Chapter 2 – Alternatives

2.0 ALTERNATIVES

2.1 INTRODUCTION

This chapter presents a description of three alternatives: (1) a no action alternative, (2) a proposed action alternative to build a 1,500 megawatt (MW) coal-fired power plant, and (3) an action alternative to build a 550 MW coal-fired power plant. As part of each action alternative, there are also alternatives for infrastructure locations associated with each power plant. Under the no action alternative, the approvals, rights-of-way, and permits for the proposed power plant, mine expansion, and all associated facilities would not be granted and therefore the proposed project would not be constructed. Under the action alternatives, it is assumed that approvals, rights-of-way, and permits for the proposed power plants, mine expansion, and all associated facilities would be granted as well as any additional permitting regulated and required by other Federal agencies, and the proposed project would be constructed and operated.

This chapter includes the following:

- Section 2.2 provides a description of the proposed project, alternatives to the proposed project, and the no action alternative.
- Section 2.3 provides an explanation of the decisions or agreements that would be required by Federal agencies and the Navajo Nation before either of the action alternatives could be implemented.
- Section 2.4 is a discussion of the alternatives that were considered initially but eliminated from detailed study in this Environmental Impact Statement (EIS).
- Section 2.5 identifies the preferred alternative of the Bureau of Indian Affairs (BIA), the lead agency, and the cooperating agencies.

2.2 ALTERNATIVES INCLUDING THE NO-ACTION ALTERNATIVE

The proposed project consists of several major elements (i.e., generating facility, coal mining actions, transmission lines, water supply wells and pipelines, and roads). Alternatives to each element of the proposed project were developed and considered based on issues derived from public comments received during the scoping process. All of the alternatives were screened to determine whether they would be technically or economically feasible or practical, whether they would satisfy the underlying purpose and need for the project, and whether they would meet the requirements to allow for the necessary agency actions. In addition, the following issues or factors were also considered in screening the alternatives: environmental issues; legal issues; design or engineering issues; scheduling and timing; response to concerns raised during scoping; and economic considerations.

Those alternatives that satisfy the screening criteria, achieve the purpose and satisfy the needs for the project, and allow the agencies to take the necessary actions outlined in Section 1.3 have been carried forward for detailed analysis. Siting or technological alternatives that did not satisfy the basic feasibility criteria as defined in Section 2.4, would be expected to cause unnecessary environmental impact, did not achieve the purpose and need of the project, or would not meet the requirements for agency actions, were dismissed from detailed study. These are described in Section 2.4.

2.2.1 Alternative A – No Action Alternative

The Council of Environmental Quality (CEQ) regulations implementing National Environmental Policy Act (NEPA) require that an agency include the alternative of no action as one of the alternatives to the proposed action (40 CFR 1502.13[d]). Under the No Action Alternative, the approvals of the long-term lease, rights-of-way, mining permits, and other permits needed for the proposed power plant and associated facilities would not be granted. Without these approvals and permits, the proposed project would not be approved for implementation. In the case of this project, documentation of the effects of taking no action serves as the baseline of environmental information against which impacts from the proposed project would be predicted to occur if the necessary agency actions are taken.

2.2.2 Alternative B – Proposed Action Alternative

This section describes the facilities and activities that would be associated with the proposed action under Alternative B, including (1) the power plant and associated infrastructure, (2) construction activities, (3) operation and maintenance activities for the proposed power plant, (4) mining operations in the BHP Navajo Coal Company (BNCC) Lease Area, and (5) decommissioning activities. The locations of proposed facilities are illustrated on Figure 2-1.

The Federal and Navajo Nation agency decisions and other agreements that would be required to implement the proposed action are described in Section 2.3.

2.2.2.1 Power Plant and Associated Infrastructure

Under Alternative B, Desert Rock Energy LLC and Dine Power Authority (DPA) propose to construct and operate a coal-fired power plant that would produce up to 1,500 MW gross of electricity. The proposed facilities include two 750-MW generation units and plant-cooling system, coal-handling and processing facilities, power transmission interconnection facilities, water-supply system, access to the plant site, waste-management operations, and other ancillary facilities associated with the generation and transmission of electricity. Table 2-1 is a summary of the proposed major facilities that would comprise the Desert Rock Energy Project and associated acreage requirements.

Table 2-1 Acreage Requirements for Proposed Facilities and Infrastructure under Alternative B

Facility	Acres
Power Plant	
Leased site	592
Footprint	149
Coal Preparation Facilities on BNCC Lease Area	101
Infrastructure	
Proposed Transmission Line (Segments A, C, D)	1,205
Subalternative Transmission Line (Segments B, C, D)	1,373
Water Well Field A (includes utility corridor)	1,040
Water Well Field B	890
Main Power Plant Access Road	21

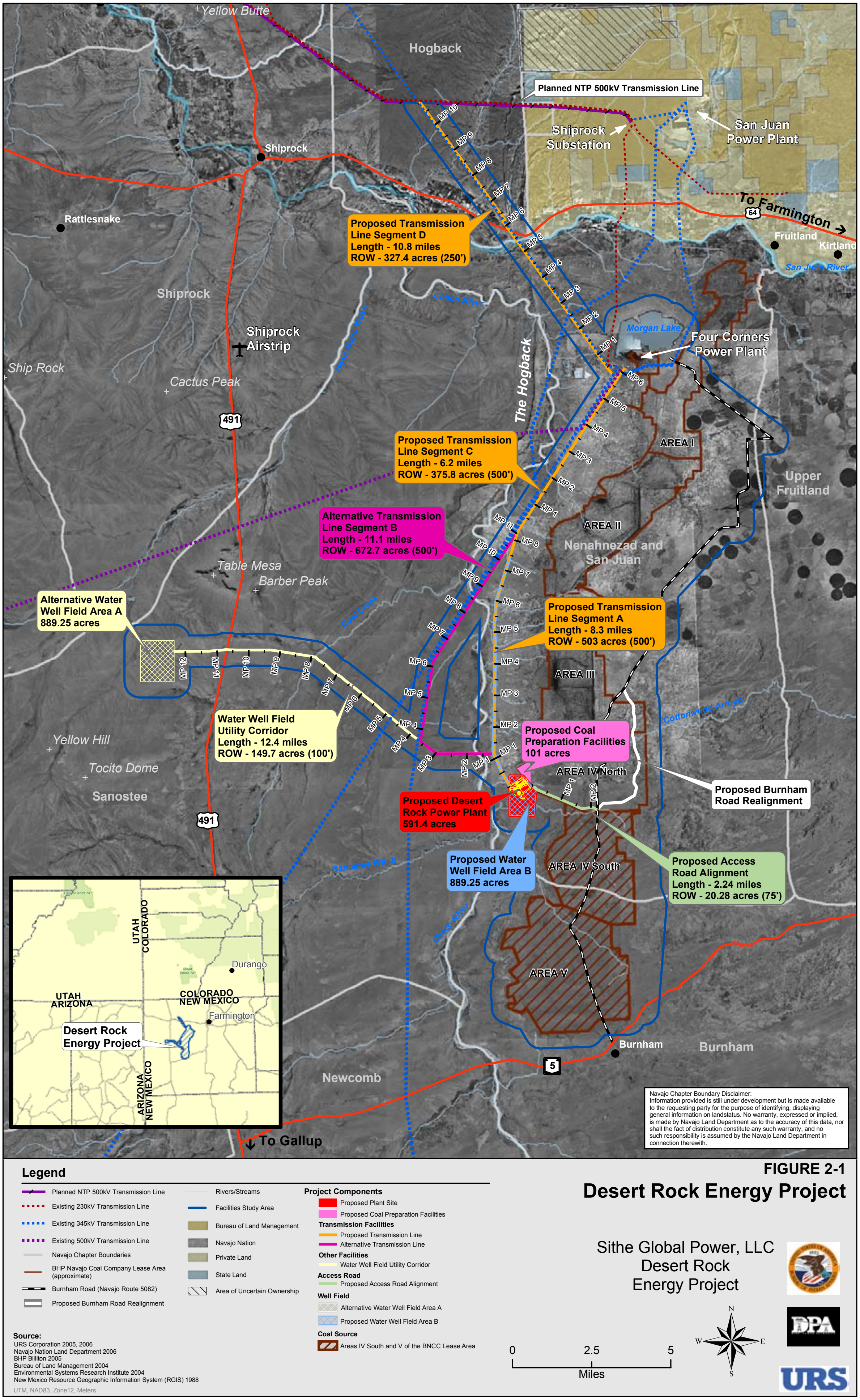


FIGURE 2-1
Desert Rock Energy Project

2.2.2.1.1 Power Plant

The power plant would be a supercritical pulverized-coal type facility. Use of a single reheat, supercritical steam cycle and other design features would enable this plant to operate with higher net efficiency than existing coal-fired power plants in the region.

The power plant site would be located within a 592-acre leased area east of the Chaco River and north of the Pinabete Wash. Within that 592-acre area, the footprint of the power plant facilities would require approximately 149 acres. The general site arrangement is shown in Figure 2-2. The facilities at the power plant site would include the following:

- administration building and control center (i.e., parking lot, perimeter fence);
- turbine hall;
- supercritical boiler;
- turbine-generator and associated systems;
- air-emission control equipment and facilities;
- coal combustion byproducts handling including storage facilities
- maintenance shop;
- diesel generators and building;
- diesel fire-water pumps and building;
- coal-conveyor transfer house;
- coal-crusher building;
- water-supply, storage, and treatment systems;
- dry-cooling towers;
- oil storage;
- electrical switchyard and main transformers; and
- warehouse and chemical storage.

Emission controls would be used to minimize emissions of potential air pollutants. Air pollution controls for the pulverized coal-fired boilers would consist of the following:

- Low nitrogen oxide (NO_x) burners and selective catalytic reduction to control NO_x emissions;
- Low sulfur coal and wet flue gas desulfurization to control sulfur dioxide (SO_2) emissions;
- Wet flue gas desulfurization and a wet stack to control acid gas emissions, including sulfuric acid mist;
- Wet flue gas desulfurization to control mercury emissions. Activated carbon and hydrated quicklime injection to be installed before the fabric filter baghouse if needed for additional reductions, with secondary reductions in SO_2 emissions and sulfuric acid mist;

- A fabric filter to control particulate emissions; and
- High efficiency combustion to control carbon monoxide (CO) and volatile organic compound emissions.

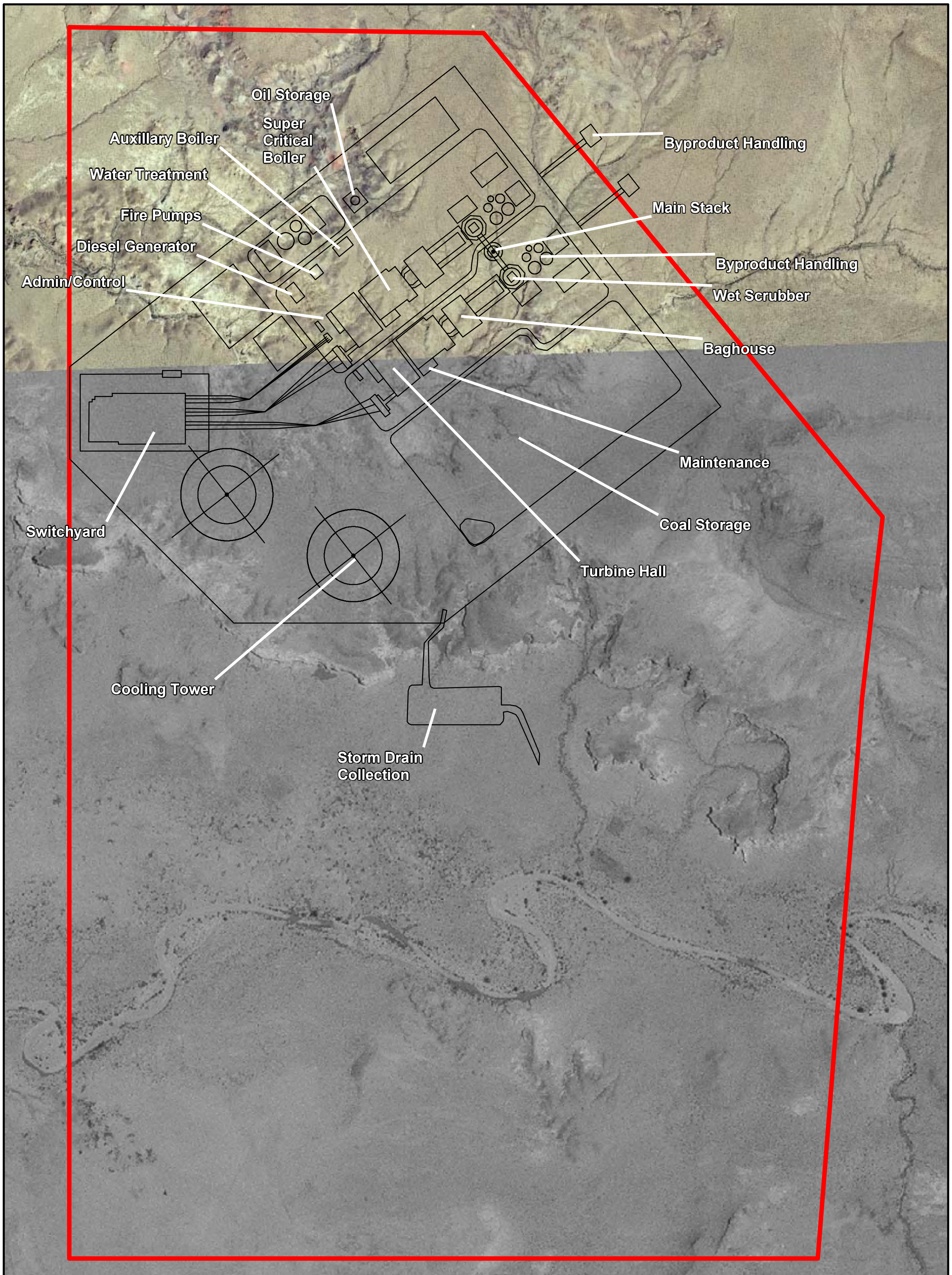
The supercritical boilers would operate at high temperatures and pressures to make steam to turn a steam turbine connected to a generator that would produce the electricity. Steam exhaust from the turbine would be cooled by a Heller natural-draft cooling system. This type of cooling system would use 80 percent less water than conventional mechanical-draft cooling systems. When the ambient temperature is below 80 degrees Fahrenheit, the cooling tower operates like a closed-cycle, natural-draft cooling tower. When the temperature exceeds 80 degrees Fahrenheit, the facility has the option of applying water overspray to the exterior radiator surfaces inside of the cooling tower to provide additional cooling. There are no particulate emissions associated with this type of cooling tower.

2.2.2.1.2 Infrastructure

Access Roads. Limited access is available within the project area; therefore, some development of new roads would be necessary. Both paved and unpaved access roads would be required for construction and long-term maintenance access. These roads must be sufficient to bear the weight and endure heavy construction vehicle use and other long-term use.

The proposed access road would access the power plant site from BIA 5082 (Burnham Road) and run west across the BNCC Lease Area along the boundary between Areas IV North and IV South. This access road alignment would interconnect with BNCC's Burnham Road Realignment Project as shown on Figure 2-1. BNCC is conditionally authorized to realign a portion of Burnham Road through Areas III and IV North of the BNCC Lease Area in conjunction with its Surface Mining Reclamation and Control Act (SMCRA) permit. Impacts related to the realignment project are addressed by a separate environmental assessment (refer to Environmental Assessment Permit No. NM-0003E; Navajo Tribal Lease 14-2-603-2505; and OSM Project No. NM-0003-E-R-01 and associated Finding of No Significant Impact Signed November 7, 2005 in Appendix A). The Desert Rock Energy Project EIS addresses impacts associated with the approximately 3.5-mile-long portion of the proposed east-west alignment that would interconnect with BNCC's project.

Transmission Lines. Two single-circuit 500 kilovolt (kV) transmission lines, each with a 250-foot-wide right-of-way, would leave the power plant site and parallel the east side of the Chaco River (Segments A and C on Figure 2-1) in a northerly direction for approximately 14.9 miles to Arizona Public Service's Four Corners Generating Station. From the Four Corners Generating Station, one single-circuit 500kV transmission line would parallel an existing 230kV transmission line within a 250-foot-wide right-of-way, across the San Juan River, to interconnect with the proposed Navajo Transmission Project (NTP) transmission line, a distance of approximately 10.8 miles (Segment D on Figure 2-1). The proposed typical structure for the transmission line would be a self-supporting, four-legged, steel-lattice structure approximately 135 feet in height with a nominal spacing of 1,200 to 1,600 feet between structures (Figure 2-3).



Legend

Proposed Desert Rock Power Plant

General Arrangement

FIGURE 2-2

GENERAL ARRANGEMENT

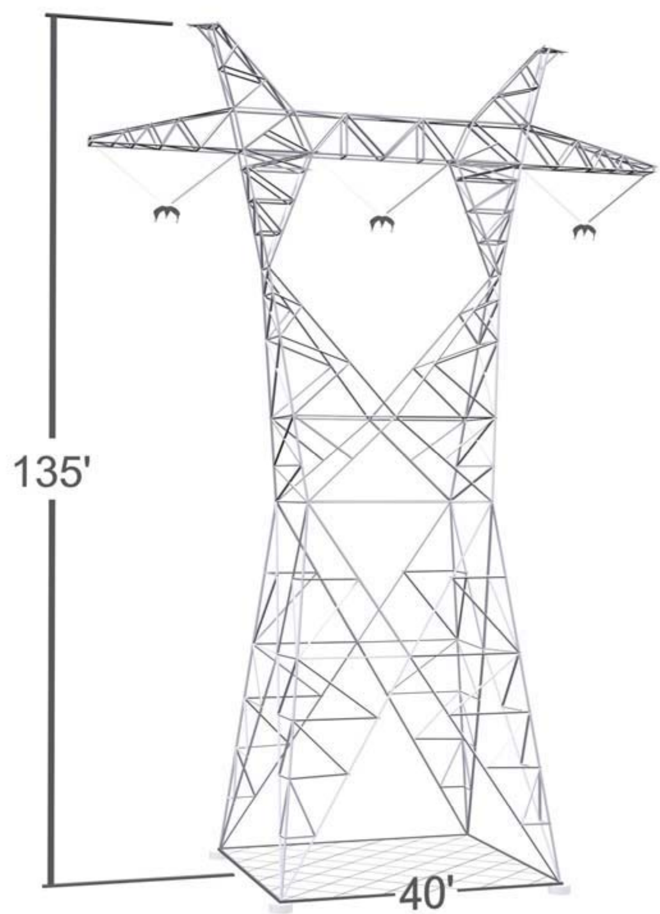
Sithe Global Power, LLC
Desert Rock
Energy Project

0 500 1,000
Feet

Source:
URS Corporation 2005, 2006
BHP Billiton 2005
Utility Engineering 2006
New Mexico Resource Geographic Information System (RGIS) 1988
UTM, NAD83, Zone12, Meters

An alternative transmission line corridor evaluated in this EIS would be comprised of Segments B, C, and D (Figure 2-1). This alternative would be longer than the proposed alignment by nearly 3 miles. The primary difference between the transmission line alternatives is that Segment B would parallel the Chaco River on the west side, and Segment A on the east side. In addition, Segment B would be co-located with existing transmission lines for about 8.8 miles of its length. No alternative alignments were evaluated in detail for Segments C and D (for discussion of alternatives considered but eliminated prior to detailed analysis, see Section 2.4.5).

Figure 2-3 Typical 500kV Structure



Water-Supply System. The average annual water consumption demand for Alternative B of the Desert Rock Energy Project is estimated to be 4,500 acre-feet per year (af/yr), or 2,795 gallons per minute (gpm) on average, of continuous flow for a period of 50 consecutive years. The major project uses of water would be emission controls (54 percent), supplemental cooling (17 percent), boiler steam losses (11 percent), dust control (8 percent), and potable needs (4 percent). Water re-use would be optimized for a zero-liquid discharge. An additional 450 af/yr would be made available to meet Navajo municipal demand, increasing the total water use to 4,950 af/yr, or 3,070 gpm, in accordance with a Large Water User Master Agreement between the project proponents and the Navajo Nation. Based on evaluation of the hydrogeologic characteristics of the Morrison aquifer in the study area and the results of the well impact analysis, it was estimated that 10 to 20 new production wells would meet this demand (URS Corporation 2005a). Ground water from nearby deep wells that access the Morrison aquifer would be the primary water supply.

The proposed well field would be located on the 592-acre power plant site lease area and potentially along the proposed transmission line Segment A, if there is not adequate space within the 592-acre parcel for all of the project wellheads (see Proposed Well Field Area B on Figure 2-1). The 10 to 20 wells generally would be placed equally apart at a minimum of 0.25-mile spacing, as practical based on surface characteristics and hydrology. Each well would be networked to the water-transmission pipeline mains that would deliver the water to the onsite 2.5-million gallon water-storage tank. Each well would be equipped with a submersible pump powered by an electric motor. The final size of the pumps and motors would be determined after test wells have been drilled and properly developed. The wells would be controlled via telemetry by the water level in the storage tank. The telemetry system would likely be connected by fiber optic cable buried in the pipeline trench.

The proposed well field location was identified based on the hydrologic structure of the Morrison aquifer, water quality, access, and proximity to the proposed power plant site. Water from the Morrison aquifer was identified as suitable for industrial use (URS Corporation 2005a, amended in September 2006); this determination was based on previous studies, well data from Navajo Nation Department of Water Resources, and water quality field tests. Depth to the Morrison-aquifer water at well field area A is approximately 1,500 feet below the surface. The proposed well field area B would require deeper wells (5,000 to 6,000 feet) to access the Morrison aquifer, but would reduce potential effects on users to the southwest at the communities of Littlewater and Sanostee (see Appendix B). The well field would be within an economically viable distance of the project, and its location was selected to avoid impacts on other groundwater and surface water users.

An alternative well field location also is evaluated in this EIS. Alternative well field area A would be located west of Highway 491 and south of Table Mesa, on nearly 890 acres about 12.4 miles northwest of the proposed plant site (see Well Field Area A on Figure 2-1). A 100-foot-wide utility corridor would be required to supply electricity to the wells.

With either well field location, each production well and associated facilities would be enclosed within an 8-foot-high chain-link fence surrounding the well yard. The well head would be enclosed in a masonry-block structure, or pump house, located within the fenced well yard (as needed to protect and secure the well equipment) and meeting the current Uniform Building Code. Within the pump house would be the well pump and motor, as well as associated well equipment, such as the shut-off valve, check valve, flow meter, air-release valve, electrical equipment, telemetry, and above ground piping. The foundation of the pump house would be constructed slightly above surrounding grade to minimize flooding potential.

The size of collector pipelines would be based on the actual location and flow rate of the wells, but they would range from 6 to 12 inches in diameter and would be made of high density polyethylene. The pipelines would include approved valves, proper thrust restraint, and cathodic protection where necessary. The collector pipelines would be connected to manifolds on the water-transmission pipeline mains that would deliver the groundwater to the water-storage tank at the power plant site.

The water-transmission pipelines would consist of two parallel 16-inch diameter high density polyethylene pipelines. Due to the topographic conditions, the pipelines would be pressurized only by the well pumps; no booster-pump station would be required. Outside the plant boundaries, the water-transmission pipelines would have a minimum cover of 3 feet below existing grades. Appurtenant facilities would include isolation valves, control valves, access manways, air release/vacuum valves and vaults, blow-off valves, fiber-optic splice vaults, cathodic-protection facilities where necessary, and pipeline-alignment markers.

Overhead or underground power lines would be constructed to supply electricity to the wells. The power lines would be constructed in the same right-of-way and paralleling the pipelines, with appropriate spacing between the utilities as needed to ensure safety. The length of each power line would be determined upon completion of design and engineering studies. Control of the well pumps would be from the power plant control room via telemeterized digital control system.

If production wells are located outside the plant boundary, road access to the wells would be needed for construction, operation, and maintenance. Unpaved access roads would be approximately 15-feet wide and constructed in accordance with BIA and/or Navajo Nation road standards. Additional roads would need additional environmental clearances.

BNCC holds Surface Permit Number 2838 issued by the New Mexico Office of the State Engineer in October 1958. This permit provides BNCC a total diversionary right of 51,600 acre-feet annually, with a consumptive right of 39,000 acre-feet annually, for waters drawn from the San Juan River. The additional consumption associated with the expansion of the surface mining operations at the Navajo Mine required to supply coal to the Desert Rock Energy Project is estimated to be approximately 600 acre-feet annually. The additional consumption is within the existing consumptive right and will cause no depletions to the San Juan River beyond those authorized under the current water right permit.

2.2.2.2 Construction Activities

Preconstruction conferences with the BIA, Navajo Nation, and local Navajo Chapters would be conducted to introduce the contractors and their field representatives; discuss construction plans, schedules, and mitigation; and introduce the appropriate construction personnel to contact if needed. As construction proceeds, the construction engineers or inspectors would monitor activities and right-of-way authorizations to ensure compliance or to initiate modifications, where necessary. In environmentally sensitive areas, if any, an environmental specialist with appropriate qualifications (e.g., biologist, archaeologist) would monitor construction activities to ensure compliance with specific mitigation. In addition, fugitive dust control measures, including application of water to exposed surfaces, would be conducted throughout the construction phases of the project to minimize emissions caused by earthmoving activity and vehicle travel on unpaved surfaces. Following completion of construction, project facilities would be mapped as built and submitted to BIA and the Navajo Nation to close the construction process. It is expected that the construction of the first unit would require about 48 months.

During construction, temporary housing would be required to house the influx of construction personnel. At times of peak construction, up to 500 motor homes could be needed to meet housing needs. These motor homes would be located in existing motor home parks or potentially at new parks built in the area.

Access Roads. As required for construction or maintenance, roads would be upgraded or constructed in accordance with standard construction practices and in coordination with the Navajo Nation. In some areas, only temporary roads would be needed. Typically, these temporary unpaved (dirt) roads would be graded to a travel-surface width of about 12 to 15 feet. Turnout areas and curves would require a wider surface. Normally a ditch drainage system would not be constructed for temporary roads. Permanent access roads would be constructed where needed for construction and long-term maintenance. Some permanent roads would be graded to 40 feet with a paved travel-surface (i.e., power plant main access road) width of 24 feet except where turnout areas and curves or specifications require a wider surface. Roads would follow the natural grade with the maximum allowable slope of 8 percent. Drainage ditches on either side of the road would handle runoff. Where necessary, some roads may need to be removed or barricaded following construction to restrict future access for general and undesired use. However, blocked access routes would have to be reopened when necessary where right of access may be impeded.

Biological and cultural resources identified during construction would be inventoried and monitored by professional biologists or archeologists as directed by the Navajo Nation, Biological Opinion, Programmatic Agreement, or other permit requirements. Any sensitive resources that are identified would be avoided during project construction and maintenance activities.

Power Plant Site. The proposed power plant and associated facilities would be constructed by a primary contractor who would perform the engineering, procurement, and construction activities. The contractor would undertake final plant design, equipment procurement, and construction. Specific plans or proposed measures for fugitive-dust control, erosion and sedimentation control, site reclamation, stormwater-runoff control, and natural and cultural resources protection would be implemented as part of the construction process.

Up to 1.2 million tons of earth material is anticipated to be removed for the construction of the proposed power plant. The cut-and-fill activities, conducted using scrapers or excavators, would be balanced over the site such that material would not need to be imported to, or exported from, the project area. Once the site has been leveled and prepared for construction, areas for the foundations would be excavated and concrete foundations would be poured for each major piece of equipment or major structure. Most of the structures would be assembled at the site and materials would be stored on a portion of the site. The structures would be erected using cranes and numerous types of supporting equipment.

Safety equipment and systems would be installed in accordance with applicable Federal regulations. Emphasis would be on protecting the public, personnel, and equipment from potential harm. The plant site would be surrounded by fencing for security and safety purposes. Normal access to the plant would be through a primary gate with security controls. Locked gates would be installed in the perimeter fencing for emergency, operations, and maintenance access.

Areas within and outside the power plant site would be monitored for safety and security in accordance with a plant operations and management plan that would be in place before commencing operation of the plant.

Transmission Lines. The transmission lines would be constructed in a sequence of activities as follows:

- surveying the transmission line centerline;
- geotechnical surveying;
- identifying/upgrading or constructing temporary and long-term access roads;
- clearing activities for right-of-way, tower sites, construction yards, batch plants;
- excavating and installing foundations;
- assembling and erecting towers with temporary and permanent pad sites;
- clearing of pulling, tensioning, and splicing sites;

- stringing conductors and ground wires;
- installing counterpoise (tower grounds) where needed; and
- cleaning up and reclaiming affected land areas.

A description of these activities is provided in Appendix C.

2.2.2.3 Operation and Maintenance Activities

The power plant would be a mine-mouth operation fueled by sub-bituminous coal from the adjacent resources on Areas IV South and V of the BNCC Lease Area. Operation of the power plant would require the mine to supply an average of 6.2 million tons of coal per year; this amount could vary, and the maximum amount of coal that would be required in any 12-month period could reach 7 million tons. The coal fuel supply would be transported from Areas IV South and V of the BNCC Lease Area to a proposed coal preparation facility located in Area IV North, adjacent to the power plant site. At this facility, coal would be crushed and blended to the desired specification for delivery to the power plant via a delivery conveyor. The coal would then be pulverized prior to injection into the boilers, for optimized burning. See Section 2.2.2.4 below for more detailed information related to mining activities.

Covered or enclosed coal-transfer systems would be used for the receipt, transportation, and storage of the active coal pile to reduce dust and noise. Onsite coal-storage areas would be earthen-covered or sealed to prevent emissions and spontaneous combustion. Dust suppression, enclosures, or filters would be used, as appropriate, to control emissions from material transfer points and the coal bunkers. All transfer stations would operate under a slight negative pressure with vents routed through a fabric filter to achieve 99 percent particulate-matter control efficiency. The coal-storage pile would be treated to reduce dust emissions.

Other materials that would be stored onsite include quicklime and ammonia, and possibly activated carbon. Quicklime would be delivered to the site by trucks and pneumatically conveyed to a quicklime storage silo. The silo would be equipped with a baghouse to control PM_{10} emissions. Quicklime would be withdrawn from the bottom of the silo and pneumatically transported to the quicklime slaker tank where it would be mixed with water. The quicklime slurry would be used in the wet flue-gas desulfurization system. Activated carbon, if needed, would be delivered to the site by trucks and pneumatically conveyed to storage silos that also would be equipped with a baghouse to control PM_{10} emissions. Hydrated quicklime and activated carbon slurry would be injected in the fluegas duct prior to the fabric filter to control acid-gas and mercury emissions. Quicklime would be converted to synthetic gypsum and would be sold or disposed with the coal combustion byproducts (see discussion below).

Anhydrous ammonia would be delivered to the site by truck for storage in a pressurized tank. There are no air pollutant emissions from the pressurized storage tanks. The anhydrous ammonia system consists of all equipment required to unload, store, transfer, vaporize, and convey the ammonia/air mixture into the ammonia injection grid upstream of the selective catalytic reduction system.

Plant equipment would be continuously maintained in accordance with vendor, regulatory, and industry standards to help prevent unscheduled outages and maintain equipment in safe and proper working order. Maintenance would occur in the form of inspections, changing out fluids, calibrations, replacing equipment, vibration analysis, testing, and other activities that protect the equipment from failure. Maintenance schedules may be daily, weekly, monthly, quarterly, and annually.

Maintenance outages would occur periodically for minor and major maintenance, and would typically be scheduled in the spring and fall in accordance with regional power demand. These outages would rotate between short (2 to 3 weeks) and long (1 to 3 months) duration annually. Unscheduled outages are expected to occur upon occasion and would be addressed expediently.

The transmission lines would be inspected annually or as required by both air and ground patrols. Maintenance would be performed as needed.

As stated previously, the wells would be operated remotely by digital telemetry. The well field would be inspected regularly and maintenance would be performed as needed.

There would be an estimated 200 employees on rotating shifts for normal operations and maintenance of the Desert Rock power plant. These employees would access the plant via the proposed access road from the east side of the power plant through the BNCC Lease Area.

2.2.2.3.1 Coal Combustion Byproducts

Coal combustion byproducts (CCBs) generated by the plant would include bottom ash, fly ash, and synthetic gypsum. Fly ash and bottom ash are generated by the combustion of coal. The fly ash would be collected in emission control baghouses located within the flue gas stream. Ash particles that are too large to be carried by the flue gas would fall to the bottom of the boiler during the combustion process and would be removed as bottom ash. Scrubber product, also known as Flue Gas Desulfurization product, results from the removal of SO_2 from the flue gas emissions. The SO_2 reacts with lime to form calcium sulfite and calcium sulfate.

In general, the major chemical constituents of CCBs include: Silicon Dioxide (SiO_2), Aluminum Oxide (Al_2O_3) and Calcium Sulfite ($CaSO_3$). Analytical results for the mineralogy of ash from coal sampled in Area IV South of the BNCC Lease Area are shown in Table 2-2. Testing for metals concentrations of the CCBs would be performed as part of SMCRA permitting process, including tests for constituents of concern before reuse.

Table 2-2 Ash Mineralogy from Area IV South of the BNCC Lease Area

Mineral	Mineral Analysis of Ash (Percent of Ash by Weight)		
	Average	Minimum	Maximum
Phosphorous Pentoxide, P_2O_5	0.21	0.03	0.66
Silica, SiO_2	57.61	43.50	64.07
Ferric Oxide, Fe_2O_3	6.08	4.31	11.00
Alumina, Al_2O_3	24.78	22.48	31.43
Titania, TiO_2	0.94	0.71	1.15
Calcium Oxide, CaO	3.85	1.47	9.68
Magnesium Oxide, MgO	0.83	0.53	1.03
Surfur Trioxide, SO_3	2.21	0.78	7.59
Potassium Oxide, K_2O	0.99	0.36	1.49
Sodium Oxide, Na_2O	1.69	1.44	2.03

Trace metals such as Arsenic, Cadmium, Selenium, Mercury, and Boron also are present in most CCBs. The metal concentrations would vary depending on the characteristics of the coal burned by the power plant and on the combustion processes of the plant. Typical trace metal concentrations in the ash from coal sampled in Area IV South of the BNCC Lease Area are shown in Table 2-3.

Table 2-3 Ash Trace Metals Content from Area IV South of the BNCC Lease Area

	In parts per million															
Trace Metal	**Lead**	**Selenium**	**Arsenic**	**Thallium**	**Zinc**	**Copper**	**Nickel**	**Cobalt**	**Cadmium**	**Silver**	**Chromium**	**Manganese**	**Barium**	**ASntimony**	**Beryllium**	**Mercury**
Average Content	15.4	1.1	5.9	<2.0	21.2	21.5	4.3	2.2	<2.0	4.1	9.5	32.0	136.2	1.6	1.4	0.1
Maximum Content	40.0	2.0	17.0	2.0	43.0	34.0	8.0	6.0	11.0	10.0	16.0	81.0	339.0	3.0	7.8	0.4
Minimum Content	5.0	ND	ND	ND	6.0	9.0	2.0	1.0	ND	2.0	5.0	9.0	46.0	ND	0.2	ND

ND = non-detect

Up to 1.35 million tons of CCBs could potentially be generated annually. The CCB generation rate would vary, depending on power plant output and coal quality. The CCBs produced annually would include up to 1.12 million tons of fly ash, 124,515 tons of bottom ash, and 108,300 tons of synthetic gypsum (calcium sulphate). As part of the Desert Rock Energy Project, CCBs would first be sold for commercial purposes, as possible, and any remaining CCBs would be backfilled into the mine. During boxcut development (the first dragline cut), a portion of the pit would remain unfilled as the dragline advances during subsequent mining operations. These pits and inactive ramps would be the likely placement area for CCBs, subject to OSM regulatory approval. Efforts would be made to market CCBs for reuse, which would effectively reduce the amount backfilled into the mine each year.

Market Uses of CCBs. According to the American Coal Ash Association's 2004 Annual Survey, approximately 122 million tons of CCBs were produced in the United States in 2004. Approximately 40 percent of these materials were beneficially reused in various applications.

Fly ash is commonly used as an additive in concrete and soil amendment applications due to its pozzolanic behavior. Pozzolan in this instance refers to artificially produced silica-based mineral used for its binding properties. The addition of fly ash to cement mixtures has been shown to provide additional strength and workability to concrete. This practice is widely accepted in the United States. Fly ash and bottom ash are also commonly used as structural fill in road construction and pavement projects. This use is an approved practice by the U.S. Department of Transportation.

Synthetic gypsum that is suitable for use in wallboard includes flue-gas desulfurization gypsum, fluorogypsum, citrogypsum, and titanogypsum. U.S. manufacturers currently consume about one and a half million tons of synthetic gypsum annually in the manufacture of wallboard; this approaches seven percent of the industry's total calcined gypsum. The principal origin of synthetic gypsum in North America is flue gas desulfurization of pollutants from the flue gas of power-generating or similar plants.

CCB reuse applications would be pursued as part of the Desert Rock Energy Project. The Coal Combustion Products Partnership (C^2P^2) program is a cooperative effort between the U.S. Environmental Protection Agency (USEPA), American Coal Ash Association, Utility Solid Waste Activities Group, U.S. Department of Energy (DOE), and U.S. Federal Highway Administration to help promote the beneficial use of CCBs. Coordination with the C^2P^2 Program can help target specific markets for CCB reuse. Preliminary conversations with USEPA Region 9 C^2P^2 coordinators indicate that potential markets may exist in the area of the project. Reuse applications would be pursued through continued coordination with the C^2P^2 partnership and other interested parties, to identify potential reuse opportunities at the time when materials would be available.

CCB Disposal and Use in Mine Reclamation. CCBs that cannot be marketed for reuse would be disposed in mine pits as part of mine reclamation efforts. Similar reclamation activities are currently being conducted in the BNCC Lease Area, as well as the nearby San Juan mine. The Office of Surface Mining and Reclamation (OSM), DOE, and non-government organizations including American Coal Ash Association, USWAG and others have long recognized the practice of mine reclamation using CCBs as a viable, cost-effective and environmentally responsible practice when managed correctly.

Typical reclamation practices using CCBs as backfill require disposal of the CCBs in dry areas of mined-out pits and ramps. The CCB fill is then capped with approximately 10 feet of low permeability material (i.e., overburden derived backfill enriched in smectitic clays). Final reclamation surfaces are designed to prevent water from flowing along the length of an ash disposal area, to minimize the potential for erosion and infiltration.

Storage silos and load-out and transfer equipment would be used for CCB products, and are shown on the general arrangement (Figure 2-2). To control dust, moisture would be added to ensure an average moisture content of 20 percent.

Regulation of CCB Disposal. CCB disposal would comply with requirements established by the OSM. SMCRA is the current regulatory vehicle for minefilling CCBs. CCB disposal activities would be regulated and monitored to avoid any potential environmental impacts, including the following actions:

- All CCBs would be buried a minimum of 10 feet below the surface.
- All CCB disposal areas would be located at least 50 feet from major drainages.
- The OSM Albuquerque Field Office would be notified when CCBs are being covered with overburden.
- The Permit Application Package must include up-to-date maps certified by a Registered Professional Engineer with respect to the locations of ash disposal (on an annual basis) as well as drainage patterns in their proximity.
- SMCRA requires groundwater monitoring every three months with the placement of wells based on the operator's probable hydrogeologic consequences and OSM's cumulative hydrologic impact analysis.
- Typically 10 years of post-reclamation monitoring would occur.

In 1993, the USEPA made a final regulatory determination that CCBs are exempt from regulation as a hazardous waste under Subtitle C of the Resource Conservation and Recovery Act (or RCRA, 58 FR 42466, August 9, 1993). In its regulatory determination, USEPA concluded that the State or Tribal industrial solid waste management programs implemented under Subtitle D of RCRA were adequate regulatory controls for managing the disposal of CCBs.

In 2000, USEPA commissioned a study from the National Academy of Sciences (NAS) addressing minefilling of CCBs, resulting in *Managing Coal Combustion Residues in Mines* (NRC 2006). In response to this study, USEPA and OSM are developing enforceable regulations for this practice. OSM published an advance notice of proposed rulemaking for CCB placement in active and abandoned coal mines in the Federal Register on March 14, 2007. USEPA is developing rules for placement of CCBs in noncoal mining locations such as landfills.

The Navajo Nation codified the Navajo Nation Solid Waste Act on 18 October 1990 (4 N.T.C. 101 as amended by the Navajo Nation Council Resolution No. CJY–51– 97) and finalized their regulations on February 1, 1999. The Navajo Nation Solid Waste Regulations specifically excludes CCB from the definition of a Solid Waste. Based on this exclusion, CCB are not regulated by Navajo Nation as a solid waste. In accordance with the following documents, BNCC has the right to dispose of CCB on leased premises:

- A mining lease between the Navajo Nation and BHP (Utah Construction Company) dated July 26, 1957 and the subsequent amendments.
- Resolution ACAP-43-68 of the Advisory Committee of the Navajo Tribal Council dated April 15, 1968
- Approval of Resolution ACAP-43-68 by the BIA dated May 15, 1968.

2.2.2.4 Mining Operations in the BNCC Lease Area

A new surface mine (the Navajo Mine Extension Project) would be developed to provide coal to the Desert Rock Energy Project. This mine would be located on the existing BNCC lease areas IV South and V, which are located adjacent to the proposed power plant site (see Figure 2-1). At full production, 6.2 million tons of coal would be mined per year. The mine would have a life of 50 years.

2.2.2.4.1 Production Sequence and Schedule

There would be two discrete production phases for the BNCC Navajo Mine Extension Project: pre-production and full production, which would include CCB disposal and ongoing reclamation operations. Mine closure and final reclamation would occur when mining operations are discontinued.

For more information regarding the Navajo Mine Extension Project, see Appendix D.

Pre-Production. Pre-production activities consist of surface infrastructure development, topsoil removal from the initial mining blocks, pre-stripping to develop the initial drilling benches, and boxcut development.

Surface infrastructure development would provide adequate roads and power into the initial mining area, to facilitate development stripping and early haulage operations. Field coal storage stockpiles also would be developed during this period. Surface infrastructure development to support initial mining activities would be expected to begin approximately 18 months in advance of Desert Rock Unit 1 commercial operations. Infrastructure elements planned for development during this initial phase are shown in Figure 2-4 and would include:

- Diversion of the Pinabete Arroyo would be required to allow stripping operations to begin in Area IV South. The diversion would carry ephemeral Pinabete flows to the west into the natural channel of the No Name Arroyo, for the duration of mining operations in Area IV South. The size of this diversion would be set by regulation to ensure a capacity sufficient to safely convey the peak flows from a 10-year, 6-hour event. It is likely that the final design would be sized for larger flows to reduce the risks to the surrounding environment and to the mining operations.
- An access road from Area IV North to Area IV South would provide primary access for personnel and equipment to the mining operations. This road would fill the need for primary access between the two operating areas within the BNCC lease and would allow all BNCC vehicles and

equipment to travel over a private road that keeps mining equipment and on-shift employees off the public Burnham Road.

- Area IV South main haulroad would serve as the primary coal haulage route from the active pits to the field stockpile/conveyor origin. This route would extend to the planned Area IV South facilities, where all maintenance shops would be located.
- Area IV South Main 69kV powerline would loop completely around the perimeter of Area IV South and provide power to both mine facilities and dragline operations.
- Area IV South Field Coal Storage Stockpile and Conveyor Origin will provide up to 1.6 million tons of field stockpile capacity in the interim between first coal mining and commencement of coal plant and overland conveyor operations.
- Area IV South haulage ramps 1, 2, 3, 4, and 5 would be developed on the indicated alignments (see Figure 2-4), in a progression that follows and facilitates the dragline strip sequence.
- Other infrastructure elements, e.g., shops/offices and the new, dedicated coal processing facility required to support the Desert Rock Energy Project in Area IV North.

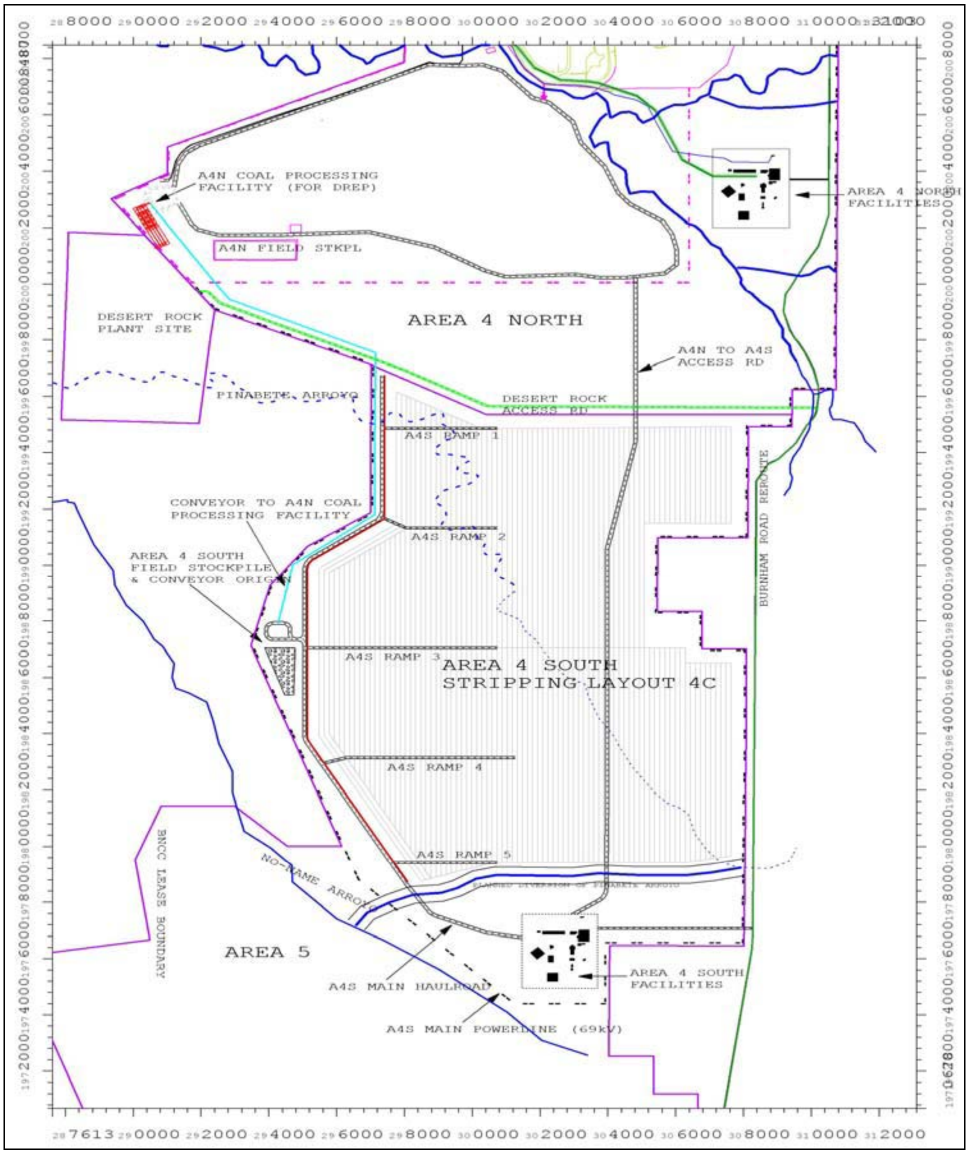


Figure 2-4 General Arrangement of BNCC Lease Area IV South Infrastructure and Mining Layout

Topsoil would be removed and stockpiled in advance of both infrastructure development and initial mining.

Pre-stripping and development of initial drilling benches would begin in approximately 12 months in advance of Desert Rock Unit 1 commercial operations. The extent of both boxcut strips, plus any identified truck/shovel pre-strip areas adjacent to the boxcuts would be prepared for drilling and blasting activities.

Limited quantities of truck/shovel pre-strip also may be required to construct uniform grades in haul roads and conveyor corridors; to provide level, safe working surfaces for drill and blast operations; or to build buttress walls at the planned toe of the boxcut spoils.

Truck/shovel operations also would be used to prepare stockpile locations and to excavate/fill as required for construction of the conveyor truck dump, the overland conveyor, and the coal processing facility. To the extent possible, BNCC would not construct out-of-pit overburden dumps or storage sites.

Boxcut (the first dragline cut) development would begin roughly one year in advance of Desert Rock Unit 1 commercial operations. Preliminary mine plans are outlined in Appendix D.

Where the boxcut spoils impinge on the established channel of the Pinabete Arroyo, they would be selectively handled to reduce the likelihood of excessive sediment yield to the ephemeral channel during the active pit life. The original channel alignment would be re-established during the final reclamation phase.

Haulage ramps developed during the boxcut phase may not be located on the design alignments shown in Figure 2-4. Rather, the ramps would be placed as needed to expedite removal of the coal uncovered by the draglines. During the boxcut phase, haulage ramps are often chopped in parallel to the pit strike, due to the very limited lengths available to ramp down in directions more perpendicular to the pit strike. After the pit has advanced several strips to the east, it becomes easier to develop the conventional through-spoil ramps shown in Figure 2-4.

It is probable that the two boxcut strips would be developed in a stair-step fashion, with the initial strip or cut being completed at the bottom of four seams. The second cut then would take the full planned sequence, stripping down through two seams. Stair-stepping the boxcuts reduces the excess (out-of-pit) spoil placement west of the boxcuts. This practice has the added benefit of reducing the graded elevation of the final reclamation surface.

Production Phase. The production phase in Area IV South would last approximately 35 years. After the depletion of recoverable reserves in Area IV South, the mining operations within the BNCC Lease Area would transition to Area V of the mine lease. A preliminary mine plan is provided in Appendix D.

Overburden and Waste Disposal. Since this would be a dragline operation, no large out-of-pit waste dumps would be constructed. Waste material would be disposed of in-pit by the draglines, as is done at the current BNCC operations.

2.2.2.5 Decommissioning

The power plant would have a 50-year design life without major capital improvements. At the end of its useful life, the power plant and all associated facilities would be decommissioned. All structures and equipment at the site would be dismantled and removed as stipulated in the lease agreement with the Navajo Nation. All wells would be decommissioned and abandoned or transferred to the Navajo Nation in accordance with Navajo Nation procedures and regulations. Following removal and abandonment of facilities, any areas disturbed would be rehabilitated as nearly as possible to their original condition including all areas of the BNCC Lease Area disturbed by mining activities. All mining areas associated with the proposed project would be reclaimed in accordance with the terms and conditions of BNCC's SMCRA permit as administered by OSM.

As part of the lease agreement with the Navajo Nation, the project operators would be required to annually fund a Trust to ensure that funds are available to remove the improvements at the end of the lease term. Annual contributions to a reserve account begin on the first anniversary of the commercial operation date for Unit 1 and would continue each year that the lessee or sublessee holds title to the improvements.

2.2.3 Alternative C – 550 MW Sub-critical Facility

Under Alternative C, the proposed action would include the construction, operation, and maintenance of a 550-MW sub-critical coal-fired power plant. The site location would remain the same as Alternative B; however, the size of the plant would be smaller (see Figure 2-5). Alternative locations for the transmission lines and well fields would remain the same as described in Alternative B above.

The generating facility evaluated in Alternative C represents an actual proposal submitted to the USEPA, and would involve different levels of impacts to those resources identified as most important by the public during scoping (air and water resources). The BIA determined that the smaller generating facility discussed as Alternative C would be evaluated in detail in this EIS to provide a comparison of potential environmental impacts.

2.2.3.1 Power Plant and Associated Infrastructure

Alternative C would be similar to the Cottonwood Energy Project proposed by BNCC in 2002 at the same site as proposed for the 1,500-MW project under Alternative B. This project would also be similar to the Springerville Unit #3 which was completed in 2006 in central Arizona that is owned by Tri State Generation and Transmission Association. Compared to Alternative B, this alternative would have lower efficiency and higher emission and water usage per unit of power produced, but would have lower overall emissions and water consumption because of the reduced size of the unit. Coal usage under Alternative C would be 10 to 15 percent higher per megawatt-hour because of the higher heat rate of the sub-critical plant.

Proposed facilities under this alternative would include one 550 MW generation unit, one plant-cooling system, coal handling facilities, power transmission interconnection facilities, a water-supply system, access to the plant site, and waste-management operations. Under Alternative C, the project would be located in the same location as the proposed project, approximately 30 miles southwest of Farmington in San Juan County, New Mexico and entirely on the Navajo Reservation. Table 2-4 provides the acreage requirements for the project facilities under Alternative C.

Table 2-4 Acreage Requirements for Primary Facilities and Infrastructure under Alternative C

Facility	Acres
Power Plant	
Leased site	592
Footprint	110
Coal Preparation Facilities on the BNCC Lease Area	101
Infrastructure	
Proposed Transmission Line (Segments A, C, D)	766
Subalternative Transmission Line (Segments B, C, D)	829
Water Well Field A (includes utility corridor)	942
Water Well Field B	792
Main Power Plant Access Road	21

2.2.3.1.1 Power Plant

The alternatively sized power plant site would be located at the same site as the proposed Desert Rock Project, within a 592-acre leased area east of the Chaco River and north of the Pinabete Wash. Within that 592-acre area, the footprint of the power plant facilities would require approximately 110 acres, or

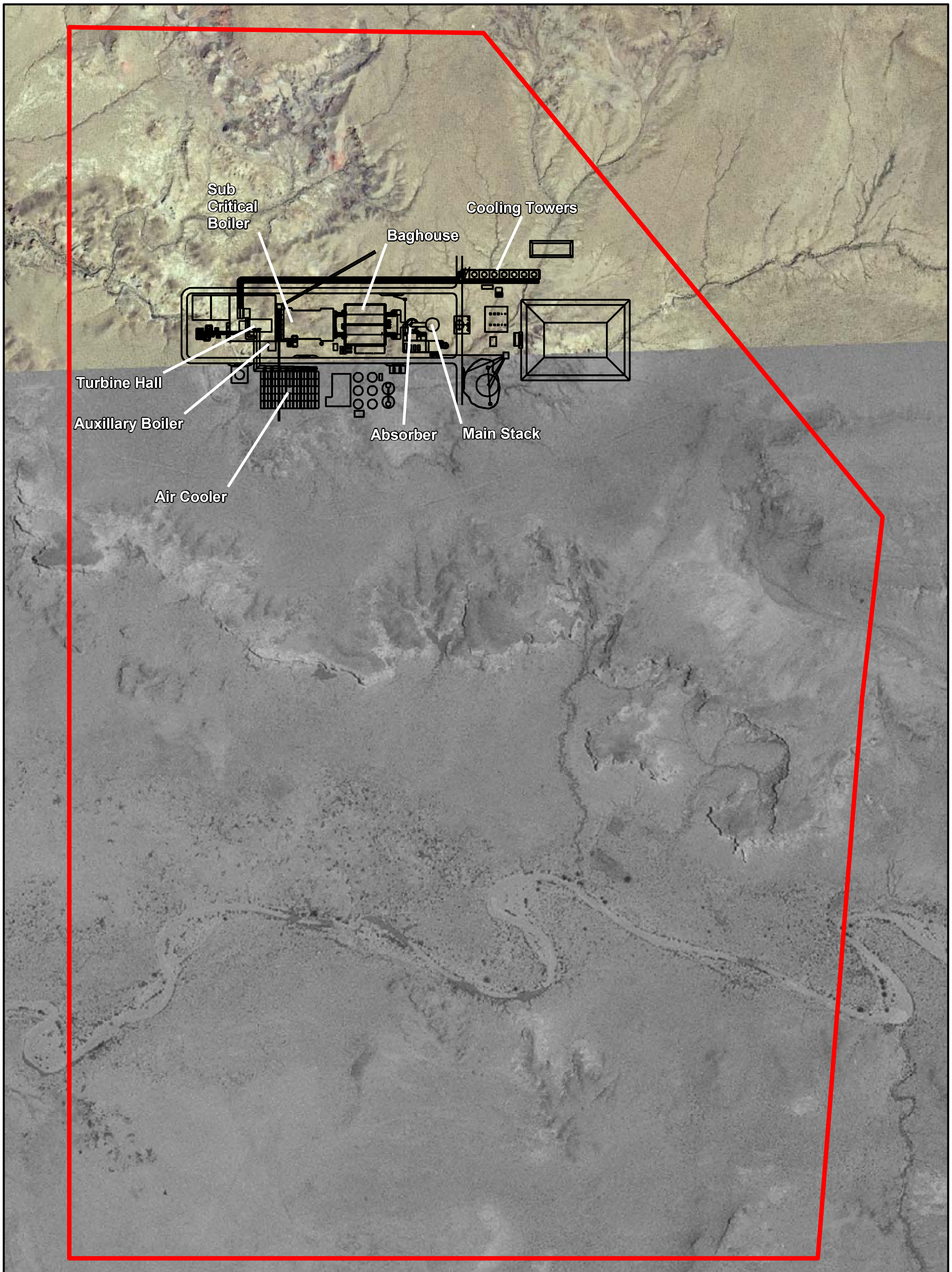
39 acres fewer than Alternative B. It is estimated that the stack would be about 492 feet tall. The facilities at the power plant site would include the following:

- administration building and control center (i.e., parking lot, perimeter fence);
- turbine hall;
- subcritical boiler;
- turbine-generator and associated systems;
- air-emission control equipment and facilities;
- coal combustion bi-products handling including storage facilities
- maintenance shop;
- diesel generators and building;
- diesel fire-water pumps and building;
- coal-conveyor transfer house;
- coal-crusher building;
- water-supply, storage, and treatment systems;
- Hybrid cooling towers;
- oil storage;
- electrical switchyard and main transformers; and
- warehouse and chemical storage.

Emission controls would be used to minimize emissions of potential air pollutants. Air pollution controls for the pulverized coal-fired boilers would consist of the following:

- low NO_x burners and selective catalytic reduction to control NO_x emissions;
- low sulfur coal and flue gas desulfurization to control SO_2 emissions; and
- fabric filters to control particulate emissions.

Steam exhausted from the turbine would be cooled by a hybrid cooling system utilizing part air cooling (cooling that uses no water) and part evaporative cooling (cooling that uses large amounts of water). The hybrid cooling system for Alternative C would have a capital cost that is 90 percent less than the Heller system proposed for Alternative B. In order to minimize the unit cost of the alternative sized project (cost per each kW of capacity of the power plant) the ancillary equipment like the cooling system must be at a lower cost than what would be installed in a larger capacity project.



Legend

Lease Area for Plant Site

General Arrangement

Source:
URS Corporation 2005, 2006
BHP Billiton 2005
Utility Engineering 2006
New Mexico Resource Geographic Information System (RGIS) 1988
UTM, NAD83, Zone12, Meters

FIGURE 2-5

550MW ALTERNATIVE POWER PLANT GENERAL ARRANGEMENT

Sithe Global Power, LLC
Desert Rock
Energy Project

0 500 1,000
Feet

N W E S

DPA

URS

2.2.3.1.2 Infrastructure

Access Roads. Access road construction, use and maintenance would be the same as described in Alternative B.

Transmission Line. The proposed and alternative locations for the transmission lines would be the same as described for Alternative B, but the right-of-way requirements would be reduced because one single-circuit transmission line would be constructed. The proposed transmission line would require about 766 acres under Alternative C, a reduction of about 439 acres from Alternative B. The alternative transmission line corridor would require 829 acres under Alternative C, or 544 acres fewer than Alternative B.

The proposed typical structure for the transmission line would be a self-supporting, four-legged, steel-lattice structure approximately 135 feet in height with a nominal spacing of 1,200 to 1,600 feet between structures. These characteristics would be the same as the proposed project under Alternative B.

Water-Supply System. The anticipated needs for water would be 4,000 af/yr, which would be a reduction in water usage of 12 percent compared to Alternative B. An additional 450 acre-feet would be provided for municipal use annually, assuming the same water agreement would apply for both Alternatives B and C. The proposed water source would be groundwater from the Morrison aquifer, similar to Alternative B. Based on evaluations of the hydrogeologic characteristics of the Morrison aquifer, it was estimated that 9 to 18 new production wells would meet this anticipated water demand. The alternative locations for the well field would be the same as those evaluated under Alternative B; however, the well field itself would be about 11 percent smaller.

Each well would be networked to the water-transmission pipeline mains that would deliver the water to the onsite 1.5-million gallon water-storage tank. Each well would be equipped with a submersible pump powered by an electric motor. The wells would be controlled via telemetry by the water level in the regulating/storage reservoir. The collector pipelines would be connected to manifolds on the water-transmission pipeline mains that would deliver the groundwater to the water-storage tank at the power plant site.

2.2.3.2 Construction Activities

Construction activities would be the same as described for Alternative B, although less earth material would be removed.

2.2.3.3 Operation and Maintenance Activities

Operation and maintenance activities would be the same as described for Alternative B, except the number of permanent employees would be 125.

2.2.3.4 Mining Operations at BNCC Lease Area

Similar to Alternative B, the power plant would be a mine mouth operation fueled by sub-bituminous coal provided by the adjacent resources on the BNCC Lease Area. Operation of the power plant would require about 2.4 million tons of coal per year. No conveyor would be built under Alternative C; the coal would be delivered from the BNCC Lease Area via haul truck on mine roads. Under Alternative C, there would be one dragline and one active pit (compared to two of each under Alternative B). Because sufficient coal reserves are available in Area IV South to service entire life of 550 MW plant, Area V would not be permitted at this time. Fewer employees would be required for mining operations under Alternative C – a total of about 130, versus 220 under Alternative B.

The activities associated with pre-production, production, and reclamation phases of the mining operations would be the same as described for Alternative B. Overburden and waste disposal activities would be the same as described for Alternative B.

2.2.3.5 Decommissioning

The decommissioning process would be the same as described for Alternative B.

2.3 DECISIONS AND AGREEMENTS REQUIRED FOR THE ACTION ALTERNATIVES

For the project alternatives, the necessary Federal actions addressed in this EIS would consist of an administrative decision to approve, conditionally approve, or disapprove the permit, right-of-way grant, or other legally binding authorization. The BIA in coordination with the Navajo Nation would act on the land lease and grant of rights-of-way for the proposed project; i.e., the power plant and associated facilities (e.g., access roads, transmission line, water-supply system) as described in Sections 2.2.2 and 2.2.3. OSM would act on a future SMCRA permit application to allow mining, CCB disposal, and reclamation in Areas IV South and V of the BNCC lease area. OSM would also revise the current SMCRA permit to allow construction of coal processing facilities, conveyance systems and infrastructure in Area IV North of the BNCC lease area. The Bureau of Land Management (BLM) would approve the mine plan for Areas IV South and V. The U.S. Army Corps of Engineers (USACE) and USEPA would be responsible for permitting decisions under the Clean Water Act. Although these administrative actions are not in themselves likely to impact the environment, they would be necessary for implementation of a project that could result in environmental impacts.

In addition to the Federal actions required for the development of the project, Tribal agreements also would be needed, including agreements for (1) the use of water for the water-supply system, (2) land lease for the power plant site, (3) rights-of-way and (4) taxation agreements. A Large Water User Master Agreement was approved by the Navajo Nation in January 2006.

This agreement allows the owners of the Desert Rock Energy Project to use up to 4,500 af/yr of groundwater from an underground source and provide an additional 450 af/yr of water for municipal residential and livestock use.

The business site land lease for the power plant site (592 acres) has been developed and reviewed and approved by various appropriate divisions of the Navajo Nation. The lease/sublease was approved by the Navajo Nation Tribal Council on May 12, 2006. The President of the Navajo Nation signed the legislation on May 25, 2006. All parties to the lease/sublease (Navajo Nation, DPA, and Desert Rock Energy Company, LLC) signed the lease and sublease on May 25, 2006. Subsequently, the lease was presented to the BIA for approval.

Because the facilities of the Desert Rock Energy Project would be located on the Navajo Reservation, the project is subject to double taxation by the Navajo Nation and the State of New Mexico. The Navajo Nation Tax Department, working with DPA and Desert Rock Energy LLC, worked with an independent accounting firm to compare the tax costs on the Navajo Nation to tax costs in the four adjacent states. Desert Rock Energy LLC reached an agreement with the Navajo Tax Commission, and subsequently the Navajo Nation Council on May 12, 2006, that created a tax structure that generates tax revenues for the

Navajo Nation and still allows the plant to be competitive with other proposed plants that could be built off Navajo lands.

The total taxes paid by the project under the agreement are higher on average than taxes on a similar project located off the Navajo Nation in the four adjacent states. In general, the arrangement requires that the owners of the Desert Rock Energy Project pay the Navajo Nation the higher of a fixed amount that is escalated for inflation or a percentage of revenues during plant operations. A reduced tax amount during plant construction also was agreed to. The average yearly tax to the Navajo Nation is estimated to exceed $17 million per year over the 25-year term of the agreement if two 750-MW units would be constructed and operated. The average paid to the Navajo Nation under Alternative C would be $6.5 million per year.

In addition, the tax agreement requires that the basis of the tax be evaluated 15 and 20 years after the plant starts operations to ensure that the tax amounts are comparable to taxes that would be paid if the project was located off the Navajo Reservation. The tax agreement is included in the lease/sublease legislation that was approved by the Navajo Nation Tribal Council in May 2006.

A coal sales agreement is being developed between Desert Rock Energy LLC and BNCC. Currently, draft terms are being developed and negotiations are underway to develop a final agreement. The agreement would require that BNCC maintain approximately 90 to 120 days of coal reserves in the event there is a catastrophic equipment failure or protracted labor issues. The agreement will include payment of the taxes and coal royalties due the Navajo Nation on the coal consumed at the power plant. It is estimated that taxes and royalties would total approximately $26 million per year if two 750-MW units would be constructed. The estimated taxes and royalties for Alternative C would be $11.5 million per year. The coal supply agreement does not require approval by the Navajo Nation.

In summary, the key decisions by lead and cooperating agencies on this EIS that would be required for the implementation of the action alternatives would include:

- The proposed action for BIA is to approve, approve with conditions, or disapprove the long-term business site lease (i.e., land lease) between Desert Rock Energy LLC and the Navajo Nation for the 592 acres of land adjacent to the BNCC Lease Area. The land lease and right-of-way grants have been developed and reviewed and approved by various appropriate divisions of the Navajo Nation.
- The proposed action for the Navajo Nation is to approve the right-of-way for the power transmission line, water supply pipeline, and access roads and any other rights-of-way required for the generation and transmission of electricity on the Navajo Reservation.
- The proposed action for OSM is to approve, approve with conditions, or disapprove revisions to BNCC's current SMCRA permit application to allow development of coal processing facilities, conveyance systems, and infrastructure in Area IV North of the BNCC Lease Area; and, to approve, approve with conditions, or disapprove a future SMCRA permit application to allow coal mining, CCB disposal, and reclamation activities in Area IV South and Area V of the BNCC Lease Area.
- The proposed action for the BLM is to approve, approve with conditions, or disapprove the mine plan for Areas IV South and V of the BNCC Lease Area.
- The proposed action for the USACE is to determine whether to issue permits required under the Clean Water Act, and if so, under what conditions.

- The proposed action for USEPA is to approve, approve with conditions, or disapprove the NPDES Section 402 permit.

2.4 ALTERNATIVES CONSIDERED BUT ELIMINATED FROM DETAILED STUDY IN THIS EIS

This section presents discussion of the evaluation of alternatives for assessment in this EIS. The Federal decisions on each element of the proposed project that are subject to the requirements of NEPA are detailed in Section 2.3 and Chapter 1. The determination of alternatives to be evaluated in this EIS involved the nature of each of the different elements of the proposed project, and the decision authority of each Federal agency and the Navajo Nation.

The fundamental criteria for determining the feasibility of alternatives during the initial screening of options included:

- The technical feasibility of constructing and operating the proposed project and acquiring necessary rights-of-way
- Cost feasibility, including environmental costs relating to the potential impacts and potential mitigation and construction costs
- The ability to acquire all regulatory permits
- The ability to meet the purpose and need, including providing sufficient electric power reliability for southwestern utilities and the use of Navajo coal for economic development

The DPA was established by the Navajo Nation to develop coal-fired mine-mouth energy generating facilities. Since DPA's inception, several different proposed facilities and potential sites have been considered. Because the DPA was established on behalf of the Navajo people, the consideration of potential project impacts on tribal members were taken into account during the evaluation of each proposed facility and each potential site. In addition, the long-term economic viability of the project was an important consideration to ensure continued revenue from coal sales and continued employment. As a result of these considerations, the Navajo Nation selected the Desert Rock Energy LLC project proposal, selected the proposed project site, and negotiated agreements on the leasing of water rights and additional.

Table 2-5 summarizes the outcomes of the evaluation process for alternatives that was conducted for this EIS.

Table 2-5 Alternatives Screening Process

Alternative	Preliminary Alternative Development: Technically Feasible to Build	Preliminary Alternative Development: Economically Feasible to Build (Commercially Viable)	Preliminary Alternative Development: Meets the Purpose and Need for the Project[1]	Further Consideration of Remaining Alternatives: Avoids Environmental Impacts[2]	Further Consideration of Remaining Alternatives: Reflects Public and Agency Input[3]	Further Consideration of Remaining Alternatives: Cost-Effectiveness	Further Consideration of Remaining Alternatives: Carried Forward Based on Input from Navajo Nation	Alternatives Carried Forward for Detailed Study in the EIS
ALTERNATIVE TECHNOLOGIES								
Alternative Sizing								
Single Unit (550-750 MW)	✓	✓	✓		✓			Included in Alternative C
Double Unit (up to 1500 MW)	✓	✓	✓		✓	✓	✓	Included in Alternative B
Alternative Coal Combustion Technologies								
Super Critical Boiler	✓	✓	✓			✓	✓	Included in Alternatives B and C
IGCC	✓		✓					
Circulating Fluidized Bed	✓	✓	✓					
Alternative Fuels								
Coal	✓	✓	✓			✓	✓	Included in Alternatives B and C
Natural Gas	✓							
Solar and Wind Energy	✓							
Alternative Water Cooling Technologies								
Wet	✓	✓	✓					
Dry	✓	✓	✓	✓	✓	✓	✓	Included in Alternatives B and C
	Grant of Water Expected in Reasonable Time Frame	Adequate Water Is Available for Project	Meets Purpose and Need for the Project	Avoids Environmental Impacts[2]	Reflects Public and Agency Input[3]	Cost-Effectiveness	Carried Forward Based on Input from Navajo Nation	
ALTERNATIVE WATER SOURCES								
Surface Water - San Juan River (new direct flows)								
Surface Water - NIIP		✓	✓					
Surface Water - San Juan River (existing rights)	✓							
Groundwater - Well Field Area A	✓	✓	✓					Included in Alternatives B and C
Groundwater - Well Field Area B	✓	✓	✓		✓		✓	Included in Alternatives B and C
	In Proximity to Sufficient Coal Reserves	In Proximity to Adequate Water Supply	On the Navajo Reservation	Avoids Environmental Impacts[2]	Reflects Public and Agency Input[3]	Cost-Effectiveness	Carried Forward Based on Input from Navajo Nation	
ALTERNATIVE POWER PLANT SITES								
Black Mesa Plateau			✓					
Kolob and Kapairowits Plateau	✓		✓					
BNCC Lease Area	✓	✓	✓					
NAPI Site	✓	✓	✓					
Consol Site	✓	✓	✓					
Proposed Site	✓	✓	✓	✓	✓	✓	✓	Included in Alternatives B and C
				Avoids Environmental Impacts[2]	Reflects Public and Agency Input[3]	Cost-Effectiveness	Carried Forward Based on Input from Navajo Nation	
ALTERNATIVE INFRASTRUCTURE LOCATIONS[4]								
Alternative Access Roads								
491 - North Alignment								
491 - South Alignment								
Burnham Road - East Chaco River								
Burnham Road - West Chaco River								
Alignment through the BNCC Lease Area				✓		✓		Included in Alternatives B and C
Alternative Transmission Line Corridors								
Segment A						✓	✓	Included in Alternatives B and C
Segment B				✓			✓	Included in Alternatives B and C
Segment C				✓			✓	Included in Alternatives B and C
Segment D				✓				Included in Alternatives B and C
Segment D - Sub Alternative A West								
Segment D - Sub Alternative B Central								
Segment D - Sub Alternative C Shiprock								

[1] The purpose and need for the project include to support Navajo economic development goals, meet bulk power demands in southwestern U.S., and provide a stable power supply. (See Chapter 1 of the Draft EIS for more information.)

[2] For the purposes of this screening, generally defined as lower water requirements or more distant from existing communities. For infrastructure locations, co-location with existing facilities also was considered a positive attribute.

[3] Key scoping issues included potential effects of air emissions, leveraging resources to create economic development opportunities on the Navajo Nation, and water use. (See Chapter 1 of the Draft EIS or the Scoping Summary Report for more information.)

[4] These alternatives were not considered until the location and type of energy project were determined.

2.4.1 Alternative Coal Combustion Technologies

A variety of technologies were considered as part of studies for other coal-fired plants. Table 2-6 provides a summary of the cost considerations that was prepared for an alternatives analysis for the Mohave Generating Station.

Table 2-6 Technology Option Comparison

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

SOURCE: Sargent & Lundy et al. 2006.
NOTES:
(1) Capital costs shown do not include the costs of direct transmission access of 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) Total operating costs = variable operating costs + (fixed operating costs/kW-yr) * (1 yr/8,760 hr) * (1/assumed capacity factor) * (1,000 kW/MW)

2.4.1.1 Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC) is a developing coal technology that offers the potential for improved environmental performance and high efficiency. Proponents of IGCC point to low air-pollutant emissions, less solid waste, and reduced water consumption when compared to specific examples of direct coal combustion technologies. Although carbon dioxide (CO_2) capture is not currently proven technology or required by law, the ability of IGCC to provide for easier CO_2 capture than direct coal-combustion technologies may be an advantage in the future. In addition, the potential to co-produce hydrogen adds the potential to produce a clean transportation fuel. Comparisons between IGCC and direct coal-combustion technologies are affected by fuel composition, assumed air-pollution-control methods and performance, site elevation, cooling technology, and other factors. For example, IGCC heat rates increase as the ash content of the coal increases. High ash concentrations in some coals also create operating and maintenance issues that would negate the use of IGCC.

Currently, there are only four operating, coal-based IGCCs in the United States for power generation. Two of these are demonstration plants that are single-train systems consisting of one gasification process, one gas cleanup process, one combustion turbine, and one steam turbine. The demonstration plants, which are all partially supported by government and research funding, have net capacities of 250 MW (Tampa Electric Polk Power Plant in Florida) and 262 MW (Wabash River Plant in Indiana). Recently, the Polk

Power Plant has been operating on a 55 percent petroleum coke/45 percent coal feed and the Wabash plant has operated on 100 percent petroleum coke since the DOE demonstration program ended in 2000 (Holt 2004). Petroleum coke is less expensive than coal and offers better IGCC performance and reliability due to low ash and high heating value. In late 2004, the Wabash River Plant was reported as not operating due to business reasons (Holt 2004).

IGCC is not an inherently low-emitting or pollution-free process. Emission levels of existing IGCC plants as well as "qualifying advanced coal projects" (as defined by the Energy Policy Act of 2005) are not in total lower than proposed emission rates for the Desert Rock Energy Project, as shown in Table 2-7.

Table 2-7 Comparison of Emission Levels for Coal Combustion Technologies

	Existing IGCC	Advanced Coal Projects	Desert Rock Energy Project (Alternative B)
Removal Percentage of SO_2	98.0%	99.0%	98.0%
NOx Emissions(lb/MMBtu)	0.07	0.07	0.06
PM_{10} Emissions (lb/MMBtu)	0.015	0.015	0.01
Mercury Removal Percentage	90.0%	90.0%	80-90%

Figure 2-6 is a graphic representation of the data presented in Table 2-7.

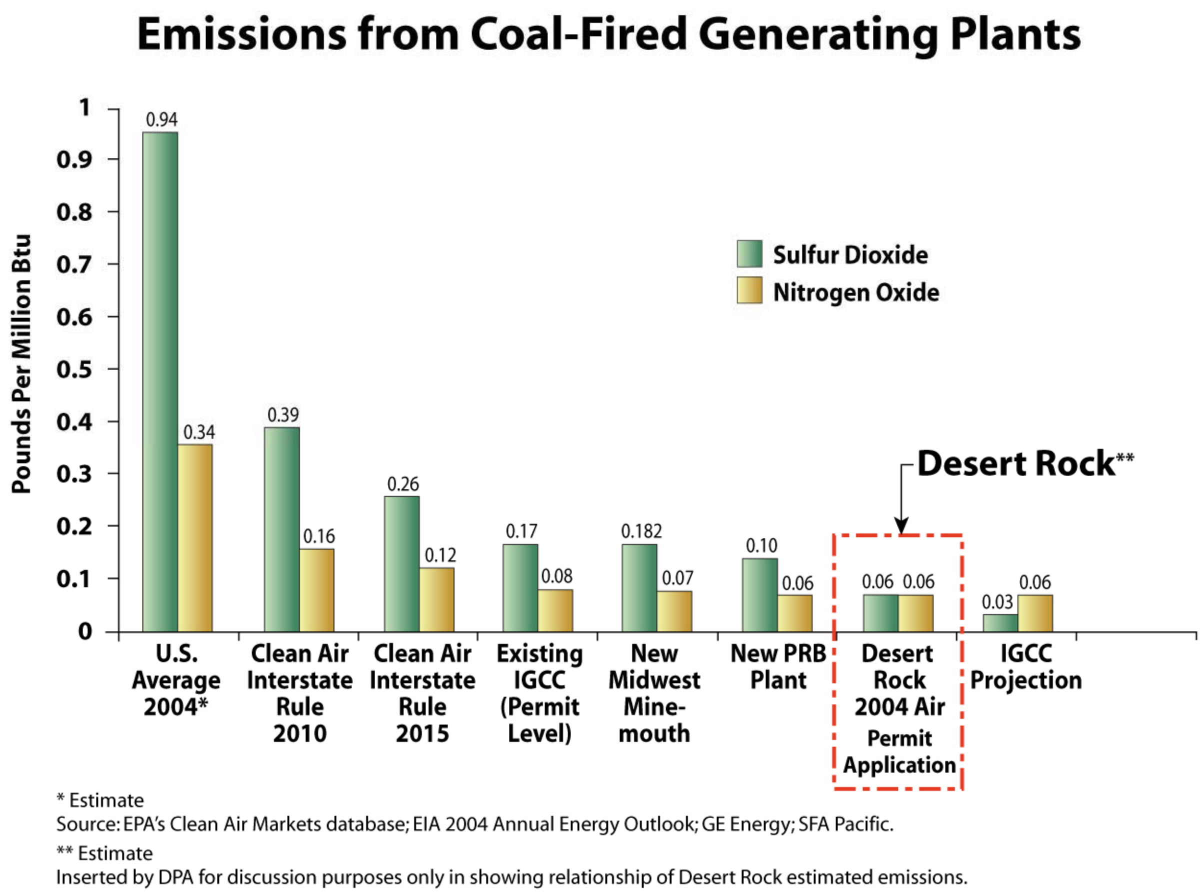


Figure 2-6 Emissions from Coal-Fired Generating Plants

IGCC plants require a series of chemical processes are required to remove sulfur from the syngas and control sulfur dioxide (SO_2) emissions. Sulfur removal typically begins with a carbonyl sulfide hydrolysis unit to convert carbonyl sulfide to hydrogen sulfide (H_2S). This is followed by either acid gas removal processes based on aqueous dimethyldiethanolamine or the Selexol process, which uses mixtures of dimethyl ethers and polyethylene glycol. A Claus sulfur plant is required to process sulfur-containing compounds collected by the acid gas removal or Selexol process. Finally, for high sulfur removal, a Claus tail-gas treating process is required. Using these processes, it is possible for an IGCC plant to achieve high SO_2 control efficiencies. The Polk Power Plant has operated at more than 97 percent SO_2 control while the Wabash River Plant has demonstrated 99 percent SO_2 control (DOE 2004, 2002). The SO_2 control efficiency of the proposed Desert Rock Energy Project would have a removal rate of approximately 98 percent.

Both the Wabash River Plant and Polk Power Plant have operated at nitrogen oxide (NO_x) emission rates of approximately 0.15 pounds per million British thermal units (lb/MMBtu) or 2.5 times the proposed Desert Rock Energy Project emission of 0.06 lbs/MMBtu. In July 2003, the permit limit for the Wabash River Plant was reduced to 15 (ppmvd) at 15 percent (O_2), which is approximately 0.07 lb/MMBtu based on coal feed, which is 17 percent higher than the Desert Rock Energy Project emission rate. This revision to the Wabash River Plant emission rate was reported to represent a major challenge because neither selective catalytic reduction nor dry low NO_x combustion can be applied to syngas fired turbines (DOE 2002).

An evaluation of the IGCC option for the Desert Rock Energy Project reached the following conclusions:

- IGCC plants can achieve particulate matter (filterable only) and Volatile Organic Compounds (VOC) emission rates similar to the emission rates proposed for the Desert Rock Energy Project.
- CO emission rates proposed for IGCC projects are approximately 40 to 50 percent of the emission rate proposed for the Desert Rock Energy Project. However, the benefits of lower CO emissions are insignificant because ambient impacts are insignificant and CO is converted to CO_2 in the atmosphere within about 30 days.
- IGCC plants can achieve lower mercury emission rates than required for the proposed Desert Rock Energy Project but the difference may be small. IGCC plants are eligible to qualify to receive tax credits as a “qualifying advanced coal project” if they meet other criteria and achieve 90 percent mercury control. Desert Rock will achieve a minimum mercury control of 80 percent and may achieve actual control of greater than 90 percent.
- The heat rate for an IGCC plant would be adversely affected by fuel composition. The heat rate for an IGCC plant is estimated as 9,775 Btu per kilowatt hour (Btu/kWh) while the estimated heat rate for Desert Rock Energy Project is 8,792 Btu/kWh (net, higher heating value basis). This increase in heat rate will result in an IGCC plant at the Desert Rock site having higher fuel consumption and greater generation of green house gases such as $SO_{2.}$
- IGCC plants do not have the same economies of scale as the planned supercritical boilers. The Desert Rock Energy Project would consist of two 750-MW (gross) trains with each train including a single boiler, an air-pollution-control system, and a steam-turbine generator. An IGCC plant capable of achieving the same power output would consist of 3 trains with each train including 2 air-separation units, 4 gasifiers (one is a spare), 2 gas cleanup systems, 2 GE FA or better gas turbines with HRSGs, and a steam turbine. In addition, some arrangement for an additional GE7 FA and HRSG would be needed for an IGCC to achieve the required power output at the site elevation of 5,415 feet since s gas turbines loose generation capacity at high elevation projects sites due to reduced air – oxygen density. In total, an IGCC plant would require

6 air-separation units, 12 gasifiers, 6 gas-cleanup systems, 7 GE 7FA gas turbines with HRSGs, and 3 steam turbines.

- Capital costs for an IGCC plant would be affected by the Desert Rock Energy Project location. Capital costs for an IGCC plant, with spare gasifiers, would exceed the Desert Rock costs by $250/kW to $400/kW. This represents a capital cost increase of $350 million to $600 million or 17 to 28 percent. While the some of the cost difference may be reduced by incentives in Title XVII of the Energy Policy Act of 2005, the credits are limited to a maximum of $135.5 million to a single project and the amount of the credit can be reduced or eliminated depending on the actual allocation of the credits to a given project.
- The cost of electricity for an IGCC plant would be $3.5 per megawatt hour (MWh) to $6/MWh higher than the proposed Desert Rock Energy Project (this would total $35-60 million annually). As an SO_2-control method this cost increase is equivalent to $23,000 to $40,000 per ton of SO_2 controlled.
- IGCC plants have lower availability than supercritical pulverized-coal plants, especially in the early years of operation and they are more prevalent to incidents of forced outage as operations of the plants mature. The analysis presented in this study assumes that a spare gasifier for each IGCC train would mitigate this problem. However, there is no demonstrated experience showing that a spare gasifier would eliminate the reliability problems that have been experienced. Therefore, there may be additional costs associated with lost electricity production and/or a need for a firm natural-gas supply. These potential additional costs have not been quantified.
- The technological risk of building an IGCC plant might make the plant less desirable to utility investors and power purchasers. The increased risk also would increase financing costs, as lenders would want more equity and higher maintenance and debt coverage reserves. These factors would increase the total capital cost.
- Should it ever be technically viable, CO_2 capture in an IGCC plant would increase the heat rate by 20 to 30 percent, increase the capital cost by an additional $550/kW, and increase the cost of electricity by an additional 35 to 47 percent.
- IGCC is not a commercially viable option for the Desert Rock Energy Project.

An IGCC project would not result in lower overall emissions; the project would be less efficient, burn more fuel and generate greater amounts of greenhouse gases; the project would be much higher cost and would entail substantial technological risk that would make the plant unattractive to power purchasers and investors. For these reasons, and the technical and economic feasibility factors discussed above, the BIA determined this was not a reasonable alternative and it was eliminated from detailed evaluation.

2.4.1.2 Circulating Fluidized Bed

Circulating Fluidized Bed (CFB) combustion power plants, subcritical pulverized-coal power plants, and supercritical pulverized-coal plants are being proposed and built in the United States. The technology choice depends on many factors including the size of the project, the types of fuel that would be burned, fuel properties, plant location, and local solid-waste and water issues. In addition, the technology choice is affected by the developer's or utility's experience with the technology and their perception of technological risk and maintenance issues as well as future fuel costs and electricity prices.

There are several key differences between a CFB plant and a supercritical pulverized-coal plant. The maximum size of a CFB boiler is currently 300 MW net while pulverized-coal units can be as large as 1,200 MW net. For large plants, the need for multiple CFB units adversely impacts the capital cost.

Currently, all CFB plants in operation are subcritical units with significantly higher heat rates and lower efficiencies when compared to supercritical pulverized-coal units. A supercritical CFB plant is planned for construction in Poland; however, there is no demonstrated experience with supercritical CFB plants. In comparison, there are hundreds of supercritical pulverized-coal plants with long operating histories. In some areas of the United States, the ability of CFB plants to provide fuel flexibility and the ability to burn fuels with high sulfur and metal content and low volatility such as petroleum coke, waste coal, and biomass is important.

The following conclusions were reached by the applicants in considering the application of this technology to the Desert Rock Energy Project:

- Five or six CFB units would be required instead of two supercritical pulverized-coal units to achieve the planned Desert Rock Energy Project power output. The loss of economy-of-scale would significantly increase the capital and operational costs of a CFB plant.
- On a lb/MMBtu basis, most emissions from a CFB plant would be similar to the proposed Desert Rock Energy Project supercritical pulverized-coal power plant.
- The heat rate for a CFB plant would be about 9,950 British thermal units per kilowatt hour (Btu/kWh) while the heat rate for the Desert Rock Energy Project would be 8,792 Btu/kWh (net, higher heating value basis). For the same net electricity production and emission rates, a CFB plant would generate 11 percent more emissions than the proposed Desert Rock Energy Project, including CO_2 emissions.
- On an annual tons-per-year basis, all emissions from a CFB plant would be higher than the proposed Desert Rock Energy Project supercritical pulverized-coal power plant due to the higher heat rate.

CFB would be associated with higher project costs and annual emission rates. Based on these considerations and the technical and economic feasibility factors discussed above, the BIA determined this was not a reasonable alternative and it was eliminated from detailed evaluation.

2.4.2 Alternative Fuel Sources

2.4.2.1 Renewable Energy Sources: Solar and Wind

Solar energy is a renewable energy generated through the use of photovoltaic cells (or “solar cells”) that convert sunlight into direct-current electricity by the interaction of photons and electrons with a semiconductor material. This electricity is best used directly and/or fed into an electric-power grid system. When sunlight is not available and the photovoltaic modules cannot generate electricity, battery energy storage is needed in order to meet the demands of supplying energy on a 24-hour, 7-days-per-week basis. While shown to be an effective technology for many uses, the majority of these uses are small in scale compared to the projected power needs that would be met by the proposed Desert Rock Energy Project. A number of utility companies and private developers are investigating large-scale photovoltaic power plants (which consist of many photovoltaic arrays installed together requiring sizeable parcels of land). Although the costs are decreasing with advances in technology, photovoltaic power generation still costs much more than electricity generated by conventional power plants.

Another technology that utilizes solar energy is the parabolic trough. It is constructed as a long parabolic mirror (usually coated silver or polished aluminum) with a tube running its length at the focal point. Sunlight is reflected by the mirror and concentrated on the tube. The trough is aligned on a north-south axis, and rotated to track the sun east-to-west. Heat transfer fluid (usually oil) runs through the tube to absorb the concentrated sunlight. The heat transfer fluid can be used to heat water before it goes to the boiler in the same function as the boiler economizer. An economizer uses flue gas from the exhaust of the boiler to heat boiler feed water before it enters the boiler. This function increases the efficiency of the power plant. The energy required to replace the economizer of the proposed 1,500 MW plant would require a solar system that would need approximately 250 acres of land and an estimated equipment cost of $160 million, which does not include water pumping costs and power required to circulate the water from the plant through the solar thermal system and back to the plant. The typical availability of solar energy is about 30 percent in the proposed project area (Sargent & Lundy et al, 2006). Given this, the power plant would require a standard economizer on the boilers to operate when the solar energy is not available. During times of solar heating the flue gas energy that would otherwise be used to heat feed water in the boiler is wasted into the atmosphere as flue gas exhaust, and the net power output of the plant would be reduced due to the additional power load required to operate water pumps for the solar thermal system. There would be no cost savings by adding the solar system, since the economizer section of the boiler is required as back-up. The parabolic trough requires flat land in an east-to-west direction for each row of mirrors in the 250-acre site, necessitating substantial earthwork. The cost of the solar system would increase the cost of the project by almost 10 percent and during operation the net output of the plant would be reduced, diminishing the commercial viability of the project. A solar thermal-coal hybrid plant would use solar-thermal arrays for pre-heating steam at coal-fired power plants. This alternative was evaluated and determined to be economically unviable.

Wind energy is produced by wind turbines converting wind flow into mechanical power. This mechanical power can then be used for specific tasks (e.g., pumping water) or by a generator that converts this energy into electricity for various uses. Turbines are available in a variety of sizes and ratings. Wind turbines used to generate bulk electricity are often grouped into a single wind power plant, or “wind farm.” Electricity from these farms is fed into the power grid and distributed to customers just as it is with conventional power plants. However, wind energy generation requires a reasonably strong, steady, and predictable wind source, and wind farms require sizeable parcels of land.

One of the factors that currently restrict wind energy development in the western U.S. is a lack of transmission to move power from distant wind resources to load centers. The cost of the necessary transmission upgrades in combination with the low load factor and typically small size associated with wind energy generation often makes the wind resources uneconomic. The transmission upgrades associated with new coal facilities such as the proposed project can produce excess transmission capacity that may be available for wind projects. One of the transmission options being considered for the Desert Rock Energy Project would utilize the proposed Navajo Transmission Project (NTP), which is anticipated to have a capacity approximately 10 percent higher than the needs of the Desert Rock Energy Project. DPA is currently actively working to identify commercial quality wind sites on the Navajo Reservation and to commercially develop these resources.

While solar and wind sources are highly desirable as renewable, environmentally friendly energy sources, these sources are intermittent and cannot be relied upon entirely for a constant source of bulk power. The technology for renewable energy sources is still developing and does not yet provide viable options for large-scale use. For example, a single photovoltaic cell generates 0.8 watts of energy for every 25 square inches. Therefore, 1,500 MW of capacity would require 7,500 acres of photovoltaic surface area, plus space for energy-collecting infrastructure and support systems. Because a solar system would produce energy at less than a 30 percent capacity factor and a coal plant operates at near a 90 percent capacity factor, to generate 1,500 MW would require up to 22,500 acres.

Although solar and wind renewable energies are technically feasible to build and would have fewer air emissions, the land and cost requirements were determined to be impractical to generate a reliable bulk power supply that would meet the purpose and need for the project. The BIA has determined that the use of alternative energy sources would not meet the purpose and need for the project (i.e., the economic development though sale of Navajo Nation coal resources) or were otherwise unfeasible. Therefore, the BIA determined this was not a reasonable alternative and it was eliminated from detailed evaluation.

2.4.2.2 Natural Gas-Fired Plants

According to the Western Electricity Coordinating Council, over 80 percent of planned resource additions for the period 2005-2014 will be natural gas (WECC 2005). The Desert Rock Energy Project and other proposed coal-fired projects currently being permitted in the Southwest would increase fuel diversity by reducing the need for new natural gas resources. Natural gas prices have increased substantially over the last three years and prices have been volatile. In addition, sites on the Navajo Nation are generally less attractive for the development of a natural gas-fired plant due to distance from load and high elevations.

Natural gas was eliminated as an alternative fuel source for the proposed Desert Rock Energy Project because the lack of fuel diversity and associated price volatility would diminish the commercial viability of the project. Navajo coal sold under long-term contract would be expected to cost 70 percent less than natural gas, largely because of reduced price volatility due to the long-term contract. In addition, the use of natural gas would not meet the purpose and need of the project to leverage Navajo coal resources for economic development opportunities. A substantial portion of the employment and economic benefits of the Desert Rock Energy Project would be directly associated with the mining activities and the associated taxes and royalties from the use of Navajo coal.

The BIA has determined that the use of natural gas as the fuel for the proposed generating facility would not meet the purpose and need for the project (i.e., the economic development though sale of Navajo Nation coal resources). Therefore, the BIA eliminated this alternative from detailed evaluation.

2.4.3 <u>Alternative Water Cooling Technologies and Water Sources</u>

2.4.3.1 Water Cooling Technologies

Wet cooling and dry-cooling options have both been considered as reasonable options for the Desert Rock Energy Project. The primary advantage of a dry-cooling system is that it would require less water, which would respond to the concerns of the Navajo Nation and the public at large regarding the adequacy and value of water supplies in the area.

Currently, the region is in a drought and there is widespread concern over water use and potential shortages of surface water. For a 1,500 MW plant, wet cooling would require about 26,000 to 28,000 af/yr of water; dry cooling would use approximately 4,500 af/yr. In addition, a wet-cooling system would require water storage facilities and would produce 2,744 af/yr of water discharge. The following summarizes the rationale for developing dry cooling water technologies as part of the proposed project:

- Water consumption would be reduced by over 80 percent;
- The project would be more environmentally compatible with a drought-stricken region;
- Dry cooling would eliminate the need for waste water discharge;

- The cost to add dry cooling would be offset by reduced water supply infrastructure costs and lower annual operating costs;
- The large amount of land needed (an additional 390 acres) for water storage and evaporation ponds of was eliminated;
- Water purchase costs were reduced and the long-term supply and price risk of the water supply was reduced;
- Reliability concerns that in drought conditions, imposed shortage sharing of surface water sources could affect plant operations; and
- The use of wet-cooling technology would have eliminated groundwater as an alternative water source, as groundwater development and pumping costs to meet water requirements (up to 28,000 af/yr) would not be economic or environmentally viable.

The use of wet cooling was considered, where cooling water would be transported to the project from the Navajo Indian Irrigation Project (NIIP). The use of the NIIP system for the delivery of cooling water would provide the following benefits to NIIP and the Navajo Nation:

- Converting NIIP to year-round operations or adding storage in Block 3 to meet the needs or the delivery of cooling water would be beneficial to the NIIP system, by improving reliability and reducing delivery times.
- NIIP diverts about 1.5 acre-feet from the Navajo Reservoir for every acre-foot it depletes. The proposed project would deplete about one acre-foot for every acre-foot it diverts from the reservoir. This difference would result in improved water supply at Navajo Reservoir.
- Fees paid by the project proponents for use of the water would provide operation and maintenance resources for the NIIP Canal.
- Wet cooling would provide additional revenue to the Navajo Nation from additional water sales.

Wet cooling has lower capital costs and higher production efficiency than dry cooling. However, wet cooling would have higher water and infrastructure costs. Wet cooling would require a surface water source which, as described in Section 2.4.3.2 below, would not provide reliable or viable options for the project. Therefore, the BIA determined wet cooling was not a reasonable alternative and it was eliminated from detailed evaluation.

2.4.3.2 Surface Water Versus Groundwater Alternative Sources

Surface water was considered for use by the proposed project and eliminated from detailed consideration primarily because the Navajo Nation could not provide assurance that a grant of surface water rights could be made in the time frame needed to meet the project's schedule. Three different surface water alternatives were considered:

- Use of new direct flows from the San Juan River
- Conversion of NIIP Navajo Dam contract water to industrial use
- Acquisition of water rights from existing holders of San Juan River water rights

The San Juan River direct flow option was determined to be not viable because it was not clear that any new surface water right could be granted in the time frame needed for the applicants to make a decision to proceed with the project. The conversion of NIIP water to industrial use would also require Congressional approval.

Again, it is not clear that the Congressional authorization to convert the NIIP water contract to industrial use would occur in the timeframe necessary needed for the applicants to make a decision to proceed with the project. Also, concern was expressed that the conversion of NIIP water to industrial use would impact Navajo Agricultural Products Industry (NAPI) operations.

While short-term water rights appeared to be available from the third option, long-term rights that could meet the project's need were not identified as available for purchase. This option also would be associated with water-supply delivery risk in time of drought. The BIA determined that surface water sources would not provide a viable alternative and they were eliminated from detailed evaluation.

2.4.4 Alternative Power Plant Sites

Prior to the submission of the proposed project to the BIA, the proponents (DPA and Desert Rock Energy LLC) evaluated several different potential locations for the proposed power plant. This evaluation, while not part of the formal NEPA consideration of alternatives, did serve as a source of information concerning the feasibility of several alternative locations. Some of the additional criteria used by the applicants in their evaluation process were based largely on natural resource requirements, and included: (1) locations with sufficient coal reserves or in proximity to coal reserves to minimize the distance required for transporting the coal to the power-generation facility, (2) locations with adequate source of water nearby, and (3), as part of the development agreement with DPA, locations within the boundaries of the Navajo Reservation. Coal fields meeting these criteria include the Black Mesa Coal Field in northern Arizona, the Kolob and Kaiparowits Plateau Fields in southern Utah, and fields within the San Juan Basin (BNCC Lease Area and the closed Consolidation Coal Company [Consol] mine in Burnham Chapter, both in northwestern New Mexico). Considerations for site evaluations included capital costs to build facilities, operation costs (such as costs for fuel and water supply), and anticipated impacts on communities.

The Black Mesa Coal Field was eliminated from consideration because the majority of the economically recoverable coal reserves are already leased to a major coal producer and the coal is dedicated under two long-term contracts for deliveries to the Navajo Generating Station in Page, Arizona, and the Mohave Generating Station in Laughlin, Nevada. While the Kolob and Kaiparowits Plateau Fields contain adequate reserves of coal for the Desert Rock Energy Project, the recoverable coal would have to be mined underground, and the estimated, delivered-coal costs would be excessive and not economically feasible for the Desert Rock Energy Project. For this reason, these coal fields were eliminated from further consideration as sources for coal. The BNCC Lease Area coal field in northwestern New Mexico offers large quantities of coal that can be produced by surface mining methods at economical costs. The closed Consol mine in Burnham, located just north of Burnham Chapter House and south of the BNCC mine, could provide adequate coal. However, it is anticipated that the Consol mine would be associated with greater environmental impacts and capital and operating costs relative to the BNCC Lease Area, since it would entail the opening of a new mine instead of the expansion of an existing mine.

Adequate quantities of water must be accessible from a feasible location for the Desert Rock Energy Project. The only sources of surface water near enough to any one of these mines sufficient to support the Desert Rock Energy Project, would be limited to the Navajo Reservoir and Lake Powell. Sources of groundwater suitable for the Desert Rock Energy Project in proximity to these fields also are limited. There is also local concern in the Black Mesa Mine area over the existing use of groundwater associated with mining and coal slurry transport. However, water suitable for the proposed project is available from the Morrison aquifer at the proposed project site, at a depth of 5,000 to 6,000 feet.

Three potential power plant sites surrounding the BNCC Lease Area were studied for the Desert Rock Energy Project (see Figure 2-7), including the proposed project site. The following sections describe each of the three plant sites and the results of an evaluation of each alternative.

2.4.4.1 NAPI Plant Site

The NAPI plant site is located at the northeast corner of Area III of the BNCC Lease Area on NAPI farmland. The NAPI plant site was recommended for consideration by the Navajo Nation and DPA to enable access to potential future, expanded NIIP water canals and infrastructure. Access to the NIIP canals and infrastructure would be an important consideration for a wet-cooled plant, with its higher water requirements. The positive aspect of this site was its being on flat land and ease of access from Farmington, New Mexico. The negative aspect of this location is that it is farther from the fuel source (Area IV South and Area V of the BNCC Lease Area) than other site options.

The NAPI plant site would be situated on what is now three or four agricultural crop circles. At 5,600 feet elevation, the area is very flat with no escarpments or cuestas and eroded knobs. The NAPI farmland has a series of canals that extend throughout the area. None of these canals would be affected by siting the Desert Rock Energy Project in this location.

The site is located along BIA Road 5082 and in proximity to three or four active home sites and four Navajo Nation housing developments. These housing developments include Ojo Amarillo, Fort Defiance Housing development, Bluffview Village, Sky Mesa View, and a Region 2 housing Development. It is 19 miles from Farmington; a plant at this site would be more visible from Farmington than the Four Corners and San Juan Power Plants, due to its hilltop location. There would be greater visibility of the project structures from Farmington than if constructed in the proposed project site. Also, the NAPI plant site is close to businesses and communities and would have a greater visual impact in an area frequented by agricultural workers and local residents.

The Desert Rock Energy Project would employ about 200 people to operate and maintain the power plant. It is assumed that most of the plant employees will live in the Farmington, NM or Shiprock, NM communities. Farmington, NM is utilized as the base case for commuting estimates. The round–trip commuting distance for the NAPI plant site from Farmington is 50 miles. Costs to operate and maintain an employees' automobile is estimated at $0.485/mile (Internal Revenue Service 2006), therefore the estimated costs for one year of the roundtrip commute would be $4,656 for one person or $698,400 for all 200 employees. This assumes 25 percent of the employees commute with one other employee and work 4 days per week, 48 weeks each year.

Use of the NIIP infrastructure to provide water was eliminated primarily because of the uncertainty of the Navajo Nation's ability to provide assurance that a grant of surface water rights could be made within the time frame needed to meet the project's schedule. The Morrison Formation was selected as the target aquifer for this alternative because: (1) it has a relatively higher water-bearing potential than the overlying formations in the study area, and (2) withdrawal of groundwater from the Morrison Formation is anticipated to minimize drawdown to existing wells in the area. The estimated cost to source water from the Morrison aquifer at this site is estimated to be between $62 million and $93 million for infrastructure with an annual operating cost for 20 to 30 wells near the project site of between $480,000 and $720,000.

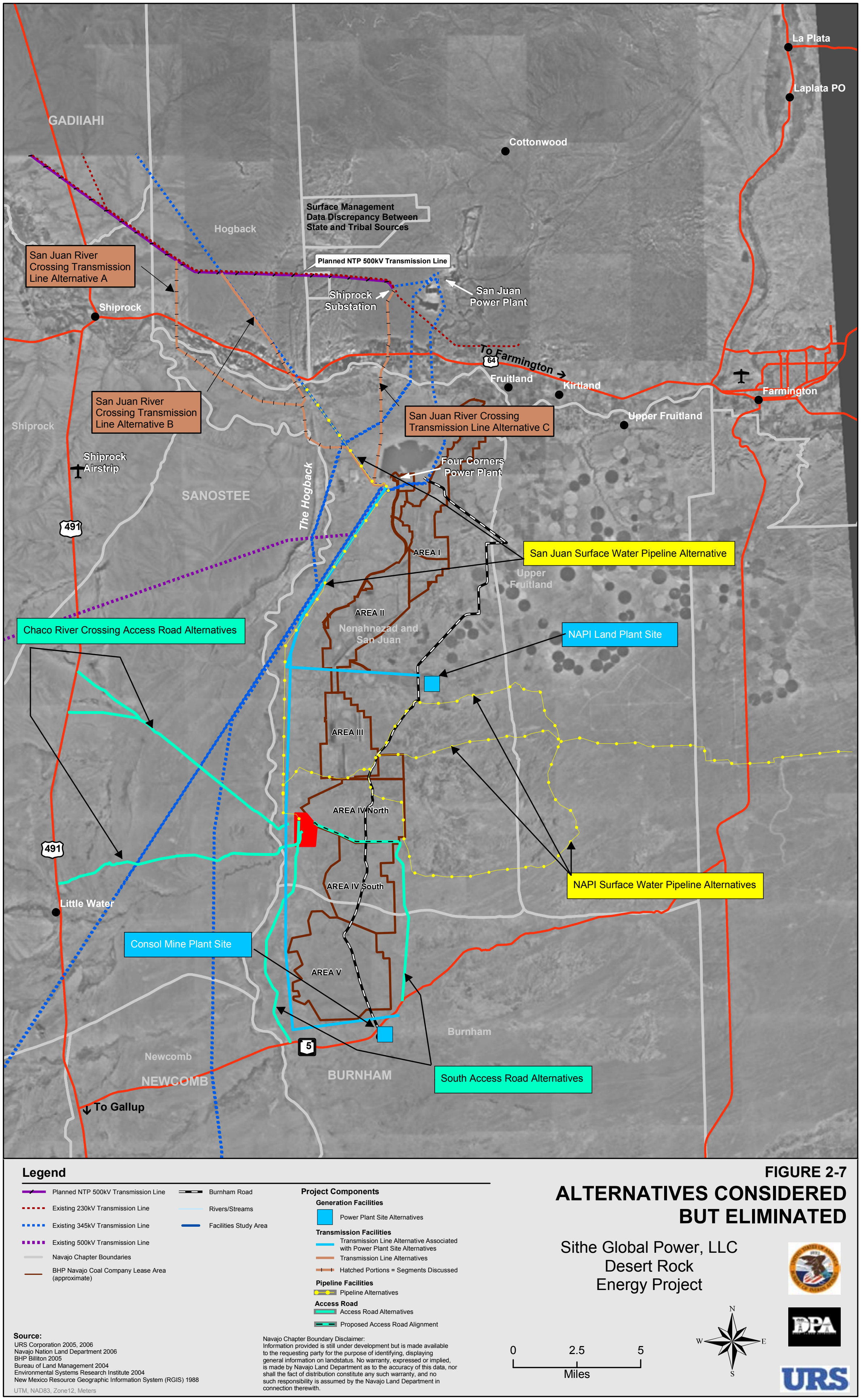


FIGURE 2-7
ALTERNATIVES CONSIDERED BUT ELIMINATED

The coal fuel supply would be transported by conveyor or rail to a coal preparation facility. Coal would be crushed and blended to the desired specification for delivery to the power plant via a delivery conveyor. Coal would be moved from Area IV South BNCC mine, a distance of 12 miles, for an estimated cost for overland conveyor equipment of $38,400,000. If a conveyor system is not practical because of the length of the conveyor, a rail system would be required to move coal from the Area IV South BNCC mine to the plant site on a route that traverses the west side of the BNCC mine then east into the NAPI farmland. This route would require 12 miles of track with a fork at each end allowing two shuttles each containing a row of engines and hoppers. The estimated cost to build this rail and procure the engines and hoppers is $78,607,000, a considerable cost increase compared to a conveyor system.

The location of this site would require a route that takes the transmission line near agricultural activity and over the mining area of the BNCC mine. The estimated cost of two single-circuit transmission lines and supporting structures is $56,680,000.

The NAPI plant site's proximity to population centers along the San Juan River and existing pollutant sources (such as the Four Corners and San Juan Power Plants) would serve to locate the plant in an area that already contains concentrations of pollutants from other sources. In addition, the location of the NAPI site (closer to residential uses and Farmington) would increase the possibility that that project would have impacts on local communities.

2.4.4.2 Consol Mine Plant Site

The Consol Mine plant site was chosen for evaluation because it would allow for easy transport of coal to the proposed project from a future coal mine. Consol tested the mine in the early 1990's, but shut down its operations and began to reclaim the abandoned mine in 1995. The mine could be opened by a new lessee. Indications are that there are coal reserves sufficient to fuel the Desert Rock Energy Project for its projected 50-year life. The site is one half mile north of the Burnham Chapter House and in proximity to about 240 residents. At 5,500 feet elevation, this site is located adjacent to land that is now reclaimed mine land. Navajo Road 5 runs along the north side of the site, and serves traffic from all areas. The visual impact of the project at this site would be apparent to the traffic on the Navajo Road 5 and nearby residents of the Burnham Chapter. During construction of the power plant and mine, dust from construction equipment and activities would greatly affect the activities of the Burnham Chapter and its residents. Also operations at the mine site would require that some residents be relocated to allow for extraction of coal, and to allow for the construction of access roads for operation of the power plant and mine.

At a round-trip distance of 76 miles from Farmington, the project is at an undesirable distance for commuting for employees of both the power plant and the mine. The annual estimated cost to maintain and operate employees' automobiles for this commute is $1,948,032 for all 200 power plant employees plus 200 mine employees. This assumes that 25 percent of the employees commute with one other employee and commute 4 days per week, 48 weeks each year.

The estimated cost to source water from the Morrison Aquifer at this site is $31 million to $61 million for infrastructure and $200,000 to $400,000 annual operating cost for 10 to 20 wells near the project site.

In this area, it would be necessary to use groundwater for mining operations, which would require about 600 af/yr. The estimated cost to develop, drill, and commission a well field to support the mining operation would cost $10,205,000. This capital cost includes 3 wells with pumps and ancillaries at $2,585,000 per well, equipment for the top side of the well at $150,000 per well and 2 miles of piping at $1,000,000 per mile. The estimated ongoing cost for the water and pumping would be $900,000 using a cost of $1,000 per acre feet of water and $300,000 a year for maintenance and operating costs for the pumping equipment and wells.

Coal would be moved from the mine at a distance of up to 2 miles at an estimated cost for overland conveyor equipment of $6,400,000 using a per mile cost of $1,200,000 for rollers, belt and motors; $1,000,000 for support structures; and $1,000,000 for engineering and civil work. The operating estimated cost for the conveyor would be $618,000 annually.

The transmission line would have 48 circuit miles, single-circuit 500 kV transmission lines and 190 self-supporting, four-legged, steel structures. The estimated cost to of the power transmission line is $104,640,000 at a cost of $2,180,000 per circuit mile for engineering, equipment, rights-of-way and construction.

Compared to the NAPI site, the Consol site is more distant from the Four Corners Power Plant, nearby communities, and some Navajo housing developments. However, the proximity of the Consol site to the Burnham Chapter suggests that those residents could be more subject to impacts from the project in this location.

2.4.4.3 Proposed Project Site

The proposed plant site was recommended by DPA and BNCC as a site that would be very close to the BNCC mine and as a site that BNCC was in the process of permitting for the Cottonwood Energy Project, a 550-MW, coal-fired plant. The site is remotely located 10 miles east of U.S. Highway 491 and 18 miles south of U.S. Highway 64. This distance allows for less than 4 miles of conveyor transport to the power plant. At 5,200 feet elevation, this site is located on land that has the topography of relatively flat to gently rolling hills that slope to the west toward the Chaco River. Like the Consol Mine plant site, the vegetation in this area can be characterized as over-grazed grasslands, mainly short-grass sod interspersed with bare areas.

Of the three sites evaluated, the proposed project site would be expected to have the least impact on nearby residents and agriculture, because of the site's relative distance from them. Its location on the west side of the existing BNCC mine would buffer the proposed project from NAPI agricultural activities and would preclude the need to construct major infrastructure facilities across the mine.

The commuting distance for the proposed project site is 64 miles round trip from Farmington. This site places the plant 7 miles farther driving distance than the NAPI plant site. The estimated annual cost to operate and maintain employees' automobiles is $820,224 for all 200 employees. This assumes 25 percent of the employees commute with one other employee and work 4 days per week, 48 weeks each year.

The estimated cost to source water from the Morrison aquifer at this site is $31,000,000 to $61,000,000 for infrastructure and $200,000 to $400,000 annual operating cost for 10 to 20 wells near the project site.

Coal would be moved from Area IV South on a conveyor for a distance of approximately 3.5 miles. The estimated capital cost for overland conveyor equipment is $11,200,000 using a per mile cost of $1,200,000 for rollers, belt and motors; $1,000,000 for support structures; and $1,000,000 for engineering and civil work. The estimated operating cost for the conveyor would be $1,082,000 annually.

The proposed transmission corridor for this site would go west from the plant site to the Chaco River. It would then go northerly along the west side of the BNCC mine to the substation. This would require 29 circuit miles, single-circuit 500 kV transmission lines and 87 self-supporting, four-legged, steel structures. The estimated cost for the power transmission line is $63 million, at a cost of $2,180,000 per circuit mile for engineering, equipment, rights of way and construction.

The increased distance between this site and the San Juan River communities and Farmington would cause the visual impact of the power plant to be less severe, and may reduce or avoid other impacts on these communities as well. However, this site is located near the Hogback and is closer to the San Juan River communities than the Consol plant site.

2.4.4.4 Alternative Site Evaluation Summary

The selection of the NAPI plant site would be expected to result in the highest visual and local impacts on the San Juan River area, and would be associated with high water infrastructure costs. Construction on the NAPI site also would displace flat, fertile farmland. This site would provide the shortest commuting distance from Farmington for employees.

Activities on the Consol plant site would affect the nearby Burnham Chapter community. This site received little to no Chapter support. The selection of this site would result in higher costs for operating the mine, and the highest capital cost for all equipment. The advantages of the Consol site are its proximity to the coal mine and relatively lower cost for water.

The proposed site would have a median of the commuting distance among the alternatives, strong public support from the Nenahnezad Chapter and the Navajo Nation, farther distance from local communities, and lower cost for water infrastructure. Table 2- summarizes the conclusions of the evaluation of locations alternatives for the power plant site and associated infrastructure. A summary of the cost considerations for each site is provided in Table 2-8. BIA determined that the NAPI and Consol sites would not provide economically or technically viable options and they were eliminated from detailed evaluation.

Table 2-8: Estimate of Costs Associated with the Alternative Power Plant Sites

	Costs (in millions of dollars)		
	NAPI Site	**Consol Site**	**Proposed Site**
Employee commuting	.69	1.95	.82
Transportion (coal conveyor)	38.40	6.40	11.20 (1.08 annually)
Rail	78.61 (Option if coal conveyor is not viable)	0	0
Transmission	56.68	104.64	63.00
Water Supply			
Infrastructure	62 - 93	3 1- 61	31 - 61
Operating costs	.48 - .72	.20 - .40	.20 - .40
Totals	**158.25 (with coal conveyor) – 229.7 (with rail)**	**144.19 – 174.39**	**106.22 – 136.42**

2.4.5 <u>Alternative Utility Corridors</u>

A summary comparison of alternative utility corridors considered but eliminated is discussed below. Tables 2-9 and 2-10 and Figure 2-7 represent a summary of issues and concerns identified through the scoping process for the EIS and the potential compatibility of each alternative evaluated in a pair-wise (i.e., one alternative compared to its alternate) analysis.

In evaluating linear alternative locations, additional criteria to determine more desirable routes were established through agency participation and public input, including:

- Co-location with existing facilities or utility corridors where possible and to the extent practicable where doing so would not be detrimental to environmental and cultural factors.
- Co-location with existing infrastructure such as roads, trails, and developed rights-of-way.
- Locations or alignments that follow existing legal or jurisdictional boundaries where possible.
- Locations or alignments that would avoid sensitive or regulatory areas where possible, such as known habitat of threatened or endangered species, regulated water courses, known cultural or historical sites, and visual resources.
- Locations or alignments that would avoid the view shed of the most concentrated existing residential areas.

Table 2-9 Summary Evaluation of Siting Alternatives Considered but Eliminated

Alternative (see Figure 2-7)	Summary of Evaluation
Alternative Plant Sites	
NAPI Plant Site	This site was considered early in the evaluation of potential power plant sites, but was eliminated for a number of reasons. Costs associated with transportation of coal would be prohibitive, as a conveyor system may not be feasible and a rail line would need to be constructed. In addition, the 500kV power transmission line would bisect the BNCC Lease Area. It is also more likely that higher land use and visual impacts would occur in this more populated area of the San Juan Valley.
Consol Plant Site	This site was considered but eliminated from detailed study because it would require the development of a new coal mine in the heart of the Burnham Chapter. Higher visual and land use impacts would be likely to occur with the development of this alternative because of its location near existing communities, and the associated transmission line would be nearly twice as long as what is currently being proposed.
San Juan River Crossing Transmission Line Alternatives	
Alternative A	This alternative was eliminated from detailed study because it did not parallel any existing similar features and would have an adverse effect on views and viewers along the San Juan River. In addition, it was the longest alternative considered of the three crossings.
Alternative B	This alternative was eliminated from detailed study because it did not parallel an existing linear feature west of the Hogback, and therefore would have created a new utility corridor in an area in fairly pristine condition.
Alternative C	This alternative was eliminated from detailed study because it would affect more land uses and have a higher level of impact on views and viewers than the current proposed alignment.
Chaco River Access Road Alternatives	These alternative access roads were eliminated from detailed study because they would require a bridge to be constructed over a fairly pristine reach of the Chaco River. This reach of the Chaco River has been considered for designation as preserved open space by the local chapters within their land use plans.
South Access Road Alternatives	These alternatives were eliminated from detailed study based on steep terrain and high costs associated with their development.
San Juan Surface Water Pipeline Alternative	This surface water alternative was eliminated from detailed study because of the long-term, ongoing litigation surrounding water rights along the San Juan River.
NAPI Surface Water Pipeline Alternatives	This surface water alternative was eliminated from detailed study because of the potentially lengthy regulatory approval process that would be required for approving this water source for industrial use.

Table 2-10 Evaluation of Locational Alternatives

		NATURAL RESOURCES		HUMAN RESOURCES		PERMITTING	ENGINEERING	COSTS
		Surface Water Resources	Biotic Resources	Land Use and Recreation	Visual Resources			
Transmission Line Alternatives Crossing San Juan River	A	Yellow	Red	Green	Yellow	Yellow	Green	Red
	B	Green	Yellow	Yellow	Yellow	Green	Yellow	Yellow
	C	Red	Green	Red	Red	Red	Red	Red
Surface Water Pipeline Alternatives	San Juan River	Red	Red	Red	Green	Red	Yellow	Yellow
	Navajo Agricultural Products Industry	Red	Yellow	Green	Yellow	Red	Red	Red
Access Road Alternatives	From Highway 491	Red	Red	Red	Red	Red	Red	Red
	From Burnham Road	Red	Yellow	Yellow	Yellow	Yellow	Red	Yellow
Power Plant Site Alternatives	Consol Mine Site	Red	Yellow	Red	Red	Red	Yellow	Red
	NAPI Land Plant Site	Yellow	Yellow	Yellow	Red	Yellow	Red	Yellow

Red: Worst*
Yellow
Green: Best*

* When compared to other alternative facilities considered but eliminated.

2.4.5.1 Transmission Line Alternatives

Three transmission line interconnects with the NTP were evaluated. The fundamental difference between the alternatives revolved around the crossing of the San Juan River. Two of the three alternatives evaluated would require a new transmission line corridor to be constructed that did not parallel a similar feature (Alternatives A and B, Figure 2-7). The third alternative (Alternative C) would potentially impact more land uses and have potentially higher visual impacts than the proposed alternative. Further, with the construction of the NTP, loop flows could occur within ringed circuits between the Desert Rock Energy Project and the Four Corners and San Juan Generation Stations, which would cause additional transmission losses and could impact lower voltage lines in the area. For these reasons, these alternative transmission line routes were eliminated from detailed evaluation.

2.4.5.2 Alternative Access Roads

Several alternative access road alignments were evaluated west of the proposed power plant site to Highway 491 (see Figure 2-7). Each of the alternative alignments would require a bridge to be constructed over the Chaco River. These alignments were eliminated due to unnecessary environmental damage that would be created by the construction of this bridge.

Two alternative access roads were evaluated north from Burnham Road to the proposed power plant site (see Figure 2-7). One was aligned east of the BNCC Lease Area and the other on the west side of the BNCC Lease Area. Neither alignment paralleled an existing similar feature and traversed areas that have steeper topography and crossed more water drainage channels than the proposed alignment.

For reasons of engineering and to avoid unnecessary environmental impacts, these access road alternatives were eliminated from detailed evaluation.

2.4.5.3 Surface Water Delivery Alternatives

The cost and engineering issues related to delivery of the surface water also were studied. Two primary options were considered: (1) water intake from the San Juan River and (2) using the NAPI irrigation canals to deliver water from the Navajo Reservoir.

The San Juan River option would have involved building a 27-mile-long pipeline and pump stations from the San Juan River to the Desert Rock Power Plant. This alternative would have potentially impacted San Juan River hydrology in addition to native and endangered fish populations.

The NAPI canal option would have used the existing irrigation canals. Because the canals only operate 6 months per year this option would have required large investments to upgrade the canal system to 10 months per year, as well as the construction of a large storage system that would have included a dam and 340 surface acres of water storage.

For these reasons, as well as the considerations in Section 2.4.3.2 regarding the viability of using surface water resources for the proposed project, BIA eliminated these alternatives from detailed evaluation.

2.5 PREFERRED ALTERNATIVE

The BIA has proposed a preferred alternative, as follows:

Alternative B – Approval of the long-term lease, rights-of-way, and all associated components of the Desert Rock Energy Project

<u>**Power Plant**</u>

Approval of the long-term business land lease between the Navajo Nation and DPA and the sublease between DPA and Desert Rock Energy Project LLC (BIA).

Approval of a National Pollutant Discharge Elimination System (NPDES) permit associated with the power plant (USEPA).

Approval of an individual permit for the proposed power plant under Section 404 of the Clean Water Act and to ensure compliance with the Clean Water Act (USACE).

Approval of water quality certification under Section 401 of the Clean Water Act for the power plant (Navajo Nation).

Coal Supply and Coal Combustion Byproduct (CCB) Disposal

Approval of a significant revision to the BNCC's NPDES permit associated with the mining and reclamation operations and coal preparation facilities (USEPA).

Approval of revisions to BNCC's current SMCRA permit to allow development of coal processing facilities, conveyance systems, and infrastructure in Area IV North of the BNCC lease area (OSM).

Approval of a future SMCRA permit to allow coal mining, CCB disposal, and reclamation activities in Area IV South and Area V of the BNCC lease area (OSM).

Approval of the Resource Recovery and Protection Plan or a Mine Plan of Operations for Area IV South and Area V of the BNCC lease area (BLM).

Approval of nationwide permits or an individual permit for under Section 404 of the Clean Water Act for the mining operations in Area IV South and Area V, and to ensure compliance with Section 404 of the Clean Water Act (USACE).

Approval of water quality certification under Section 401 of the Clean Water Act for the mining operations in Area IV South and Area V (Navajo Nation).

Water-Supply System

Approval to grant the rights-of-way requested for the water-supply system (BIA, Navajo Nation).

Approval of an individual permit for the proposed water-supply system including pipelines under Section 404 of the Clean Water Act and to ensure compliance with Section 404 of the Clean Water Act (USACE).

Approval for use of tribal water resources (Navajo Nation).

Transmission Line (Segments A, C, and D)

Approval to grant the right-of-way requested for the proposed transmission lines (BIA, Navajo Nation).

Approval of an individual permit for the proposed transmission lines under Section 404 of the Clean Water Act and to ensure compliance with Section 404 of the Clean Water Act (USACE).

Access Roads

Approval to grant the right-of-way requested for the proposed access roads (BIA, Navajo Nation).

Approval of an individual permit for the proposed access roads under Section 404 of the Clean Water Act and to ensure compliance with Section 404 of the Clean Water Act (USACE).