205. The taxable value of such an interest would be 100% of the valuation; 24 N.N.C. § 216.[10] The rate of tax currently in effect (according to the Code) is 3%, subject to change within the range of 1% to 10%; 24 N.N.C. § 206.

- **Business Activity Tax**, which applies the gross receipts ("source-gains") from personal property produced, processed or extracted within the Navajo Nation ("Navajo goods") or from services performed within the Navajo Nation of any person engaged in trade, commerce, manufacture, power production, or other productive activity wholly or in part within the Navajo Nation ("branch"); 24 N.N.C. § 404 (A)-(D).[11] Gross receipts are generally based on fair market value; 24 N.N.C. § 404 (F). The rate of tax is set by regulation within the range of 4% to 8%, but is reduced by 40% for construction activity; 24 N.N.C. § 406.

- **Sales Tax**, which applies to the gross receipts of person from the sale of real or personal property, services, or other productive activity; 24 N.N.C. § 607 (H). The tax rate is set by

[10] It is possible that some possessory interests, such as those relating to DSM options would be classified as commercial uses. Also, certain renewable technology options might include in their implementation commercial, industrial, manufacturing, assembly or fabrication uses. Such purposes would be classified as "Class three possessory interests" and would be taxable at 10% of their valuation. 24 N.N.C. §§ 204 (J) and 217.

[11] Various deductions from these gross receipts are allowed including, in particular, compensation paid to members of the Navajo Nation, certain payments to the Navajo Nation, and purchases of Navajo goods and services and cost of raw materials imported into the Navajo Nation to be used in manufacturing Navajo Nation goods. 24 N.N.C. §§ 405 (B) and 408 (H). Amounts on which Navajo Sales Tax has been paid are exempt. 24 N.N.C. § 480 (A). Navajo Nation government, subdivisions and wholly owned enterprises are exempt. 24 N.N.C. § 408 (B). Special provisions apply to credits that coordinate with other taxes, especially for "new business" (post-1998). 24 N.N.C. §§ 404 (I) and 409 (B) (1).

regulation within the range of 2% to 6%; 24 N.N.C. § 605. Effective during and after calendar 2006, sales by the Navajo Nation government, political subdivisions and enterprises are subject to 100% of the Sales Tax; 24 N.N.C. § 608 (B) (5). Certain exemptions relevant to this study exist, including for sales for resale and sale of certain securities; 24 N.N.C. § 609 (C).

The Oil and Gas Severance Tax (24 N.N.C. §§ 301-345) and the other taxes set out in Title 24 of the N.N.C. do not appear to apply to the technology options under consideration in this study.

The Hopi Tribe does not, at present, have a tax code; and, under the Hopi Tribe's Constitution, a referendum vote of the Tribe's members would be necessary to change that situation.

In the next subsection, this basic information regarding tribal taxes that would apply to the technologies that may be considered for tribal land (IGCC at Black Mesa, Solar 1 and 2, and the four wind sites) is used, along with the investment and O&M estimates, to estimate the tax payments that would be due under identified provisions of the Navajo Nation Code.

9.3.2 Estimation of Navajo Nation Possessory Interest Tax

Table 9-2 presents estimates of the Possessory Interest Tax (PIT) payments that would be required for selected technology options and locations. The notes following the table explain the derivation of input values and assumptions made during the calculation of these estimates. In general, where assumptions were required, the option resulting in the larger tax due was used.

Table 9-2 — Navajo Nation Possessory Interest Tax Estimate

All dollar amounts are in 2006 dollars

Option	Land Requirement (acres) (Note 7)	Fair Market Value (FMV) (Note 6)	Capital Cost for Generating Options OR Annual Budget for EE Options	Annual Net Income (Note 8)	Present Value (PV) of Projected Net Income (Note 8)
IGCC at Black Mesa	300	$90,000	$1,082,992,688	$77,975,474	$967,600,863
Parabolic Trough	2,610	$783,000	$1,066,333,920	$76,776,042	$952,717,070
Solar Stirling Engine	2,125	$637,500	$730,095,000	$52,566,840	$652,304,082
Wind (150 MW at Gray Mountain)	10,000	$3,000,000	$711,205,595	$51,206,803	$635,427,325

Option	Land Requirement (acres) (Note 7)	Fair Market Value (FMV) (Note 6)	Capital Cost for Generating Options OR Annual Budget for EE Options	Annual Net Income (Note 8)	Present Value (PV) of Projected Net Income (Note 8)
EE on Reservation	2	$160,000	$30,520,000	$15,260	$62,569
EE from Reservation	10	$800,000	$30,520,000	$152,600	$625,690

Computation of Tax	PIT Class	Initial Tax Rate per N.N.C.	Applicable Percentage	PIT Based on FMV ($/year)	PIT Based on PV of Projected Net Income ($/year) (Note 9)	Notes
IGCC at Black Mesa	2	3%	100%	$2,700.00	$29,028,026	1, 5
Parabolic Trough	2	3%	100%	$23,490.00	$28,581,512	5
Solar Stirling Engine	2	3%	100%	$19,125.00	$19,569,122	5
Wind (150 MW at Gray Mountain)	2	3%	100%	$90,000.00	$19,062,820	5
EE on Reservation	3	3%	10%	$480.00	$188	2, 4
EE from Reservation	3	3%	10%	$2,400.00	$1,877	3, 4
EE on Reservation	None			$0.00	$0	2, 4
EE from Reservation	None			$0.00	$0	3, 4

Other Inputs		
Value of undeveloped rural land (Note 11)	$300	per acre
Value of undeveloped commercial real estate (Note 11)	$80,000	per acre
Real discount rate	7%	per year
Economic Life of generating options	30	years
Program Life of EE options	5	years
ROE for generating options	16%	per year
Equity percentage for generating option	45%	
Profit percentage for EE options	5%	per year
Percent of EE delivered on Reservation	1%	
Percent of EE delivered on or from Reservation	10%	

Notes:

1. For IGCC at Black Mesa, the study assumes that Navajo Nation (NN) PIT applies. The study does not need to reach the question of whether the proceeds (or other NN tax proceeds) are subject to sharing under Secakaku v. Navajo Nation, 964 F. Supp. 1359 (D. Ariz. 1997), because sharing of the tax proceeds does not necessarily affect the amount of those proceeds.

2. For the Demand Side Management (DSM)/Energy Efficiency (EE) on the NN Reservation option, for illustrative purposes, the study assumes that a small percentage of the total program is delivered on the NN by a non-tribal enterprise based on the Reservation. This is not meant to imply any position regarding the best or most likely way of organizing such an enterprise. The assumed percentage of savings delivered on Reservation is shown under “Other Inputs.”

3. For the EE from Reservation option, for illustrative purposes, the study assumes that a percentage of the total program is delivered both on and off of the NN Reservation by a non-tribal enterprise based on the Reservation. This is not meant to imply any position regarding the best or most likely way of organizing such an enterprise. The percentage is shown under “Other Inputs.”

4. This analysis considers two extreme alternatives for EE options with regard to PIT. First, the study assumes that EE options would operate out of pre-existing rented commercial space and that they would not require any new leases of tribal land. This means that no new lease would be required for lands, nor the severance of any products from tribal lands. Therefore, the study also assumes that EE options would not be subject to PIT. Alternatively, the study considers the possibility that a new lease of tribal land would be required to house the operations of the EE option, and that such an operation would be classified as a commercial operation and as a Class 3 possessory interest. 24 N.N.C. section 204(K). NOTE: Due to the exemption for PIT amounts less than $100,000 per year, any amount less than that would not be due.

5. PIT Class 2 possessory interest applies to generation at voltages above 14.5 kV. 24 N.N.C. § 204(J). The wind options are specifically expected to produce power at 34.5 kV. Projects of the size of the IGCC and solar options usually interconnect at 34.5 kV or higher.

6. FMV (Fair Market Value) is estimated based on a value per acre of undeveloped rural land in the southwest, except for the EE options. For the EE options, FMV is based on a value per acre for undeveloped commercial real estate. Both values are shown under “Other Inputs.”

7. Land requirements do not include ROW for any necessary transmission lines. Land for IGCC assumes a requirement for ash storage; (Prelim. Draft page 2-15). Land for parabolic trough option is estimated based on 300 MW plant size and 6 acres/MW; (Prelim. Draft Table 3-3). Land for Stirling engine option is estimated based on 425 MW plant size and 4 acres/MW; (Prelim. Draft Table 3-3). Land for EE is based on estimated requirement for office, shop, garage, warehouse space for two different program sizes.

8. Projected Net Income for generating options is assumed to be a fixed percentage of the overnight capital cost of each option. That percentage is the product of the ROE and the equity percentage shown under “Other Inputs.” Projected Net Income for EE options is assumed to be a fixed percentage of the annual expenditure on efficiency program. NPV (Net Present Value) of Projected Net Income is calculated using the real discount rate (excluding inflation) and assumed operating lives shown under “Other Inputs.”

9. PIT is subject to various exemptions and valuation is subject to various exclusions. In particular, PIT amounts less than $100,000 per year are exempted. Also, in the PV of Projected Net Income method of valuation, certain expenses are deducted. However, since the analysis begin with net income, such exclusions do not appear to be relevant.

10. This analysis assumes that one 50-MW block of EE is acquired spread out over 5 years of implementation. To the extent that more than one block is acquired, PIT revenue could occur. However, even if eight blocks (400 MW) were acquired, the PIT based on PV of projected net income would still be only $15,017 per year for the 10% “on or near reservation” scenario, which is below the $100,000 per year exemption amount.

11. The land values used in the study are the midpoints of estimates provided by Simmons Realty of Winslow Arizona.

    Simmons price ranges:

    —Undeveloped rural land: $100 to $500 per acre

    —Commercially zoned land in a small town: $10,000 to $150,000 per acre

9.3.3 Estimation of Navajo Nation Business Activity Tax

Table 9-3 presents estimates of the Navajo Nation Business Activity Tax (BAT) payments required for selected technology options and locations. The notes following the table explain the derivation of input values and assumptions made during the calculation of these estimates.

Table 9-3 — Navajo Nation Business Activity Tax Estimate

All dollar amounts are in 2006 dollars

Option	Ongoing Salaries Paid to NN members (Note 1)	Annual Water Use (acre-ft) (Note 5)	Land Requirement (acres) (Note 5)	Purchase of NN Goods and Services (Note 2)	Payment to NN other than Taxes under 24 N.N.C. (Note 2)	Standard Deduction (Note 3)	Deductions (Note 4)
IGCC at Black Mesa	$11,536,000	1,919	300	$1,893,562	$88,633,360	$18,935,616	$102,062,922
Parabolic Trough	$4,928,000	58	2,610	$452,016	$840,815	$4,520,160	$6,220,831
Solar Stirling Engine	$6,608,000	8	2,125	$446,760	$645,594	$4,467,600	$7,700,354
Wind (150 MW at Gray Mountain)	$1,291,500	0	11,333	$210,240	$1,365,000	$2,102,400	$2,866,740
EE on Reservation	$85,456	0	2	$3,052	$600	$125,000	$125,000
EE from Reservation	$854,560	0	10	$30,520	$3,000	$305,200	$888,080

	Generation output (MWh per year) (Note 5)	Gross Receipts (2006$ per year) (Note 6)	Deductions (2006$ per year) (Note 4)	Taxable Gross Receipts (Gross Receipts - Deductions)	Annual BAT Payable on Ongoing Operations	Notes
IGCC at Black Mesa	4,733,904	$189,356,160	$102,062,922	$87,293,238	$4,364,662	
Parabolic Trough	1,130,040	$45,201,600	$6,220,831	$38,980,769	$1,949,038	
Solar Stirling Engine	1,116,900	$44,676,000	$7,700,354	$36,975,646	$1,848,782	
Wind (150 MW at Gray Mountain)	525,600	$21,024,000	$2,866,740	$18,157,260	$907,863	
EE on Reservation	N/A	$305,200	$125,000	$180,200	$9,010	7
EE from Reservation	N/A	$3,052,000	$888,080	$2,163,920	$108,196	7

Other Inputs		
Percent of salaries paid to NN members--generation options	80%	
Percent of salaries paid to NN members--EE options	80%	
Illustrative value for coal	$40	per ton
Illustrative value for water	$1,000	acre-ft
Annual coal use for IGCC	2,165,609	tons

Other Inputs		
Percent of gross receipts for other NN goods and services	1%	
BAT Tax Rate	5%	
Illustrative price for power sold by generation options	$40.00	per MWh
Value of undeveloped rural land (Note 8)	$300	per acre
Value of undeveloped commercial real estate (Note 8)	$80,000	per acre

Notes:

1. The analysis assumes that 80% of salaries are paid to Navajo Nation members. For EE options, labor is based on estimates of breakdown for total budget of $30,520,000 per year. In addition, the analysis assumed $70,000 per year as the salary and compensation per employee. Wind ongoing labor costs were assumed per tables provided in this study.
2. Navajo goods and services and other payments are assumed to include coal (where applicable), water, and contract services. For coal and water, for illustration, the analysis assumes the purchase value shown in "Other Inputs." If this purchase value is paid to the Navajo Nation, there would be a resulting deduction for purposes of BAT, as shown in these tables. For other goods and services, the study assumes a percentage of the remaining gross receipts as shown under "Other Inputs." For this analysis, the study assumes that land is leased at the value shown in "Other Inputs" and that lease payments are made to the Navajo Nation, resulting in a deduction for purposes of BAT. Payments for land, water, and coal are shown under "Payment to NN other than Taxes." *If any of the above payments are shared with or made to another entity such as, for example, the Hopi Tribe, the deductions available under the BAT Code would be reduced accordingly.*
3. The standard deduction is 10% of gross receipts or $125,000, whichever is greater.
4. Greater of (Salaries + Purchase of NN Goods and Services + Payments to NN other than Taxes) OR Standard Deduction.
5. Generation output for each option = (Capacity * Capacity Factor * 8,760). Data for IGCC is from Chapter 2. Data for Parabolic Trough and Dish/Stirling are from Chapter 3. Gray Mountain land lease value is in Chapter 4.
6. Gross receipts for generation options is annual output times illustrative price shown under "Other Inputs." Gross receipts for EE options are annual budget of $30,520,000 times 1% for "On Reservation" and 10% for "From Reservation."
7. For EE from Reservation, the analysis assumes that 10% of the total program is delivered off of the NN Reservation by a non-tribal enterprise based on the reservation. This is not meant to imply any position regarding the best or most likely way of organizing such an enterprise.
8. Land values are derived from midpoint estimates provided by Simmons Realty of Winslow Arizona.

    Simmons price ranges:

    —Undeveloped rural land: $100 to $500 per acre

    —Commercially zoned land in a small town: $10,000 to $150,000 per acre

9.3.4 Estimation of Navajo Sales Tax

Table 9-4 presents estimates of the Navajo Sales Tax (NST) payments that would be due for selected technology options and locations. The notes following the table explain the derivation of input values and assumptions made during the calculation of these estimates. Materials and equipment used in construction of generating options are assumed to be purchased off the reservation.

Table 9-4 — Navajo Nation Sales Tax Estimate

All dollar amounts are in 2006 dollars

Option	Construction Services (Note 1)	Annual O&M Contract Services (Note 1)
IGCC at Black Mesa	$23,975,000	$3,160,000
Parabolic Trough	$72,650,939	$616,000
Solar Stirling Engine	$210,073,000	$826,000
Wind (150 MW at Gray Mountain)	$52,690,207	$1,598,049
EE on Reservation	N/A	$30,520
EE from Reservation	N/A	$305,200

	One-time NST on Construction Services	Annual NST on Contract Services
IGCC at Black Mesa	$719,250	$94,800
Parabolic Trough	$2,179,528	$18,480
Solar Stirling Engine	$6,302,190	$24,780
Wind (150 MW at Gray Mountain) (Note 2)	$1,580,706	$47,941
EE on Reservation	$0	$916
EE from Reservation	$0	$9,156

Other Inputs	
NST tax rate	3%

Notes

1. For IGCC, the annual value of contract services is from Chapter 2. For IGCC, the construction value is the estimated labor requirement times $70,000 per person-year. For parabolic trough, the construction services value is as shown in Chapter 3. Annual value is assumed to be 10% of permanent O&M labor (88 positions at $70,000). For dish/Stirling engine, the construction value is as given in Chapter 3. Annual value is assumed to be 10% of permanent O&M labor (118 positions at $70,000). For wind, the annual and construction values are as given in Chapter 4. The salary and compensation per employee was assumed to be $70,000 per year. EE annual value estimated at 10% of on Reservation budget. See Table 9-3 sheet for budgets.

2. *One-time sales tax amount for wind does not include sales tax on the wind turbines themselves.* This is estimated to be $7,166,250 (see Chapter 4)

9.3.5 Summary of Navajo Nation Tax Estimates

Table 9-5 summarizes the results of the above estimation process. For the Navajo Sales Tax, there is a separate estimate of the amount due as a result of initial investment activity and an estimate (in 2006 dollars) of the ongoing annual taxes due. The PIT, BAT, and NST (Annual) estimates reflect the first year values of items that would be expected to be ongoing taxable items. It is important to keep in mind that these tax revenues exclude any royalties for coal or water and any land lease payments. Also, if any of the above payments are shared with or made to another entity, such as, for example, the Hopi Tribe, the deductions available under the BAT Code would be reduced accordingly, and the one-time sales tax amount for wind does not include sales tax on the wind turbines themselves, estimated by S&L to be $7,166,250.

Table 9-5 — Summary of Navajo Nation Taxes

Option	PIT	BAT	NST (Annual)	Total (Annual)	NST (One-Time)
IGCC at Black Mesa	$29,028,026	$4,364,662	$94,800	$33,487,488	$719,250
Parabolic Trough	$28,581,512	$1,949,038	$18,480	$30,549,031	$2,179,528
Solar Stirling Engine	$19,569,122	$1,848,782	$24,780	$21,442,685	$6,302,190
Wind (150 MW at Gray Mountain)	$19,062,820	$946,080	$47,941	$20,056,841	$1,580,706
EE on Reservation	$188	$9,010	$916	$10,113	$0
EE from Reservation	$1,877	$108,196	$9,156	$119,229	$0

It should be noted that certain Navajo Nation taxes may apply to projects that are outside the Reservation, but on Navajo fee land. The Nation explicitly claims jurisdiction over such lands; 7 N.N.C. § 254(A). The Nation has in fact applied its Business Activity Tax to non-Indian activities on those lands; see, for example, *Texaco v. Zah*, 5 F.3d 1374 (10th Cir. 1993). It seems likely that leases of such land would also be subject to the Nation's Possessory Interest Tax, inasmuch as the tax applies to ". . . the property rights under a lease approved, consented to, or granted by the Navajo Nation," which consent would certainly be required for any leases on lands it owns; 24 N.N.C. § 204(A). Finally, since the Navajo Nation's Sales Tax applies to ". . . all areas within the territorial jurisdiction of the Navajo Nation government . . ." that tax may also apply on off-reservation land owned by the nation in fee; 24 N.N.C. § 607(J).

9.4 EMPLOYMENT IMPACTS

9.4.1 Overview of Technology Options Modeled

Eight alternative energy options that could be developed on or near the Navajo or Hopi reservations were characterized for the purpose of estimating the potential economic impacts associated with each. All the scenarios were based on the schedules and costs set out elsewhere in this report. Three additional information sources were used to develop the detailed expenditure patterns. The Stirling Engine/Dish scenario was based on a combination of expenditure and employment data from Sargent & Lundy and SES, while the detailed breakdown of capital expenditures for wind generation was taken from a study of the inputs to wind generation manufacturing and construction.[12] The breakdown of DSM outlays was based Synapse's experience. Only the effect of the actual outlays for capital goods, labor, and O&M expenses were modeled. Taxes and royalties were not modeled.

The eight simulation scenarios, plus one variation on the first scenario, were defined as follows:

1. **Integrated Gasification Combined Cycle (IGCC)**. Assumptions associated with this development include no carbon dioxide removal, dry cooling, a plant located in the Black Mesa area on Navajo reservation land with approximately 540 MW capacity, no specific ownership designation, approximate plant construction period of 4 years, and total initial plant investment of $1,082,993,000. This scenario did not address the economic impacts of purchase or transportation of coal fuel for the plant.

   Simulation variant 1A includes all of the above plant specifications, but includes the effect of purchasing 100% of the coal used to fuel the plant from mines on Navajo and Hopi reservation land. Only the direct purchase of the coal, estimated by Sargent & Lundy to total 2,165,609 tons per year[13], was represented in the modeling; no royalty fees or Navajo or Hopi taxes or fees in connection with the coal mining were modeled in this variant.

2. **Solar Parabolic Trough**. Assumptions associated with this development include no storage systems, air-cooled condenser, three plants with approximately 300 MW total capacity located on Navajo reservation land in Navajo County, no specific ownership designation, approximate plant construction period of 2 years, and total initial plant investment of $1,066,334,000.

[12] See "Wind Turbine Development: Location of Manufacturing Activity," Technical Report, September 2004, Renewable Energy Policy Project, available on the Internet at http://www.repp.org/articles/static/1/binaries/WindLocator.pdf

13 The direct model input was converted to an employment change in NAICS 21211 (Coal Mining) of 104 jobs per year following completion of the plant construction. This estimate was based on output per employee data of 20,828 tons, derived from U.S. Department of Energy coal production data for Navajo and Hopi tribal lands (13.538 million tons) and reported employment at the associated mines for the year 2000 (650 persons).

3. **Stirling Engine/Dish**. Assumptions associated with this development include approximately 17,000 dish/engine units, located on Navajo reservation land in Navajo County, approximately 425 MW total capacity, no specific ownership designation, approximate plant construction period of 3 years, with phased operation beginning in year 1, and total initial plant investment of $730,095,000.

4. **Wind Turbines, Gray Mountain**. Assumptions associated with this development include a location in Coconino County on Navajo tribal land, approximately 450 MW total capacity, no specific ownership designation, approximate plant construction period of 2 years, and total initial plant investment of $711,206,000.

5. **Wind Turbines, Aubrey Cliffs**. Assumptions associated with this development include a location in Coconino County on Navajo tribal lease land, approximately 100 MW total capacity, no specific ownership designation, approximate plant construction period of 1 year, and total initial plant investment of $155,170,000.

6. **Wind Turbines, Clear Creek**. Assumptions associated with this development include a location in Coconino County on Navajo tribal lease land, approximately 75 MW total capacity, no specific ownership designation, approximate plant construction period of 1 year, and total initial plant investment, $116,005,000.

7. **Wind Turbines, Sunshine.** Assumptions associated with this development include a location in Coconino County on Hopi fee land, approximately 60 MW total capacity, no specific ownership designation, approximate plant construction period of 1 year, and total initial plant investment of $91,359,000.

8. **Energy Efficiency Program.** Assumptions associated with this development include development and funding of a program serving the premises of utility customers in New Mexico and Arizona, who would subsidize the purchase and installation of energy-saving appliances, lighting, air conditioning, new building design and other fixtures and equipment that would result in annual reductions of 10 MW in electric demand each year for a five-year period, reaching a total savings of 50 MW by the end of the five-year program. Program investment would total $30,520,000 per year for each of five years. Further project description and other assumptions associated with this option are detailed below.

More detailed technical descriptions of each of these options appear elsewhere in this report. All source data associated with the above options and their costs were provided by Sargent & Lundy, Synapse Energy Economics, and Stirling Energy Systems.

9.4.2 Economic Modeling of Energy Efficiency

The Energy Efficiency option modeled in this report contemplates the creation of a five-year, $30.5 million per year, program to subsidize the purchase and installation of energy-saving appliances, lighting, air conditioning, new building design, and other fixtures and equipment for residential, commercial, and industrial utility customers in Arizona and New Mexico.

Table 9-6 presents the stream of annual expenditures necessary to support an efficiency program of the type analyzed in this study. It is based on a program that is estimated to save 10 MW per year for five years, for a total of 50 MW.

Chapter 6 of this study estimates that there is at least 400 MW of efficiency savings that are readily available in Arizona and New Mexico by 2010. The smaller amount is assumed here to represent the economic impacts of a single energy efficiency purchase by SCE from a utility or utilities in Arizona or New Mexico. If additional purchases, or purchases of greater size, are made by SCE, then the economic impacts would scale up approximately linearly from those identified here.

Table 9-6 — Expenditures in Support of Energy Efficiency

Efficiency Savings and Expenditures:					
	2006	2007	2008	2009	2010
Annual energy savings (GWh):					
Incremental	59	59	59	59	59
Cumulative	59	117	176	235	293
Annual capacity savings (MW):					
Incremental	10	10	10	10	10
Cumulative	10	20	30	40	50
Annual efficiency cost (1000$)	30,520	30,520	30,520	30,520	30,520

Associated with each 10-MW increment of capacity savings is an estimated 59 GWh/yr of energy savings, based on a load factor of 67% from the SWEEP study. After five years of efficiency programs, these programs would result in 293 GWh of savings in each year.

The efficiency savings are assumed to cost $40/MWh. This cost includes roughly $30/MWh from the electric company and $10/MWh from the participating customer. The estimate of $40/MWh is based on the full lifetime savings from efficiency measures. At this cost of saved energy, there will need to be roughly $30 million dollars per year invested in energy efficiency in order to save 10 MW and 59 MWh per year.

These annual expenditures are allocated to three customer sectors (residential, commercial, and industrial) for three different types of efficiency programs (new construction, appliances, and retrofit). Table 9-7 presents the portion of the total expenditures that are assumed to be invested in each of the sectors and in each of the program types.

The allocation of expenditures by program type (in percentage terms) is based on typical utility efficiency programs that are both mature and comprehensive. That is, the programs seek to address all cost-effective efficiency markets, and makes programs available to all customer types.

Table 9-7 — Investment by Sector

Annual Expenditures by Program Type (1000$):				Allocation of expenditures by program type:			
	New Construction	Appliances	Retrofit	NC	Appliances	Retrofit	Total
Residential	3,052	4,578	3,052	10%	15%	10%	35%
Commercial	6,104	3,052	4,578	20%	10%	15%	45%
Industrial	1,526	1,526	3,052	5%	5%	10%	20%
Total	10,682	9,156	10,682	35%	30%	35%	100%

Finally, the annual expenditures by program type are allocated to different types of goods and services, for the purposes of modeling their impact on the economy. Table 9-8 presents the assumptions of the percentages of annual expenditures that will flow to the different types of goods and services, and Table 9-9 presents the annual expenditures that result from these assumptions.

Table 9-8 — Percentages of Allocation of Expenditures to Types of Goods and Services

Percentage allocation of expenditures:			
	NC	Appliances	Retrofit
Residential:			
Labor	40%	10%	30%
Lighting	10%	50%	30%
Refrigeration	5%	20%	20%
HVAC	45%	20%	20%
Commercial:	---	---	---
Labor	40%	10%	30%
Lighting	15%	50%	40%
Refrigeration	5%	20%	15%
HVAC	40%	20%	15%
Industrial:	---	---	---
Labor	40%	10%	30%
Lighting	15%	40%	20%
Refrigeration	5%	10%	15%
HVAC	40%	10%	15%
Miscellaneous / n	0%	30%	20%

Table 9-9 — Annual Expenditures by Types of Goods and Services ($000s)

Annual Expenditures by Type of Goods and Services:	New Construction	Appliances	Retrofit
Residential:			
Labor	1,221	458	916
Lighting	305	2,289	916
Refrigeration	153	916	610
HVAC	1,373	916	610
Commercial:	---	---	---
Labor	2,442	305	1,373
Lighting	916	1,526	1,831
Refrigeration	305	610	687
HVAC	2,442	610	687
Industrial:	---	---	---
Labor	610	153	916
Lighting	229	610	610
Refrigeration	76	153	458
HVAC	610	153	458
Miscellaneous	0	458	610
Totals	10,682	9,156	10,682
All Sector Totals:			
Labor	4,273	916	3,205
Lighting	1,450	4,425	3,357
Refrigeration	534	1,679	1,755
HVAC	4,425	1,679	1,755
Miscellaneous	0	458	610

As noted earlier, the assumptions in Table 9-8 are based on typical utility programs that are both mature and comprehensive. Thus, the programs are assumed to address a variety of cost-effective end-uses and measures, specifically ones that prevent cream-skimming and, therefore, promote efficiency across lighting, refrigeration, HVAC, and miscellaneous industrial end-uses such as motors.

Nonetheless, it is assumed that lighting measures will be a large portion of the efficiency investments, because these measures are very cost effective and readily available. HVAC measures will also be a large portion of the efficiency investments, particularly in the new construction sector, because of the high degree of air conditioning in the region and the relatively rapid growth in homes and businesses in the region.

It is also assumed that these programs will be managed by an electric utility, but that it will be agreed in advance that the utility will hire a tribal-based energy service company to perform a certain portion of the energy auditing and efficiency installation and retrofitting activities. Specifically, it is assumed that about 10% of the audit and measure installation services delivered by the program will be on customer premises within normal contractor travel distances from the Navajo reservation and, therefore, will be delivered via a tribal-based energy service company described above. In addition, we assume, for illustrative modeling purposes, that of the approximately 10% of work performed by that tribal-based energy service company, about two-tenths (i.e., 2% of the total program) will actually be performed on one or both reservations.[14]

It is estimated that approximately 10% of the program delivery, with a total wage bill of $750,000, would employ approximately 15 energy efficiency specialists based in Apache County, Arizona, close to the Arizona/New Mexico state line. The modeling does not, however, reflect, any additional labor input required to provide training for those energy efficiency specialists.

The labor categories in Table 9-7 and Table 9-8 include the labor associated with the utility's administration, marketing, and monitoring and evaluation activities, as well as the energy service company's labor.

Even though these energy service company employees will be based on the Navajo reservation, the economic impacts of this are diluted by the fact that much of their time and associated expenditures will occur in the most heavily populated urban areas of Arizona and New Mexico. As a result, only about half of the income generated by these activities is assumed to be retained as a direct local economic input.

It is also assumed that certain aspects of the program, especially the residential lighting and appliance portions, will rely on mail order of efficient goods and fulfillment of rebates for point-of-sale and coupon discounts. Therefore, an order-fulfillment and distribution facility will be associated with this program. For this study, we assumed that this facility will be operated on reservation land (also located in Apache County, Arizona, for economic modeling purposes) employing approximately 16 persons, with a total wage bill of $800,000. We do not mean to imply that this would actually be the best or most likely location on the two reservations for such a facility, only that it is a plausible location that was used for modeling purposes.

9.4.3 Economic Impact Model Methodology and Specification

The economic model used to perform all eight simulations and variants was developed by Regional Dynamics, Inc. (REDYN), based in Phoenix, Arizona. The REDYN model is a dynamic, multi-regional, nonlinear, endogenous, Input-Output (I/O), computable general equilibrium (CGE) economic and demographic model based on the North American Industrial Classification System (NAICS). The model is based on I/O methodology, with detailed make and use tables and social accounting matrix features for all entities, a

[14] These shares were based on county and regional shares of population, total nonagricultural employment and manufacturing and mining employment. Reservation shares were based solely on population shares of each of the six reservation counties in the year 2000. While it is recognized that this approach may overstate the demand for some energy efficiency products, due to the relatively low rural electrification rates and household incomes on the

comprehensive commodity production transformation function, and impedance-based commodity trade flows developed by Oak Ridge National Laboratories.

The REDYN model incorporates advances in New Economic Geography (NEG) to calculate all local and multi-regional trade flow effects due to direct and endogenous changes in demand for supplies, other resources, and final goods and services. The model includes active regions for more than 3,100 U.S. counties, 700 industries, 820 occupations, hundreds of commodities, and a 50-year forecast horizon in a 2-terabyte database.

The model estimates employment, output, wages, occupations, income, gross product, demand, self-supply, trade flows, and demographic impacts associated with user-defined economic events, such as the eight subject scenarios. All model inputs associated with these scenarios were developed with consultation from the REDYN model architect and the Synapse Energy Economics project manager.

The REDYN model constructed for this analysis consists of nine county-defined regions:

- Apache County, Arizona
- Coconino County, Arizona
- Navajo County, Arizona
- Balance-of-State, Arizona
- McKinley County, New Mexico
- San Juan County, New Mexico
- Balance-of-State, New Mexico
- San Juan County, Utah
- Balance-of-State, Utah

Thus, Arizona is divided into four regions (one for each reservation county and one for the rest of the state); New Mexico is divided into three regions (again, one for each reservation county and one for the rest of the state); and Utah into two regions (one for San Juan County and one for the rest of the state).

The model simulations make no assumptions regarding plant ownership and associated profits, royalties, leasing arrangements, or special taxes or fees. It should be noted that tribal ownership of these facilities or payment of

reservation lands, this may be offset by understated demand associated with industrial efficiency work associated with mining and associated operations on royalty, lease, and fee revenues could yield substantial additional income streams and related local economic benefits for the Navajo and Hopi tribes and the surrounding counties.

Due to very limited tribal data available, model extensions to estimate Hopi and Navajo reservation impacts were limited to sharing algorithms applied to REDYN model output, based on benchmark population, employment, and other economic and demographic data. That is, for each type of job created in the reservation counties, a portion was allocated to each of the tribes. For some types of jobs, the allocation was based on the population of each tribe compared to the total county population. For others, the allocation was based on project-specific data that affected tribal employment shares. Tribal population shares were adjusted in each model simulation to reflect tribal hiring preference laws and the mix of skill levels associated with various employment categories for both plant construction and operational periods. Given current tribal experience in the management and operation of energy production facilities, it was assumed that tribal employment shares at similar proposed facilities on or near reservation land would equal 80% of total direct plant employment, slightly above levels at existing facilities now operating near the edge of reservation lands. [15]

9.4.4 Summary of Economic Impacts

All of the economic impacts shown in Table 9-10 below represent total employment impacts, including direct, indirect, and induced jobs[16]. All employment impacts are expressed as incremental changes in employment above baseline economic model projections.

- **Simulation 1: Integrated Gasification Combined Cycle (IGCC).** Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are expected to total more than 330 jobs per year. Depending upon preferential hiring practices and job training provisions, at least 200 of these positions would be likely to be filled by Navajo or Hopi tribal members. Employment gains during the

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reservation lands.

[15] The net impact of these modifications varied in the nine simulations due to the number of jobs estimated in each county by the REDYN model, the types of jobs estimated and specific information associated with each potential project. During the construction phase, the net effect of these adjustments served to increase the tribal share of employment in the six counties encompassing the Hopi and Navajo reservations as follows: Simulations 1 and 1A, from 32% to 65%; Simulation 2, from 33% to 37%, Simulation 3, from 33% to 44%, Simulation 4, from 27% to 51%, Simulations 5-7, from 27% to 51%, and Simulation 8, from 56% to 96%. During the operational phase of each project, these shares increased as follows: Simulation 1, from 33% to 60%, Simulation 1A, from 33% to 56%, Simulation 2-3, from 33% to 45%, Simulations 4-6, from 24% to 68%, and Simulation 7, from 24% to 72%.

[16] Employment multipliers in the REDYN model vary by type of employment (or investment category), and county/region. Because model simulation inputs were often dollar-based investment values and not employment counts, especially during the construction phase, simple employment multipliers are not available. For example, in Simulation #3, the addition of 118 direct jobs per year associated with plant operation and maintenance in Navajo County results in 153 jobs in Navajo County, a net multiplier of 1.29, 244 jobs in the six counties encompassing the Hopi and Navajo reservations, a net multiplier of 2.06, and 665 jobs in the three state region, a net multiplier of 5.63.

four-year plant construction period will total approximately 215 new jobs, with about two-thirds of these (approximately 140) expected to be among tribal members on the two reservations.

- **Simulation 1, Variant 1A: Integrated Gasification Combined Cycle (IGCC) with coal inputs from Navajo County.** Construction phase economic impacts for this variant are identical to those in Simulation 1. Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations, however, are expected to total 565 positions, as coal mining jobs in Navajo County to supply fuel for the plant are included. Assuming approximately 80% of the plant operation personnel and 90% of the incremental mining operation jobs are tribal members, about 280 of these positions are estimated to be Navajo nation members, with about 40 positions to be held by Hopi tribal members.

- **Simulation 2: Solar Parabolic Trough.** Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are estimated to total about 180 positions, with average annual employment during the two-year construction period exceeding 725 jobs. The magnitude of this project, its compressed construction schedule, and significant on-site assembly work is estimated to result in the largest single-year construction impacts of any of the contemplated projects. Tribal employment during the two-year construction phase is estimated to total about 530 annual jobs, with about 495 of these estimated to be filled by Navajo tribal members and about 40 by Hopi tribal members.

- **Simulation 3: Stirling Engine/Dish.** Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are estimated to exceed 240 jobs per year, with average annual construction employment during the three-year construction period of about 475 jobs in the same six counties. This project is estimated have significant on-site assembly work and related employment opportunities for tribal members, representing more than 210 jobs per year during the construction period. During operation, this facility is estimated to generate nearly 110 jobs for tribal members in the six counties encompassing the Navajo and Hopi reservations, most of which will be in Navajo County, where the plant would be located.

- **Simulation 4: Wind Turbines, Gray Mountain.** Although construction-related employment associated with this project is estimated to exceed 350 jobs per year during the two-year construction period, total permanent employment impacts following completion of this wind turbine facility in the six counties encompassing the Navajo and Hopi reservations are estimated to total about 21 jobs per year. About two-thirds of these permanent jobs are estimated to accrue to tribal members.

- **Simulation 5: Wind Turbines, Aubrey Cliffs.** Tribal employment growth during the one year construction phase of the Aubrey Cliff wind turbines is estimated to total about 65 jobs, with permanent tribal job growth of about 4 positions. Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are estimated to total 6 jobs.

- **Simulation 6: Wind Turbines, Clear Creek.** Total construction-related job growth in the six counties encompassing the Navajo and Hopi reservations during the one-year construction of the Clear Creek wind turbines is estimated to total approximately 115 jobs, with about 50 of these likely to be among tribal members. Permanent employment gains associated with this facility is estimated to total about 17 in the entire New Mexico/Arizona/Utah region, with about 6 of these in the six-county reservation area.

- **Simulation 7: Wind Turbines, Sunshine.** Employment impacts associated with the Sunshine wind turbine facility are estimated to be the lowest among the nine scenarios contemplated. With a total investment value of about $91 million, this facility is estimated to result in about 90 new jobs in the six counties encompassing the Navajo and Hopi reservations during the one-year construction phase. Total permanent employment impact in the Arizona/New Mexico/Utah region following completion of the plant is estimated to be about 12 new jobs, with approximately 4 of these in the six-county reservation area. With the facility located on Hopi fee land, it is anticipated that a higher percentage of both construction and operational positions would accrue to Hopi tribal members.
- **Simulation 8: Energy Efficiency Program.** Total employment impacts over the five-year life of the program in the six counties encompassing the Navajo and Hopi reservations are estimated to total about 205 net new annual jobs throughout Arizona and New Mexico, with the most significant job impacts in the balance of Arizona and New Mexico regions. Because the program distribution center and installation crews are assumed for the sake of this simulation to be based in Apache County, on the Arizona/New Mexico border, most of the tribal job growth is estimated to be among Navajo Nation members. About 40 full-time jobs per year during the five-year life of the program are estimated to result from this investment among Navajo tribal members.

Table 9-10 — Employment Impacts

Total Plant Investment

Economic Simulation #	1	1A	2	3[17]	4	5	6	7	8
Total Plant Investment ($ millions)	$1,083	$1,083	$1,066	$730	$711	$155	$116	$91	$153

Construction Phase Total Average Annualized Jobs

Economic Simulation #	1	1A	2	3	4	5	6	7	8
Six Reservation Counties	213	213	727	477	355	156	116	92	41
Navajo Nation	129	129	247	193	170	60	44	35	39
Hopi Tribe	9	9	20	18	12	4	3	2	1
Remainder of Arizona	744	744	3,090	2,778	1,669	733	548	432	426
Remainder of New Mexico	237	237	977	424	222	98	73	57	105
Remainder of Utah	163	163	376	193	270	120	90	71	20

[17] Note: In Simulation 3, some operational impacts begin during the construction period, as operation is phased in.

Economic Simulation #	1	1A	2	3	4	5	6	7	8
Remainder of U.S.	9,573	9,573	19,995	9,591	14,071	6,216	4,647	3,659	1,028
Number of Years to Completion	4	4	2	3	2	1	1	1	5

Construction Phase Total Employment Impact (job-years)

Economic Simulation #	1	1A	2	3	4	5	6	7	8
Six Reservation Counties	852	852	1,454	1,431	710	156	116	92	205
Navajo Nation	515	514	494	579	340	60	44	23	194
Hopi Tribe	36	36	39	53	24	4	3	14	3
Remainder of Arizona	2,976	2,976	6,180	8,334	3,338	733	548	432	2,130
Remainder of New Mexico	948	948	1,954	1,272	444	98	73	57	525
Remainder of Utah	652	652	752	579	540	120	90	71	100
Remainder of U.S.	38,292	38,292	39,990	28,773	28,142	6,216	4,647	3,659	5,140

Operation Phase Total Average Annual Jobs

Economic Simulation #	1	1A	2	3	4	5	6	7	8
Six Reservation Counties	333	565	182	244	21	6	6	4	N/A
Navajo Nation	172	278	72	96	14	4	4	1	N/A
Hopi Tribe	27	41	9	13	1	0	0	2	N/A
Remainder of Arizona	297	581	209	282	22	5	5	4	N/A
Remainder of New Mexico	113	214	82	111	4	1	1	1	N/A
Remainder of Utah	31	59	21	27	2	1	1	0	N/A
Remainder of U.S.	1,909	3,606	1,199	1,619	119	30	30	22	N/A

Last page of Section 9.

10. FINANCIAL ISSUES

This section summarizes those financial incentives that are available to owners and investors of electric generation facilities. The incentives are broken down into two general categories:

- Those directed towards the commercialization of specific generation technologies of interest in the Mohave Alternatives/Complements Study (including IGCC, wind, solar, NGCC, and energy efficiency);
- Those directed towards tribal activities or to economic development activities for which tribes are likely to be eligible. For this study, this category specifically focuses on financial incentives directed towards tribal-owned generation facilities and those directed towards low-income communities.

In both cases, financial incentives generally come from the federal or state governments in the form of tax advantages. This include income tax credits, exemptions and deductions for investments, sales tax exemptions on equipment purchases, variable property tax exemptions on the value added by the generation system, production credits based on the quantity of energy produced, job creation credits, and accelerated or special depreciation allowances. Other non-tax incentives generally come in the form of federal, state, and private foundation grants, loans with advantageous terms, or loan guarantee programs. Various forms of technical assistance are also available in some cases. The overall affect of the combined incentives is to help decrease generation costs, increase revenues, and stimulate the construction of new facilities using, perhaps, new technologies that might otherwise be uneconomic or in regions that, for whatever reason, would benefit from an economic boost. This study explores all federal incentives, plus state incentives in Nevada, New Mexico, and Arizona.

The applicability of each of the incentives depends not only on the nature of the business, but also on the type of owner(s) and the specific legal relationship of the owner(s) to the electric generation project. In other words, different legal entities qualify for different incentives.

All in all, the value of the financial incentives and the movement of monies directed towards development is significant (potentially tens of millions of dollars annually for some types of projects or recipients) and can truly drive not only specific types of generation but also their geographic location.

The following section reviews various financial incentives that are potentially available. The next section details information on business classifications. Thereafter, there is a section that looks at hypothetical packages of financial incentives directed at specific technologies/business entities.

10.1 FINANCIAL INCENTIVES

10.1.1 Methodology

This subsection reviews incentives available to different types of supply and demand-side technologies along with incentives directed towards tribal activities and towards economic development, in general. The list of incentives was developed by reviewing the following sources:

- The Domenici-Barton Energy Policy Act of 2005 (EPACT 2005)
- Various Internal Revenue Service income tax forms
- USDA, DOE, and U.S. Small Business Administration websites
- Federal Grants Wire website
- The Database of State Incentives for Renewable Energy (DSIRE), which is an ongoing project of the Interstate Renewable Energy Council (IREC), funded by the U.S. Department of Energy and managed by the North Carolina Solar Center.
- Community Development Financial Institutions Fund website
- The Administration for Native Americans (ANA) website
- The Minority Business Development Agency website
- Indian Community Development Block Grant website
- Buzgate website: Buzgate is a business-to-business resource portal that provides information, goods, and services tailored to small and medium sized businesses.
- City of Henderson, Nevada website: lists many economic development opportunities.
- EDAWN website: EDAWN (Economic Development Authority of Western Nevada) is a private/public partnership committed to recruiting and expanding quality companies that have a positive economic impact on the quality of life in the western Nevada region.
- Various papers including Nancy Pindus's "Overcoming Challenges to Business and Economic Development in Indian Country, " presented to the Department of Health and Human Services: Office of the Assistant Secretary for Planning and Evaluation, August 2004.
- Various additional documents and websites.

A series of tables has been developed, – one for each technology alternative considered in this study, and one for economic development incentives. The tables are laid out in similar formats, with information regarding the eligible technology, name of the incentive program, the dollar amount of the incentive, terms associated with the program, the program administrator, eligible recipients, and the effective dates that the incentive is in place.

10.1.2 Technology-Specific Financial Incentives

Table 10-1 — IGCC Incentives

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
IGCC	EPACT 2005, Section 1307. Credit for Investment in Clean Coal Facilities	Tax Credits	Up to $800 million for IGCC projects and up to $500 million for other advanced coal-based technologies and up to $350 million for industrial gasification.	(1) 20% credit for industrial gasification projects, (2) 20% credit for integrated gasification combined-cycle (IGCC) electric generation projects, and (3) 15% credit for other advanced coal-based projects that produce electricity. The Federal share of the cost of a coal or related technology project funded by the Secretary cannot exceed 50%.	Secretary of Energy	The project must be located in the United States.	2006-2014
IGCC	EPACT 2005, Section 414, Coal Gasification	Loan Guarantees	The DOE Secretary shall provide guarantees for no more than $2 billion at any time.	Plants must be at least 400 MW in capacity. Power must be sold to the deregulated marketplace (the generation facility cannot receive any subsidy from ratepayers.) The guarantees can only be for 80% of the cost of a project.	Secretary of the Interior	Not specified	Not specified
IGCC	EPACT 2005, Section 1701, Incentives for Innovative Technologies	Loan Guarantees	Not specified	A guarantee shall not exceed an amount equal to 80% of the project cost of the facility. Maximum of 30 year loan; maximum of 90% of the projected useful life of the project to be financed; must have design that accommodates carbon capture	Secretary of Energy	Gasification projects, as well as others	Not specified
IGCC	EPACT 2005, Section 1301, Extension and Modifications of Renewable Electricity Production Credit	Tax Credits	The Tax Act extends the availability of the Section 45 energy credit. Two new qualifying energy resources are added: hydropower and Indian coal. The credit for electricity generated from a hydropower facility is reduced by 50%, however. For Indian coal	Eligible Technologies: Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, CHP/Cogeneration, Refined Coal, Indian Coal, Anaerobic Digestion, Small Hydroelectric; A business can take the credit by completing Form 8835, "Renewable Electricity Production Credit,"	Secretary of Energy, U.S. Treasury	Commercial and Industrial sectors	Through January 1, 2008

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
			facilities, there is a seven-year credit period. Indian coal production facilities will receive an increase in tax credit during the 7-year period beginning January 1, 2006 in the amount of \$1.50/ton through 2009, and \$2.00/ton after 2009.	and Form 3800, "General Business Credit."			

Table 10-2 — Natural Gas CC Incentives

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Natural Gas CC	EPACT 2005, Section 1327. Arbitrage rules not to apply to prepayments for natural gas.	Tax exempt bonds	Not specified	Tax exempt bonds for pre-payment towards natural gas contracts.	Secretary of Energy	*still under study and possibly not applicable to SCE or tribes. Applies to any contract to acquire natural gas for resale by a utility owned by a governmental unit	Applies to obligations after 8/8/2005

Table 10-3 — Carbon Sequestration Incentives

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Carbon Sequestration	EPACT 2005, Section 2602, Indian Energy Education Planning and Management Assistance	Grants for energy education, research and development, planning and management needs	$20,000,000 per year	Programs focus is: energy efficiency, studies that support tribal acquisitions of energy related activities; planning, construction, operations, maintenance of electrical and T&D facilities on Indian Lands, carbon sequestration; Priority will be given to tribes with adequate electric service (as determined by the Director.)	Director of the Office of Indian Energy Policy and Programs, Department of Energy	Indian tribes	2003-2016
Carbon Sequestration	EPACT 2005, Section 1701, Incentives for Innovative Technologies	Loan Guarantees	Not specified	A guarantee shall not exceed an amount equal to 80% of the project cost of the facility. Maximum of 30-year loan.	Secretary of Energy	Carbon capture and sequestration practices and technologies, including agricultural and forestry practices that store and sequester carbon	Not specified
Carbon Sequestration	Enhanced Oil Recovery Tax Credit: IRS Form 8830	Tax Credits	15% tax credit for costs associated with a qualified enhanced oil recovery project, including cost of the CO_2 injectant, cost of depreciable, tangible property, and cost of intangible drilling related to the project.	The 15% credit is reduced when the reference price per barrel of oil exceeds the base value of $28 (as adjusted by inflation.) For 2004, there was no reduction of the credit. Not applicable to those paying alternative minimum tax (AMT).	U.S. Treasury	Those filing income taxes with IRS	1990

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Carbon Sequestration	Proposed H.R.1128	Tax Credits	Amends the Internal Revenue Code to allow a business tax credit for amounts of Sets the credit amount at 75 cents (adjusted for inflation) per 1,000 standard cubic feet of the carbon dioxide captured.	Qualified carbon dioxide must be from anthropogenic industrial sources (e.g., an ethanol plant, fertilizer plant, or chemical plant) and used as a tertiary injectant in enhanced oil and natural gas recovery.	U.S. Treasury	Those filing taxes with IRS	Latest Major Action: 3/3/2005 Referred to House committee. Status: Referred to the House Committee on Ways and Means.

Table 10-4 — Energy Efficiency Incentives

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Energy Efficiency	EPACT 2005, Section 2602, Indian Energy Education Planning and Management Assistance	Grants for energy education, research and development, planning and management needs	$20,000,000 per year	Programs focus is: energy efficiency, studies that support tribal acquisitions of energy related activities; planning, construction, operations, maintenance of electrical and T&D facilities on Indian Lands, carbon sequestration; Priority will be given to tribes with adequate electric service (as determined by the Director.)	Director of the Office of Indian Energy Policy and Programs, Department of Energy	Indian tribes	2003-2016
Energy Efficiency	EPACT 2005, Sec. 126. Low Income Community Energy Efficiency Pilot Program	Grants	$20 million annually	Monies issued for--(1) investments that develop alternative, renewable, and distributed energy supplies;(2) energy efficiency projects and energy conservation programs;(3) studies and other activities that improve energy efficiency in low income rural and urban communities;(4) planning and development assistance for increasing the energy efficiency of buildings and facilities; and(5) technical and financial assistance to local government and private entities on developing new renewable and distributed sources of power or combined heat and power generation.	Secretary of Energy	Units of local government, private, non-profit community development organizations, and Indian tribe economic development entities	2006-2008
Energy Efficiency	USDA Renewable Energy Systems and Energy Efficiency Improvements Program , Section 9006 of the 2002 Farm Bill	Guaranteed Loan Funds/ Grants	2005 funding: up to $200 million; Grants: 25% of eligible project costs; Guaranteed loans: 50% of eligible project costs ; maximum grant: Grants: $500,000 per renewable-energy project; maximum guaranteed loans: $10 million (pending)	The guarantees can only be for 80% of the cost of a project; developers will share in the risk.	USDA	Funds are targeted towards agricultural producers and small rural businesses. Biomass (including anaerobic digesters), geothermal, hydrogen, solar, and wind energy, as well as energy efficiency improvements. Eligible participants: · A	2003-2007

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
						private entity including a sole proprietorship, partnership, corporation, cooperative (including a cooperative qualified under section 501(c)(12) of the Internal Revenue Code, and an electric utility, including a Tribal or Governmental Electric Utility that provides service to rural consumers on a cost-of service basis without support from public funds or subsidy from the Government authority establishing the district. These entities must operate independent of direct Government control.	

10.1.3 Renewable Energy Incentives

Table 10-5 — Federal Incentives for Renewables

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Renewable Energy	USDA Renewable Energy Systems and Energy Efficiency Improvements Program, Section 9006 of the 2002 Farm Bill	Guaranteed Loan Funds/ Grants	2005 funding: up to $200 million; Grants: 25% of eligible project costs; Guaranteed loans: 50% of eligible project costs ; maximum grant: Grants: $500,000 per renewable-energy project; maximum guaranteed loans: $10 million (pending)	The guarantees can only be for 80% of the cost of a project; developers will share in the risk. Funds are targeted towards agricultural producers and small rural businesses. Biomass (including anaerobic digesters), geothermal, hydrogen, solar, and wind energy, as well as energy efficiency improvements.	USDA	Eligible participants: · A private entity including a sole proprietorship, partnership, corporation, cooperative (including a cooperative qualified under section 501(c)(12) of the Internal Revenue Code, and an electric utility, including a Tribal or Governmental Electric Utility that provides service to rural consumers on a cost-of service basis without support from public funds or subsidy from the Government authority establishing the district. These entities must operate independent of direct Government control.	2003-2007
Renewable Energy	EPACT 2005: Section 54 holders of clean renewable energy bonds	Tax Credits from Bond Issuances	Bonds designated specifically for “Clean Renewable Energy.” The credit rate on the bonds will be determined by the Secretary of the Treasury and will be a rate that permits issuance of CREBS, an interest-free loan –	95% of proceeds from the bond issuance must be used to finance capital expenditures incurred for qualifying facilities. The credit will be includable in gross income (as if it were an interest payment on the bond) and can be claimed against regular income tax	Secretary of Energy and Secretary of Treasury	Qualified issuers include governmental bodies (including Indian tribal governments) and mutual or cooperative electric companies.	January 1, 2006 ton December 31, 2008

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
			that is, without original issue discount and at a 0% interest rate. A national limitation of $1 billion of CREBS is available to qualified projects.	liability and alternative minimum tax liability.			
Renewable Energy	EPACT 2005: Section 202, Renewable Energy Production Incentive Program	Production Incentive	Production credits vary by technology. They are based on kilowatt-hours of generated electricity; For any facility, the amount of such payment shall be 1.5 cents per kilowatt hour, adjusted for inflation for each fiscal year beginning after calendar year 1993. No maximum specified regarding total amount of funding availability	Qualifying facilities: solar, wind, biomass, or geothermal energy, landfill gas, livestock methane, ocean	U.S. Treasury and Secretary of Energy	A not-for-profit electric cooperative, a public utility, a State, Commonwealth, territory, or possession of the U.S., or the District of Columbia, or a political subdivision, an Indian tribal government or subdivision, or a Native Corporation	2006-2026
Renewable Energy	EPACT 2005, Section 1301, Extension and Modifications of Renewable Electricity Production Credit	Tax Credits	The Tax Act extends the availability of the Section 45 energy credit for two years (through December 31, 2007) for electricity produced from renewable resources, for all except solar facilities (expires December 31, 2005) and refined coal facilities (expires December 31, 2008). It extends the credit period from five to ten years for qualifying facilities placed in service after August 8, 2005. Two new qualifying energy resources are added: hydropower and Indian coal. The credit for electricity generated from a hydropower facility is reduced by 50%, however. For Indian coal facilities, there is a seven-year credit period. Indian coal production facilities will receive	Eligible Technologies: Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, CHP/Cogeneration, Refined Coal, Indian Coal, Anaerobic Digestion, Small Hydroelectric; A business can take the credit by completing Form 8835, "Renewable Electricity Production Credit," and Form 3800, "General Business Credit."	Secretary of Energy, U.S. Treasury	Commercial and Industrial sectors	Through January 1, 2008

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
			an increase in tax credit during the 7-year period beginning January 1, 2006 in the amount of $1.50/ton through 2009, and $2.00/ton after 2009.				
Renewable Energy	EPACT 2005, Section 1701, Incentives for Innovative Technologies	Loan Guarantees	Not specified	A guarantee shall not exceed an amount equal to 80% of the project cost of the facility. Maximum of 30 year loan.	Secretary of Energy	Projects include renewable energy systems and others	Not specified
Renewable Energy	EPACT 2005, Sec. 126. Low Income Community Energy Efficiency Pilot Program	Grants	$20 million annually	Monies issued for--(1) investments that develop alternative, renewable, and distributed energy supplies;(2) energy efficiency projects and energy conservation programs;(3) studies and other activities that improve energy efficiency in low income rural and urban communities;(4) planning and development assistance for increasing the energy efficiency of buildings and facilities; and(5) technical and financial assistance to local government and private entities on developing new renewable and distributed sources of power or combined heat and power generation.	Secretary of Energy	Units of local government, private, non-profit community development organizations, and Indian tribe economic development entities	2006-2008
Renewable Energy	Energy Policy Act of 2005 (Section 1336 - 1337), Business Solar Investment Tax Credit, Credit For Business Installation Of Qualified Fuel Cells And Stationary Microturbines	Tax Credits	Currently 10% for geothermal electric and solar; from January 1, 2006 until December 31, 2007, the credit is 30% for solar, solar hybrid lighting, and fuel cells, and 10% for microturbines. The geothermal credit remains at 10%. Maximum incentive: $550 per 0.5 kW for fuel cells; $200/kW for microturbines; no maximum specified for other technologies	Microturbines must be less than 2 MW; fuel cells must be at least 0.5 kW; eligible technologies: Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Geothermal Electric, Fuel Cells, Solar Hybrid Lighting, Direct Use Geothermal, Microturbines	Secretary of Energy and Secretary of Treasury	Those businesses filing taxes with IRS	1/1/2006-12/31/2007

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Renewable Energy	26 USC § 168, UNITED STATES CODE SERVICE TITLE 26. INTERNAL REVENUE CODE SUBTITLE A. INCOME TAXES Modified Accelerated Cost-Recovery System. (MACRS)	Depreciation	Businesses can recover investments in solar, wind and geothermal property through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to 50 years, over which the property may be depreciated. In the case of investments on Indian Property: recovery period is: 3-year property ....2 years 5-year property ....3 years 7-year property ....4 years 10-year property ....6 years 15-year property ....9 years 20-year property ....12 years Nonresidential real property .... 22 years.	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Geothermal Electric.;	U.S. Treasury	Those businesses filing taxes with IRS	1986
Renewable Energy	EPACT 2005, Section 210.	Grants	$50,000,000 annually	Grants to improve the commercial value of forecast biomass for electric energy, useful heat, transportation fuels, and other commercial purposes	Secretary of Energy	Any Indian tribe is eligible, as are towns, townships, municipalities, local governments, and counties	2006-2016
Renewable Energy	DOE's Office of Energy Efficiency and Renewable Energy's Tribal Energy Program	Grant	The FY2004 program budget included $6 Million, and 2.5 million in funding for 18 tribes for FY2005.	Financial and technical assistance to tribes for feasibility studies and shares the cost of implementing sustainable renewable energy installations on tribal lands. This program seeks to promote tribal energy self-sufficiency and fosters	Department of Energy, Office of Energy Efficiency and Renewable Energy	Tribal government	Not specified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
				employment and economic development on America's tribal lands			
Renewable Energy	USDA: Value Added Producer Grants	Grants	A total of $14.3 million in grants was allocated for fiscal year 2005' Grant awards for fiscal year 2005 supported energy generated on-farm through the use of agricultural commodities, wind power, water power or solar power. The maximum award per grant was $100,000 for planning grants and $150,000 for working capital grants. Matching funds of at least 50% were required.	"On-farm" Biomass, wind, water power, solar	USDA	Value-Added Producer Grants are available to independent producers, agricultural producer groups, farmer or rancher cooperatives, and majority-controlled producer-based business ventures	Not specified
Renewable Energy	The Farm Security and Rural Investment Act of 2002 (2002 Farm Bill): USDA Conservation Security Program (CSP) Production Incentive	Grant	The 2005 CSP sign-up includes a renewable-energy component. Eligible producers will receive $2.50 per 100 kWh of electricity generated by new wind, solar, geothermal and methane-to-energy systems. Payments of up to $45,000 per year will be made using three tiers of conservation contracts, with a maximum payment period of 10 years.	Wind, solar, geothermal, methane-to-energy systems. The goal is to promote the conservation and improvement of soil, water, air, energy, plant and animal life, and other conservation purposes on Tribal and private working lands. Working lands include cropland, grassland, prairie land, improved pasture, and range land, as well as forested land that is an incidental part of an agriculture operation.	USDA's Natural Resources Conservation Service	Farmers; The program is available in all 50 States, the Caribbean Area and the Pacific Basin area. The program provides equitable access to benefits to all producers, regardless of size of operation, crops produced, or geographic location.	Not specified

Table 10-6 — State Incentives for Renewables

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Nevada							
Renewable Energy	Nevada Administrative Code, NAC 704.8901 through NAC 704.8937, Nevada Renewable Energy Credits	Tax credits for production	Varies; Higher value for solar RECs than other technologies; "Renewable energy credit" means a unit of credit which: 1. Equals 1 kilowatt-hour of electricity generated by a renewable energy system. 2. For a solar facility that reduces the consumption of electricity by the generation of solar energy, equals the amount of consumption of electricity, natural gas or propane that is reduced at the facility by the operation of the solar facility. 3. For a net metering system, equals the amount of metered electricity generated by the system or, if the system does not use a meter to measure the kilowatt-hours of electricity generated by the system, equals the estimate of the electricity generated by the system	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric, Solar Pool Heating	Nevada Public Utilities Commission of Nevada	Commercial, Industrial, Residential, Nonprofit, Schools, Local Government, Utility, State Government, Tribal Government, Agricultural, Institutional	Effective through June 30, 2007
Renewable Energy	NEVADA REVISED STATUTES ANNOTATED TITLE 32. REVENUE AND TAXATION CHAPTER 361. PROPERTY TAX Nevada's	Property tax abatement	50% property tax abatement for real and personal property used to generate electricity from renewable energy.	The exemption may be taken over a 10 year period for a facility with a generating capacity of at least 10 kW. Renewable energy includes biomass, solar, and wind. The definition of biomass includes agricultural crops and agricultural wastes and residues; wood and wood wastes and residues; animal wastes; municipal wastes; and aquatic plants.	Nevada Commission on Economic Development and Nevada Department of Taxation	Commercial, Utility, (Renewable Energy Power Producers)	2001 to unspecified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	Renewable Energy Producers Property Tax Abatement						
Renewable Energy	TITLE 32. REVENUE AND TAXATION, Ch. 361. Property tax assessment § 361.079 Renewable Energy Systems Property Tax Exemption	Property Tax Exemption	In Nevada, any value added by a qualified renewable-energy system shall be subtracted from the assessed value of any residential, commercial or industrial building for property tax purposes. 100% exemption.	Qualified equipment includes solar, wind, geothermal, solid waste and hydroelectric systems. This exemption applies for all years following installation.	Nevada Department of Taxation	Commercial, Industrial, Residential	Not specified
Renewable Energy	NEVADA ASSEMBLY BILL No. 3, Renewable Energy/Solar Sales Tax Exemption	Sales Tax Exemption	100% exemption from local sales taxes; 2% state sales tax still applies	Nevada law exempts from local sales and use taxes the sale, storage and consumption of any products or systems designed or adapted to use renewable energy to generate electricity and all of its integral components. Included in the exemption are all sources of energy that occur naturally or are regenerated naturally, including biomass (agricultural crops, wastes and residues, wood, wood wastes, and residues, animal wastes, municipal waste and aquatic plants), fuel cells, geothermal energy, solar energy, hydropower and wind.	Nevada Department of Taxation	Commercial, Residential, General Public/Consumer	Currently set to expire 12/31/05
Arizona							
Renewable Energy	ARIZONA REVISED STATUTES, A.R.S. § 42-5075, TITLE 42. TAXATION, Arizona Solar	Sales Tax Exemption	$5,000 per system for retailers; $5,000 per contract for contractors	Solar/wind retailer or contractor must register with the Arizona Department of Revenue	Arizona Department of Revenue	Commercial contractors	1/1/97-1/11/2011

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	and Wind Equipment Sales Tax Exemption						
New Mexico							
Renewable Energy	HB 995 of 2005: New Mexico Biomass Equipment & Materials Deduction	Sales Tax Exemption	100% of value of biomass equipment and biomass materials used for the processing of biopower, biofuels or bio-based products may be deducted for purposes of calculating Compensating Tax due. New Mexico's Compensating Tax is an excise, or "use" tax, which is typically levied on the purchaser of the product or service for using tangible property in the state.	The tax applies to imports of factory and office equipment, and other items. The rate is 5% of the value of the property or service.	New Mexico Taxation & Revenue Department	Commercial, Industrial taxpayers	4/5/2005 to unspecified
Renewable Energy	House Bill 251 of 2004, New Mexico Clean Energy Grants Program	Grants	Program Budget: $2,000,000 for 2005 RFP; maximum amount: $200,000	Supports the development of renewable energy, energy efficiency, and alternative transportation fuels technologies. Capital projects resulting from the current Request for Proposals will be required to meet performance measures established for the Program, including a 5% reduction in energy consumption in building projects or 15% increase in alternative fuel usage.	New Mexico Energy, Minerals and Natural Resources Department, Energy Conservation and Management Division	Schools, Local Government, State Government, Tribal Government	Unspecified
Renewable Energy	New Mexico Renewable Energy Production Tax Credit	Production Credit, Enacted in 2002, and amended in 2003 by HB 146,	A tax credit against the corporate income tax of one cent per kilowatt-hour for companies that generate electricity from wind, solar, or biomass	The credit is applicable only to the first 400,000 megawatt-hours of electricity in each of 10 consecutive years. To qualify, an energy generator must use a zero-emissions generation technology and have capacity of at least 10 megawatts. Energy generation from all participants combined must not exceed two million megawatt-hours of production annually.	New Mexico Taxation & Revenue Department	Commercial, Industrial taxpayers	2002 to unspecified

10.1.4 Financial Incentives for Tribal Activities and Economic Development – General

These incentives, by definition, include the use of programs, services, and funding to attract new business or to retain and expand existing businesses. This study examined incentives directed specifically towards tribes (who may also qualify for economic development incentives targeted to low-income and rural areas.) These include tax-exempt revenue bonds, federal grant and loan guarantee programs, freedom from liability of federal income tax and more. Those economic incentives that are currently available at the federal level, as well as state initiatives in Nevada, Arizona, New Mexico, and Utah are reviewed below.

Table 10-7 — Currently Available Economic Incentives

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Energy - all resources	EPACT 2005, Section 2602, Indian energy resource development program	Grants to develop or obtain managerial and technical capacity to develop energy on Indian land; grants and low interest loans to promote the integration of energy resources, and to process, use, or develop these energy resources; grants to an tribal environmental organization that represent multiple Indian tribes.	There are authorized “such sums as are necessary”	Activities might include training programs, development of model environmental policies and tribal laws, recommended standards for reviewing implementation of tribal environmental laws and policies	Secretary of the Interior	Indian tribes	2006-2016
Energy Efficiency, conservation, carbon sequestration	EPACT 2005, Section 2602, Indian energy Education Planning and Management Assistance	Grants for energy education, research and development, planning and management needs	$20,000,000 per year	Programs focus is: energy efficiency, studies that support tribal acquisitions of energy related activities; planning, construction, operations, maintenance of electrical and T&D facilities on Indian Lands, carbon sequestration; Priority will be given to tribes with adequate electric service (as determined by the Director.)	Director of the Office of Indian Energy Policy and Programs, Department of Energy	Indian tribes	2003-2016

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Not specified	EPACT 2005, Section 2602, Department of Energy Loan Guarantee Program	Loan Guarantees	The aggregate outstanding amount guaranteed at any time under this section shall not exceed $2 billion	Loans are provided to provide for and expand the provision of electricity on Indian lands. Loan amount cannot be more than 90% of the unpaid principle and interest due on any loan made to an Indian tribe for energy development	Secretary of Energy	Preference will be given to an energy and resource production enterprise, partnership, consortium, corporation, or other business with a majority of interest that is owned and controlled by one or more Indian tribes.	Available under funds are expended
Not specified	EPACT 2005, Section 2603, Indian tribal Energy Resource Regulation	Grants	Not specified	Grants for development of energy resource inventory, feasibility studies, development and enforcement of tribal laws relating to energy, development of technical infrastructure to protect the environment	Secretary of the Interior	Indian tribes	Not specified
Not specified	EPACT 2005, Section 2604. Leases, Business Agreements, and Rights-of-way involving Energy Development or Transmission	Leases and Business Agreements	Unspecified amount; establishes a process by which an Indian tribe, upon demonstrating its technical and financial capacity and receiving approval of their Tribal Energy Resource Agreement, could negotiate and execute energy resource development leases, agreements and rights-of-way with third parties without first obtaining the approval of the Secretary of the Interior.	The tribe may enter leases or business agreements for the purpose of energy resource development on tribal land. Lease agreement cannot exceed 30 years	Secretary of the Interior	Indian tribes	Not specified
Energy Efficiency	EPACT 2005,	Grants	$20 million annually	Monies issued for--(1) investments	Secretary of Energy	units of local	2006-2008

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	SEC. 126. Low Income Community Energy Efficiency Pilot Program			that develop alternative, renewable, and distributed energy supplies;(2) energy efficiency projects and energy conservation programs;(3) studies and other activities that improve energy efficiency in low income rural and urban communities;(4) planning and development assistance for increasing the energy efficiency of buildings and facilities; and(5) technical and financial assistance to local government and private entities on developing new renewable and distributed sources of power or combined heat and power generation.		government, private, non-profit community development organizations, and Indian tribe economic development entities	
Renewable Energy	EPACT 2005: Section 202, Renewable Energy Production Incentive Program	Tax Credits	Production credits vary by technology. They are based on kilowatt-hours of generated electricity; For any facility, the amount of such payment shall be 1.5 cents per kilowatt-hour, adjusted for inflation for each fiscal year beginning after calendar year 1993. No maximum to total amount of funding availability.	Qualifying facilities: solar, wind, biomass, or geothermal energy, landfill gas, livestock methane, ocean	U.S. Treasury and Secretary of Energy	a not-for-profit electric cooperative, a public utility, a State, Commonwealth, territory, or possession of the U.S., or the District of Columbia, or a political subdivision, an Indian tribal government or subdivision, or a Native Corporation	2006-2026
Energy Efficiency/Renewable Energy	USDA Renewable Energy Systems and Energy Efficiency Improvements Program , Section 9006 of the 2002 Farm Bill	Guaranteed Loan Funds/ Grants	2005 funding: up to $200 million; Grants: 25% of eligible project costs; Guaranteed loans: 50% of eligible project costs ; maximum grant: Grants: $500,000 per renewable-energy	The guarantees can only be for 80% of the cost of a project; developers will share in the risk.	USDA	Funds are targeted towards agricultural producers and small rural businesses. Biomass (including anaerobic digesters), geothermal,	2003-2007

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
			project; maximum guaranteed loans: $10 million (pending)			hydrogen, solar, and wind energy, as well as energy efficiency improvements. Eligible participants: · A private entity including a sole proprietorship, partnership, corporation, cooperative (including a cooperative qualified under section 501(c) (12) of the Internal Revenue Code, and an electric utility, including a Tribal or Governmental Electric Utility that provides service to rural consumers without support from public funds or subsidy from the Government authority establishing the district. These entities must operate independent of Government control.	
Renewable Energy	DOE's Office of Energy Efficiency and Renewable	Grant	The FY2004 program budget included $6 Million, and 2.5 million	Financial and technical assistance to tribes for feasibility studies and shares the cost of implementing sustainable	Department of Energy, Office of Energy Efficiency	Tribal government	Not specified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	Energy's Tribal Energy Program		in funding for 18 tribes for FY2005.	renewable energy installations on tribal lands. This program seeks to promote tribal energy self-sufficiency and fosters employment and economic development on America's tribal lands.	and Renewable Energy		
Not applicable	Taxpayer Relief Act of 1997: USDA Empowerment Zone and Enterprise Community (EZ / EC) Program	Grants, Tax-exempt bonds, wage credit provision, work opportunity tax credit, Qualified Zone Academy Bonds, Brownfields Deductible Expense, Internal Revenue Code 26 U.S.C. § 179 Expensing:	Grant amount is unspecified; Round III rural zones can each issue up to $60,000,000 in "new bonds" to finance zone facilities in addition to Round I type tax exempt bonds. Round II "new bonds" are not subject to private activity bond volume caps or the special limits on issue size applicable to Round I type issues; 20% tax credit for the first $15,000 in wages paid to a qualified employee (for a tax credit of up to $3,000 per employee).	It addresses a comprehensive range of community problems and issues, including many that have traditionally received little federal assistance, reflecting the fact that rural problems do not come in standardized packages but can vary widely from one place to another; it represents a long-term partnership between the federal government and rural communities—ten years in most cases—so that communities have enough time to implement a series of interconnected and mutually-supporting projects and build the capacity to sustain their development beyond the term of the partnership.	USDA Rural Development	Tribes and others	1997- Dec.31, 2009
Not applicable	USDA / Rural Business Cooperative Service: Federal Agriculture Improvement and Reform Act of 1996	Grant	Unspecified amount.	Grants are targeted towards business and economic development planning, training, etc.			1996- unspecified
Not applicable	USDA / Farm Service Agency, Indian Tribes and Tribal Corporation	Loan Guarantees	$2 million is authorized.	The purpose of this program is to eliminate fractional ownership of lands. Through loans, tribes and tribal corporations can acquire additional	Loan funds cannot be used for any improvement or development	Limited to any Indian tribe recognized by the Secretary of the	Unspecified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	Loans			land. Loan funds may be used to acquire land and interest therein for the benefit and use of the tribe or its members for purposes such as rounding out farming and ranching units or elimination of fractional heir ships. Funds may also be used for incidental costs connected with land purchase such as appraisals, title clearance, legal services, land surveys, and loan closing. Loan funds may be used to refinance non-United States Department of Agriculture preexisting debts that applicant incurred to purchase land subject to certain conditions.	purposes, acquisition or repair of buildings or personal property, payment of operating costs, payment of finder's fees, or similar costs	Interior or tribal corporation established pursuant to the Indian Reorganization Act or community in Alaska incorporated by the Secretary of Interior pursuant to the Indian Reorganization Act which does not have adequate uncommitted funds to acquire lands within the tribe's reservation or in a community in Alaska. The tribe must be unable to obtain sufficient credit elsewhere at reasonable rates and terms and must be able to show reasonable prospects of repaying the loan as determined by an acceptable repayment plan and a satisfactory management plan for the land being acquired.	
Not applicable	HUBZone Act of 1997	Contract preferences	This program provides federal contract preferences to small businesses located in		USDA, HUD, SBA	All Native American lands qualify for preferential treatment.	1997-unspecified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
			HUB Zones - historically underutilized business zones. The purpose of the program is to increase employment, capital investment, and economic development in these zones.				
Not applicable	U.S. Treasury Indian Reservation Economic Investment Act of 2001	Tax Credits	Provides tax credits to those investments that promote Indian reservation economic development. Credit is based on the level of unemployment on the reservation.		U.S. Treasury	Unclear	2001-unspecified
Not applicable	U.S. Treasury Indian Employment Tax Credit	Tax Credits	A tax credit is provided to those that employ Native Americans that live on or near a reservation. More specifically, for every Native American employee or employee who is a spouse of a Native American, the employer can claim a credit of 20% of the first $20,000 of wages and medical insurance expense.		U.S. Treasury	Unclear	Unspecified
Not applicable	U.S. Treasury Community Development Financial Institution Fund: Native CDFI, Established under the Reigle	loans, investments, financial services and technical assistance, and training;		The Fund seeks to assist Native Communities to create CDFIs that will primarily serve Native communities as well as to strengthen CDFIs already primarily serving those communities. "Primarily Serves" is defined as 50% or more of the applicant's activities being directed to a Native Community	U.S. Treasury	CDFIs that serve Native communities.	1994 - unspecified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	Community Development and Regulatory Improvement Act of 1994.			(such as a reservation, Alaska Native Village, or Hawaiian Home Land or to Native American, Alaska Native, or Native Hawaiian people). "Native CDFI" is defined as a CDFI that primarily serves a Native Community.			
Not applicable	New Markets Tax Credit	Tax Credits	The project receives a tax credit of 39% of the qualified investment over a 7-year period. The structure of the project is important – can be structured such that the project investor receives credit without controlling the project; in this, taxpayers make equity investments in low-income businesses located in low-income communities. The taxpayer can claim a tax credit equal to 5% of its equity investment of the first three years and 6% over the next four years. (Total 39%)	The taxable investor must create a special purpose entity known as a community development entity (CDE). To do this, the CDE must be classified as either a domestic corporation, a limited liability company, or a partnership with a valid employment identification number. At least 60% of CDE activities must be directed towards serving low-income communities.	U.S. Treasury	The New Markets Tax Credit was devised to encourage third-party investors to invest in low-income communities. Qualifying businesses must therefore be located in a low-income community and have a substantial connection to that low-income community. Reservations qualify and are given some priority.	1994 - unspecified
Not applicable	Small Business Association: Public Law 95-507	Preferential treatment for subcontractors	Requires each public contract to be performed in the United States which exceeds $10,000 in amount to include a clause requiring that small business concerns owned and controlled by socially and economically disadvantaged individuals be given the		SBA	Eligible individuals: (1) Black Americans; (2) Hispanic Americans; (3) Native Americans; (4) other minorities; and (5) other individuals determined by the SBA pursuant to the Small Business Act.	1978- unspecified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
			maximum practicable opportunity to participate in such contracts. Defines such ownership and control as: (1) at least 51% ownership by disadvantaged individuals; and (2) management of such concerns by one or more disadvantaged individuals.				
Not applicable	Department of Commerce: Public Works and Economic	Grants	Investments in facilities such as water and sewer system improvements, industrial access roads, industrial and business parks, port facilities, railroad sidings, distance learning facilities, skill-training facilities, business incubator facilities, redevelopment of brownfields, eco-industrial facilities, and telecommunications infrastructure improvements needed for business retention and expansion.	Eligible projects must fulfill a pressing need of the area and must: 1) improve the opportunities for the successful establishment or expansion of industrial or commercial plants or facilities; 2) assist in the creation of additional long-term employment opportunities; or 3) benefit the unemployed/underemployed residents of the area or members of low-income families.	Department of Commerce	Indian tribes qualify, as well as others	1965 - unspecified
Not applicable	Department of Commerce: Minority Business Development Administration	one-on-one assistance in writing business plans, marketing, management and technical assistance and financial planning	Not specified	Not specified	Department of Commerce: Minority Business Development Agency	Assistance is available to minority business owners (including Native Americans.)	Not specified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Not applicable	U.S. Department of Housing and Urban Development Indian Community Development Block Grant Program	Grants	Direct grants for use in developing viable Indian and Alaska Native Communities, including decent housing, a suitable living environment, and economic opportunities, primarily for low and moderate income persons.	Wide variety of commercial, industrial, agricultural projects that may be recipient owned and operated or which may be owned and/or operated by a third party.	The program is administered by the six area ONAPs with policy development and oversight provided by the Denver National Program Office of ONAP.	Eligible applicants for assistance include any Indian tribe, band, group, or nation (including Alaska Indians, Aleuts, and Eskimos) or Alaska Native village which has established a relationship to the Federal government as defined in the program regulations. In certain instances, tribal organizations may be eligible to apply.	Not specified
Not applicable	Bureau of Indian Affairs Indian Economic Development	Grants	Unspecified; funds are used to improve Native American economies.	Not specified	Department of the Interior	Tribes	Not specified
Not applicable	U.S. Department of Interior Indian Loans	Direct and guaranteed loans	The Bureau has Credit Reform loan accounts (post 1991) for the Indian Direct Loan Program and Indian Loan Guarantee Program and a Liquidating Fund for loans made before 1992.	Funds are to be used for economic development.	Department of the Interior	Indian tribes and organizations, Indian individuals, and Alaska Natives	Not specified
Not applicable	U.S. Department of Health and Human Services / Administration for	Grants	ANA promotes lasting self-sufficiency and enhances self-government largely		U.S. Department of Health and Human Services	American Indians, Native Americans, Native Alaskans, Native Hawaiians	Not specified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	Native Americans Program: Social and Economic Development Strategies (SEDS)		through grant awards that support social and economic development strategies. These awards are competitive financial assistance grants in support of locally determined and designed projects to address community needs and goals. This approach of promoting self-sufficiency supports native communities in their efforts to reduce dependency on public funds and social services by increasing community and individual productivity through community development. In FY 2003, ANA awarded approximately $20 million for social and economic development projects.			and Pacific Islanders	

In addition to the above, there are a variety of resources that are available to assist local businesses, provide business information, and support specific industry sectors. Many of these are aimed primarily at small business, but may be of interest in connection with tribal enterprises or businesses on or near tribal lands that could supply goods and services to larger projects.

Nevada

- THE NEVADA DEPARTMENT OF EMPLOYMENT, TRAINING AND REHABILITATION (DETR). Provides a number of labor related services to Nevada's job seekers and employers. Services include, but are not limited to, applicant recruitment and screening, career enhancement training program, and provision of labor market information.
- THE COMMUNITY COLLEGE OF SOUTHERN NEVADA, INSTITUTE FOR BUSINESS & INDUSTRY. Offers Corporate and Customized Training to address training and educational needs of Southern Nevada business and industry. This program specializes in developing customized group training to help companies achieve staff development and company performance objectives.
- NEVADA BUSINESS SERVICES. Funded by the U.S. Department of Labor through the Workforce Investment Act to provide employment and training services to eligible residents of four southern Nevada counties. Services that can be offered to employers include new employee assessment, pre-screening and recruitment, on-the-job training and customized training.
- MANAGEMENT ASSISTANCE PROJECT (MAP). Is the industrial extension program of the Nevada System of Higher Education and its partners. Its primary purpose is to work directly with Nevada companies to strengthen their global competitiveness by providing information, decision support and implementation assistance in adopting new, more advanced technologies, techniques and best business practices. MAP focuses on the manufacturing, mining, and construction industries. It provides its knowledge in employee development, specialized worker, supervisory, and managerial training, technology development, business systems improvement, and also provides field engineers to support Nevada industry.
- THE TECHNOLOGY BUSINESS ALLIANCE OF NEVADA (TBAN). Dedicated solely to the development of the high-tech community in Southern Nevada. Through its innovative "Virtual Accelerator" program, TBAN seeks to foster entrepreneurs and attract Venture Capital partners to the region.
- THE NEVADA TECHNOLOGY COUNCIL. Is a membership-supported organization, with a statewide membership base of both private and public sector individuals who are interested in effecting change and affecting policy to enhance technology growth in Nevada. NTC membership includes entrepreneurs, business leaders, technologists, prominent government officials, scientists and involved citizens.
- THE HENDERSON BUSINESS RESOURCE CENTER. Provides business development expertise to new and growing businesses in Southern Nevada. The Business Resource Center

provides opportunities for new and developing companies. Three distinct programs for Applicants, Tenants and Affiliates—support all types of new and existing businesses.

- THE NEVADA SMALL BUSINESS DEVELOPMENT CENTER (SBDC). Provides free and low-cost business management training and counseling for new and expanding businesses throughout Nevada.

- THE NEVADA MICROENTERPRISE INITIATIVE (NMI). A private non-profit community development financial institution founded in 1991 that provides business tools to assist in overcoming barriers that entrepreneurs face in starting or expanding a business. They offer business training, business loans, and networking.

- THE SERVICE CORPS OF RETIRED EXECUTIVES (SCORE) "COUNSELORS TO AMERICA'S SMALL BUSINESS." A source of free and confidential small business advice to help build businesses—from idea to start-up to success. The SCORE Association is a nonprofit association dedicated to entrepreneurial education and the formation, growth and success of small businesses nationwide.

  SCORE's national network of 10,500 retired and working volunteers are experienced entrepreneurs and corporate managers/executives. These volunteers provide free business counseling and advice as a public service to all types of businesses, in all stages of development.

- THE NEVADA PROCUREMENT OUTREACH PROGRAM (POP). Works to increase the flow of contract dollars to Nevada businesses by providing training and technical assistance to find, bid on, and win federal, state and local contracts.

- THE NEVADA COMMISSION ON ECONOMIC DEVELOPMENT (CED). Administers Nevada incentive programs, Nevada's International Trade Program, Procurement Outreach Program (POP), and Nevada Film Office. CED also offers tax information, county statistics, financing options and current information on what's happening in economic development in NV.

- THE COMMUNITY BUSINESS RESOURCE CENTER. Acts as an information provider for business related services for entrepreneurship and enterprise development. CBRC is a recognized leader in community economic development as it works closely with industry, government, and non-profit sector organizations, to assist Nevada small businesses. The services offered by CBRC include direct referral services to resource providers, coordination of work groups addressing economic development issues, and leadership among community development organizations involved in improving the quality of life in Nevada.

- CHURCHILL ECONOMIC DEVELOPMENT AUTHORITY'S (CEDA). This organization's primary goal is to diversify and improve the local economy. This is achieved by trying to expand and grow businesses by providing them with the most current information and assistance possible, including walking them through the various permitting agencies.

- NEW VENTURES CAPITAL DEVELOPMENT COMPANY. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.

- SOUTHERN NEVADA CERTIFIED DEVELOPMENT CORPORATION. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.
- ECONOMIC DEVELOPMENT AUTHORITY OF ESMERALDA/NYE. EDEN is a regional development organization dedicated to building partnerships that foster sustainable economic growth and prosperity in the communities of Esmeralda and Nye Counties.
- EDAWN. The Economic Development Authority of Western Nevada is a private, non-profit corporation that works with primary industry entities to help them relocate, expand, retain or start and grow their businesses.
- NEVADA STATE DEVELOPMENT CORPORATION. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.

Arizona:

- SMALL BUSINESS ADMINISTRATION (SBA) ARIZONA DISTRICT OFFICE. Works to aid, counsel, assist and protect the interests of small business concerns, to preserve free competitive enterprise and to maintain and strengthen the overall economy of our nation.
- PRESTAMOS CDFI, LLC. Provides small loans ranging from under $100 to a maximum of $25,000 to prospective, small business borrowers and backed by the U.S. SBA.
- SELF-EMPLOYMENT LOAN FUND, INC WOMEN'S BUSINESS CENTER. Provides small loans ranging from under $100 to a maximum of $25,000 to prospective, small business borrowers and backed by the U.S. SBA. Also provides training, technical assistance, etc.
- SOUTHWESTERN BUSINESS FINANCING CORPORATION. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.
- ARIZONA DEPARTMENT OF COMMERCE. Offers tax information, county statistics, financing options and current information on what's happening in economic development in Arizona.
- BUSINESS DEVELOPMENT FINANCE CORPORATION. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.
- FUND A SCIENTIST. A website where individuals or institutions with funding can seek out scientists with innovative projects and provide support.
- PPEP HOUSING DEVELOPMENT CO. Provides small loans ranging from under $100 to a maximum of $25,000 to prospective, small business borrowers and backed by the U.S. SBA.
- SMALL BUSINESS DEVELOPMENT CENTER (SBDC), (with locations at Central Arizona College, Coconino Community College, Mohave Community College, Gila Community

College, Maricopa Community College, Yavapai College, Northland Pioneer College, Cochise College, Eastern Arizona College, pima Community College, Arizona western College). The SBDC works with start-up and existing business owners providing free counseling services on issues such as business planning, registering a business, financing, regulations, licensing, and more.

- SELF-EMPLOYMENT LOAN FUND, INC WOMEN'S BUSINESS CENTER. Provides small loans ranging from under $100 to a maximum of $25,000 to prospective, small business borrowers and backed by the U.S. SBA. Also provides training, technical assistance and access to loans for low-income individuals.
- MICROBUSINESS ADVANCEMENT CENTER OF SOUTHERN ARIZONA. Provides training, resources, referrals, support and advocacy to those seeking to create, sustain or grow micorbusinesses in southern Arizona.
- SCORE COUNSELORS TO AMERICA'S SMALL BUSINESS. The Service Corps of Retired Executives (SCORE) "Counselors to America's Small Business" is a source of free and confidential small business advice to help build businesses—from idea to start-up to success. The SCORE Association is a nonprofit association dedicated to entrepreneurial education and the formation, growth and success of small businesses nationwide.

  SCORE's national network of 10,500 retired and working volunteers are experienced entrepreneurs and corporate managers/executives. These volunteers provide free business counseling and advice as a public service to all types of businesses, in all stages of development.
- TUCSON/PIMA COUNTY WOMEN'S BUSINESS CENTER ARIZONA COUNCIL FOR ECONOMIC CONVERSION. Offers three business training tracks including "Growing Business," "Expanding Business," and "Start-up Business." All tracks are supported by a quarterly schedule of short and long-term training.

New Mexico

- SMALL BUSINESS ADMINISTRATION (SBA) NEW MEXICO DISTRICT OFFICE. Works to aid, counsel, assist and protect the interests of small business concerns, to preserve free competitive enterprise and to maintain and strengthen the overall economy of the nation.
- ENCHANTMENT LAND CERTIFIED DEVELOPMENT CORPORATION. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.
- WOMEN'S ECONOMIC SELF-SUFFICIENCY TEAM (WESST). SBA's network of more than 60 Women's Business Centers (WBC) provide a wide range of services to women entrepreneurs at all levels of business development.
- NEW MEXICO ECONOMIC DEVELOPMENT DEPARTMENT. Offers tax information, county statistics, financing options and current information on what's happening in economic development in New Mexico.

- FUND A SCIENTIST. A website where individuals or institutions with funding can seek out scientists with innovative projects and provide support.
- SMALL BUSINESS DEVELOPMENT CENTER (SBDC) (with offices located in NMSU-Alamogordo, Albuquerque, South Valley, New Mexico State University-Carlsbad, Clovis Community College, Northern New Mexico Community College, San Juan College, University Of New Mexico-Gallup, New Mexico State University-Grants, New Mexico Junior College, Las Cruces, Luna Community College, University Of New Mexico-Los Alamos, University Of New Mexico-Valencia, Eastern New Mexico University-Roswell, Santa Fe Community College, Western New Mexico University, Mesalands Community College). The SBDC works with start-up and existing business owners providing free counseling services on issues such as business planning, registering a business, financing, regulations, licensing, and more.
- SCORE COUNSELORS TO AMERICA'S SMALL BUSINESS. The Service Corps of Retired Executives (SCORE) "Counselors to America's Small Business" is a source of free and confidential small business advice to help build businesses—from idea to start-up to success. The SCORE Association is a nonprofit association dedicated to entrepreneurial education and the formation, growth and success of small businesses nationwide.

  SCORE's national network of 10,500 retired and working volunteers are experienced entrepreneurs and corporate managers/executives. These volunteers provide free business counseling and advice as a public service to all types of businesses, in all stages of development.
- BUSINESS INFORMATION CENTER (BIC). provides counseling, access to hardware, software, telecommunications, and more.

Utah

- SMALL BUSINESS DEVELOPMENT CENTER (SBDC) (with offices located in Blanding, Cedar City Office, Ephraim Office, Logan Office, Ogden Office, Orem/Provo Office, Price Office, Salt Lake City Office, St. George Office, State Director's Office, Uintah Basin Office, Utah District Office). The SBDC works with start-up and existing business owners providing free counseling services on issues such as business planning, registering a business, financing, regulations, licensing, and more.
- BUSINESS INFORMATION CENTER (BIC). provides counseling, access to hardware, software, telecommunications, and more.
- WOMEN'S BUSINESS CENTER. Supports the success of women business owners throughout Utah with counseling, training and loan-packaging assistance.
- SMALL BUSINESS ADMINISTRATION (SBA) UTAH DISTRICT OFFICE. Works to aid, counsel, assist and protect the interests of small business concerns, to preserve free competitive enterprise and to maintain and strengthen the overall economy of the nation.
- UTAH MICROENTERPRISE LOAN FUND (UMLF). A private, non-profit, multi-bank community development financial institution (CDFI) providing financing and management support to new and existing small businesses.

- FUND A SCIENTIST. A website where individuals or institutions with funding can seek out scientists with innovative projects and provide support.
- UTAH DEPARTMENT OF COMMUNITY AND ECONOMIC DEVELOPMENT. A state wide government agency which offers tax information, county statistics, financing options and current information on what's happening in economic development in Utah.
- SCORE COUNSELORS TO AMERICA'S SMALL BUSINESS. The Service Corps of Retired Executives (SCORE) "Counselors to America's Small Business" is a source of free and confidential small business advice to help build businesses—from idea to start-up to success. The SCORE Association is a nonprofit association dedicated to entrepreneurial education and the formation, growth and success of small businesses nationwide.

  SCORE's national network of 10,500 retired and working volunteers are experienced entrepreneurs and corporate managers/executives. These volunteers provide free business counseling and advice as a public service to all types of businesses, in all stages of development.
- NORTHERN UTAH CAPITAL, INC. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.
- DESERET CERTIFIED DEVELOPMENT COMPANY. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.

10.1.5 Summary

Based on the tables above, it is clear that there are many sources of incentives that can be used to fund the development and construction of the various technologies being reviewed in this study. Many of the incentives were recently devised through the enactment of the Energy Policy Act of 2005. Additional federal incentives are available through the Department of Agriculture, Department of Treasury, Department of Energy, and others. In addition to these federal programs, states offer many energy-related incentives, particularly with regard to renewable generation.

In addition, many incentives are available on the federal, state, and local levels to spur economic development, particularly for low-income communities, including tribes. These incentives can be significant, in terms of spawning new technologies on reservation lands.

In sum, each of the reviewed programs has very specific eligibility requirements. If these requirements are met, large amounts of money are potentially available to fund technology options.

10.2 BUSINESS CLASSIFICATIONS

Businesses that are owned by Indian tribes and by tribal members can operate under a variety of legal structures. The choice of classification affects to a great extent the business's—

- Federal and state tax status,
- Ability to attract investment monies,
- Business strategy and day-to-day operational authority,
- Liabilities, and
- Law and government.

All of the above must be taken into account when a business opportunity is initiated. When a land owner proposes a new generating facility, for example, the owner must consider not only the natural resources (such as land, oil, gas, coal, and wind), but also the business's access to federal programs that are associated with these resources, legal immunities, authority over day-to-day business operations, and more.

Many of the above are defined or constrained by the business's legal structure. Depending on its ownership and specific attributes, a business organization may be defined as—

- A tribal enterprise that is owned and controlled by the tribe and subject to tribal law;
- A non-tribal enterprise that is either (a) subject to the laws of the tribe, and perhaps also to the laws of the state in which the enterprise operates or (b) only subject to the laws of the state in which it operates.

In this section, business classifications for both tribal and non-tribal enterprises are explored. The report then looks at how those classifications affect taxes, ability to issue bonds, gain investment funds, liabilities, and more. Finally, the report discusses which structure may be most appropriate for each of the Mohave Alternatives and Complements Study's technology options.

10.2.1 Non-Tribal Enterprises

Businesses that are formed under state law are generally classified as sole proprietorships, corporations, limited liability companies (LLCs), partnerships, or business trusts. Each of these entities is described in more detail below.

- **Sole Proprietorships.** A sole proprietorship is owned by one individual, who retains responsibility for any business liabilities that are incurred. Any business revenues and expenses are included on the owner's personal tax return. This type of business is unincorporated.

- **Corporation.** A corporation is a legal entity with rights similar to those of a U.S. citizen; the corporation must abide by the laws of the state of incorporation and those of the states or other jurisdictions where it does business. The most salient features of a U.S. business corporation include the following:

  Corporations are owned by stockholders who own shares in the business.

  Although stockholders own the business, they do not control the day-to-day business operations. Instead, they vote to elect a board of directors, who oversees the business and ensures that business decisions reflect shareholders' best interests. The board of directors often consists of top management within the organization, along with some outside persons with relevant industry expertise. The separation of ownership from management gives corporations permanence and allows for perpetual lifetime.

  Corporations are established with no defined termination date; the assets and structure exist beyond the lifetime of any specified individuals. This allows the structure of the business to persist over time, which helps mitigate uncertainties that investors would have if the business was to be dissolved on a certain date.

  In a limited liability type of corporation, stockholders have no individual responsibility for the corporation's debt's and obligations. The most a stockholder can lose is the amount he/she paid for the stock, hence their "limited liability." This feature allows corporations to venture into projects that entail some level of risk.

  Corporations can both borrow and lend money.

  Corporations can deduct health insurance premiums paid on behalf of an owner-employee from the corporations' federal income taxes.

  Corporations can deduct other expenses such as life insurance costs from the corporations' federal income taxes.

  Corporations can readily establish retirement plans for employees.

  The United States federal taxation system recognizes two types of corporations:

  — **C-Corp.** The most common form of corporation, the C-corporation has few ownership restrictions and must pay corporate taxes; all publicly traded corporations have C-corporation status. C-corporations pay income taxes just as an individual does, and C-corporations do not receive a deduction on dividends they pay to stockholders. This leads to the so-called "double-taxation" of corporate profits: a given profit becomes subject to income tax twice, once at the corporate level, as an item of income, and once at the stockholder level, as a dividend.

  — **S-Corp.** Commonly used by small business proprietors, the S-corporation pays no corporate taxes, but instead passes profits and losses directly to its owners (the stockholders) who declare such profits and losses as part of their personal taxable income. In this manner, S-corporations resemble partnerships, although some subtle differences in taxation exist. As a result, S-corporations do not become subject to the "double-taxation" that C-corporations must endure. However, not all corporations qualify for S-corporation treatment. An S-corporation must generally have no more than 75 stockholders, all of them natural persons (not other corporations or entities), and all of them residing in the United States; moreover, the S-corporation can only issue a single class of stock."[1]

- **Partnership.** A partnership represents an agreement between individuals and/or corporations both of which share profits and losses. Unlike Corporate shareholders, all partners retain liability for the debts of each fellow-partner. When a partnership is established, it must specify a termination date, such as the death of one of the partners. Upon occurrence of such an event, the partnership may undergo a reorganization and re-establish itself. However, this presents major business uncertainty for all parties involved. Partnerships offer tax advantages relative to classification as a Corporation.[2]

- **Limited Liability Company (LLC).** A limited liability company has members, rather than partners. The LLC is a relatively new business entity, which was adopted by most states only in the last 10 years. The benefits of an LLC are that it is free from many of the tax and business problems inherent in the corporate and partnership structure. More specifically, "the LLC provides the *protection from liability* of a corporation without the formalities of corporate minutes, bylaws, directors, and shareholders. In contrast to corporate law, which allows shareholders and officers to be individually sued if the corporate formalities are not followed, the LLC law specifically bars a lawsuit against a member for the liabilities of the LLC. That is an important distinction to understand. The principle shareholders and officers of a corporation are routinely named as defendants in lawsuits against the company, forcing them to incur attorney's fees to defend themselves and rendering the corporate shield meaningless from a practical standpoint. A primary goal of the LLC legislation was to change this result by clearly stating that the members and managers of the LLC could not be named in a lawsuit against the company. The new law was drawn specifically to provide a vehicle which would protect the owners from liability associated with the business, what the corporation was intended for but no longer accomplished. The LLC is also convenient to maintain. The owners are permitted to adopt flexible rules regarding the administration and operation of the business. For tax purposes, it is treated like a partnership. That means the LLC itself pays no income tax. All of the income and deductions flow through directly to the members and is reported on their personal tax returns."[3]

- **Business Trust.** This business entity is mostly used for investment projects, such as mutual funds, real estate, etc. Some state jurisdictions allow this classification, including. Utah,

[1] http://en.wikipedia.org/wiki/Corporation#Taxation_of_non-corporate_entities

[2] Since 1996, United States partnerships and limited liability companies have had the right to elect whether the United States government will treat them as corporations or as "flow-through" entities under the IRS' check-the-box regulations (see form 8832). The income tax assessment process does not treat a flow-through entity as a person for income tax purposes; instead it divides its income and loss (and every other tax attribute) among its partners, who report them proportionately to the IRS. Some limits exist on an entity's ability to elect flow-through treatment: most importantly, a publicly traded company cannot elect flow-through treatment; in practice this means that publicly traded corporations remain subject to a more stringent tax régime than do closely held companies.

[3] The Asset Protection Law Center, 2005. "A complete reference source on offshore trusts, family limited, partnerships, limited liability companies and advanced asset protection strategies," The Asset Protection Law Center , The Law Offices of Robert J. Mintz, found at http://www.rjmintz.com/appch6.html

Nevada, and Arizona. It is unclear whether New Mexico allows the establishment of this type of entity.

Like U.S. natural citizens, Indian tribes are eligible to establish each of the above entities with the exception of S-Corporations, which are primarily reserved for natural citizens. As for taxes, a summary of tax-related features of the various structures is shown below in Table 10-8. In addition, it is important to keep in mind that each of these business structures is subject to the laws of the state of incorporation.

Table 10-8 — U.S. Business Classification Options and Tax Consequences

Business Entity	Tribes eligible to own?	Business is required to pay federal and state income taxes?	Distributions to tribes, as owners, are free of federal income taxes?	Distributions to tribes, as owners, are free of state income taxes?
Sole Proprietorship	Yes	Yes	Yes	Yes
C-Corporation	Yes	Yes	Yes	Yes
S-Corporation	No	Not applicable	Not applicable	Not applicable
LLC	Yes	Yes	Yes	Yes
Partnership	Yes	Yes	Yes	Yes
Business Trust	Usually not applicable	Not applicable	Not applicable	Not applicable

Note: Generally, if the tribal members live on the reservation, distributions paid to them by corporations that operate on reservation land are not subject to state income taxes, but are subject to federal income taxes

Because most stakeholders of this study are likely more familiar with the above state-defined organizational structures and because in many ways they are similar to one another, the remainder of this study compares these, as a group, in general, to those of the individual tribal business structures. From this point forward, sole proprietorships, C-corporations, partnerships, and LLCs will together be referred to as “state corporations.”

10.2.2 Tribal Enterprises

While U.S. tribes and tribal members can establish any of the business structures (except S-corporations) that U.S. citizens can establish, tribes and tribal members also can establish tribal-specific enterprises. Such businesses and organizations may offer their owners some discreet advantages, financially and socially. Tribal business entities are described in greater detail below:

- **Tribal Government Entities.** This category includes tribal governments, subdivisions of tribal government (including tribal government agencies and divisions) and unincorporated enterprises of tribal governments. By definition, businesses operated by tribal governments or subdivisions of tribal governments are wholly owned by the tribe. Tribal governments and subdivisions are exempt from federal and state income taxes, and the tribe maintains control of day-to-day business decisions and operations. Businesses operated as arms of tribal governments are subject to generally applicable federal substantive law, but are not subject to state law unless a specific federal law has made them so, or unless (and to the extent) they operate outside a reservation; and such businesses have been held to possess immunity from nonconsented suits in state, federal, and tribal courts. This immunity may be seen as a risk by non-tribal investors, without an explicit waiver.

Unlike state corporations, tribal governments generally do not separate ownership from business management. For tribal organizations, the owner is the tribe, the same entity that makes major business decisions. This direct tribal control may be seen as a risk in the eyes of non-tribal investors, who might be concerned that business decisions could be tied to political considerations

- **Federally Chartered Tribal Corporation.** These entities are incorporated under Section 17 of the Indian Reorganization Act of 1934. In order to qualify for this classification, the business must by wholly owned by the tribe. Applying for Section 17 status, which must be approved by the Secretary of the Interior, is not always a simplistic process. However, one advantage of this classification is clear exemption from federal taxes.

  Under a federally chartered tribal corporation, the tribe may or may not retain control of the basic business decisions and operations, depending on the terms of the corporation's charter. Such entities are subject to generally applicable federal laws and, presumably, are subject to tribal law, but are not subject to state laws unless they have been made so by federal law or unless (and to the extent) they operate outside a reservation.

- **Tribally Chartered Corporation**. Tribally chartered corporations can be owned, in whole or in part, by a tribal government, by tribal members, or by non-Indians. It is presently unclear whether tribally chartered corporations are exempt from federal income taxes (this issue is currently being reviewed by the Internal Revenue Service). However, it is likely that income derived by shareholders from a tribally chartered corporation that is not owned by a tribal government will remain subject to federal income taxation; but income derived by shareholders who are tribal members living on a reservation from a tribally chartered corporation doing business on a reservation will likely be exempt from state income taxation. Finally, business revenues earned off the reservation will likely be subject to state income taxes for all shareholders.

  Tribally chartered corporations are subject to tribal law, but if they are not owned by the tribe, their business decisions are not controlled by the tribe; and they do not have sovereign immunity from nonconsented suits. These factors may or may not be attractive to non-tribal investors or financing sources.

The table below summarizes the main features of the tribal business classifications.

Table 10-9 — Major Features of Various Tribal Business Classifications Compared to Those of a State Chartered Corporation

	Must by owned wholly owned by the tribe?	Exempt from federal and state income taxes?	Tribe retains control over operations, jobs, employee training, incomes, and tribal way of life?	Immunity from nonconsented lawsuits? *	Preferred by third-party investors?	Preferred with respect to new technology risks?
Tribal Gov't, Subdivision of Tribal Gov't, Unincorporated Enterprises of Tribal Gov't	Yes	Yes	Yes	Yes, absent explicit waiver	No	Presents challenges (see text on Implementation of "unproven" technologies or processes)
Federally Chartered Tribal Corporation under section 17	Yes	Yes	Possibly, depending on terms of charter	Yes, absent explicit waiver	Yes	Yes
Tribally Chartered Corporation	No	Unclear **	No	No	Presents challenges (see text on capital investment requirements)	Yes
State corporations, in general	No	No	No	No	Yes	Yes

Source: Atkinson, Karen, 2005. "Choosing a Business Structure," a presentation presented at Law Seminars International: *Tribal Energy Southwest Conference*, Las Vegas, Nevada, April 7-8, 2005.

* Investors and developers of major projects typically insist on some sort of waiver of tribal immunity. In addition, the federal government is not barred from suing tribes. Without such a waiver, the sovereign immunity of the tribe precludes lawsuits.

** The U.S. Internal Revenue Service is currently reviewing rules regarding this issue.

It is clear from Table 10-9 that different business classifications offer different advantages for tribal owners. Yet, to some extent, this table oversimplifies the task of determining which structure is best for a tribally-owned business; individual businesses have very specific concerns, each of which should be considered before choosing a legal business classification.

A number of issues that tribes should consider before choosing and structuring a specific classification for a business enterprise are discussed below. The major issues include authority, third-party investor preference, revenue type and potential, technology risks, and whether the business would be exempt from federal and state taxes and eligible for special incentives.

10.2.2.1 Tax Implications

Certain types of business classifications are exempt from paying federal and state income taxes. Such savings represent a significant percentage of retained earnings over those business entities that must make such payments. However, while the tax breaks that are identified in Table 10-9 exist for tribal governments, business subdivisions of tribal governments, and federally chartered tribal corporations, the U.S. Treasury Department and Internal Revenue Service are currently examining whether tribally chartered corporations will be free of federal income tax on revenue-generating activities, and how tribal/non-tribal partnerships will be viewed for tax purposes.

In any case, a tribe or a business owned by a tribal government may qualify for the following additional special tax treatments and financing options:

Federal:[4]

- Persons and organizations that contribute to tribally owned enterprises are allowed to deduct their contribution from their income taxes.
- Persons and organizations that contribute to tribally owned enterprises are eligible to reduce their owed estate and gift taxes.
- Treatment as a government under the private foundation excise tax rules.
- Tax-exempt bond financing authority (Indian Tribal Governmental Tax Status Act of 1982 [IRC §7871]).[5]
- Exemption from federal excise tax on gasoline, diesel, kerosene if fuel is used for an essential government function. (Tribal utilities have been accepted as essential governmental purposes.)
- Accelerated deprecation for equipment and infrastructure on tribal lands.
- Conduit financing capabilities.
  - Utilizes a tax-exempt entity, other than a Tribal Authority, to issue tax-exempt bonds (the borrower issues bonds—proceeds are lent to Tribal Authority).
  - The IRS is currently challenging this type of financing.
- Tax-exempt utility can use tax-exempt bonds to pre-pay for natural gas and electricity.
  - In effect since 2003.[6]
  - 90% of the gas or electricity must be used to serve retail customers of the issuer or to sold to another governmental utility for its retail customers.

[4] Nilles, Kathleen, 2005. "Structuring Energy Projects: Tax Considerations," a presentation presented at Law Seminars International: Tribal Energy Southwest Conference, Las Vegas, Nevada, April 7-8, 2005.

[5] Tribes are treated like states for purposes of the bond act with two restrictions: 1) bonds can only be issues to finance facilities that serve an "essential governmental functions," 2)Tribes cannot issues private activity bonds except for manufacturing facilities operated by the tribal government. Tribal utilities qualify for such bonds.

[6] Golub, Howard, 2005. "Financing Tribal Energy Projects," Nixon, Peabody, LLP, Las Vegas, NV, April 7, 2005.

State:

- Exemption from sales tax and other taxes for purchases made on Indian reservations. (However, tribes can levy their own sales taxes.)
- Exemption of Native Americans from state income taxes, provided that they live on reservation land and that the income in question is earned on the reservation.
- Example: One example of an implementation of one of the above-described benefits involves the Mississippi Choctaw Tribe, whose principles of business success include (1) a tribal land base under tribal government control, (2) a stable tribal government, and (3) an institutional structure designed to facilitate business decisions. In 1969, this tribe issued a tax-exempt bond to help fund the construction of an industrial park on the reservation. This project and the Choctaw's business development practices, in general, have been considered a great success.

In summary, when choosing a business classification, it is particularly important for an organization to think about how that classification will affect its eligibility for all of the above special tax treatments. For those projects where freedom from income taxation and, for example, ability to issue tax-exempt bonds, is most important, a tribe might prefer to directly own and operate the business.

10.2.2.2 Capital Investment Requirements[7]

Capital intensive projects often require financing from third parties. Typically, before investors bring capital to business investments, they consider whether the organization has a defined business plan, financial growth potential, reasonable business risks, and managers with excellent track records.

For tribal-businesses, these same criteria apply. However, in addition to the project's characteristics, investors might have a preference for certain organizational entities, as seen in Table 9-2. Investors might be concerned about investing in businesses operated by tribal governments, as they would businesses managed day-to-day by a state or municipal government. Such a concern could arise as a consequence of a belief that political considerations might unduly influence daily business decisions. This control might bring some concerns to third-party investors, who may be unfamiliar or uncomfortable with tribal rules and activities.

Other investor issues regarding funding tribal entities include the following:

- Disputes with tribes and with businesses operated as arms of tribal governments, including federally chartered tribal corporations, cannot be settled by courts, without an explicit waiver of sovereign immunity by the tribal entity. Non-tribal investors see this as an enormous risk, which

[7] Carey, Jeffrey, 2005. "Beyond Extraction: Maximizing the Value of Energy Resources for Tribes," a presentation by Merrill Lynch for Law Seminars International: *Tribal Energy Southwest Conference*, Las Vegas, Nevada, April 7-8, 2005.

may prevent them from investing in tribal enterprises. To allay this risk, however, tribes and investors can and do enter agreements that establish mutually accepted processes to resolve disputes, including the use of federal and state courts.

- Tribal trust land cannot be mortgaged, and a legal question exists as to whether land owned by a tribe in fee can be subject to mortgage. This can present a disadvantage to tribal enterprises seeking investment monies because such land is not available as collateral. Certain tribes have circumvented this problem by leasing property to third parties, either tribal or non-tribal, and permitting the leasehold, which is regarded by law as personal property rather than real property, to become the subject of a mortgage. The Mohegan Tribe of Connecticut used this arrangement when it obtained financing for its large Mohegan Sun Casino: the tribe leased the land on which the casino was to be built to a tribally created entity that, in turn, issued publicly traded bonds that were secured by a mortgage on the leasehold. The Navajo Nation has also participated in this sort of arrangement. More details about how this can be accomplished are illustrated below:

> Three tribes in the study (Citizen Potawatomi, Mississippi Choctaw, and Navajo Nation) reported they were able to induce banks to make loans to them using leasehold improvements as collateral. In each case, the tribe wanted to construct a building or to renovate an existing building needed to operate a tribally owned business or tribal program. A bank was willing to accept as collateral the improvements on the land (the new or renovated building) rather than the trust land.
>
> A leasehold improvement approach used by Navajo Nation can serve as a model for other tribes. This effort promoted entrepreneurial activities by tribal members, rehabilitated a building that had been long vacant, leveraged federal welfare reform funding, and provided facilities required to operate the federally funded program. A large building in one of the largest Navajo communities (Shiprock, New Mexico) was structurally sound but had remained abandoned for eight years after the manufacturing business using it was closed. When Navajo Nation took over operation of the TANF program, it sought to open several satellite offices throughout the reservation, including Shiprock. A construction firm owned by a tribal member negotiated a deal with Navajo Nation to rehabilitate the building in accordance with the specifications of the tribal TANF program. No TANF funds were expended to renovate the building—the TANF program signed a long-term lease with the construction company, which used the lease as collateral for a bank loan. The construction company used the loan to finance the rehabilitation needed by the TANF program. In addition, the builder was able to develop space in the renovated building for a restaurant and retail stores. [8]

The above example shows that there are ways to interest third-party investors and circumvent apparent investment barriers associated with tribal businesses.

To summarize, for those businesses that are particularly capital intensive, it is very important for the owners to choose a business classification that will be acceptable to outside investors. With regard to this study, as shown in the table below, IGCC and solar parabolic trough technologies appear to be the most capital intensive. Project financing for these particular technologies must be considered as part of the business classification decision.

Table 10-10 — Capital Costs of the Study's Technologies

Technology	Approximate Total Capital Investment ($/kW)
Solar Parabolic Trough with Storage	3,600
IGCC CO_2 Removal without Shift Conversion scenario	2,200
Solar Dish/Stirling Engine	1,500
Wind	1,700
Natural Gas Combined Cycle	600

10.2.2.3 Implementation of "Unproven" Technologies or Processes

When an organization chooses to finance a project that uses relatively new technologies or processes, the organization is taking on risk. There is performance risk (will the facility be as efficient as anticipated?); there is financial risk (will construction and operations cost more than expected?); and there is alternative technology risk (will a new, better, and less expensive technology come to the marketplace in the near future?). In addition to these kinds of risks, "unproven" technologies might require some sort of specialized expertise on the part of the employees and management.

It is easy to see how great responsibility and a high degree of comfort with risk are important in building and operating facilities using new technologies. With this in mind, it is important to consider the various business structures and their features. For certain business classifications, it is the tribe that retains authority and overall responsibility for day-to-day business decisions, as well as the attendant risks. With regard to this study, IGCC (especially with carbon capture) and solar dish/Stirling engine appear to be the most risky in terms of technical and financial performance. As such, should the tribes be wary of taking on risks, these technologies might be more suited to corporate structures, either tribal or state chartered. On the other hand, DSM, wind, and solar parabolic trough are established technologies, which might be more suited as tribal enterprises.

10.2.2.4 Ability to Control Jobs, Expand Tribal Knowledge Base, and Enhance Tribal Incomes

Certain business structures give tribes the authority to make decisions not only concerning day-to-day operations, but also concerning general business strategy. This can be extremely valuable to the tribes. For

[8] The Urban Institute, Inc., 2004.

instance, the tribe can put a strategy in place that protects its members from unemployment. The tribe might accomplish this by training member employees in practices that promise future growth potential on tribal lands. The tribe can also strive to expand its overall revenues. One way to accomplish this might be to become the industry leader in a specific sector. This might be achieved by becoming an expert in a new technology or process.

Some of the business classifications that have been discussed allow the tribes to retain more business strategy control than others. Specifically, structuring an enterprise as an arm of the tribal government gives the tribe direct control over jobs impacts and the ability to direct the businesses to follow the tribe's overall economic development and business strategy. For instance, tribal government enterprises can themselves decide whether to continue to run or to abandon an existing project. This would not be the case if the project was operated by a non-tribal or tribal corporation.

With regard to this study of generation alternatives, if the tribes are concerned with job impacts and long-term economic development of their tribes, they may choose to establish any technology options as tribal government organizations. In addition, some of the technology options may offer specific openings for long-term tribal development strategies. Wind, solar dish/Stirling, DSM, and possibly solar parabolic trough might fall under this category. For each of these technologies, there is great potential for the tribes to export their gained knowledge in construction and operation of such projects to new developments, both on and off reservation land.

10.2.2.5 Ability to Promote and Enhance Tribal Way of Life

Specific tribes have specific cultures or ways of life. Having businesses on their land that operate in tune with cultural preferences may be vital to the tribes in terms of respecting and preserving their culture.

With this in mind, certain business structures allow the tribes to retain more control over the principles under which a business operates than do others. Specifically, tribal government entities and unincorporated enterprises of tribal government give tribes overall authority concerning business operations and culture. Alternatively, some federally chartered tribal corporations (depending on the details of their charters), tribally chartered corporations, and state corporations allow the tribes a more passive role. In some instances, this might be preferred, as controlling a business might involve a great amount of tribal resources in terms of time and effort.

In summary, if consistency with cultural values is a key requirement for businesses on reservation lands, tribal government or unincorporated enterprises of tribal government would likely be the preferred organizational structure. With regard to this study, due to its aesthetic impacts, wind would likely be a key technology where cultural enforcement might be critical.

10.2.2.6 Royalty Potential vs. Direct Revenue Potential

In order to be approved for business activities on reservation land, some tribes require non-tribal businesses to pay them annual royalties and land and water use fees. Together, these fees can be significant and represent a very stable flow of income for the tribes. These fees are also independent of business risk. So, a tribe may benefit substantially if a successful non-tribal business, which was initially deemed risky, resides on their reservation land over the long-term.

On the other hand, all the revenue from a tribal government enterprise belongs to the tribe, but that revenue may be subject to uncertainties and business risk.

In terms of the generation options, IGCC on tribal land represents a technology that might provide large and long-term revenue streams in the form of royalties and permitting fees to the tribes if the facility is held by a non-tribal business. Also, as pointed out above, IGCC is also considered to be a somewhat risky technology in terms of performance characteristics at this time. Together these traits may imply that, currently, tribes may prefer to have an IGCC facility owned and operated by a state corporation rather than by a tribal business entity.

10.2.3 Study Technology Options and Recommended Organizational Structures

Table 10-11 summarizes the general findings regarding recommended ownership structures for the proposed technology options evaluated in this study. It is important to note, however, that these recommendations should be viewed simply as starting points, subject to reconsideration when a specific project and its details are fully available. It is premature to conclude that a particular technology is, or is not, suited to tribal ownership. Such decisions must, in the end, be made with full knowledge of the particular project and project financing options. However, the following reflects reasonable *generic* conclusions that can be considered as starting points, subject to reconsideration when a specific project and its details are ready to examine.

Table 10-11 — Generic Ownership Structures Recommendations for the Various Technology Options

Technology	Potentially Attractive as a Tribal Business?	Primary Reason for Recommendation
IGCC	Probably not	High capital cost; all-or-nothing investment; high business risk; high potential for royalty income from non-tribal enterprise.
NGCC	Not applicable	Proposed location is on private land.
Wind	Yes	Moderate and modular cost; low business risk; control is critical because of aesthetics; high potential to create future jobs for tribes, both on and off reservation. The Navajo Tribal Utility Authority is already taking action in wind development.
Solar/Parabolic trough	Maybe	High capital cost; low technology risk; medium potential to create future jobs for tribes, both on and off reservation.
Solar Dish/Stirling Engine	Maybe	Moderate and modular capital cost; moderate technology risk; moderate potential to create future jobs for tribes, both on and off reservation.
Biomass/Geothermal	Unclear	Information on project specifics, including proposed locations, job impacts, costs, business risks, etc. still pending
DSM/EE	Yes	Low and modular capital cost; low risk under sound management; no royalty potential from non-tribal business; high potential to create future jobs for tribes, both on and off reservation.

Based on these recommendations, the following conclusions may be drawn:

- **IGCC.** Due to its high capital costs, business risks, and high potential for royalty income from non-tribal enterprises, it would likely be in the tribes' best interests if the proposed IGCC facility were owned and operated by a non-tribal entity formed under state law.
- **Wind and DSM/EE Technologies.** For each of these, there is only moderate capital and operational costs, low technology risk, and a high potential to create future jobs for the tribes, both on and off of reservation territories. For all of these reasons, wind and DSM technologies might be attractive as tribal business entities.
- **Solar Dish/Stirling Engine Technology**. Business risks associated with this technology probably fall somewhere between those of IGCC and wind. Dish/Stirling engines systems have moderate, but modular capital costs. The technology may be a source of expanded jobs for the tribes in the future. Given these consideration, solar dish/Stirling engines may be potentially attractive to tribal businesses.
- **Solar Parabolic Trough Technology**. Solar parabolic troughs are usually very large projects; unlike solar Stirling technology, parabolic troughs are not generally built in a modular fashion

or to produce small amounts of energy. Parabolic troughs have high capital costs. Yet, they are a well-proven technology option. Given these factors, this technology may potentially be attractive to tribal businesses.

- **Natural Gas Combined-Cycle Facility.** At this time, no conclusions are offered with regard to NGCC. The proposed location of the natural gas plant is on private land. Therefore, whether or not it would potentially be attractive as a tribal business is a non-issue.
- **Other Renewables.** No conclusions can be made at this time regarding biomass or geothermal technologies. Information on proposed project specifics, including proposed locations, job impacts, costs, business risks, and so forth needed to make a solid conclusion regarding best business structure is still pending.

Again, it is important to reiterate that project specifics may alter the general conclusions above.

In addition, for the more modular technologies (wind, solar dish/Stirling, DSM/EE, other renewables), it might make sense for the tribes to consider the option of having a diversity of business entities on their lands. For example, it is certainly feasible for one wind site to be owned and operated by a tribal government, while another is owned and operated by a non-tribal entity. Such a scenario would allow both types of owners to benefit from each other's experiences with the technology.

10.3 HYPOTHETICAL PACKAGES OF INCENTIVES FOR SPECIFIC BUSINESS STRUCTURES

While the previous sections of this chapter separately examine financial incentives and business structures, this section combines the two concepts together and provides hypothetical packages of financial incentives that might apply to the capital costs of specific resources, owned by specific types of entities. The following packages are explored:

- IGCC without the sequestration option operated by non-tribal business owners at both the Black Mesa and Mohave sites.
- IGCC with sequestration option operated by tribal business owners at the Black Mesa site.
- DSM implemented in part by tribes on and near reservation land.
- Wind turbines at Gray Mountain operated by NTUA.
- Wind turbines at Aubrey Cliffs operated by Foresight.
- Solar dish/Stirling facility owned by tribes.
- Solar parabolic facility owned by non-tribal business entity.

With regard to the hypothetical packages, it is important to note that, in many cases, the owners of the facilities are not entitled to receive all of the hypothetical incentives simply by right; many of the incentives are competitive and require applicants to submit detailed paperwork in order to qualify and perhaps receive grant monies, tax breaks, loans, and/or other financial incentives. In addition, many incentives not only have annual distribution limits, but also a maximum that can be applied towards any individual project or owner. Furthermore, the ability of taxable corporations to take advantage of tax benefits depends on the details of the corporation's tax obligations and other factors.

For the hypothetical projects described below, a 35% federal income tax rate and a 10% nominal discount rate were assumed.

Table 10-12 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of IGCC without the Sequestration Option Operated by Non-Tribal Business Owners at Both the Black Mesa and Mohave Sites

IGCC without sequestration: Non-tribal ownership at Black Mesa Site			
IGCC capital cost at Mohave with No C02 removal and dry cooling			**$910,033,600**
Net reduction due to EPACT 2005, Section 1307, Credit for Investment in Clean Coal Facilities	Must apply for this incentive	Assumes 20% tax credit on investment available in year 1	$182,006,720
Net reduction due to EPACT 2005, Section 1301, Renewable Electricity Production Credit	Automatic incentive	7-year credit period: $2/ton indian coal; 5,930 tons/day of coal; $4,328,900 annually; NPV over 7 years starting in year 3:	$17,417,271
Net reduction due to Title 26. IRS tax code: Modified Accelerated Cost Recovery	Automatic incentive	20 year property can be deducted over 12 years; $26,542,647 annually; NPV of this incentive over years 3-14	$149,465,634
Net reduction due to US Treasury Indian Empoyment Tax Credit	Automatic incentive	20% tax credit on first $20,000/tribal employee; 80% of 120 craft labor tribal employees assumed; $384,000 annually; NPV over 1st 2 years:	$666,446
Net reduction due to US Treasury Indian Empoyment Tax Credit	Automatic incentive	20% tax credit on first $20,000/tribal employee; 80% of 206 tribal employees assumed; $659,200 annually; NPV over years 3-12:	$3,347,520
Total Cost After Incentives Applied			**$557,130,009**
% Capital Cost Saved			**38.78**

IGCC without sequestration: Non-tribal ownership at Mohave site			
IGCC capital cost at Mohave with No C02 removal and dry cooling			**$910,033,600**
Net reduction due to EPACT 2005, Section 1307, Credit for Investment in Clean Coal Facilities	Must apply for this incentive	Assumes 20% tax credit on investment available in year 1	$182,006,720
Net reduction due to EPACT 2005, Section 1301, Renewable Electricity Production Credit	Automatic incentive	7-year credit period: $2/ton indian coal; 5,930 tons/day of coal; $4,328,900 annually; NPV over 7 years starting in year 3:	$17,417,271
Total Cost After Incentives Applied			**$710,609,609**
% Capital Cost Saved			**21.91**

Notes:

An IGCC unit owned by a non-tribal business at Black Mesa could take part in the Title 26 Modified Accelerated Cost Recovery for property on tribal land. This is not the situation at the Mohave site, which is not located on tribal land. Table assumes no tribal employees at Mohave site.

Table above assumes construction over years 1 and 2, with a fully operational unit in Year 3.

Table 10-13 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of IGCC with Sequestration Option Operated By Tribal Owner at the Black Mesa Site

IGCC with Sequestration: Tribal ownership at Black Mesa Site			
IGCC capital cost at Black Mesa with 90% C02 removal and dry cooling			**$ 1,158,425,600**
Net reduction due to EPACT 2005: Section 2602: Indian Energy Education Planning and management Assistance	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$ 1,000,000
Net reduction due to Administration for Native Americans Program: Social and Economic Development Strategies	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$ 1,000,000
Total Cost After Incentives Applied			**$ 1,156,425,600**
% Capital Cost Saved			**0.17**

Notes:

The above assumes construction over years 1 and 2, with fully operational unit in Year 3.

Most of the financial incentives available for IGCC are tax credits. Because the tribes would not pay taxes, they would not benefit from the tax credits potentially available to non-tribal owners of an IGCC plant.

Table 10-14 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of DSM Implemented by Tribes On and Near Reservation Land

Cost of Energy Efficiency: Tribal Ownership			
Assume 50 MW savings total over 5 years			
Cost of 10% of EE that is implemented on or near the reservations			**$13,874,241**
Net reduction due to EPACT 2005, Section 2602, Indian Energy Education, Planning, and Management Assistance	Must apply for this incentive	Assume 5% of $20,000,000 available immediately	$1,000,000
Net reduction due to EPACT 2005, Section 126. Low Income Community Energy Efficiency Pilot Program	Must apply for this incentive	Assume 5% of $20,000,000 available immediately	$1,000,000
Net reduction due to USDA Renewable Energy Systems and Energy Efficiency Improvements Program	Must apply for this incentive	$500,000 per project available immediately	$500,000
Net reduction due to Administration for Native Americans Program: Social and Economic Development Strategies	Must apply for this incentive	Assume 5% of $20,000,000 available immediately	$1,000,000
Net reduction due to New Mexico: House Bill 251, Clean Energy Grants Program	Must apply for this incentive	$200,000 per project available immediately	$200,000
Total Cost After Incentives Applied			**$10,174,241**
% Capital Cost Saved			**26.67**

Notes:

The EE budget for 50 MW savings is $30,520,000 per year for five years. For illustrative purposes, the Study assumes that 10% of the work and budget can be performed either on the reservation (a small part of that 10%) or on premises of electricity consumers near the reservation, but by enterprises based ON the reservation and staffed by tribal members. Workers would commute to job sites in places like Albuquerque, Flagstaff and so on.

Table 10-15 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of Wind Turbines at Gray Mountain Operated by NTUA

Wind at Gray Mountain: Owned by NTUA			
Cost of facility			**$237,068,532**
Net reduction due to EPACT 2005, Section 2602, Indian Energy Education, Planning, and Management Assistance	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$1,000,000
Net reduction due to EPACT 2005, Section 126. Low Income Community Energy Efficiency Pilot Program	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$1,000,000
Net reduction due to USDA Renewable Energy Systems and Energy Efficiency Improvements Program	Must apply for this incentive	Assumes $500,000 per project available in year 1	$500,000
Net reduction due to DOE's Office of Energy Efficiency and Renewable Energy's Tribal Energy Program	Must apply for this incentive	Assumes $138,889 available in year 1 based on 2005 allottment of $2.5 million for 18 tribes	$138,889
Net Reduction due to EPACT 2005: Section 202, Renewable Energy Production Incentive Program	Automatic Incentive	465,896,224kWH/year; 1.5 cents/kWH, adjusted for inflation annually since '93;(Value = $9,317,924 annually);NPV of incentive over years 3-12:	$47,317,859
Net reduction due to Administration for Native Americans Program: Social and Economic Development Strategies	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$1,000,000
Total Cost After Incentives Applied			**$186,111,784**
% Capital Cost Saved			**21.49**

Notes:

Assumes construction in Years 1 and 2 and fully operational in Year 3.

In response to a stakeholder request, certain financial incentives were considered for the above hypothetical. However, some of them were not applicable. For instance, money from EPACT Section 2603 is earmarked for regulatory issues, not for capital costs. Similarly, the Indian Employment Tax Credit is not applicable to NTUA. In addition, while the idea of the New Market Tax Credit is an excellent one, 60% of funds must be directed towards serving tribal needs. The Gray Mountain wind farm would not meet this definition. Finally, the value of loan guarantees is discussed in a separate section of this chapter.

Table 10-16 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of Wind Turbines at Aubrey Cliffs Operated By Foresight

Wind at Aubrey Cliffs: Owned by Foresight			
Cost of facility			**$155,170,028**
Net reduction due to USDA Renewable Energy Systems and Energy Efficiency Improvements Program	Must apply for this incentive	Assumes $500,000 available per project available in year 1	$500,000
Net reduction due to DOE's Office of Energy Efficiency and Renewable Energy's Tribal Energy Program	Must apply for this incentive	Assumes $138,889 available in year 1 based on 2005 allottment of $2.5 million for 18 tribes	$138,889
Net reduction due to EPACT 2005: Section 1301, Renewable Electricity Production Credit	Automatic Incentive	273,266,054 kWH/year; credit for 10 years for facilited placed in service after August 8, 2005; (=$5,465,321 annually); NPV over years 3-12.	$27,753,745
Net reduction due to US Treasury Indian Empoyment Tax Credit	Automatic Incentive	20% tax credit on first $20,000/tribal employee; 80% of 95 tribal employees assumed; $304,000 annually); NPV over years 1 and 2 of construction	$527,603
Net reduction due to US Treasury Indian Empoyment Tax Credit	Automatic Incentive	20% tax credit on first $20,000/tribal employee; 80% of 4 tribal employees assumed; (= $12,800 annually); NPV over years 3-12	$65,000
Net reduction due to AZ Statue ARS 42-5075, Title 42. Taxation, Arizona Solar and wind	Automatic Incentive	Assumes $5,000 per project available in year 1	$5,000
Total Cost After Incentives Applied			**$126,179,790**
% Capital Cost Saved			**18.68**

Note: Assumes construction in Years 1 and 2 and fully operational in Year 3.

Table 10-17 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of Solar Stirling Facility Owned by Tribes

Solar Stirling: Owned by tribes			
Cost of facility		**$1400/KW and 425MW facility**	**$595,000,000**
Net reduction due to EPACT 2005, Section 2602, Indian Energy Education, Planning, and Management Assistance	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$1,000,000
Net reduction due to EPACT 2005, Section 126. Low Income Community Energy Efficiency Pilot Program	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$1,000,000
Net reduction due to USDA Renewable Energy Systems and Energy Efficiency Improvements Program	Must apply for this incentive	Assumes $500,000 available per project in year 1	$500,000
Net reduction due to DOE's Office of Energy Efficiency and Renewable Energy's Tribal Energy Program	Must apply for this incentive	Assumes $138,889 available in year 1 based on 2005 allottment of $2.5 million for 18 tribes	$138,889
Net Reduction due to EPACT 2005: Section 202, Renewable Energy Production Incentive Program	Automatic Incentive	Assumes 1,120,000 MWH/year; 1.5 cents/kWH, adjusted for inflation annually since '93 (=$22,400,000/year); NPV over years 4-13	$103,409,694
Net reduction due to Administration for Native Americans Program: Social and Economic Development Strategies	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$ 1,000,000
Total Cost After Incentives Applied			**$487,951,417**
% Capital Cost Saved			**17.99**

Note: Assumes construction in years 1-3 and fully operational in year 4.

Table 10-18 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of Solar Parabolic Facility Owned by Non-Tribal Business Entity

Solar Parabolic: Owned by non-tribal enterprise			
Cost of facility		**$3600/kw and 300MW facility**	**$1,080,000,000**
Net reduction due to EPACT 2005, Section 1336-1337. Business Solar Investment Tax Credit	Automatic Incentive	10% of captial cost can be taken as tax credit through 2008	$108,000,000
Net reduction due to USDA Renewable Energy Systems and Energy Efficiency Improvements Program	Must apply for this incentive	Assumes $500,000 available per project in year 1	$500,000
Net reduction due to Title 26. IRS tax code: Modified Accelerated Cost Recovery	Automatic Incentive	20 year property can be deducted over 12 years; Value is $31,500,000 annually; NPV over years 4-13	$145,419,883
Net reduction due to US Treasury Indian Empoyment Tax Credit	Automatic Incentive	20% tax credit on first $20,000/tribal employee; 80% of 83 tribal employees assumed; NPV over 1st three years	$660,508
Net reduction due to US Treasury Indian Empoyment Tax Credit	Automatic Incentive	20% tax credit on first $20,000/tribal employee; 80% of 88 tribal employees assumed; $281,600 annually; NPV over years 4-13	$1,300,008
Net reduction due to AZ Statue ARS 42-5075, Title 42. Taxation, Arizona Solar and wind	Automatic Incentive	Assumes $5,000 available per project in year 1	$5,000
Total Cost After Incentives Applied			**$824,114,602**
% Capital Cost Saved			**23.69**

Note: Assumes construction in years 1-3 and fully operational in year 4.

10.3.1 Role of Loan Guarantees

The above packages of incentives do not factor in loan guarantees, which are available for many of the hypothetical facility/owner combinations. As an example, the EPACT 2005, Section 2602, Department of Energy Loan Guarantee Program was reviewed with regard to the Gray Mountain Wind facility, hypothetically owned and operated by NTUA. Section 2602 provides loans valued at no more than 90% of the project cost for projects that expand the provision of electricity on Indian lands. Table 10-19 shows the difference in cost of capital between being able to finance the project under EPACT 2005 Section 2602 and financing the project through more traditional means. Two factors add up to big savings: (1) A federal loan guarantee allows a greater percentage of the project cost to be funded by debt. This is important, because debt, in general, is less expensive than equity. (2) The cost of debt on a federally guaranteed loan is likely to be less than that of a standard loan instrument. As can be seen in the table below, there can be a tremendous reduction in weighted average cost of capital with use of federal loan guarantee programs. (In our hypothetical example, there is a 17% reduction in the weighted average cost of capital through use of Section 2602.)

Note that a tribal entity, which does not pay taxes, does not see any benefit from interest payment deductions. Therefore, tribal corporations, with the same capital structure and costs of debt and equity, will have a higher cost of capital than a non-tribal entity. However, both types of entities do benefit from loan guarantees.

Table 10-19 — Loan Guarantees That Could Drastically Reduce Cost of Capital for both Tribal and Non-Tribal Entities

EXAMPLE: Gray Mountain Wind Farm Guaranteed Loan		
	Without Low-interest Loan Guarantee	With Low-interest loan guarantee
Capital Structure		
% debt	45	65
% equity	55	35
Cost of debt:	8.40%	7.40%
Cost of equity:	16.0%	16.0%
Weighted average cost of capital for non-paying tax entity under EPACT section 2602:	12.6%	10.4%
Equivalent weighted average cost of capital for tax paying entity:	11.3%	8.7%

10.3.2 Value of Long-Term Contracts

In addition to other incentives, there are likely opportunities for underwriting investments in alternative energy generation through long-term procurement agreements with owners of Mohave and other utilities in the region. These opportunities may include purchase preferences for minority or economically depressed sources and for purchasing power from sources that meet California's newly adopted performance standards for reducing greenhouse gas emissions. Such opportunities can also be valuable to business owners looking to build new generation facilities.

10.3.3 Summary Regarding Hypothetical Packages of Incentives

From the preceding discussion, it is clear that there are a large variety of financial incentives that can potentially be used to offset the capital costs of new supply- and demand-side alternatives, both on and near tribal reservation land. Business owners, however, should not simply come to expect the realization of these incentives; many of them have strict requirements and many of them are competitive. Equally important, incentive availability changes over time; business owners should continually review available incentives to make sure they are aware of any changes or additions to offerings.

Last page of Section 10.

11. GENERATION AND DEMAND PROFILES

Another aspect of the Study was to evaluate the correlation between various potential Mohave alternatives/ complements and the SCE load and costs, identify possible alternative/complementary resource mixes, and calculate their benefit to meeting SCE load demand. Work on this task proceeded as follows:

- Collected information about SCE load profiles.
- Collected, analyzed, and converted profiles of complements/alternatives into comparable formats.
- Evaluated the correlation between various potential resources and SCE load and costs
- Identified possible resource mixes and calculating their benefit to meeting SCE load.

11.1 SCE LOAD DEMAND

For the demand profiles, hourly load and price data for SCE were collected for the year 2002 and for the more recent 12-month period from October 2004 through September 2005. A monthly summary of this information is shown in the graphs and table below. Note that the maximum loads occur in July, August, and September.

Figure 11-1 — Load Profile and Prices of Electricity for SCE by Month in the Year 2002

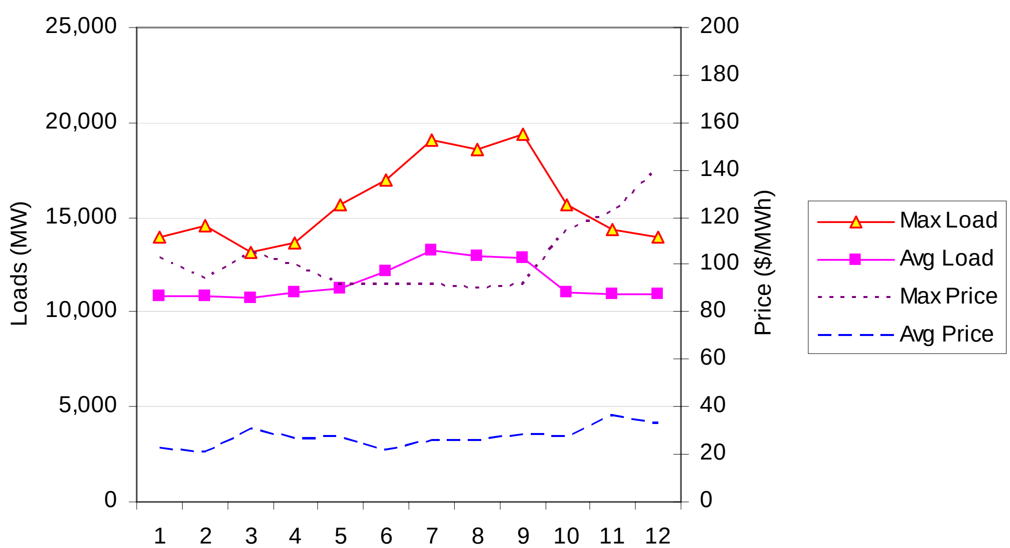


Figure 11-2 — California Monthly Loads and SCE Prices for October 2004 – September 2005

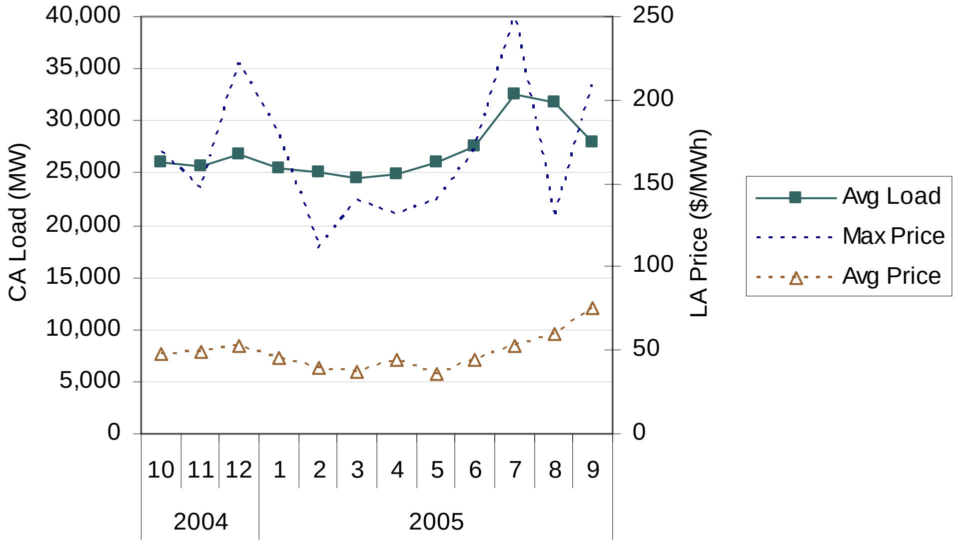


Table 11-1 — Load Profile and Prices of Electricity for SCE by Month in the Year 2002

Month	Avg. Load (MW)	Max. Load (MW)	Avg. Price ($/MWh)	Max. Price ($/MWh)
1	10,856	14,000	22.27	103.17
2	10,831	14,588	20.57	94.19
3	10,731	13,155	30.41	104.83
4	11,031	13,653	26.26	99.70
5	11,271	15,696	26.98	91.87
6	12,160	16,956	21.93	91.87
7	13,241	19,051	25.86	91.86
8	12,922	18,597	25.37	90.17
9	12,833	19,342	28.33	91.87
10	11,014	15,699	27.08	114.69
11	10,925	14,310	36.24	121.98
12	10,951	13,914	33.02	140.38

In addition, the two graphs below show the typical daily load and price patterns by season. The nighttime and evening loads are fairly consistent throughout the year. The big difference occurs in afternoon loads, which are much higher during July, August, and September, with June being a transitional month. The hourly prices show a similar, but much more erratic pattern. The relative price differences are much more extreme with afternoon and evening prices at roughly $35/MWh, which is over three times greater than the early morning prices of about $10/MWh. Thus, there are significant relative benefits for those resources that are available during the mid-day through evening period.

Figure 11-3 — Typical Hourly SCE Daily Price Pattern by Season

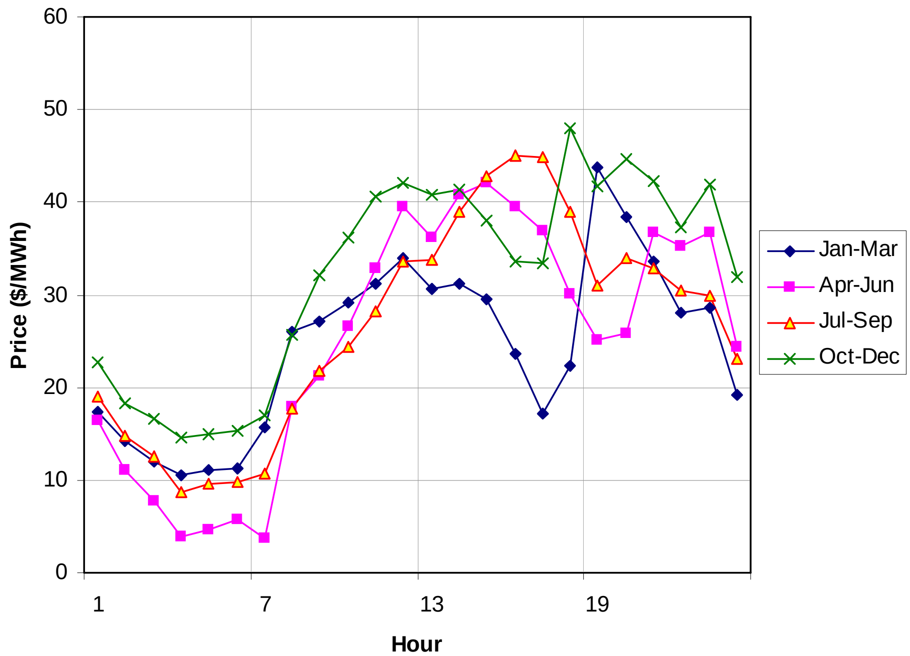
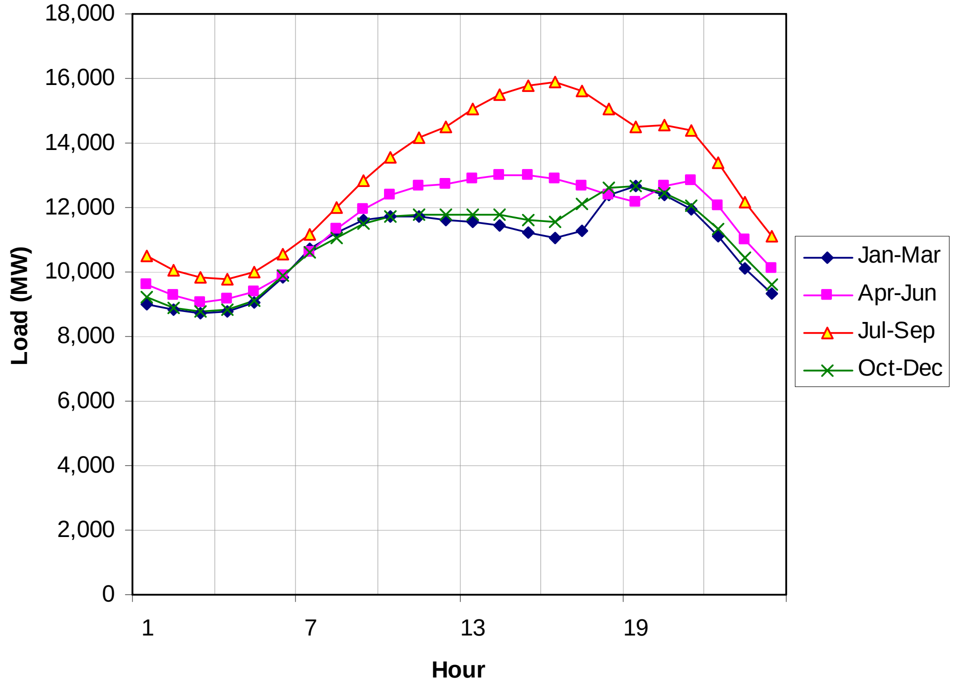
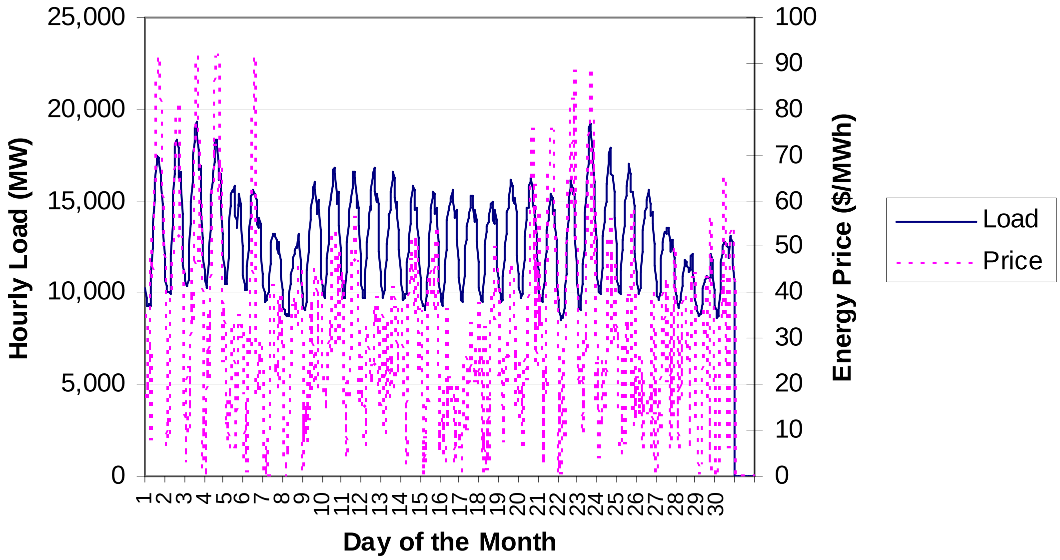


Figure 11-4 — Typical Hourly SCE Daily Load Pattern by Season



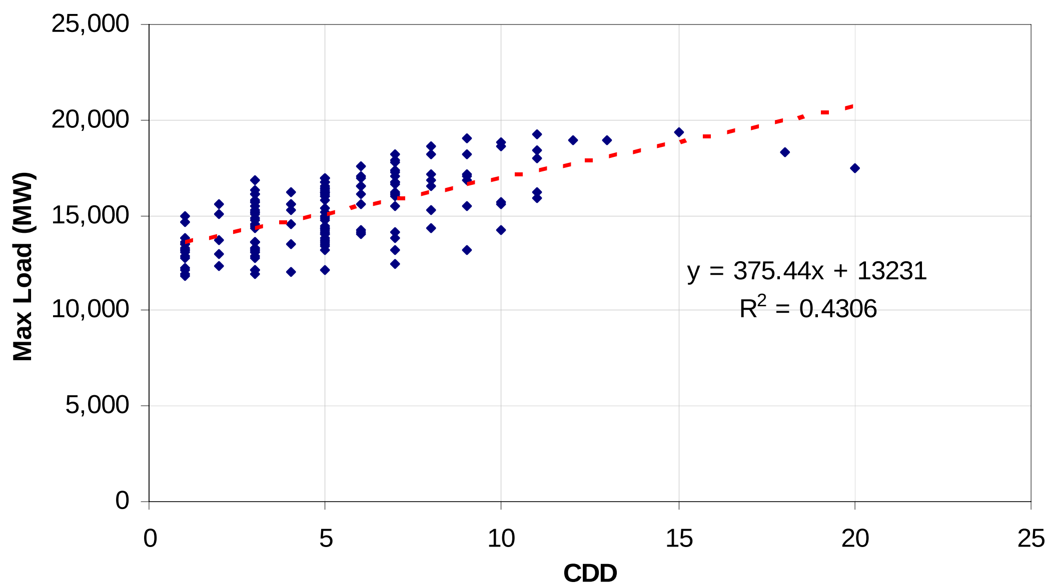
A more detailed look at loads and prices is shown in the following graph for September 2002, which shows that the highest prices are associated with the greatest loads. But that is not always the case; there are some days when loads are high but prices are not, and vice versa. Again, there is a very wide range of daily prices, with typical daily highs ranging from $40 to $90 per MWh, while daily lows are very often below $10/MWh.

Figure 11-5 — Hourly Price and Load Demand Correlation for September 2002



Based on this pattern, it seems likely that a portion of the peak daily loads are related to air conditioning. To determine this correlation, daily peak load and cooling degree days (CDD) was analyzed as shown below. This analysis shows a definite but modest relationship.

Figure 11-6 — Relationship between Daily Peak Energy and Cooling Loads



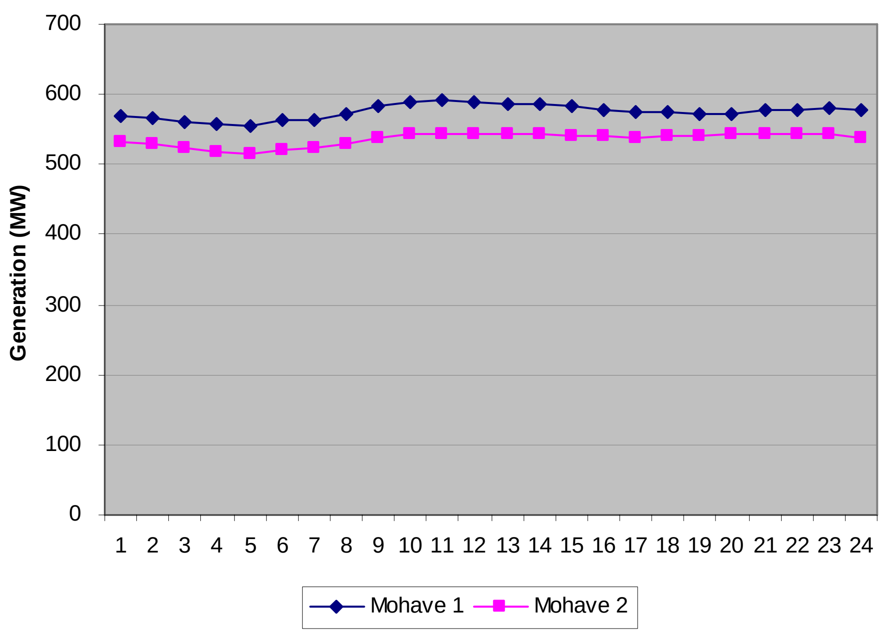
Note: Cooling degree days are those days where the average daily temperature is above 65 degrees Fahrenheit. The x-axis scale for CDD = average daily temperature minus 65 degrees.

11.2 ALTERNATIVE / COMPLEMENT PROFILES

The question that follows the preceding analysis is How well do the resources match up against the load? As discussed above, resources that preferentially provide more energy during the afternoon and evening hours and during the summer days would be of greater value. A description of the output profile of the existing plant and the various alternatives is provided below:

- **Existing Mohave Plant.** The daily generation profile for the existing Mohave station is very flat as shown in the following graph. Thus its most direct replacement would be another base generation resource. But a resource with a better match to the load profile would be even more valuable.

Figure 11-7 — Mohave Average Hourly Generation Profile for 2003



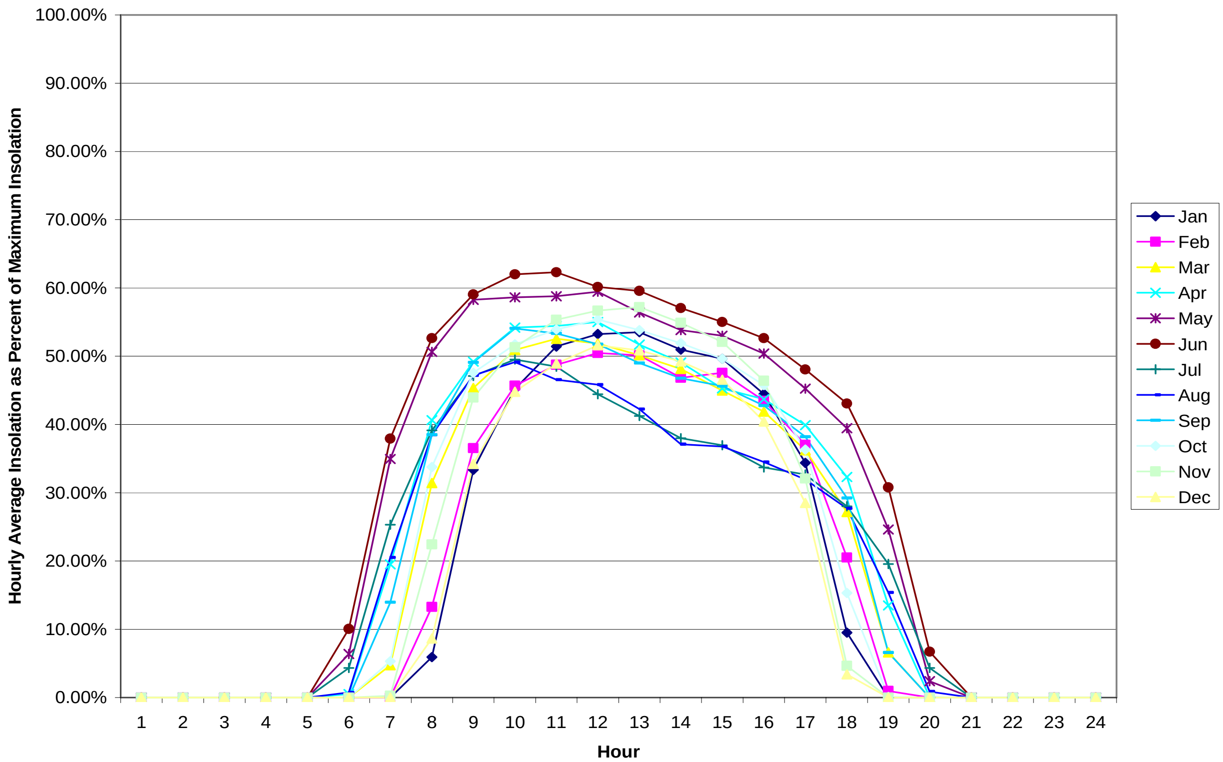
- **Integrated Gasification Combined Cycle.** An IGCC plant is a dispatchable resource that could be operated to some extent to match the loads. However, IGCC plants have very high fixed costs along with low fuel and operating costs. In addition, there may be operational limitations in the rate at which generation can be raised or lowered, especially in configurations that include carbon capture. Thus, an IGCC plant would most likely be run in a baseload pattern similar to Mohave and providing the same amount of energy at all load and price levels.

- **Natural Gas Combined Cycle.** These plants are dispatchable resources that could be run to match the load levels. NGCC plants have moderate capital costs and low emissions, but have fairly high fuel costs since natural gas prices on an energy basis have risen substantially in the last several years and are much greater than coal. These plants also tend to be fairly flexible in ramping up and down to match load. Given these characteristics, a NGCC plant would operate during higher load and price periods. Based on hourly prices shown previously, a plausible scenario would be that an NGCC plant would operate during the “peak” 16-hour period of each day and at additional times if needed for reliability or economy. An NGCC plant with carbon capture, however, may have operational constraints that limit ramp up and ramp down more tightly than for a basic NGCC plant. Also, NGCC plants with carbon capture would have higher capital costs. These factors may limit their dispatchability, either from engineering or economic considerations.

- **Solar.** Solar resources provide a good match, specifically with the daytime peak. However, as shown in the graph below, solar output peaks earlier than the SCE load does and falls off rapidly in the early evening. There is a further time offset since these data are for Flagstaff, Arizona, which is in a different time zone than California and physically farther east. The data also shows a significant afternoon decline in July and August when SCE loads are greatest. It is believed that this is a result of cloud cover conditions in Flagstaff. Such conditions are likely to vary by location and altitude, so the specific Solar 1 and 2 sites may present somewhat different conditions.

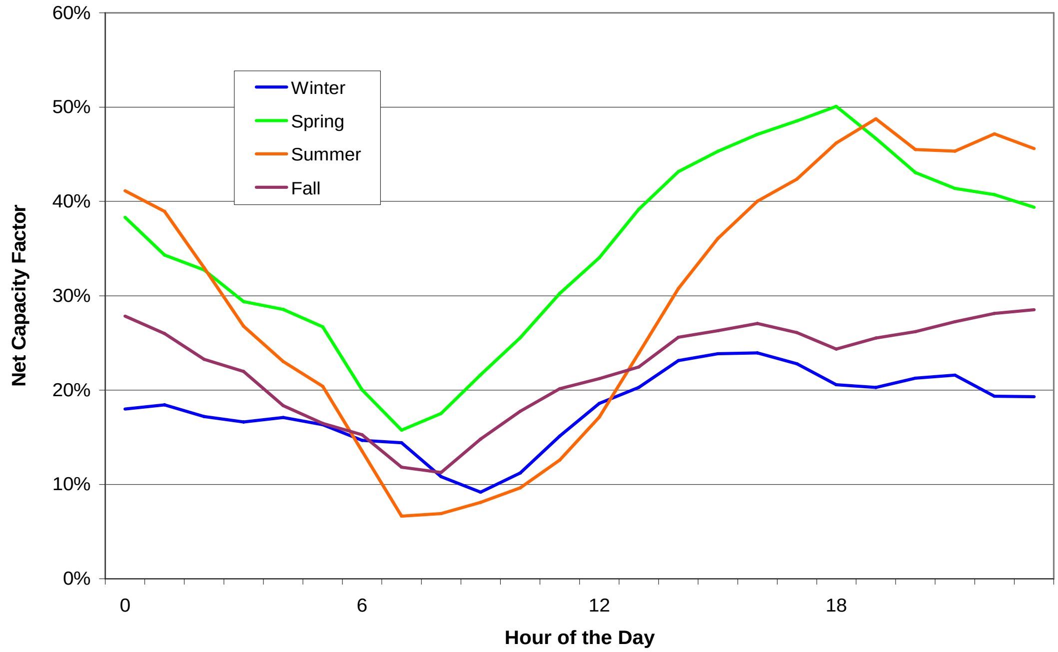
  The output for a photovoltaic device would closely follow this solar profile. A solar thermal device, depending on its design, might not generate at all below a threshold level. Of some of the designs being considered, a dish/Stirling engine with a parabolic reflector would best be able to provide power throughout the entire solar day, but at added expense. Systems with parabolic troughs would have lesser, but still good technical performance. Such a system with storage could shift the generation to later in the day and provide a better match with the SCE load.

Figure 11-8 — Hourly Solar Insolation in Flagstaff, Arizona, by Month



- **Wind.** Wind resources, while variable from one day to the next, show both positive and negative correlations with the SCE load. Seasonally, the wind energy is high in summer, as are loads. The daily pattern shows greater availability in the late afternoon and evening hours, which is a good complement to solar shown above. Generation is also high in the midnight to 6 a.m. period when loads and prices are lowest.

Figure 11-9 — Diurnal Wind Generation Output by Season at the Mogollon Rim in Northeastern Arizona



Note: Sites studied are Gray Mountain, Aubrey Cliffs, Clear Creek and Sunshine.

- **Demand Side Management (DSM) Resource.** The resource output of the DSM alternative or complement to Mohave cannot be described in the same terms as the resource output of the supply options because there are two separate components to the potential transaction. The DSM alternative being explored will consist of a power purchase agreement with SCE coupled with the implementation of DSM measures in a utility service territory located outside of SCE. The nature of the DSM portfolio is not yet known, and its actual physical characteristics (i.e., the hourly profile of energy and/or capacity savings resulting from a portfolio of installed DSM measures) will depend on the set of measures installed, which are yet to be determined with any specificity. However, it is likely that cost-effective DSM portfolios in New Mexico or Arizona, for example, will contain considerable peak load reduction characteristics. The predominance of air conditioning and commercial lighting measures, for example, usually found in such programs, ensures peak load reduction.

  Two broad approaches were considered to analyze the DSM alternative. With each approach, the DSM implementation is coupled with a power purchase agreement for physical flow into SCE's territory.

  The baseline quantitative example used in this analysis assumed that the power purchase contract, which will be coupled with the DSM implementation, will be of the same or similar profile as the current Mohave output, i.e., a baseload plant. (The actual profile used in the example was a flat, 24 x 7 shape power purchase.) In this way, the DSM "resource" can be more easily compared to other supply options. The actual cost, or price, of this resource might ultimately depend on negotiated arrangements between SCE and the neighboring utility supplier, or on results of a competitive solicitation. If the DSM measures being installed tended to focus on reduction of peak load, then the value of the DSM measures to the neighboring utility would be high, allowing for a lower “baseload” power purchase contract price (all else being equal). Conversely, to the extent that the DSM measures produced relatively “flat” savings (e.g., did not focus on daytime air conditioning uses or commercial lighting applications), the value to the host utility might be lower, and thus the purchase price for a “baseload” power flow to SCE would be higher.

A second approach could simply assume that the energy flows associated with the power purchase contract are of a similar shape as the actual DSM resource, or are shaped the same as the host utility’s load profile. In either instance, the price for such a resource would be higher than the price for a flatter-profile product, for the same quantity of energy.

11.3 SUMMARY AND FURTHER ANALYSIS

The SCE load demand shows a distinct seasonal and hourly variation. The variation in prices is even more dramatic than for load. Thus, some resources are more valuable than others depending on how they relate to load. Of course, one consideration is the economic value of the generation for the SCE system. Resources that provide more generation during the peak loads periods have greater energy value. Resources that provide greater reliable capacity during peak load periods are also of greater system value. However, there are also multiple other considerations having to do with locational economic and resource effects.

One of the study’s goals was to evaluate the correlation between various potential Mohave alternatives/ complements and SCE load and costs. SCE nighttime and evening loads are fairly consistent throughout the year. The big difference occurs in afternoon loads, which are much higher during July, August, and September. The data also indicate that a portion of the peak daily loads are related to air conditioning use. Based on this information, resources that preferentially provide more energy during the afternoon and evening hours and during summer days would correlate best with SCE loads and costs.

As it is a baseload generation facility, the daily generation profile for the existing Mohave station is very flat. Thus, its most direct replacement would be another base generation resource, such as an IGCC or NGCC plant. Solar resources, on the other hand, provide a good match specifically with the daytime peak. However, solar output peaks earlier than SCE’s load does and falls off rapidly in the early evening. Of some of the designs being considered, a dish/Stirling engine would best be able to provide power throughout the entire solar day. Systems with parabolic troughs would have lesser, but still good technical performance. Such a system with storage could shift the generation to later in the day and provide a better match with the SCE load.

As with solar, wind energy is high in summer, as are SCE loads. The daily wind pattern shows greater availability in the late afternoon and evening hours, which is a good complement to the solar option.

As for the resource output of the DSM alternative or complement to Mohave, it cannot be described in the same terms as the resource output of the supply options. The hourly profile of energy and/or capacity savings resulting from a portfolio of installed DSM measures will depend on the set of measures installed, which are yet to be determined with any specificity. As the DSM options being studied are in the Southwest, the available end uses would be, to some extent, similar to SCE's, and available savings would have a profile quite similar to SCE's, depending on the programs chosen. However, the commercial terms for such an exchange of DSM for power could shape the power provided in various ways to suit SCE loads.

The next step is to quantify the degree of fit between the various resources being considered and the SCE load profile. The approach used is to consider the relative value of energy from the different resources by matching their generation profiles with a SCE price profile. For each resource, the value of its generation is calculated by multiplying its hourly output by the hourly energy price for typical days to obtain a total avoided cost. Then, for comparison, the average energy value of a baseload resource (such as Mohave) is normalized to 1.0 and other resources (or resource portfolios) ranked relative to that.

Recent annual load and price profiles are shown in Figure 11-10 below. Figure 11-11 shows the average load profiles for various resources being considered.

Figure 11-10 — Average Hourly Load and Price Profiles for October 2004 – September 2005

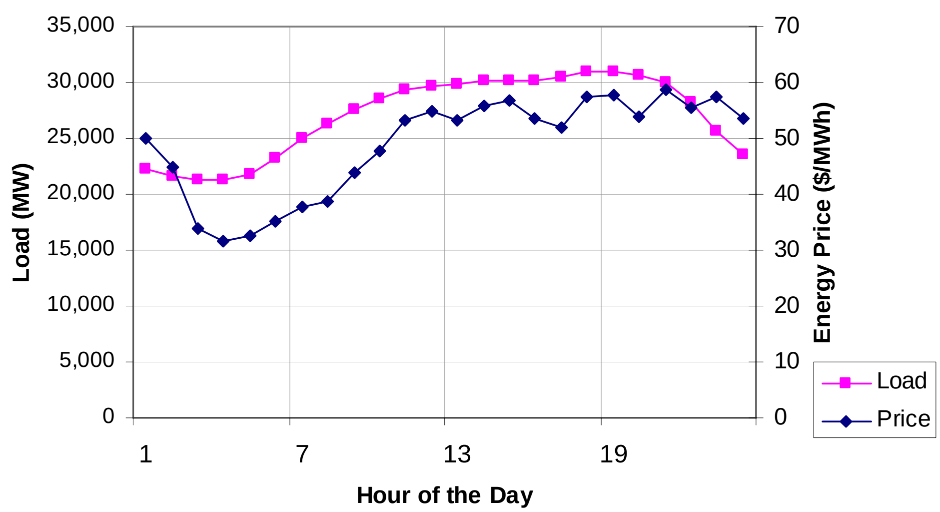
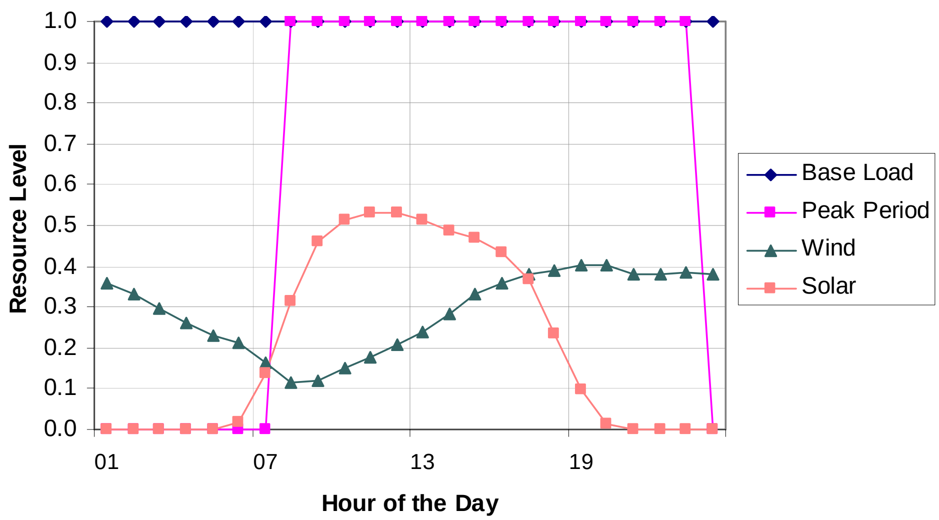


Figure 11-11 — Hourly Relative Resource Profiles



The results of this comparative analysis are shown in Table 11-2 below.

Table 11-2 — Relative Resource Energy Values

Resource Type	Baseload	Peak Period	Wind	Solar
Average Price, $/MWh	48.8	53.2	50.4	51.4
Price Premium	0.0%	9.1%	3.4%	5.5%

Based on recent price patterns, resources that more closely match load and price profiles can obtain average unit prices that are higher relative to baseload resources during the hours in which they operate. This is contrasted against the possible inability of these resources to serve load during other hours and obtain whatever premiums are available during those hours as, for example, in the case of certain solar resources during night hours. In order to characterize performance during both favorable hours and the rest-of-period hours, a more complete electric system operational modeling should be employed.

Last page of Section 11.

12. TRANSMISSION ISSUES

The original scope of work to determine transmission requirements for Mohave Alternatives and Complements included the following:

- Determine the status of transmission availability into the SCE region from the Study area.
- Use information available on the California ISO and wesTTrans OASIS sites to determine the nearer-term availability of transmission capacity into the SCE region.
- Review total transfer capability and available transfer capability to assess the near-term level of capacity availability. As necessary, information from the other western OASIS sites (the Northwest OASIS and the Rocky Mountain OASIS) will supplement data from California ISO and wesTTrans. This approach is to be supplemented with direct oral or written queries to transmission system operators in the Study Area to confirm or clarify the information obtained through OASIS queries.
- Review the information available from the California ISO on holders of existing transmission capacity, and holders of firm transmission rights (FTRs).
- Review existing studies conducted by the California ISO on transmission capability, and review California ISO market reports to determine which interfaces are more likely to be congested, and which interfaces are more likely to support additional capacity transfer into the SCE region. This includes California ISO Department of Market Analysis (DMA) annual and monthly reports and presentations.
- Review existing studies available from transmission owners in the Study Area, in particular those available from Nevada Power, Arizona Public Service, the Western Area Power Administration, the Salt River Project, and the Bonneville Power Administration. The estimates of existing transmission capacity determined through OASIS availability is to be confirmed by cross-checking those results against the transmission capacity information provided by these studies.

12.1 METHODOLOGY USED

The scope of work was limited to the desert southwest region and excluded assessment of transmission availability from the regions north of California. This limitation resulted from two factors: (1) confirmation that the group of supply alternatives and complements to be studied would be limited to locations in or near the Navajo and Hopi tribal lands and (2) the determination that DSM alternatives would focus on the desert southwest states. This was based on the greater level of utility-sponsored DSM already in place in Oregon and Washington, compared to the level of DSM activity and likely opportunities in the desert southwest regions. The methodology used focused on three specific sub-tasks:

- Review of OASIS data and determination of existing available transmission capability.
- Review of existing California ISO and desert southwest utility studies and consideration of future expected changes to the transmission system, focusing on the effect that major transmission upgrade proposals would have on changing (increasing) the level of transmission capacity available for transactions between the desert southwest and California.
- Completion of load flow studies.

12.2 BACKGROUND ON TRANSMISSION ACCESS IN THE REGION

Access to transmission in the desert southwest and the California regions occurs under two separate paradigms: one for users who take transmission service under the California ISO tariff structure and one for transmission service taken under all other transmission tariffs in the region. Many transmission users, especially those with loads in California, must work within both of these constructs to secure access to transmission. The transmission must be used to meet load obligations served by a variety of supply sources, often including those situated throughout the region and not limited solely to local (i.e., intra-state) resources. For example, customers of SCE receive power both from close-in sources of power that use transmission solely under the California ISO's purview (e.g., San Onofre Nuclear Generating Station) and also from more remote sources that rely on external transmission systems and transmission tariff structures (e.g., Four Corners Coal Generating Station, using Arizona Public Service transmission lines).

The California ISO coordinates all transmission use across the major investor-owned utility transmission systems in California, including those of SCE.[1] Users schedule transactions across and/or into the transmission system and pay usage charges based on the injection and withdrawal points of those transactions and based on the results of California ISO's daily and hourly assessments of transmission congestion across the system. The California ISO (1) uses a commercial network model of the transmission system (shown below), (2) defines major internal zones of use (NP15, SP15, and ZP26), and (3) separately models approximately 30 interchange tie points, including multiple tie points with the internal California regions of the Los Angeles Department of Water and Power, the Sacramento Municipal Utility District, and the Imperial Irrigation District. The California ISO tariff also includes a separate set of charges designed to recover the fixed costs of the transmission system.

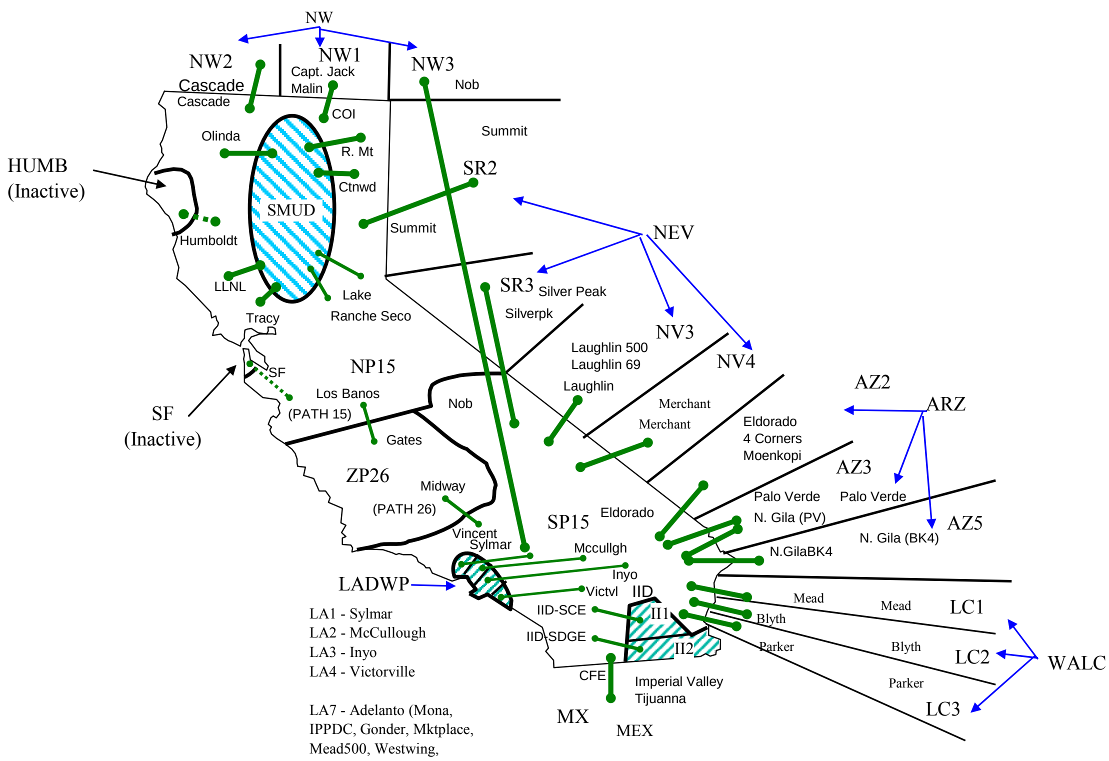
Users of the California ISO grid cannot reserve physical transmission capacity in advance of the day-ahead timeframe, except for uses associated with "Existing Transmission Contracts" (ETCs), which may represent on

[1] The rates, terms and conditions of transmission system use are contained in the current California ISO transmission tariff, available at http://www.caiso.com/pubinfo/tariffs/.

the order of 42% of the total California ISO peak grid use.[2] However, financially firm transmission rights (FTRs) are available for purchase through the California ISO's annual auction. These FTRs allow users to hedge the cost of congestion for one year between California ISO internal zones and between the internal zones and the interchange tie points. FTRs are not necessary in order to schedule energy into the California ISO internal zones.

Figure 12-1 — Congestion Zones and Pathways for California ISO Grid, 2004

Network Model, Effective 1/1/2005



Source: California ISO, Takeout Points, Network and Load Groups (effective January 1, 2005) available at http://www.caiso.com/marketops/technical/index.html.

In contrast to the California ISO tariff structure, the "contract path" paradigm, used by all transmission providers in the west except the California ISO, is best defined as a construct where all transmission is secured based on a fictional contract path from source point to sink point, for defined periods and defined quantities, with certain terms and conditions depending on the degree of "firmness" of the transmission. Individual transmission providers regularly compute the amount of transmission needed to serve native load uses, and then, based on

[2] The FERC Guidance Order in Docket No. ER02-1656-02 states the following: "On July 23, 2004, in Docket No. ER04-928-000, parties filed the requested information detailing approximately 64 contracts. Based on contract termination dates reported, 54 contracts representing approximately 19,000 megawatts

such computations, they determine the amount of transmission available for residual uses and thus offered for sale over OASIS. These computations are complex and are repeated at different intervals to determine the availability for different levels of service. For example, offerings for monthly transmission may be based on a computation performed once per week; offering for daily or hourly transmission service may be based on computations performed daily or several times during the day.

The structure used by the California ISO differs from that in use in the desert southwest in that physical transmission reservations in the California ISO cannot be made in advance;[3] instead, all users of the transmission system pay a usage charge based on computations of congestion derived from a simplified locational pricing model. This methodology implies that the energy output from a technology option can be imported into the SCE service territory if transmission can be secured from the option site to any of the California ISO interchange tie points.[4] While it is possible that physical curtailment of scheduled interchange can occur on an import path into California, it seems that this is a rare occurrence and that all users willing to pay congestion charges will be able to schedule energy into California.[5] For desert southwest regions, power can be delivered to any of the major Nevada or Arizona interchange tie points (NV3, NV4, AZ2, AZ3, or AZ5, via delivery over Arizona and Nevada transmission systems, as indicated on the network map above) or the remaining “lower Colorado” tie points (LC1, LC2, or LC3 via delivery over the Western Area Power Administration [WAPA] lower Colorado transmission system).

12.3 EXISTING AVAILABLE TRANSMISSION CAPACITY AS REFLECTED IN OASIS TRANSMISSION OFFERINGS

The Open Access Same-Time Information System (OASIS) is a transmission access and reservation construct mandated by the FERC through its open access Order 889 and its subsequent follow-on orders.[6] Order 889 was

(MWs) may still be in place upon implementation of MRTU in February 2007. These contracts may represent as much as 42 percent of the CAISO’s 2004 peak load of 45,000 MWs.” (paragraph 8).

[3] Transmission use under ETCs is scheduled with the California ISO in the day-ahead timeframe.

[4] The interchange tie zone “AZ2” includes a “pseudo” tie at Four Corners. This represents the ability to import certain generation at Four Corners directly into the California ISO control area, using existing transmission rights. It does not imply that new generation physically connected at Four Corners can automatically schedule into the California ISO control area; physical transmission to the California border points must first be obtained.

[5] An analysis of the magnitude of congestion charges for power flowing into California from desert southwest paths was beyond the scope of this project. However, California ISO reports that in 2004, the total congestion changes for imports from Palo Verde were $21 million, reflecting an average congestion charge of $6.10/MWh and path congestion for 22.3% of the hours in the year. Source: 2004 Annual Report on Market Issues and Performance, Table 5.2 and 5.3, pages 5-3 through 5-9.

[6] FERC Order 889 (April 24, 1996), 889-A (March 4, 1997), and 889-B (November 25, 1997), available at http://www.ferc.gov/legal/maj-ord-reg/land-ord.asp.

a companion Order to FERC's landmark Order 888[7], which promoted wholesale competition through open access to FERC-jurisdictional transmission systems. Many non-jurisdictional transmission system operators have also provided reciprocal open access on terms similar or identical to those reflected in Orders 888 and 889, including transmission systems used to supply power into California such as those operated by WAPA and the Bonneville Power Administration (BPA).

The promise of Order 889 is to provide transmission customers information about availability and pricing of transmission in a non-discriminatory fashion.[8] The OASIS structure facilitates this transparency by allowing customers to query the status of transmission availability on any given transmission provider's system,[9] and it also seeks to provide additional information, such as the results of system studies, that further informs transmission customers on the status of the transmission system robustness. A core purpose of the order is also to ensure that transmission providers do not grant preferential access to any user, including any affiliated company. Notably, however, "native load" uses of a transmission provider's system are considered outside the open access construct, and the information gleaned through OASIS reflects pricing and availability for uses incremental to native load.

Transmission owners in the Western U.S. initially provided open access reservation systems individually. Recently, many of the transmission-owning entities in the western region have coordinated their OASIS's under a single framework operating as the wesTTrans OASIS (http://www.westtrans.net/OASIS.html). The wesTTrans OASIS coordinates transmission reservation requests for the following transmission systems:

- Arizona Public Service
- Avista Corp. (formerly Washington Water Power)
- British Columbia Transmission Corporation (formerly, BC Hydro transmission)
- El Paso Electric
- Idaho Power Company

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[7] FERC Order 888 (April 24, 1996), available at http://www.ferc.gov/legal/maj-ord-reg/land-ord.asp.

[8] FERC Order 889, "Under this final rule, each public utility (or its agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce will be required to create or participate in an OASIS that will provide open access transmission customers and potential open access transmission customers with information, provided by electronic means, about available transmission capacity, prices, and other information that will enable them to obtain open access non-discriminatory transmission service." (page i)

[9] FERC Order 889, "The second provision sets out basic rules requiring that jurisdictional utilities that own or control transmission systems set up an OASIS. Under these rules, the utilities are required to provide certain types of information on that electronic information system as to the status of their transmission systems and are required to do so in a uniform manner. With these requirements, we are opening up the "black box" of utility transmission system information. When in place, the OASIS will allow transmission customers to determine the availability of transmission capacity and will help ensure that public utilities do not use their ownership, operation, or control of transmission to deny access unfairly." (page xx)

- Imperial Irrigation District
- Los Angeles Department of Water and Power
- Nevada Power
- Northwestern Energy
- Portland General Electric
- Public Service of Colorado
- Public Service of New Mexico
- Puget Sound Energy
- Sacramento Municipal Utility District
- Salt River Project
- Sierra Pacific Power Company
- Southwest Transmission Cooperative
- Texas/New Mexico Power Company
- Tri-State Generation and Transmission Cooperative
- Tucson Electric Power
- Western Area Power Administration (Rocky Mountain and Desert Southwest regions)

In addition, Colorado Springs Utilities and Transmission Agency of Northern California will begin use of the wesTTrans OASIS platform in November and December 2005.

The transmission systems in the West are either individually or jointly owned by transmission providers, and those individually owned can include the existence of long-term ownership rights for transfers over designated paths. The Western systems continue to use the "contract path" approach, whereby transfer capability is allocated on a path- or line-specific basis to owners or rights holders. This system of ownership and rights allocation is reflected in the OASIS database, as queries to ascertain transmission availability result in "available transmission capability"[10] across any given path from one or more than one transmission owning entity. For example, the major lines transmission from Four Corners to Palo Verde are owned by Arizona Public Service,

[10] The wesTTrans OASIS system provides available transmission capacity in most cases on the "offerings" screen, rather than the "ATC" screen. The ATC screen often indicates the following, which accompanies a query to ascertain ATC: "Note: Your Provider may post ATC's under Offerings". We determined available transmission capacity using the values from the "offerings" screens.

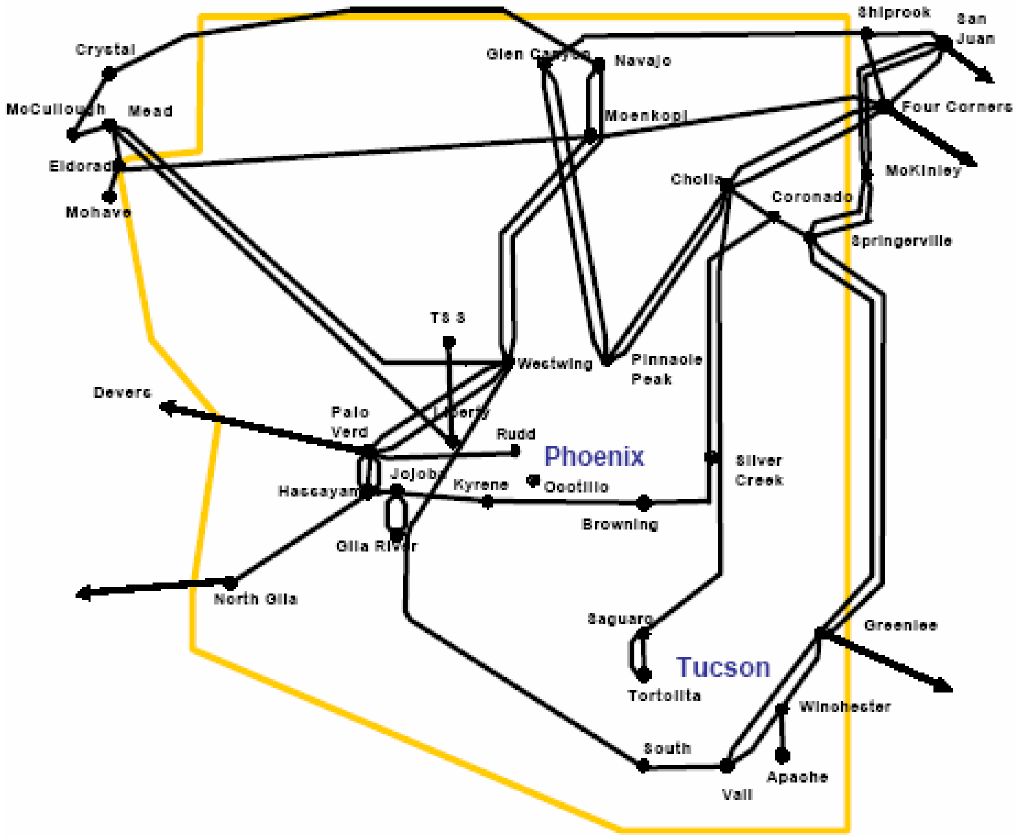
but the only “yearly” firm available transmission on that path is offered by Tucson Electric Power, which has rights to firm use for a portion of that path.

Synapse queried the wesTTrans OASIS platform during August and September 2005 to obtain information on the availability of transmission from the Study Area to SCE’s service territory. The Study Area included central and northeastern regions of Arizona. For determining transmission availability, Synapse focused on a number of potential “source” points in the region, or “points of receipt” into the transmission system, into which a number of alternative supply sources could be connected or could have their power output flow. These source points included the following:

- The Four Corners/Shiprock region of northwestern New Mexico, a hub point for generation supply sources in the region;
- The Moenkopi and Navajo 500-kV connection points in north central Arizona; and
- The Cholla substation in eastern central Arizona, a connection point to the 500-kV system in the region.

The rough proximity of these source points is shown on the Arizona extra-high voltage transmission system map below.

Figure 12-2 — Arizona Extra-High Voltage Transmission Facilities



Note: This map is reproduced directly from the Arizona Corporation Commission Staff and KEMA Inc. report, "Third Biennial Transmission Assessment 2004-2013," November 30, 2004, filed in Docket No. E-00000D-03-0047 with the Arizona Corporation Commission.

The analysis assumes that any of the supply alternatives would be responsible for either connecting to the transmission grid at these locations or for securing adequate transmission to enable power injected at the supply point to flow to these locations. Transmission availability information for a number of lower voltage points on the transmission grid at locations closer to the exact locations of the supply alternatives was not obtainable through the OASIS system. These points include, for example, the Leupp, Seligman, and Coconino 230-kV connection points, and the 345 kV Flagstaff connection point, all of which are in the proximate north-central Arizona region.

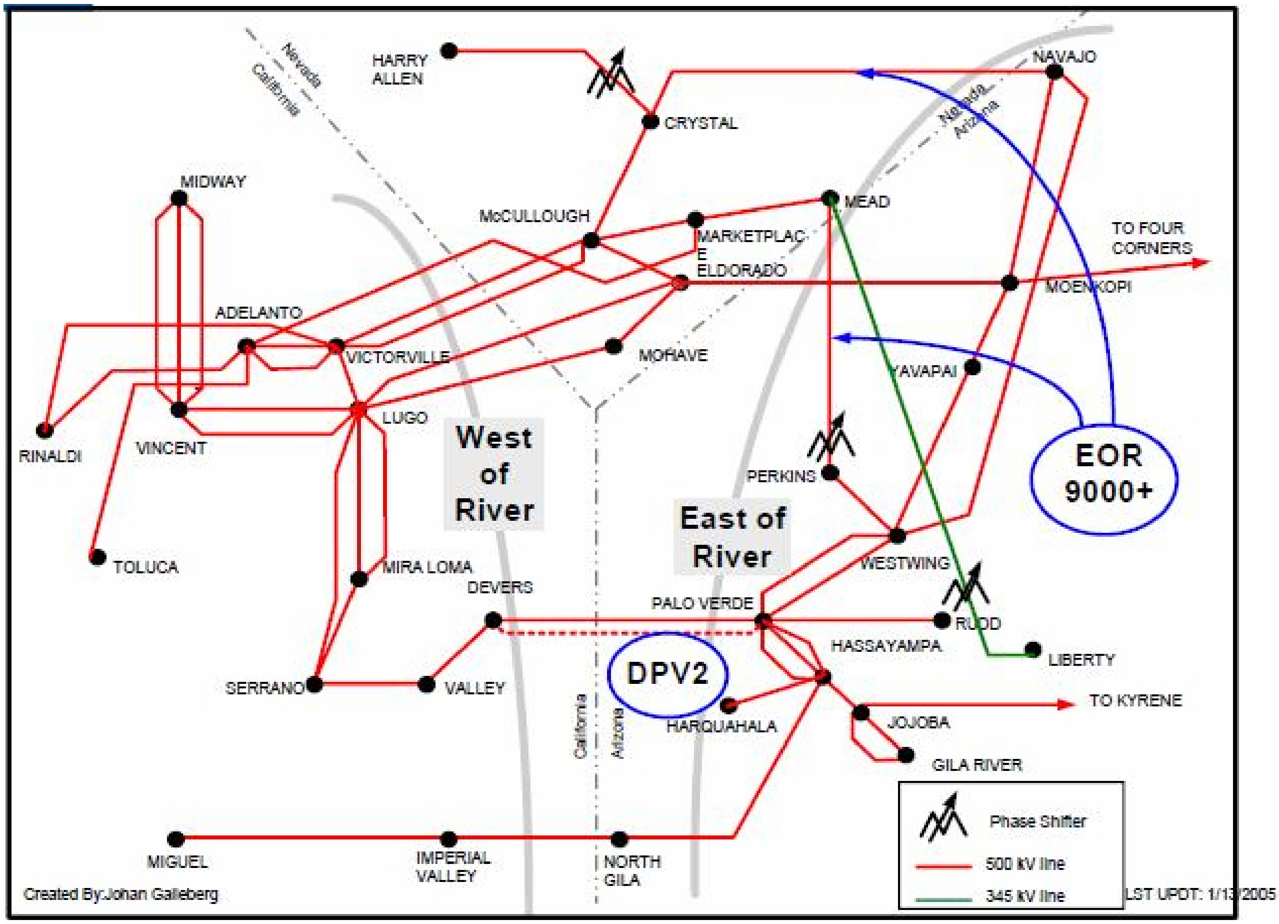
The following table maps the "source points" studied with regard to each of the different Mohave alternatives or complements. Unless otherwise indicated, all source points are located at the 500-kV level. In general, the methodology used to determine available transmission capacity was not tied directly to any particular technology option, but rather it established the level of capacity that remained available for any given power injection at the source point indicated. Thus, if capacity is (or is not) available for a transfer from Four Corners to Palo Verde, then that capacity could be used (up to the level available) for any number of alternatives that might connect via Four Corners, for example, an IGCC at Black Mesa, a wind plant at Black Mesa, or a Solar Site 1 plant.

Table 12-1 — Transmission System "Source" Points Associated with Each Technology Option

Technology Option	Transmission System Source Point
IGCC – at Black Mesa	Four Corners, Navajo, Moenkopi
Wind – Aubrey Cliffs	Hilltop (230 kV), Moenkopi
Wind – Gray Mountain	Moenkopi
Wind – Clear Creek / Sunshine	Cholla
Solar Site 1	Four Corners, Navajo
Solar Site 2	Moenkopi
DSM – New Mexico (PNM)	No transmission study conducted – coupled with purchased power at Palo Verde
DSM – Arizona (APS)	No transmission study conducted – coupled with purchased power at Palo Verde
IGCC at Mohave	No transmission study conducted – at CA border already
Combined Cycle at Mohave	No transmission study conducted – at CA border already

To serve SCE customers, electricity supply sourced from the Study Area would need to flow to California via any of two major transit paths and one minor transit path. The major transit paths include the Palo Verde-to-Southern California route, via two major 500-kV transmission lines, one from Palo Verde and one from its companion "switching station" at Hassayampa; and the set of 500-kV and 230-kV transmission lines emanating from the southern Nevada area at the McCullough, Marketplace, Eldorado, Mohave, and Mead substations. Those paths are schematically represented in the California ISO map below.

Figure 12-3 — Schematic of Major Transmission Infrastructure between Arizona, Nevada and California



Note: This map was produced by the California ISO and shows schematically the major constrained paths into California from the desert southwest, the "East of River (EOR)" and "West of River" paths indicated on the figure. This map also shows the location of two of the proposed new transmission projects designed to increase transfer capacity from Arizona into California: the "DPV2" or Devers-Palo Verde 2nd 500 kV line; and upgrades to increase the transfer capacity across the EOR path to 9,000 MW.

The third transit path includes access via the WAPA 230-kV facilities between the region west of Phoenix and the Parker dam facilities at the California border. Transit paths have been analyzed in this way in order to determine transmission availability to these "sink" points from the Study area.

Another way to characterize the routes into southern California would be to use the California ISO's set of interchange tie points with the region east and northeast of southern California, which includes the three transit paths described above. The California ISO models these interchange points as "branch groups" and computes congestion charges for import power flows sourced at any of these points.

The study sought to determine transmission availability from Arizona and Nevada to the California ISO border, to any of the physical interchange tie points, all of which are included as possible "sink" points or "points of delivery" in the OASIS database. The interchange tie points are listed in Table 12-2 below.

Table 12-2 — Interchange Tie Points between California and Arizona/Nevada

Interchange Tie Point	From	To	DESCRIPTION
ELDORD_5_MOENKP	AZ2	SP15	ELDORADO
PVERDE_5_DEVERS	AZ3	SP15	PALOVERDE
PVERDE_5_NG-PLV	AZ3	SP15	N.GILA (PV)
NGILA_5_NG4	AZ5	SP15	N.GILA (BK 4)
ELDORD_5_MCLLGH	LA2	SP15	MCCULLOUGH
MEAD_2_WALC	LC1	SP15	MEAD
BLYTHE_1_WALC	LC2	SP15	BLYTHE
PARKR_2_GENE	LC3	SP15	PARKER
MOHAVE_6_69KV	NV3	SP15	LAUGHLIN 69
MOHAVE_5_500KV	NV3	SP15	LAUGHLIN 500
MRCHNT_2_ELDORD	NV4	SP15	MERCHANT PLANT

Source: California ISO, Takeout Points, Network and Load Groups (effective January 1, 2005) available at http://www.caiso.com/marketops/technical/index.html. Note: Pseudo Ties are excluded from this listing.

Transmission availability was categorized according to the structure used by transmission providers offering access to their systems. Transmission can be obtained on a firm or a non-firm basis, and it can be obtained for varying time periods: hourly, daily, weekly, monthly, or yearly. Yearly transmission access is available only on a firm basis, and hourly transmission availability is generally available only on a non-firm basis, although OASIS entries do exist, indicating hourly firm transmission.

12.4 RESULTS OF THE OASIS QUERIES

The results of our OASIS queries are summarized in the tables below. The values listed in the tables are based on a careful examination of the results of numerous queries made through the wesTTrans OASIS system for various transmission paths. The maximum capacity available, the time frame, and the seller(s) are listed. For the paths reviewed, sellers include Tucson Electric Power (TEP), Arizona Public Service (APS), Los Angeles Department of Water and Power (LDWP), and Salt River Project (SRP). These entities either own the transmission assets in question or have rights to use the transmission. Appendix K contains more detailed data based on the OASIS queries that were used to develop these summary tables. The data in Appendix K reveal, for example, the pattern of available transmission across a succession of time periods and across different owners, from which the summary data were extracted based on maximum capacity available.

Table 12-3 — Summary of Transmission Availability “Into California” from Four Corners to Palo Verde

	Yearly Firm	Monthly Firm	Monthly Non Firm	Weekly Firm	Weekly Non Firm	Daily Firm	Daily Non Firm	Hourly Non Firm
Maximum Capacity Available	94 MW	104 MW	104 MW	104 MW	104 MW	117 MW	117 MW	422 MW
Time Frame	2007 and 2008	June – Aug 2006	June – Aug 2006	October 2005	October 2005	September 2005	September 2005	September 2005
Seller	TEP	TEP	TEP	TEP	TEP	TEP	TEP	APS

Notes:

Lower volumes of firm and nonfirm monthly transmission are available for the months November 2005 through February 2006, and September through October, 2006.

For hourly transmission, lower volumes are available for many hours; the maximum quantity listed is available for selected hours or groups of hours in the time period indicated.

Table 12-4 — Summary of Transmission Availability “Into California” from Four Corners to Mead

	Yearly Firm	Monthly Firm	Monthly Non Firm	Weekly Firm	Weekly Non Firm	Daily Firm	Daily Non Firm	Hourly Non Firm
Maximum Capacity Available	0 MW	0 MW	0 MW	1 MW	0 MW	1 MW	58 MW	211 MW
Time Frame				September 2005		September 2005	September 2005	September 2005
Seller				APS		APS	APS	APS

Note:

For hourly transmission, lower volumes are available for many hours; the maximum quantity listed is available for selected hours or groups of hours in the time period indicated.

Table 12-5 — Summary of Transmission Availability "Into California" from Navajo 500 to Palo Verde

	Yearly Firm	Monthly Firm	Monthly Non Firm	Weekly Firm	Weekly Non Firm	Daily Firm	Daily Non Firm	Hourly Non Firm
Maximum Capacity Available	169 MW	572/547 MW	572/547 MW	274 MW	234 MW	450 MW	390 MW	605 MW
Time Frame	2006	Jan – Sept 2006	Jan – Sept 2006	September 2005	September 2005	September 2005	September 2005	September 2005
Seller	TEP, APS	LDWP, APS, TEP	LDWP, APS, TEP	TEP, SRP, APS	TEP, APS	LDWP, APS, TEP, SRP	LDWP, APS, TEP	LDWP, SRP, APS

Notes:

125 MW of yearly transmission is available for 2007 and 2008 through TEP.

572 MW of monthly firm or non-firm transmission is available for January through March, 2006; 547 MW is available for April through September, 2006.

For hourly transmission, lower volumes are available for many hours; the maximum quantity listed is available for selected hours or groups of hours in the time period indicated.

Table 12-6 — Summary of Transmission Availability "Into California" from Cholla 500 to Palo Verde

	Yearly Firm	Monthly Firm	Monthly Non Firm	Weekly Firm	Weekly Non Firm	Daily Firm	Daily Non Firm	Hourly Non Firm
Maximum Capacity Available	0 MW	230 MW	115 MW	115 MW	69 MW	115 MW	115 MW	462 MW
Time Frame		Jan – Oct 2006	Jan – Oct 2006	September 2005	October 2005	September 2005	September 2005	September 2005
Seller		APS	APS	APS	APS	APS	APS	APS

Note:

For hourly transmission, lower volumes are available for many hours; the maximum quantity listed is available for selected hours or groups of hours in the time period indicated.

Table 12-7 — Summary of Transmission Availability "Into California" from Moenkopi to Palo Verde

	Yearly Firm	Monthly Firm	Monthly Non Firm	Weekly Firm	Weekly Non Firm	Daily Firm	Daily Non Firm	Hourly Firm*
Maximum Capacity Available	125 MW	641 MW	169 MW	463 MW	134 MW	663 MW	334 MW	538 MW
Time Frame	2006, 2007, 2008	Jan-Sept 2006	Jan-Oct 2006	September 2005	September 2005	September 2005	September 2005	September 2005
Seller(s)	TEP	SRP, TEP, APS	TEP, APS	SRP, TEP, APS	TEP, APS	SRP, TEP, APS	TEP, APS	SRP, APS

Note:

Hourly service is listed as available as firm for APS and SRP. Non-firm hourly maximum quantity is 334 MW, available from APS and TEP.

Table 12-8 — Summary of Transmission Availability "Into California" from Moenkopi to Eldorado, Mead, McCullough, or Marketplace

	Yearly Firm	Monthly Firm	Monthly Non Firm	Weekly Firm	Weekly Non Firm	Daily Firm	Daily Non Firm	Hourly Non Firm
Maximum Capacity Available	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW

These results illustrate that current transmission system availability as reflected in the information posted on the OASIS site is limited and, in particular, that long-term firm transmission (e.g., yearly) is not available in the quantities needed for the supply alternatives other than those located at the existing Mohave site. However, the summary information does indicate that monthly period transmission service is often available in quantities approaching the approximate size of some of the technology options being considered (i.e., on the order of hundreds of megawatts). The summary information also indicates that paths originating at Moenkopi or Navajo appear to have greater shorter-term firm availability (e.g., monthly) than paths originating in the Four Corners area, likely reflecting the relative limitation on the first portion of the path from the Four Corners area. This implies that connection points at or around Navajo or Moenkopi locations may be preferable to those at the Four Corners area, all else being equal.

Lastly, it is important to note that this examination of transmission availability is based on current snapshots of the transmission system and does not take into account any of the transmission system upgrades under consideration for the region (discussed below). Use of OASIS data as an indicator of near-term transmission availability also presumes that the existing physical transmission reservation construct will continue to be used for power flowing to the California ISO grid border. However, if the desert southwest region were to implement a regional form of transmission access under an RTO-like structure with a form of financial transmission rights, a different approach to transmission use and scheduling could arise.[11] Under such a construct, Mohave technology options located in the Study Area might not need to secure physical transmission in the same manner as is currently contemplated, but rather might face a set of financial congestion charges for transshipment of power to the California ISO border.

12.5 EXISTING STUDIES OF TRANSMISSION CAPABILITY FOR THE ARIZONA–NEVADA–CALIFORNIA REGION

The following studies were reviewed to assist in determining the extent of available transmission capacity in the region:

- California ISO 2004 Annual Report on Market Issues and Performance
- California ISO CARTS/STEP (California Arizona Regional Transmission Study / Southwest Transmission Expansion Plan), various studies/presentations from the California ISO and transmission owners, including those associated with the following projects:
- Devers Palo-Verde #2 500-kV transmission line
- EOR 9000+ Upgrade Project
- SCE Short-term transmission projects – Devers area upgrades
- Path 46 West-of-River Phase I upgrades and path rating study
- Colorado River Transmission Planning Committee Status update
- STEP Expansion Plan Effects on Congestion Between Arizona, Nevada, and California
- 2004 California ISO Controlled Grid Study Report
- Arizona Public Service presentations – miscellaneous material available on APS's portion of the wesTTrans OASIS, including a presentation by Arizona Public Service at the WestConnect Transfer Capability Informational Conference.

[11] A number of transmission-owning utilities in the Arizona/New Mexico region have been considering a desert region RTO in various forms for numerous years. The current coordinated OASIS operation of wesTTrans represents the first phase of a multi-phased process that could result in an RTO with coordinated ATC computation or even an eventual common energy market platform. See, for example, the information available at www.westconnectrto.com or www.ssg-wi.com.

- Arizona Public Service Ten-Year Plan
- Arizona Corporation Commission (ACC)/KEMA 3rd Biannual Transmission Assessment
- Central Arizona Transmission System (CATS) Reports
- Conceptual Plans for Electricity Transmission in the West, Report to the Western Governors' Association, August 2001.

As a whole, the information contained in these studies indicated the following key points:

- Short-term upgrades to existing 230- and 500-kV transmission lines will increase the ratings of the major East-of-River and West-of-River transmission constraints and will help reduce near-term congestion costs for flows into the California ISO region.
- The planned addition of a second 500-kV transmission line between Devers (California) and Palo Verde (actually, just southwest of Palo Verde at the Harquahala Substation) along with the "East of River" upgrades to the existing 500-kV system "will eliminate the majority of the major path congestion in the STEP/SWAT [southwest transmission expansion plan/southwest area transmission] area."
- Transmission paths from Palo Verde east have been improved, and new transmission projects planned will continue to increase capacity east of the hub; however, paths west of the hub need to be upgraded to allow for full access of Palo Verde hub generation to the California market. The summary information in the above two points illustrates that capacity-increasing projects for paths west from Palo Verde are being examined.
- There remains an incremental amount of intra-Arizona transmission transfer capability available for firm sales, but the total amount is limited and is mostly on the order of a few hundred megawatts for different point-to-point paths.
- Consideration should be given to spreading the costs of new transmission system use across all users of the regional system, possibly through use of RTOs as the vehicle for cost recovery. Implementation of the "open season" model of the natural gas pipeline industry should be considered in order to provide capital for new construction.

A key summary point is notable, from the ACC/KEMA study:

> There is very little existing long-term firm transmission capacity available to export or import energy over Arizona's transmission system. Studies investigating transmission additions required between Arizona and California and between New Mexico and Arizona continue to explore the scope, participation and timing of alternative projects. [12]

[12] Arizona Corporation Commission Docket No. E-00000D-03-0047, *Third Biennial Transmission Assessment, 2004-2013*, November 30, 2004. Prepared by ACC Staff and KEMA Inc. Executive Summary, page iii.

Based on the information examined, it seems that there is little long-term firm capacity for increased Arizona–California flows, but increased capacity from proposed transmission projects will increase available transmission capacity.

12.6 PROPOSED MAJOR NEW TRANSMISSION PROJECTS

There are numerous transmission projects planned or proposed for the southern California and the desert southwest region. The following list includes four major projects that, if constructed, will affect transmission availability from western Arizona to the SCE service territory, and from the Study Area to the California border region:

- **East of Colorado River Path 49 Short Term Upgrades.** The major path limiting transfers to the California ISO control area from the Arizona/Southern Nevada region is the WECC Path 49, or "East of [Colorado] River" ("EOR") path. Planned short-term upgrades to EOR Path 49 include installation of capacitors, phase-angle regulating transformers, and static VAR compensators on lines and substations in Arizona, California, and Nevada. These upgrades will increase the path rating from 7,550 MW to 8,055 MW in 2005 and 9,300 MW in 2006. These upgrades together are known as the EOR 9000 project.
- **Palo Verde – Devers #2 500 kV**. A second 500-kV line between Palo Verde and Devers is planned for operation in 2009. This line will increase the Path 49 rating by at least 1,200 MW and possibly by as much as 2,000 MW. As noted in a California ISO presentation (Jeff Miller, California ISO, Jan 2005 presentation)—

  > The EOR 9000 project and the Palo Verde-Devers #2 project are complimentary and function well together. The addition of both the PVD2 project and the EOR 9000 project would eliminate the majority of the major path congestion in the STEP/SWAT area.

- **Palo Verde – N. Gila – San Diego #2 500 kV.** This project is not as well-defined as the PV-Devers #2 line noted above. However, its addition will significantly increase the path rating of EOR.
- **Navajo Transmission Project.** The proposed Navajo transmission project is a 460-mile, 1,200 to 1,800-MW, 500-kV transmission line between the Four Corners/Shiprock region and the Las Vegas (McCullough substation) area. The project is planned for construction in three stages:
  - Shiprock (4 Corners) to Red Mesa;
  - Red Mesa to Moenkopi; and
  - Moenkopi to Las Vegas area (McCullough)

  The project is proposed by the Diné Power Authority, in conjunction with TransElect. The source of funding and likelihood of project implementation is unknown at this time. A 2008 operation is proposed. Additional information is available at the following sites:
  - http://www.cc.state.az.us/utility/electric/biennial/B-DNTP.ppt#258,1,Slide 1
  - http://www.trans-elect.com/navajo/navajo_background.htm.

- **Miscellaneous 500-kV Projects.** Increases to the major bulk transmission systems in the California-desert southwest region are likely to affect the ability of the Mohave technology options to move power to the California border, although some individual projects will not substantially change the transfer capability from the northeastern Arizona region to the California border. The Phoenix area is undergoing significant load growth, and substantial 500-kV system improvements are planned in the area. San Diego Gas and Electric and Southern California Edison are planning internal territory improvements that can affect the transfer rating across the major Arizona–Nevada–California paths.

12.7 TRANSMISSION INTERCONNECTION

This transmission evaluation analyzed the feasibility of adding generation at a number of sites in terms of upgrades required for transmission service. The interconnection cost is based on transmission upgrades required to relieve any overloaded facility that would prohibit the evacuation of power from the generation area. Upgrades required for interconnection allow the generator to inject power into the transmission system. However, this does not necessarily grant transmission service, allowing the generator to transfer power.

This transmission study reviews the impact of injecting power into the transmission network in 10 different generation scenarios. The 10 scenarios include 5 single-plant cases and 5 multiple-plant cases. The power flow studies were conducted using cases developed from the FERC 2005 summer case. The FERC case was modified for this analysis to incorporate the effect of capacity resources. Since information to distinguish capacity resources is not made public, capacity resources were accounted for by increasing the output of all generators within five buses of the new generation site to full capacity. In addition, newly completed generation projects and future generation projects with a high probability of completion were incorporated into the model. This resulted in the addition of eight generation projects, six that are completed and two that are expected to be in operation by 2010. Each of the 10 cases was then run two ways—first with existing transmission only, and then with two transmission projects that are scheduled for completion by 2010 for comparison.

Once the cases were developed for each scenario, our analysis identified overloaded transmission facilities for normal operation and for contingency conditions. The interconnection studies included contingencies for outages of transmission facilities above 100 kV and within four to five busses of the new plant. After the overloaded facilities were identified, a cost estimate was prepared for each case.

Our interconnection feasibility study for each case indicates that potential costs of interconnection vary between cases. Table 12-9 summarizes the interconnection cost estimates for each case both with and without the transmission upgrades.

Table 12-9 — Interconnection Cost Estimates

Case Number	Case Description	Estimated Cost *without* Path 49 Upgrades ($ in Millions)	Estimated Cost *with* Path 49 Upgrades ($ in Millions)
1	Black Mesa IGCC (500 MW)	$173.0	$48.0
2	Gray Mountain Wind (450 MW)	$0.0	$0.0
3	Solar Site 2 (425 MW)	$0.0	$0.0
4	Aubrey Cliffs (100 MW)	$60.0	$130.0
5	Clear Creek & Sunshine (135 MW)	$0.0	$0.0
6	Black Mesa IGCC & Solar Site 1 (925 MW)	$216.9	$158.7
7	Black Mesa IGCC & Gray Mountain Wind & Aubrey Cliffs (1050 MW)	$170.0	$195.0
8	Solar Site 2 & Gray Mountain Wind & Aubrey Cliffs (975 MW)	$272.5	$117.4
9	Solar Sites 1 & 2 (850 MW)	$214.5	$46.6
10	Gray Mountain Wind & Aubrey Cliffs & Clear Creek & Sunshine (685 MW)	$162.5	$70.0

By using the summer period load flow case, the transmission interconnection requirements identified for most of the supply-side technology options effectively provide firm transmission service during peak periods. However, use of existing regional grid capacity only (but including site-specific interconnection costs to get to the grid) could be considered if curtailing output for some periods proved economically viable, or if short-term transmission use in additional to what is transparently available through OASIS could be secured through negotiations with existing users who have rights to use the grid during peak periods. Thus, it is possible that the estimated costs for transmission system upgrade include certain regional grid upgrades that could be foregone in some instances, provided economic viability remained with reduced operation of the supply option. Detailed evaluation of these circumstances is beyond the scope of this study.

Furthermore, the regional grid upgrades identified for some of the supply options would have regional benefits; examining a likely or reasonable allocation of costs for those upgrades among the beneficiaries was beyond the scope of this project. However, when considering the individual projects that may require regional grid upgrades, it must be recognized that not all of the regional grid upgrade costs would likely be allocated solely to the supply option.

12.7.1 Methodology

The first task in evaluating a transmission system for a generation location is to develop the base case model. The FERC 2005 summer case was modified to include newly completed generation projects and future generation projects with a high probability of completion. The addition of newly operating plants near northern Arizona supplied 2,351 MW from six plants, all located in northern Arizona and Clark Country, Nevada. Next, two plants identified as having a high probability of completion by 2010 were included, namely Chuck Lenzie Generating Station and Copper Mountain Power, both in Clark County, Nevada, which added 1,700 MW of generation. Finally, Mohave Generating Station was turned off, resulting in a decrease in generation of 1,650 MW. Changes in generation output were accounted for by adjusting generation in surrounding areas to maintain the supply/demand balance. The FERC case was modified and analyzed using PowerWorld Simulator (Version 10.0) software, which is widely used by electric utilities, power developers, consultants, and reliability councils in the analysis of power flow cases.

To examine the effect of new transmission projects, a subcase was analyzed along with each numbered case. Of the new projects discussed in this report, the East of Colorado River Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 projects were identified as having a high probability of completion. The transmission upgrades were included in the subcases and the simulations were rerun. The differences between the main case and subcase results are highlighted.

Finally, developing the base case also includes preparation of one-line diagrams. One-line diagrams were prepared to show the topology of various voltage levels in the transmission system so that the direction and magnitude of transmission line loading, as well as areas with transmission congestion, can be understood visually. By analyzing the power flow paths, the one-line diagram can also display areas that contain large amounts of generating capacity and major load centers.

After the base case for each scenario was prepared, generation cases were developed by adding 100 to 1,050 MW at one to four generation busses to represent possible combinations of generation additions. In order to maintain the supply/demand balance, outputs in neighboring control areas were scaled down by an equal amount of generation as was added.

The base case and new generation case for each scenario were then compared by monitoring loading on transmission facilities under normal and contingency conditions. Transmission facilities that overload in the new generation case, but do not overload in the base case, will require mitigation. The transmission facility rating is based on the steady-state limit (A Limit) under normal operating conditions and the long-term emergency rating (B Limit) for contingency conditions. Only overloaded transmission facilities that have a distribution factor greater than 3% were deemed to require mitigation. The distribution factor indicates the percentage of the new generation that flows on a transmission facility. For example, if a 100-MW plant is added and the transmission line loading increases by 10 MW, then the distribution factor is 10%.

A summary of results is shown in Appendix K2 for all proposed generation scenarios. The summary sheets list all overloaded transmission facilities with a distribution factor greater than 0.1%. Summary tables shown in the body of this report include only transmission facilities with a distribution factor higher than the 3% threshold, that is, those that will require upgrades. Appendix K1 contains the list of contingencies run for each scenario.

12.7.2 Case 1: Black Mesa IGCC

Case 1 models 500 MW of new generation from one new plant: Black Mesa IGCC provides 500 MW via connection to a 500-kV bus between Four Corners and Moenkopi substations.

12.7.2.1 Normal Operating Conditions

The impact of adding 500 MW at Black Mesa is shown by comparing the base case against the new generation case shown as Appendixes K3-1 and K3-2, respectively. Those one-line diagrams show the change in loading on transmission facilities in the area near the new generation bus. Under normal operating conditions, two transmission facilities overload. Other facilities do not change significantly. Note that some transmission lines are modeled in segments in the system model, so that multiple bus-to-bus overloads indicate a single transmission line overload. For example, the second and third overloads in Table 12-10 represent one transmission line overload.

Table 12-10 — Overloads during Normal Operating Conditions: Case 1A

Transmission Facility	Base Case*	New Gen (500 MW)*
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	94.5	100.3
KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1	91.1	105.1
KAYENTA (79043) -> KAYENT&1 (79051) CKT 1	89.7	101.3

*Percent flow based on pre-contingency (normal) rating.

As indicated above, two transmission facilities (one 500-kV transmission line and one 230-kV transmission line) overload under normal operating conditions as a result of adding 500 MW at Black Mesa.

12.7.2.2 Contingency Conditions

The contingency analysis reviewed 116 independent outages centered on the new generation bus. A single contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 500 MW at Black Mesa). A complete list of all contingencies reviewed is included in Appendix K1-1. The results of the contingency analysis are summarized Table 12-11 below:

Table 12-11 — Results of Contingency Analysis: Case 1A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (500 MW)*
_ L_14100CHOLLA-14101FOURCORNC&1-MS	NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO	94.7	107.1

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Black Mesa. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that one facility (a 230-kV transmission line) overloads due to the new generation.

12.7.2.3 Mitigation

The interconnection feasibility study indicates that three transmission facilities will require mitigation due to normal and contingency operating conditions. The following table lists the transmission facilities requiring upgrades, with an estimated cost of each upgrade:

Table 12-12 — Required Transmission Upgrades: Case 1A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Palovrde – N.Gila 500 kV	125 mi	$125.0
Kayenta – Shiprock 230 kV	90 mi	$45.0

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Glen PS – Navajo 230 kV	6 mi	$3.0
Total Cost		$173.0

The estimated cost figures in Table 12-12 include equipment, materials, labor, and contingency for rebuilding transmission lines and substations as required.

12.7.2.4 Case 1B: Differences Resulting from Path 49 Upgrades

Case 1 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. Results were similar to those presented above. Two of the overloads from Case 1A also appeared in Case 1B, but the third, Palo Verde to North Gila 500 kV, did not. The net change was a reduction of $125 M, resulting in a total cost for Case 1B of $48 M.

12.7.3 Case 2: Gray Mountain Wind

Case 2 models 450 MW of new generation from one new plant: Gray Mountain Wind provides 450 MW via connection to a 500-kV bus at Moenkopi Substation.

12.7.3.1 Normal Operating Conditions

The impact of adding 450 MW at Gray Mountain is shown by comparing the base case against the new generation case shown as Appendixes K3-3 and K3-4, respectively. Those one-line diagrams show the change in loading on transmission facilities in the area near the new generation bus. Under normal operating conditions, no transmission facilities experience significant load changes. Five facilities are overloaded, but they are also overloaded in the base case.

Table 12-13 — Overloads during Normal Operating Conditions: Case 2A

Transmission Facility	Base Case*	New Gen (450 MW)*
None	—	—

*Percent flow based on pre-contingency (normal) rating.

As indicated in Table 12-13, no transmission facilities overload under normal operating conditions as a result of adding 450 MW at Gray Mountain.

12.7.3.2 Contingency Conditions

The contingency analysis reviewed 141 independent outages centered on the new generation bus. A single contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 450 MW at Gray Mountain). A complete list of all contingencies reviewed is included in Appendix K1-2. The results of the contingency analysis are summarized Table 12-14 below:

Table 12-14 — Results of Contingency Analysis: Case 2A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (450 MW)*
—	None	—	—

*Percent flow based on post-contingency (emergency) rating.

Table 12-14 shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Gray Mountain. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that no facilities overload due to the new generation.

12.7.3.3 Mitigation

The interconnection feasibility study indicates that no transmission facilities will require mitigation due to normal and contingency operating conditions.

12.7.3.4 Case 2B: Differences Resulting from Path 49 Upgrades

Case 2 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. No upgrades were required in Case 2A, and no new overloads were identified in Case 2B. Thus the total cost for Case 2B is $0 M.

12.7.4 Case 3: Solar Site 2

Case 3 models 425 MW of new generation from one new plant: Solar Site 2 provides 425 MW via connection to a 500-kV bus between Four Corners and Moenkopi substations.

12.7.4.1 Normal Operating Conditions

The impact of adding 425 MW at Solar Site 2 is shown by comparing the base case against the new generation case shown as Appendixes K3-5 and K3-6, respectively. Those one-line diagrams show the change in loading on transmission facilities in the area near the new generation bus. Under normal operating conditions, no transmission facilities experience significant load changes.

Table 12-15 — Overloads during Normal Operating Conditions: Case 3A

Transmission Facility	Base Case*	New Gen (425 MW)*
None	—	—

*Percent flow based on pre-contingency (normal) rating.

As indicated in Table 12-15, no transmission facilities overload under normal operating conditions as a result of adding 425 MW at Solar Site 2.

12.7.4.2 Contingency Conditions

The contingency analysis reviewed 104 independent outages centered on the new generation bus. A single contingency is defined as an outage of one transmission facility (e.g. transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 425 MW at Solar Site 2). A complete list of all contingencies reviewed is included in Appendix K1-3. The results of the contingency analysis are summarized Table 12-16 below:

Table 12-16 — Results of Contingency Analysis: Case 3A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (425 MW)*
—	None	—	—

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Solar Site 2. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that no facilities overload significantly due to the new generation. A number of transmission lines overload, but none carry 3% of the added generation, so no upgrades are required.

12.7.4.3 Mitigation

The interconnection feasibility study indicates that no transmission facilities will require mitigation due to normal and contingency operating conditions.

12.7.4.4 Case 3B: Differences Resulting from Path 49 Upgrades

Case 3 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. No upgrades were required in Case 3A, and no new overloads were identified in Case 3B. Thus the total cost for Case 3B is $0 M.

12.7.5 Case 4: Aubrey Cliffs

Case 4 models 100 MW of new generation from one new plant: Aubrey Cliffs provides 100 MW via connection to a 230-kV bus at Round Valley substation.

12.7.5.1 Normal Operating Conditions

The impact of adding 100 MW at Aubrey Cliffs is shown by comparing the base case against the new generation case shown as Appendixes K3-7 and K3-8, respectively. Those one-line diagrams show the change in loading on transmission facilities in the area near the new generation bus. Under normal operating conditions, no transmission facilities overload due to the added generation. Overloaded facilities were already overloaded without the additional generation.

Table 12-17 — Overloads during Normal Operating Conditions: Case 4A

Transmission Facility	Base Case*	New Gen (100 MW)*
None	—	—

*Percent flow based on pre-contingency (normal) rating.

As indicated in Table 12-17, no transmission facilities overload under normal operating conditions as a result of adding 100 MW at Aubrey Cliffs.

12.7.5.2 Contingency Conditions

The contingency analysis reviewed 112 independent outages centered on the new generation bus. A single contingency is defined as an outage of one transmission facility (e.g. transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 100 MW at Aubrey Cliffs). A complete list of all contingencies reviewed is included in Appendix K1-4. The results of the contingency analysis are summarized in Table 12-18 below:

Table 12-18 — Results of Contingency Analysis: Case 4A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (100 MW)*
T_19315PEACOCK345-19314PEACOCK230C1	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at PRESCOTT	117.3	135.2
T_19315PEACOCK345-19314PEACOCK230C1	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at TOPOCK	101.3	103.4

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Aubrey Cliffs. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that two facilities—two 230-kV transmission lines—overload due to the new generation.

12.7.5.3 Mitigation

The interconnection feasibility study indicates that two transmission facilities will require mitigation due to normal and contingency operating conditions. The following table lists the transmission facilities requiring upgrades, with an estimated cost of each upgrade:

Table 12-19 — Required Transmission Upgrades: Case 4A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Roundvly – Prescott 230 kV	75 mi	$37.5
Topock – Blk Mesa 230 kV	45 mi	$22.5
Total Cost		$60.0

The estimated cost figures in Table 12-19 include equipment, materials, labor, and contingency for rebuilding transmission lines and substations as required.

12.7.5.4 Case 4B: Differences Resulting from Path 49 Upgrades

Case 4 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. Results were similar to those presented above. No overloads were eliminated, but an additional overload was identified. The Imperial Valley to North Gila 500-kV line overloaded, requiring an additional $70 M in upgrades. The apparent inconsistency of increased cost with transmission upgrades is a result of base case loading. Lines that overload in the base case (without new generation applied) are not considered to require upgrades, because the new generation is not the cause of the line overload. In this case, the transmission upgrades in Case 4B relieved the Imperial Valley-North Gila line that was overloaded in Case 4A, so that it was no longer overloaded in the base case. When the new generation added load to the line, it caused the line to go over limit, and thereby require upgrades. The additional $70 M results in a total cost for Case 4B of $130 M.

12.7.6 Case 5: Clear Creek and Sunshine

Case 5 models 135 MW of new generation from two new plants: Clear Creek provides 75 MW via connection to a 230-kV bus at Leupp Substation and Sunshine provides 60 MW via connection to a 230-kV bus at Cococino Substation.

12.7.6.1 Normal Operating Conditions

The impact of adding 135 MW at Clear Creek and Sunshine is shown by comparing the base case against the new generation case shown as Appendixes K3-9 and K3-10, respectively. Those one-line diagrams show the change in loading on transmission facilities in the area near the new generation bus. Under normal operating conditions, no transmission facilities experience significant load changes.

Table 12-20 — Overloads during Normal Operating Conditions: Case 5A

Transmission Facility	Base Case*	New Gen (135 MW)*
None	—	—

*Percent flow based on pre-contingency (normal) rating.

As indicated in Table 12-20, no transmission facilities overload under normal operating conditions as a result of adding 135 MW at Clear Creek and Sunshine.

12.7.6.2 Contingency Conditions

The contingency analysis reviewed 115 independent outages centered on the new generation bus. A single contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 135 MW at Clear Creek and Sunshine). A complete list of all contingencies reviewed is included in Appendix K1-5. The results of the contingency analysis are summarized Table 12-21 below:

Table 12-21 — Results of Contingency Analysis: Case 5A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (135 MW)*
—	None	—	—

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Clear Creek and Sunshine. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that no facilities overload significantly due to the new generation. Only slight loading changes were experienced.

12.7.6.3 Mitigation

The interconnection feasibility study indicates that no transmission facilities will require mitigation due to normal and contingency operating conditions.

12.7.6.4 Case 5B: Differences Resulting from Path 49 Upgrades

Case 5 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. No upgrades were required in Case 5A, and no new overloads were identified in Case 5B. Thus the total cost for Case 5B is $0 M.

12.7.7 Case 6: Black Mesa IGCC and Solar Site 1

Case 6 models 925 MW of new generation from two new plants: Black Mesa IGCC provides 500 MW of generation via connection to a 500-kV bus between Four Corners and Moenkopi substations and Solar Site 1 provides 425 MW via connection to a 230-kV bus at Kayenta Substation.

12.7.7.1 Normal Operating Conditions

The impact of adding 925 MW at Black Mesa and Solar Site 1 is shown by comparing the base case and new generation case, as shown in Appendix K3-11 and K3-12, respectively. The one-line diagrams show the change in loading on transmission facilities in the areas near the new generation busses. Under normal operating conditions, five facilities overload: four transmission lines and one transformer. Other lines in the area increase slightly but remain within acceptable limits. Table 12-22 below lists the base case and new generation case loading percentages for transmission facility overloads.

Table 12-22 — Overloads during Normal Operating Conditions: Case 6A

Transmission Facility	Base Case*	New Gen (925 MW)*
PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1	95.1	102.1
PALOVR&2 (15023) -> N.GILA (22536) CKT 1	95.1	102.1
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	95.9	102.9
GLEN PS (79028) -> GLENCANY (79031) CKT 1	69.6	145.6
KAYENTA (79043) -> KAYENT&A (79055) CKT 1	67.9	136.7
NAVAJO (79093) -> LNGHOUSE (79096) CKT 1	62.1	131.2
KAYENT&A (79055) -> LNGHOUSE (79096) CKT 1	67.9	137.0
GLEN PS (79028) -> NAVAJO (79093) CKT 1	82.2	174.2

*Percent flow based on pre-contingency (normal) rating.

As indicated above, five transmission facilities would require mitigation. Mitigating these overloads would require upgrading one 500-kV transmission line, three 230-kV transmission lines, and one 230-kV transformer.

12.7.7.2 Contingency Conditions

The single contingency analysis reviewed 142 independent outages centered on the new generation busses. A single contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case without new generation and then again for the new generation case with an additional 925 MW at Black Mesa IGCC and Solar Site 1. A complete list of all contingencies reviewed is included in Appendix K1-6. The results of the contingency analysis are summarized in Table 12-23 below:

Table 12-23 — Results of Contingency Analysis: Case 6A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (925 MW)*
L_79043KAYENTA-79096LNGHOUSEC&1-MS	KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1	18.5	120.3
L_79043KAYENTA-79096LNGHOUSEC&1-MS	KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA	10.9	123.5
T_79032GLENCANY-79031GLENCANYC2	GLENCANY (79031) -> GLENCANY (79032) CKT 1 at GLENCANY	81.6	114.2
T_79032GLENCANY-79031GLENCANYC1	GLENCANY (79031) -> GLENCANY (79032) CKT 2 at GLENCANY	81.6	114.2

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Black Mesa and Solar Site 1. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that three facilities overload due to single contingencies: one 230-kV transmission line and two 345-kV transformers.

12.7.7.3 Mitigation

The interconnection feasibility study indicates that eight transmission facilities will require mitigation due to normal and contingency operating conditions. Table 12-24 lists the transmission facilities requiring upgrades, with the estimated costs of the upgrades:

Table 12-24 — Required Transmission Upgrades: Case 6A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Palovrde – N.Gila 500 kV	125 mi	$125.0
Kayenta – Lnghouse 230 kV	25 mi	$12.5
Navajo – Lnghouse 230 kV	50 mi	$25.0
Glen PS – Navajo 230 kV	6 mi	$3.0
Glen PS – Glencany 230 kV	200 MVA	$3.2
Kayenta – Shiprock 230 kV	90 mi	$45.0
Glencany – Glencany Ckt 1 230/345 kV	100 MVA	$1.6

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Glencany – Glencany Ckt 2 230/345 kV	100 MVA	$1.6
Total Cost		$216.9

The estimated cost figures above include equipment, materials, labor, and contingency for upgrading transformers as required.

12.7.7.4 Case 6B: Differences Resulting from Path 49 Upgrades

Case 6 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. Results were similar to those presented above. Two important loading changes occurred. The Palo Verde to North Gila 500-kV line no longer required upgrades, reducing the overall cost by $125 M. However, the Imperial Valley to North Gila 500-kV line overloaded instead, adding $70 M to the total cost. The net change was a reduction of $55 M, resulting in a total cost for Case 6B of $161.9 M.

12.7.8 Case 7: Black Mesa IGCC and Gray Mountain Wind and Aubrey Cliffs

Case 7 models 1,050 MW of new generation from three new plants: Black Mesa IGCC provides 500 MW of generation via connection to a 500-kV bus between Four Corners and Moenkopi substations, Gray Mountain Wind provides 450 MW via connection to a 500-kV bus at Moenkopi Substation, and Aubrey Cliffs provides 100 MW via connection to a 230-kV bus at Round Valley Substation.

12.7.8.1 Normal Operating Conditions

The impact of adding 1,050 MW at Black Mesa, Gray Mountain Wind, and Aubrey Cliffs is shown by comparing the base case and new generation case, as shown in Appendix K3-13 and K3-14, respectively. The one-line diagrams show the change in loading on transmission facilities in the areas near the new generation busses. Under normal operating conditions, one transmission line overloads. Other facilities in the area increase but remain within acceptable limits. Table 12-25 below lists the base case and new generation case loading percentages for transmission facility overloads.

Table 12-25 — Overloads during Normal Operating Conditions: Case 7A

Transmission Facility	Base Case*	New Gen (1,050 MW)*
PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1	95.1	102.1
PALOVR&2 (15023) -> N.GILA (22536) CKT 1	95.1	102.1
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	95.9	102.9

*Percent flow based on pre-contingency (normal) rating.

As indicated above, there is one transmission facility that overloads under normal operating conditions as a result of adding 1,050 MW at Black Mesa, Gray Mountain, and Aubrey Cliffs. Mitigating this overload would require upgrading one 500-kV transmission line.

12.7.8.2 Contingency Conditions

The single contingency analysis reviewed 202 independent outages centered on the new generation busses. A contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 1,050 MW at Black Mesa, Gray Mountain, and Aubrey Cliffs). A complete list of all contingencies reviewed is included in Appendix K1-7. The results of the contingency analysis are summarized in Table 12-26 below:

Table 12-26 — Results of Contingency Analysis: Case 7A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (1050 MW)*
L_14101FOURCORN-66235PINTOPSC1	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	91.0	101.0

*Percent flow based on post-contingency (emergency) rating.

The above table shows the change in load from the base case for overloaded transmission facilities under contingency conditions as a result of adding generation at Black Mesa, Gray Mountain, and Aubrey Cliffs. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that one 230-kV transmission line overloaded due to the new generation.

12.7.8.3 Mitigation

The interconnection feasibility study indicates that two transmission facilities will require mitigation for the addition of 1,050 MW at Black Mesa, Gray Mountain, and Aubrey Cliffs. Table 12-27 lists the transmission facilities requiring upgrades, with an estimated cost of each upgrade:

Table 12-27 — Required Transmission Upgrades: Case 7A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Palovrde – N.Gila 500 kV	125 mi	$125.0
Kayenta – Shiprock 230 kV	90 mi	$45.0
Total Cost		$170.0

The estimated cost figures above include equipment, materials, labor, and contingency for upgrading transformers as required.

12.7.8.4 Case 7B: Differences Resulting from Path 49 Upgrades

Case 7 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. Results were similar to those presented above, but with two changes. The Kayenta to Shiprock 230-kV line no longer overloads, which reduces the total cost by $45 M. However, the Imperial Valley to North Gila 500-kV line overloads in Case 7B, adding $70 M to the total cost. The apparent inconsistency of increased cost with transmission upgrades is a result of base-case loading. Lines that overload in the base case (without new generation applied) are not considered to require upgrades, because the new generation is not the cause of the line overload. In this case, the transmission upgrades in Case 7B relieved the Imperial Valley–North Gila line that was overloaded in Case 7A, so that it was no longer overloaded in the base case. When the new generation added load to the line, it caused the line to go over limit and, thereby, require upgrades. The net effect of the two changes is an increase of $25 M, yielding a total cost for Case 7B of $195.0 M.

12.7.9 Case 8: Solar Site 2 and Gray Mountain Wind and Aubrey Cliffs

Case 8 models 975 MW of new generation from three new plants: Solar Site 2 provides 425 MW of generation via connection to a 500-kV bus between Four Corners and Moenkopi substations, Gray Mountain Wind provides 450 MW via connection to a 500-kV bus at Moenkopi Substation, and Aubrey Cliffs provides 100 MW via connection to a 230-kV bus at Round Valley.

12.7.9.1 Normal Operating Conditions

The impact of adding 975 MW at Solar Site 2, Gray Mountain Wind, and Aubrey Cliffs is shown by comparing the base case and new generation case, as shown in Appendix K3-15 and K3-16, respectively. The one-line diagrams show the change in loading on transmission facilities in the areas near the new generation busses. Under normal operating conditions, one 500-kV transmission line overloads. Other facilities in the area increase slightly but remain within acceptable limits. Table 12-28 below lists the base case and new generation case loading percentage for transmission facility overloads.

Table 12-28 — Overloads during Normal Operating Conditions: Case 8A

Transmission Facility	Base Case*	New Gen (975 MW)*
PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1	95.1	100.8
PALOVR&2 (15023) -> N.GILA (22536) CKT 1	95.1	100.8
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	95.9	100.8

*Percent flow based on pre-contingency (normal) rating.

As indicated in above, one transmission facility would require mitigation. Mitigating this overload would require upgrading one 500-kV transmission line.

12.7.9.2 Contingency Conditions

The contingency analysis reviewed 183 independent outages centered on the new generation busses. A contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case, without new generation and then again for the new generation case, with an additional 975 MW at Solar Site 2, Gray Mountain, and Aubrey Cliffs. A complete list of all contingencies reviewed is included in Appendix K1-8. The results of the contingency analysis are summarized in Table 12-29 below:

Table 12-29 — Results of Contingency Analysis: Case 8A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (975 MW)*
L_14003NAVAJO-14005WESTWINGC&1-MS	MOENKO&1 (14011) -> YAVAPAI (14006) CKT 1 at YAVAPAI	90.1	103.3
L_14003NAVAJO-14005WESTWINGC&1-MS	MOENKOPI (14002) -> MOENKO&1 (14011) CKT 1 at MOENKOPI	90.4	103.2
T_19315PEACOCK-19314PEACOCKC1	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	117.3	134.5

*Percent flow based on post-contingency (emergency) rating.

The above table shows the change in load on transmission facilities under contingency conditions as a result of adding generation at Solar Site 2, Gray Mountain, and Aubrey Cliffs. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that two facilities overload due to the new generation: one 230-kV and one 500-kV transmission line.

12.7.9.3 Mitigation

The interconnection feasibility study indicates that three transmission facilities would require mitigation due to normal and contingency operating conditions. Table 12-30 lists the transmission facilities requiring upgrades, with an estimated cost of each upgrade:

Table 12-30 — Required Transmission Upgrades: Case 8A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in millions)
Palovrde – N.Gila 500 kV	125 mi	$125.0
Moenkopi – Yavapai 500 kV	110 mi	$110.0
Roundvly – Prescott 230 kV	75 mi	$37.5
Total Cost		$272.5

The estimated cost figures above include equipment, materials, labor, and contingency for upgrading transformers as required.

12.7.9.4 Case 8B: Differences Resulting from Path 49 Upgrades

Case 8 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. For this case, the added transmission upgrades caused a new set of required transmission upgrades. The changes warrant a new table for Case 8B. As can be seen in Table 12-31 below, four facilities will require upgrades. The net change from Case 8A is a reduction of $155.1 M, yielding a total cost for Case 8B of $117.4 M.

Table 12-31 — Required Transmission Upgrades: Case 8B

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in millions)
Kayenta – Shiprock 230 kV	90 mi	$45.0
Eldor 1l – Eldordo 500 kV Ckt 1	100 MVA	$2.4
Eldor 1l – Eldordo 500 kV Ckt 2	100 MVA	$2.4
Imprlvly – N.Gila 500 kV	70 mi	$70.0
Total Cost		$119.8

The estimated cost figures above include equipment, materials, labor, and contingency for upgrading transformers as required.

12.7.10 Case 9: Solar Sites 1 and 2

Case 9 models 850 MW of new generation from two new plants: Solar Site 1 provides 425 MW of generation via connection to a 230-kV bus at Kayenta Substation and Solar Site 2 provides 425 MW via connection to a 500-kV bus between Four Corners and Moenkopi substations.

12.7.10.1 Normal Operating Conditions

The impact of adding 850 MW at Solar Sites 1 and 2 is shown by comparing the base case against the new generation case shown as Appendixes K3-17 and K3-18, respectively. The one-line diagrams show the change in loading on transmission facilities in the areas near the new generation. Under normal operating conditions, five transmission facilities overload: four transmission lines and one transformer. Other facilities in the area increase slightly but remain within acceptable limits. Table 12-32 below lists the base case and new generation case loading percentage for transmission facility overloads.

Table 12-32 — Overloads during Normal Operating Conditions: Case 9A

Transmission Facility	Base Case*	New Gen (850 MW)*
GLEN PS (79028) -> GLENCANY (79031) CKT 1	69.6	135.6
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	95.9	101.1
PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1	95.1	100.3
PALOVR&2 (15023) -> N.GILA (22536) CKT 1	95.1	100.3
KAYENTA (79043) -> KAYENT&A (79055) CKT 1	67.9	127.5
KAYENT&A (79055) -> LNGHOUSE (79096) CKT 1	67.9	127.7
NAVAJO (79093) -> LNGHOUSE (79096) CKT 1	62.1	121.8
GLEN PS (79028) -> NAVAJO (79093) CKT 1	82.2	161.7

*Percent flow based on pre-contingency (normal) rating.

As indicated above, five transmission facilities would require mitigation. Mitigating these overloads would require upgrading one 500-kV transmission line, three 230-kV transmission lines, and one 230-kV transformer.

12.7.10.2 Contingency Conditions

The contingency analysis reviewed 135 independent outages centered on the new generation busses. A single contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 850 MW at Solar Sites 1 and 2). A complete list of all contingencies reviewed is included in Appendix K1-9. The results of the contingency analysis are summarized in Table 12-33 below:

Table 12-33 — Results of Contingency Analysis: Case 9A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (850 MW)*
L_79043KAYENTA-79096LNGHOUSEC&1-MS	KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1	18.0	120.3
L_79043KAYENTA-79096LNGHOUSEC&1-MS	KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA	10.0	123.5
T_79032GLENCANY-79031GLENCANYC1	GLENCANY (79031) -> GLENCANY (79032) CKT 2 at GLENCANY	81.6	107.5
T_79032GLENCANY-79031GLENCANYC2	GLENCANY (79031) -> GLENCANY (79032) CKT 1 at GLENCANY	81.6	107.5

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at the Solar Sites 1 and 2. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that three facilities overload due to the new generation: one 230-kV transmission line and two 230/345-kV transformers.

12.7.10.3 Mitigation

The interconnection feasibility study indicates that eight transmission facilities will require mitigation due to normal and contingency operating conditions. The following table lists the transmission facilities requiring upgrades, with an estimated cost of each upgrade:

Table 12-34 — Required Transmission Upgrades: Case 9A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Palovrde – N.Gila 500 Kv	125 mi	$125.0
Kayenta – Lnghouse 230 kV	25 mi	$12.5
Navajo – Lnghouse 230 kV	50 mi	$25.0
Glen PS – Navajo 230 kV	6 mi	$3.0
Glen PS – Glencany 230 kV	150 MVA	$2.4
Kayenta – Shiprock 230 kV	90 mi	$45.0
Glencany – Glencany Ckt 1 230/345kV	50 MVA	$0.8

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Glencany – Glencany Ckt 2 230/345kV	50 MVA	$0.8
Total Cost		$214.5

The estimated cost figures in Table 12-34 include equipment, materials, labor, and contingency for rebuilding transmission lines and substations as required.

12.7.10.4 Case 9B: Differences Resulting from Path 49 Upgrades

Case 9 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. Results were similar to those presented above. No additional overloads were found, but five overloads that existed in Case 9A were relieved, namely Palo Verde to North Gila 500 kV, Kayenta to Longhouse 230 kV, Navajo to Longhouse 230 kV, Glen PS to Navajo 230 kV, and Glen PS to Glen Canyon 230 kV. The reduction in total cost was $167.9 M, resulting in a total cost for Case 9B of $46.6 M.

12.7.11 Case 10: Gray Mountain Wind and Aubrey Cliffs and Clear Creek and Sunshine

Case 10 models 685 MW of new generation from four new plants: Gray Mountain Wind provides 450 MW via connection to a 500-kV bus at Moenkopi Substation, Aubrey Cliffs provides 100 MW via connection to a 230-kV bus at Round Valley Substation, Clear Creek provides 75 MW via connection to a 230-kV bus at Leupp Substation, and Sunshine provides 60 MW via connection to a 230-kV bus at Cococino Substation.

12.7.11.1 Normal Operating Conditions

The impact of adding 685 MW at Gray Mountain, Aubrey Cliffs, Clear Creek, and Sunshine is shown by comparing the base case against the new generation case shown as Appendixes K3-19 and K3-20, respectively. Those one-line diagrams show the change in loading on transmission facilities in the area near the new generation busses. Under normal operating conditions, one transmission facility overloads. Other facilities do not change significantly.

Table 12-35 — Overloads during Normal Operating Conditions: Case 10A

Transmission Facility	Base Case*	New Gen (685 MW)*
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	95.9	100.5

*Percent flow based on pre-contingency (normal) rating.

As indicated above, one transmission facility, a 500-kV transmission line, overloads under normal operating conditions as a result of adding 685 MW at Gray Mountain, Aubrey Cliffs, Clear Creek, and Sunshine.

12.7.11.2 Contingency Conditions

The contingency analysis reviewed 181 independent outages centered on the new generation busses. A single contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 685 MW at Gray Mountain, Aubrey Cliffs, Clear Creek, and Sunshine). A complete list of all contingencies reviewed is included in Appendix K1-10. The results of the contingency analysis are summarized in Table 12-36 below:

Table 12-36 — Results of Contingency Analysis: Case 10A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (685 MW)*
L_14002MOENKOPI-14006YAVAPAIC&1-MS	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	99.9	110.0

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Gray Mountain, Aubrey Cliffs, Clear Creek, and Sunshine. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that one facility overloads due to the new generation: a 230-kV transmission line.

12.7.11.3 Mitigation

The interconnection feasibility study indicates that two transmission facilities will require mitigation due to normal and contingency operating conditions. The following table lists the transmission facilities requiring upgrades, with an estimated cost of each upgrade:

Table 12-37 — Required Transmission Upgrades: Case 10A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Palovrde – N.Gila 500 kV	125 mi	$125.0
Roundvly – Prescott 230 kV	75 mi	$37.5
Total Cost		$162.5

The estimated cost figures in Table 12-37 include equipment, materials, labor, and contingency for rebuilding transmission lines and substations as required.

12.7.11.4 Case 10B: Differences Resulting from Path 49 Upgrades

Case 10 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. The additional generation relieved the two overloads identified in Case 10A. However, a different line overloaded instead, namely the Imperial Valley to North Gila 500-kV line. The net change was a reduction of $92.5 M, resulting in a total cost for Case 10B of $158.7 M.

12.8 CONCLUSIONS

The following conclusions can be drawn from the transmission evaluation:

- **Long-Term Firm Service.** Existing conditions appear to limit the availability of long-term (e.g., yearly or multi-yearly) firm service from Arizona supply sources. Shorter-term service of more limited duration is available for some source-sink path combinations.
- **Short-Term Non-Firm Service.** Based on OASIS data, shorter-term firm, or non-firm service is available from most source points examined, but not necessarily during all periods. Thus, technology options located in the Study Area connecting up to the grid in the near-term might need to rely on shorter-term transmission availability. Note that SCE’s ownership of rights for transmission service from their Four Corners generation share ownership were not considered as a possible source of transmission access for any of the Mohave alternatives or complements.
- **Tradeoffs between Increased Capacity for New Supply and Use of Existing Capabilities**. The transmission interconnection requirements identified for most of the supply-side technology options are based on provision of effectively firm transmission service during peak periods. Use of existing grid capacity could be considered if curtailing output for some periods proved economically viable, and/or if short-term transmission use in additional to what is transparently available through OASIS could be secured through negotiations with existing users who have rights to use the grid during peak periods.
- **OASIS Information.** The value of OASIS information is limited because of its time frame; it is not predictive beyond the near-term time periods, at most a few years out.

- **Proposed New Transmission Upgrades.** New transmission line proposals or works in progress add significant capacity to into-California (and likely intra-Arizona) transaction paths. To the extent these lines are built, it is possible that most technology options could secure access to import into SCE territory.

- **Alternative Locations of Alternatives.** Any technology options that source power from the existing Mohave site, or from the Palo Verde hub (e.g., the DSM alternative) will not face the transmission limitations identified in our review.

- **Effect of New Institutional Constructs.** The review did not assess the transmission availability under any new institutional constructs. If a West Connect RTO or similar regional transmission entity established coordinated transmission operations in the desert southwest area, the paradigm for transmission access and Available Transmission Capability (ATC) computation could change. One possible outcome of such arrangements is a lesser dependence on the need for source-to-sink physical transmission reservations in order to use the desert southwest grid to secure power flows into California from source points in the Study Area.

- **Wheeling Capability under Current Transmission Capacity**. The DSM and Mohave Combined Cycle technology options could each move Mohave-equivalent power into the SCE territory based on existing conditions. The California border location for these options allows this to occur during most if not all hours, although some congestion cost allocation from the California ISO would likely apply in some hours. The remaining Arizona area supply options would all be able to move power into the SCE territory for some hours of the year, based on securing available shorter-term firm or non-firm transmission, but it is unlikely they would be able to secure transmission for all hours, especially during peak periods, based on examination of the OASIS data. The latter assumes that minimal connection requirements to get to the regional grid are first made by the supply technology options in the Study Area.

- **Wheeling Capability with Reasonably Certain New Transmission Upgrades**. Most of the proposed new transmission projects that have a high likelihood of being built will result in increased transfer capability from western Arizona or southern Nevada into California, but they will not substantially affect the transfer capability from the northeastern Arizona area to the western portion of Arizona. There are numerous Arizona transmission upgrades proposed for the heavier load centers, such as Phoenix; these upgrades will not necessarily increase transfer capability over the major paths out of northeastern and north-central Arizona. Thus, even with implementation of certain new projects, it is not assured that the increased capacity will allow for Study Area technology options to secure firm, longer-term transmission service into the California border area. However, if intra-Arizona upgrades on the 500-kV system in the north and the northeast are realistically considered, then the increase in transfer capability from the Study Area to the California border would likely be on the order of the scale of output associated with SCE's share of Mohave.

- **Wheeling Capability with Uncertain New Transmission Upgrades.** It is difficult to state with any certainty what the wheeling capability with new transmission upgrades might look like without conducting additional load flow studies and accounting for the location of new supply sources that might be considered if new transmission is built. This is beyond the scope of the project. For example, even if the Navajo Transmission Project is built, the potential for new generation in the northeastern Arizona region must be considered when assessing whether such new capacity might be available for the Mohave technology options. However, if any of the major northeastern/north-central Arizona to southwestern/northwestern Arizona paths are upgraded, the potential for transmission capacity increases on the order of SCE's share of Mohave output is likely.

- **Load Flow Analyses.** The results of the load flow studies indicate that longer-term[13] firm transmission service is available in some cases without additional transmission system upgrades, but is not available in others without system upgrades. A summary of these cases and the estimated costs of required upgrades are provided in Table 12-9.

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[13] Longer-term transmission service generally implies service of at minimum a years' duration. For example, Tucson Electric Power offered 125 MW of yearly transmission service for 2006, 2007, and 2008 on its rights to the Moenkopi–Palo Verde 500-kV path. Longer-term service can also imply transmission service available for many years into the future. Data on availability of such long-term transmission are not readily provided through the OASIS system. However, some of the utility documents available through the OASIS system indicated ongoing availability of longer-term transmission over specific, limited segments of the Arizona Public Service system.