APPENDIX G:

ENERGY TRANSPORT TECHNOLOGIES AND HYPOTHETICAL ENERGY TRANSPORT PROJECTS

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G.1[1] ENERGY TRANSPORT TECHNOLOGIES

G.1.1 Electricity Transmission

Centralized power production brings the advantage of economies of scale, but may require long-distance transfers of power to reach customers. Long-distance transmission is most efficiently accomplished by economical high-voltage transmission lines.

The most important parameter dictating the size of an electric power system is the peak electrical demand. This peak demand determines the minimum amount of generating capacity and the corresponding amount of transmission and distribution facilities required to maintain a reliable electric system. The peak demand is expressed in units of power (kilowatts, megawatts, gigawatts, terawatts) and is the maximum instantaneous requirement for electricity that occurs during a specified time period. Normally, peak demand is specified separately for the summer and winter seasons. Some regions have a higher summer peak demand, others a higher winter peak demand. The peak summer demand on the entire North American system was approximately 817,000 MW in 2004. The peak winter demand was 716,000 MW. This peak demand was supplied by approximately 990,000 MW of generating capacity, which constituted a reserve margin of about 20%.

The bulk transmission system in the United States operates at voltages between 115,000 V (115 kV) and 765 kV. Over 207,200 miles of the bulk transmission system consists of lines operating at over 230 kV. In the 11-state study area, the highest operating voltage is 500 kV for long-distance transmission.

The most visible components of the electricity transmission system are the conductors that provide paths for the power and the towers that keep these conductors at safe distances from each other and from the ground and the natural and built environments through which the transmission line passes. Also visible but less common elements along the corridor may include switching stations, or substations, where lines of similar or different voltages meet to transfer power. Common elements that are generally less visible (or at least more easily overlooked) include the maintained right-of-way (ROW) along the path of the towers, access roads needed for maintenance, and staging areas used for initial construction that may be restored after initial construction is complete but may be reestablished to support repair, upgrade, or replacement actions or transmission line decommissioning.

The voltage required for economical transmission of electric power exceeds the voltage appropriate for distribution to customers. Customer equipment generally operates at only a few hundred volts rather than at the hundreds of thousands of volts used for long-distance power transmission. If high voltages were maintained up to the point of customer connection, fault protection would be extremely expensive. Therefore, transformers are required to reduce voltage before the power is introduced to a distribution or sub-transmission system. These transformers mark the end of the transmission line and are located at substations.

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1 Shaded text indicates portions of the document that underwent revision between the draft and the final PEIS in response to comments received during the public comment period as well as additional information provided by local federal land managers and resource specialists.

G.1.2 Natural Gas Transport

The United States has several major natural gas production basins and an extensive natural gas pipeline network. Of the natural gas consumed in the United States, 85% is produced domestically; most of the balance is imported from Canada.

The natural gas system is generally described in terms of production, processing and purification, transport and storage, and distribution. The transport segment of the gas industry is responsible for transporting natural gas from the producer to the market areas via pipelines. The transport system is composed of pipelines, compressor stations, city gate stations, and storage facilities. All aspects of design and operation of natural gas pipeline systems are addressed in regulations promulgated by the U.S. Department of Transportation's Office of Pipeline Safety (OPS) and in accepted industry practices.

Transport pipelines are made of steel and generally operate at pressures ranging from 500 to 1,400 pounds per square inch gauge (psig). Pipelines can measure anywhere from 6 to 48 inches in diameter, although certain component pipe sections can consist of small-diameter pipe as small as 0.5 inches in diameter. Mainline pipes, comprising the principal pipeline in a given system, are usually between 16 and 48 inches in diameter and are constructed of steel. Coatings are often applied as a means of controlling corrosion. Additional corrosion-control systems may also be installed along the mainline.

Natural gas is highly pressurized as it travels through a pipeline, to expedite its flow. To ensure that the natural gas flowing through any one pipeline remains pressurized, compression of the natural gas is required periodically along the pipe. This is accomplished by compressor stations, usually placed at 40- to 100-mile intervals along the pipeline. The natural gas enters the compressor station, where it is compressed by a turbine, motor, or engine.

In addition to compressor stations to reduce natural gas volume and push the gas through the pipe, metering stations are placed periodically along interstate natural gas pipelines. These stations allow pipeline companies to monitor and manage the natural gas in their pipes.

The natural gas for most distribution systems is received from transport pipelines and fed through one or more city gate stations, sometimes called *town border* or *tap* stations. The basic function of these stations is to meter the gas and reduce its pressure from that of the pipeline to that of the distribution system. The latter operates at a much lower pressure (reduced from approximately 500 to 1,400 psig to about 0.25 to 300 psig). Most city gate stations measure the gas flow with metering devices and reduce gas pressure with mechanical devices called pressure regulators. These devices control the rate of gas flow and/or pressure through the station and maintain the desired pressure level in the distribution system. Natural gas is odorless, and gas received at city gate stations may or may not contain an odorant, the compound that gives gas its distinctive smell; however, odorant will always be added before the gas is delivered to the consumer.

"Pigging facilities" are positioned within the interstate pipeline network to launch and recover "pigs," devices that clean the mainline pipe and monitor its condition for such critical faults as cracks or corrosion. Pigging can be done without interruption of pipeline operation, with the flow of the gas moving the pig along the mainline pipe.

Pipelines are typically operated remotely through a supervisory control and data acquisition (SCADA) system. These computerized systems allow operators in a central location to change operating parameters on pumps and valves, so as to control the flow of liquids through the lines. These control systems communicate across a range of potential telecommunication options from landlines to satellites. Many times, structures to support cellular, microwave, or satellite communications must be constructed along the pipeline to support communication of monitoring data and operating instructions via the SCADA system.

All pipeline construction is accomplished along a relatively narrow ROW, approximately 50 feet wide. The construction is accomplished with multi-skilled crews working sections of the project called "spreads." Each spread will start offset activities and move in a continuous fashion until its section is completed. After preconstruction surveying and soil and geological studies are completed, the mainline path is cleared of vegetation and support and access roads are constructed. Typically, a trenching tool or other excavation techniques are used to dig a long trench down the center of the ROW, which will serve to bury the pipeline underground. Appropriate bedding material is installed in the bottom of the trench to provide a stable base for the pipe. Unique excavation and burial techniques are used to cross under rivers, roadways, and railroads or to excavate in rocky areas.

After excavation and the addition of bedding material, sections of pipe are laid adjacent to the pipeline route on the ROW. The individual piping sections are "strung" together and welded. After extensive evaluation of the welds, the pipeline is wrapped with a protective coating as it is laid into the trench. Once the entire pipeline, including all pumps and tanks, is constructed, the pipeline is filled with water and tested under pressure (typically 125% of the maximum design operating pressure) to check for leaks. Water from this "hydrostatic" test is typically treated for contaminants before being released. The original dirt extracted from the trench is filled in, burying the pipeline, and the area is graded and revegetated.

Corrosion in pipelines is a common phenomenon, and must be controlled to effectively prevent pipeline leaks or structural problems. Beside the corrosion-control coatings applied to the pipe when it is manufactured, additional corrosion-control devices are installed in the pipeline trench to protect all segments of the pipeline system that are buried. Such devices include "ground beds," or "sacrificial anodes," that are electrically bonded to the pipe and consist of a metal that corrodes preferentially to the steel of the pipe. Impressing a current on the pipe can also provide corrosion control by counteracting the current that would be produced as the steel corrodes from metallic iron to iron oxide.

Once the natural gas pipeline is in service, the pipeline's control center continuously monitors critical operating parameters electronically. A computerized gas monitoring system reads the pressures along the pipeline on a continuous basis. The compressor stations include an emergency shutdown (ESD) system that would vent the mainline pipe (expel the gas to the atmosphere) in the event of an emergency. Additionally, each compressor unit and mainline valve facility typically includes a blowdown valve that would be used in association with maintenance activities (e.g., to relieve pressure when a unit is taken off-line). Leak detection methods may be divided into two categories, direct and inferential. Direct methods detect leaking commodity outside the pipeline. Inferential methods deduce a leak by measuring and comparing the amount of product moving through various points of a line. Routine operation would include inspection and maintenance of all above-ground facilities, vegetation maintenance along the entirety of the system for fire safety, and replacements of buried mainline pipeline segments when remote inspection and monitoring indicates potential problems with system integrity or unacceptable levels of deterioration.

G.1.3 Liquid Petroleum Transport

The U.S. liquid pipeline industry is comprised of approximately 200,000 miles of pipe in all of the fifty states, which carried more than 40 million barrels per day, or 4 trillion barrel-miles, of crude oil and refined products during 2001. Approximately 66% of domestic petroleum moves by pipeline, with marine movements accounting for 28% and rail and truck making up the balance. Pipelines may be small or large, up to 48 inches in diameter. With only minor exceptions, the pipe is buried. Some lines are as short as a mile, while others may extend 1,000 miles or more.

The materials carried in liquid pipelines embrace a wide range of liquids. Crude systems gather production from onshore and offshore fields, while transport lines carry crude oil feedstocks to terminals, interconnection points, and refineries. Pipelines also connect refineries with petrochemical plants for the transfer of secondary feedstocks. Typical refined products transported include motor gasoline, aviation fuels, kerosene, diesel fuel, heating oil, and various fuel oils as well as various liquefied petroleum gases (LPGs).

There are several types of pipeline systems. Flowlines, as part of a gathering system, are used to move produced oil from individual wells to a central point in the field for treating and storage. Crude trunk lines are used to move crude oil from central storage facilities over long distances to refineries or other storage facilities. Product pipelines carry finished products from refineries to distribution terminals. Product pipelines can carry multiple types of products concurrently in a batch-wise manner. Slurry pipelines carry coal slurry consisting of finely ground solids in water or other extremely heavy material recovered from shale oil.

The elements of a pipeline are tanks for storage, pump stations for pressure, metering stations for measuring flows, valves and manifolds for controlling flows of liquids, facilities for launching and receiving maintenance devices transferred through the pipeline, and electronic monitoring and control systems and telecommunication components.

When designing pipelines, consideration must be given to sizing, pressure, liquids being transported, and any thermal stress interactions, especially for lighter materials, such as ethane or ethylene. Soil-load issues from the weight of the soil, roads or railroads crossing over the pipeline, buoyancy effects from groundwater, impacts of local adjacent mining and blasting, and even unanticipated events like earthquakes and landslides must all be considered in siting and installing buried pipelines. For safety, most pipelines employ automated leak detection systems, pressure-relief systems, and isolation valves to minimize environmental and public safety impacts in the event of an emergency or off-normal event. All aspects of design and operation of natural gas pipeline systems are addressed in regulations promulgated by the U.S. Department of Transportation's OPS and published standard industry practices.

All pipeline construction is accomplished along a relatively narrow ROW. The construction is accomplished with multi-skilled crews working offset activities that move in a continuous path along the pipeline. Major construction phases include surveying, soil studies, clearing and site preparation, and trenching. Then, the pipe segments are welded together, coated for protection, and lowered into the trench. After testing the pipe for leaks with pressurized water, a process known as hydrostatic testing, the pipe is buried in the trench and the soil and surrounding areas are restored to their original conditions.

Corrosion in pipelines is a common phenomenon, and must be controlled to effectively prevent pipeline leaks or structural problems. Beside the corrosion-control coatings applied to the pipe when it is manufactured, additional corrosion-control devices are installed in the pipeline trench to protect all segments of the pipeline system that are buried. Such devices include "ground beds," or "sacrificial anodes," that are electrically bonded to the pipe and consist of a metal that corrodes preferentially to the steel of the pipe. Impressing a current in the soil adjacent to the pipe can also provide corrosion control by counteracting the current that would be produced as the steel corrodes from zero-valent metallic iron to iron oxide.

Pigging facilities are positioned within the pipeline network to launch and recover pigs, devices that clean the mainline pipe and monitor its condition for such critical faults as cracks or corrosion. Pigging can be done without interruption of pipeline operation, with the flow of the product moving the pig along the mainline pipe. Automated leak detection and routine integrity assessments also enhance the safety and reliability of pipeline operations.

Once the pipeline is in service, the pipeline's central control center remotely monitors critical operating parameters and controls movements of materials into, through, and out of the pipeline through a sophisticated SCADA system. The control center also monitors all leak detection systems, isolation valves, and other fire and building monitoring systems of remote facilities, such as pump stations.

Routine operation would include inspection and maintenance of all above-ground facilities, vegetation maintenance along the entirety of the system for fire safety, and replacements of buried mainline pipeline segments when remote inspection and monitoring indicate potential problems with system integrity or unacceptable levels of deterioration.

G.1.4 Hydrogen Transport

Although hydrogen pipelines date back to late 1930s, long-distance transport of hydrogen via pipeline is in its infancy when compared to natural gas or liquid petroleum pipeline systems. The existing hydrogen transport system in the United States is estimated to be from about 450 to 800 miles in total length. Estimates in Europe range from about 700 to 1,100 miles. Hydrogen pipelines in the United States are predominately along the Gulf Coast and connect major hydrogen producers with well-established, long-term customers.

Significant growth in hydrogen use is projected in the refining sector and in the mining and processing of tar sands and other energy resources, as the quality of the raw crude decreases. Furthermore, the use of hydrogen as a transportation fuel has been proposed both by automobile manufacturers and the federal government. It is anticipated that pipelines will be the dominant mode of transporting large quantities of hydrogen.

From an engineering perspective, hydrogen pipeline systems are fundamentally the same as natural gas pipeline systems. As the hydrogen pipeline network expands, many of the same construction and operating features of natural gas networks would likely be replicated. Historically carbon steel or stainless steel has been used in hydrogen pipelines. Austenitic stainless steels, aluminum (including alloys), copper (including alloys), and titanium (including alloys) are generally applicable for most hydrogen service applications. Welding provides the preferred joint for hydrogen pipelines.

Although design requirements for interstate hydrogen pipelines are yet to be established, some reasonable assumptions can be made. These assumptions are based on operating experience with both natural gas and hydrogen and on the expectations for large-scale hydrogen delivery. For example, it is likely that hydrogen pipelines would be constructed of carbon- or stainless steel, welded pipe. The pipe would be buried at least 30 inches below-ground and would rest on as much as 12 inches of bedding materials consisting of crushed rock or soft clay base. It can also be assumed that the pipe would be precoated on its exterior with a fusion-bonded epoxy or a polyethylene sleeve to inhibit corrosion. Pipe segments would likely be precoated with a corrosion inhibitor at their points of manufacture, but field applications of corrosion inhibitor may also take place. This inhibitor could be a polyethylene sleeve or wrap or a fusion-bonded epoxy. It is likely that standards promulgated by the American Petroleum Institute (API) would be used in the construction and operation of hydrogen pipelines.

Welding procedures and leak testing can be expected to be more exacting for hydrogen pipelines. Other construction practices are likely to be very similar to those for natural gas pipelines.

At a given pressure, the energy density for hydrogen is approximately one-third that of natural gas. However, for the same pipe diameter and pressure, hydrogen flows approximately three times as fast as natural gas. As a result, if hydrogen compressors can be operated to meet similar pressure requirements as natural gas compressors, it can be expected that hydrogen pipe diameters could approach those for natural gas transport pipelines.

The recompression ratio for hydrogen is four times lower than that for natural gas for a given compressor rotor speed. This necessitates a greater number of stages. Three to five stages of compression are required to elevate hydrogen to pipeline pressures. Compressor stations are each powered by compressors rated at several thousand horsepower. The compressors are typically housed in a metal building with pipe appurtenances and other critical elements above-ground. If the hydrogen pipeline shares a common corridor with a natural gas pipeline or an electricity transmission line, it would be comparatively easy to bleed some natural gas or electricity to energize the hydrogen compressor. Alternatively, a quantity of the hydrogen could be fed to the compressor directly from the pipeline that the compressor serves.

The spacing between hydrogen compressors along a pipeline would be determined by operational and economic factors. It is likely that the spacing between hydrogen compressors would be equal to or greater than the 40 to 100 miles common for natural gas transport pipelines.

Depending on transport and delivery pressure requirements, hydrogen pressures would probably have to be reduced from transport pipeline levels to distribution system levels. In a manner similar to that for natural gas systems, pressure regulators would be used to control the hydrogen flow rate through the station and to maintain the desired pressure in the distribution system. If any additives need be added to the hydrogen as it enters a distribution system, such as the odorant added to natural gas, it is likely that this would be done at the city gate stations.

Hydrogen pipeline requirements for access roads for construction, operations, and maintenance activities are likely to be virtually identical to those for natural gas pipelines. Hydrogen pipeline construction standards are currently under development. A number of federal and state agencies have standards and regulations that affect natural gas pipelines, and these would likely also govern hydrogen pipelines. The American Society of Mechanical Engineers' (ASME's) Board on Pressure Technology Codes and Standards has initiated the development of an independent consensus standard or code for hydrogen pipelines. Although it is anticipated that many of the codes and standards will be similar to those for natural gas pipelines, differences in physical properties of natural gas and hydrogen would necessitate some differences.

Because the construction, operation, and decommissioning of hydrogen pipelines would be similar to those for natural gas pipelines, it is reasonable to expect that the great majority of attendant environmental impacts would also be similar. However, some physical differences exist between hydrogen and natural gas at the molecular level, and these differences could influence potential health and safety hazards and dictate unique mitigation and emergency response strategies. Among the most important differences are the differences in fire and explosion risks. Like natural gas, hydrogen gas is colorless and odorless (i.e., before any odorants are added to more easily detect leaks). However, hydrogen is substantially less dense than air, and, while it has a broader explosive range than natural gas (4 to 75% volume percentage in air for hydrogen versus 3.8 to 17% for natural gas), its extremely low density and rapid dispersal when released into the air make it difficult for clouds of explosive mixtures to form.

Hydrogen's activation energy for ignition is about 10% the energy needed to ignite natural gas; however, burning hydrogen releases substantially less heat energy than conventional petroleum distillate fuels, and explosions of hydrogen vapor clouds release substantially less energy and cause substantially less damage than explosions of a stoichiometric equivalent of conventional petroleum distillate fuels such as gasoline. Although the only combustion product of hydrogen is water, the extremely high temperature of hydrogen burning in air would cause conversion of the nitrogen in the air to nitrogen oxides in proportionally greater amounts than results from the combustion of natural gas.

G.1.5 Alternative and Advanced Energy Transmission

G.1.5.1 HVDC Transmission Lines

Although long-distance transmission of high-voltage alternating current (HVAC) electricity is likely to continue to predominate over the 20-year planning horizon of this Programmatic Environmental Impact Statement (PEIS), long-distance transmission of direct current (DC) is equally technically feasible and brings with it some distinct advantages over alternating current (AC). Electricity transmission through superconductivity may also become commercially viable over the 20-year planning horizon. Finally, applications of nanotechnology to energy transmission could be introduced to designated energy corridors within the next 20 years. Each of these alternative or advanced energy transmission technologies is summarized below.

High-voltage direct current (HVDC) electricity transmission lines are employed around the world mainly for long-range and undersea transmission. Their use has been growing in recent decades due to technology developments that overcome the historical disadvantages of the systems, especially improving their interfaces with the more prevalent AC systems used by the majority of electric power consumers.

In general, HVDC lines of perhaps 500 kV are used to interconnect two AC regions of the power distribution grid. Expensive electronic equipment is required to convert between AC and DC power, representing a major cost factor in power transmission. However, because fewer and smaller conductors may be used for the same power level, HVDC transmission lines cost less to construct than HVAC lines delivering equivalent power. Above a break-even distance of perhaps 400 to 500 miles for overhead lines, the lower cost of the HVDC cable outweighs the cost of the electronic conversion equipment. Because of even greater advantages for submarine cables, the break-even distance for undersea HVDC is around 30 miles.

When installed as overhead lines, HVDC transmission lines are constructed in much the same way as HVAC lines. However, for a given power level, HVDC lines are smaller, lighter, and the towers from which they are suspended have a lower profile than HVAC lines. Smaller diameter conductors are used, due to the greater carrying efficiency of HVDC and reduced insulating requirements, due to lower voltages being employed. Thus, construction as well as visual impacts for HVDC overhead lines are similar to, but somewhat lower than, those from comparable HVAC lines. Converter stations, on the other hand, would be expected to be as large as, or larger than, HVAC substations, so construction impacts of these facilities could be similarly larger.

The operational impacts of overhead HVDC transmission lines are similar to those of HVAC in some respects and different in character in others. Visual impacts are similar in nature, but generally reduced due to the lower profiles, simpler designs, and ostensibly greater spacing of support structures compared to HVAC lines. Impacts for line maintenance and ROW maintenance are similar in nature and magnitude to those for HVAC. Impacts associated with high-voltage electric currents in the lines, however, are of a different character in HVDC lines than in HVAC lines.

Overall, operational impacts from HVDC transmission lines are lower than those from comparable HVAC lines. HVDC produces negligible magnetic fields, does not induce voltages in adjacent metallic conductors (such as pipelines), produces less radio interference, less corona noise, and negligible amounts of ozone or nitrogen oxides in air around conductors. Ground currents can lead to corrosion and other problems when monopolar DC systems are used, but overhead lines would typically use bipolar transmission, which does not produce ground currents during normal operation. Operational impacts from converter stations, on the other hand, would be of similar overall magnitude to those from HVAC substations.

When installed as underground or undersea cables, HVDC transmission lines likewise have construction impacts similar to, but of generally lower magnitude than, impacts from HVAC lines. Because HVDC lines run at lower voltages and produce less heat than comparable HVAC lines, smaller trenches are needed, resulting in reduced construction impacts. Less heat generated during operation reduces ground and water warming and attendant impacts, so operational impacts are lower, as well. Since both underground and undersea cables have lower transmission losses than comparable HVAC lines, the indirect impacts of carbon dioxide and criteria pollutant emissions from generating sources that burn fossil fuels to initially produce the electricity carried in those lines are also reduced.

G.1.5.2 Superconducting Systems

Electrical conductors made from superconducting materials are being rapidly developed around the world because of their promise of virtually eliminating energy losses due to electrical resistance. Conductor wires tens of meters in length constructed from superconducting filaments tens of kilometers in length are in active prototyping and are expected to be commercialized in the next few years.

The leading superconducting technologies employ so called “high temperature superconductors,” which become superconducting at liquid nitrogen (LN2) temperatures. Such technologies have a cost advantage over earlier “low temperature superconductors,” which required liquid helium for cooling. Superconducting wires are made of filaments of ceramic materials made from copper oxide combined with various other metals. Since the filaments are brittle, they are embedded in a metallic matrix or adhered to a metallic backing in the form of tapes. First-generation superconductors, which are the most developed technology, use filaments embedded in a silver matrix, which is costly. Second-generation wires are being developed that have greater potential to be cost competitive with existing technologies when energy efficiency factors are included.

Any practical transmission line using high-temperature superconductors would most probably employ LN2 cooling, which would likely require periodic chilling stations. Transmission lines would most likely be installed in underground conduits because of their rigid form and vulnerability to the elements. Construction impacts would be similar to those from underground pipelines. However, operational impacts (regular inspection, maintenance and repair of conductor joints and cooling equipment) may be greater.

G.1.5.3 Nanotechnology Applications

Nanotechnology applications have the potential to improve the efficiency of electricity transmission. Research initiatives that are focused on the energy sector include:

- A new electrical conductor material in which nanocrystalline fibers are embedded in a high-purity aluminum matrix core wire to produce an aluminum conductor composite wire with increased power carrying capacity that can withstand extreme temperatures with no chemical reactions or appreciable decreases in strength.

- "Quantum wire" made of a particular type of carbon nanotube (atoms of carbon linked into tubular shapes that can make materials extremely light, strong, and resilient) is more conductive than copper at one-sixth the weight and is twice as strong as steel. Transmission wires made with quantum wire would have no line losses or resistance, would be resistant to temperature changes, and would help minimize or eliminate sagging of conductors, allowing for greater spacing between support towers or towers of lesser dimension.

- "Nanodots" (ultra-small particles of inorganic materials typically consisting of less than 100 atoms) introduced into high-temperature superconductivity (HTS) wire allow higher amounts of electrical current to flow, even in the presence of strong magnetic fields and at relatively high operating temperatures, thus mitigating one of the major challenges to commercialization of HTS.

Other nanotechnology applications are directed at improving the efficiency (and reliability) of other components of the electricity transmission infrastructure:

- **Transformers**. Fluids containing nanomaterials could provide more efficient coolants in transformers, possibly reducing the footprint of, or even the number of, the transformers required.

- **Substations**. Smaller, more efficient batteries made possible with nanotechnologies could reduce the footprints of substations and possibly the number of substations within a corridor.

- **Nanoelectronics**. Self-calibrating and self-diagnosing nanotechnology-enabled sensors could allow for remote monitoring of infrastructure on a real-time basis and could direct maintenance or adjustment that preempts wholesale system failures.

G.1.5.4 Other Energy-Related Transport Systems

Section 368 of the Energy Policy Act of 2005 (EPAct) explicitly directs the Secretaries of Agriculture, Commerce, Defense, Energy, and Interior, in consultation with the Federal Energy Regulatory Commission (FERC), states, and other interested parties, to (in part) designate corridors for oil, gas, and hydrogen pipelines, and electricity transmission and distribution facilities on federal lands in the 11 contiguous western states. When read alone, that section appears to limit eligibility for installation in energy corridors to these few specified energy transport systems. However, when read in a broader context, the EPAct directs development or reorientation of myriad energy-related programs and initiatives involving such diverse energy sectors as renewable energy, oil and gas, oil shale and tar sands, coal, nuclear, ethanol, biofuels, hydropower, and geothermal. To the extent that they would provide logistic support for the development of any of these energy initiatives, it can be argued that energy corridors should be made available for the movements of raw materials, intermediates, and resulting fuels and power from all energy initiatives addressed in EPAct.

Among the energy-related systems that might otherwise be considered for installation in designated energy corridors are the following:

- Slurry pipelines that deliver pulverized low-sulfur coal from mines in Wyoming to coal-fired power plants located elsewhere within the 11 western states and slurry pipelines that return fly ash and sludge from sulfur dioxide exhaust gas scrubbers to mine sites, to aid in mine stabilization and reclamation.

- Carbon dioxide (CO_2) pipelines (gaseous or supercritical fluid) that deliver CO_2 from power plants and from other industries burning large amounts of fossil fuels to conventional oil and gas fields for use in enhanced oil recovery operations, and as a means of sequestering what is believed to be one of the primary compounds responsible for global warming when released into the atmosphere.

- Carbon dioxide pipelines (gaseous or supercritical fluid) that deliver CO_2 from power plants and from other industries burning large amounts of fossil fuels to oil shale and tar sands development facilities to aid in fracturing subsurface deposits as part of in-situ retorting and recovery of the organic fractions of those deposits, and simultaneously as a way to sequester the CO_2 and prevent its release into the environment.

- Pipelines that transfer secondary feedstocks between refineries and/or between refineries and petrochemical plants.

- Ethanol pipelines that deliver ethanol produced from corn or through other biochemical processes to refineries for blending with conventional gasoline stocks.[2]

- Raw materials (e.g., harvested switchgrass and other biomass materials) delivered by slurry pipeline to processing facilities that convert the biomass into biofuels.

- "Produced water" recovered from conventional oil and gas fields or coalbed methane deposits delivered by pipeline to arid or semiarid regions in the West for myriad beneficial uses, including oil shale and tar sand processing, livestock watering, irrigation, potable water use (after appropriate treatment), and public reservoir fill.[3]

- Waters derived from combustion of fossil fuels (waters of combustion) delivered by pipeline to oil shale and tar sands facilities and other energy-related industries located in arid or semiarid regions for use in processing and associated materials and waste management.

- Pipelines transporting anhydrous ammonia, which can later be

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2 Transporting ethanol by pipeline is rarely done in the United States. When it occurs, it generally involves small pipelines with few shippers and a limited slate of products. This is because ethanol tends to absorb water and other impurities in a pipeline, so the pipeline would have to be dedicated only to ethanol service and would require frequent pig cleaning, etc. There is also some evidence that ethanol in high concentrations can lead to various forms of corrosion, including internal stress corrosion cracking, which is very hard to detect.

3 As used here, "produced water" is water that is brought up from hydrocarbon-bearing strata along with produced oil and gas. Produced water can include formation water, injection water, well treatment, completion, and workover compounds added downhole and compounds used during the oil/water separation process. Formation water, also called connate water for fossil water, originates in the permeable sedimentary rock strata and is brought up to the surface comingled with oil or gas or both. Injection water is water that was injected into the formation to enhance oil and gas recovery.

catalytically converted to hydrogen and nitrogen.[4]

- Pipelines transporting helium, a by-product of natural gas processing, from points of manufacture to major fossil fuel combustion sources, to act as coolants in condensing heat exchangers used to capture and separate CO_2 and water of combustion from exhaust gas streams.[5]

- Pipelines for the transfers of wastes associated with energy production to treatment facilities or to areas more environmentally suitable to their disposal.

- Pipelines that connect oil shale and tar sands production facilities with refineries or with Strategic Petroleum Reserve (SPR) storage sites.

The above examples happen to all involve transport by pipeline. However, if indeed the broader purpose of EPAct is to support a multitude of energy initiatives, thereby improving the overall security of the nation's energy portfolio, then movements of energy-related materials should involve all efficient and practical means, including rail and motor vehicle. However, nothing in any section of EPAct implies rail or highway transport within designated energy corridors to be within the scope of Congressional intent. The absence of specific directives to the Department of Transportation (DOT) and the Federal Highway Administration to participate in the designation of energy corridors that would involve highways or railways further supports the conclusion that highways and railways were not intended for inclusion in the energy corridors. (Despite the absence of a directive to participate in corridor designation, the DOT is the federal safety authority for the nation's natural gas and hazardous liquid pipelines and retains authority over pipelines, regardless of their location.)

Ultimately, the list of potential candidates for inclusion in energy corridors is limited only by the imagination and the degrees of separation allowed between the material being transported and its conversion to, or enhancement of, consumable energy. This is a dilemma, since there is no basis for choosing one or more of the above examples over others for inclusion in the National Environmental Policy Act (NEPA) analysis. Further, there is no basis for ensuring that the list of possible candidates is exhaustive, so even if all identified transport and support options were to be included in the NEPA analysis, there would be no guarantee that the analysis would be sufficient. Other systems not directly related to energy would also conceivably need to be addressed; for example, communication systems. Further, such a broad reading of EPAct would create an unmanageable scope of analysis for this PEIS and would divert necessary attention and focus away from the explicitly stated directives of Section 368.

Consequently, the NEPA analysis contained in this PEIS is limited to impacts from those energy transport systems explicitly identified in Section 368 (electricity and oil, gas, and hydrogen pipelines), as hypothetically defined in the foregoing discussions and in Section G.2.1 below. However, at the same time, it is important to note that, both by design (i.e., the nominal width) and by intent, designated corridors could be made available for other energy-related transport systems beside those identified in Section 368, provided that the inclusion of such other transport systems would not in any way preempt the future use of the corridors from their expressed purpose and that the proponent for such systems can successfully demonstrate that inclusion of their facility in a designated corridor would not in any way

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4 Currently ammonia is transported by pipeline over long distances within the Midwest and Plains states and is being considered as a "hydrogen carrier" in a hydrogen economy.

5 BLM currently operates and maintains a helium storage reservoir and pipeline system located in the states of Kansas, Oklahoma, and Texas for the Federal Government (http://www.nm.blm.gov/amfo/helium_regs/helium_regs.html).

interfere with the construction and safe and continued operation of explicitly designated energy transport systems that are now present in the corridor segment in question or that could be installed in that segment at a later date.

G.2 A HYPOTHETICAL ENERGY TRANSPORT PROJECT DEVELOPMENT

G.2.1 What Is the Purpose of Identifying Hypothetical Energy Transport Projects?

Under the Proposed Action, federal lands in the 11 western states would be designated as federal energy corridors under Section 368 of EPAct. Designation as a Section 368 federal energy corridor does not mandate or direct development of energy transport projects within the corridors, nor does it guarantee that any energy transport projects will actually be sited and built within any designated corridor. Rather, designation merely identifies areas on federal land that have been determined to be suitable for potential energy transport projects. Thus, selection of proposed corridors does not in and of itself necessarily result in the permitting, construction, and operation of any specific energy transport project or any of the associated impacts.

To better understand what form future energy transport development might take within the designated corridors, a hypothetical set of energy transport projects was identified that could plausibly be developed within the corridors. The hypothetical projects provide a frame of reference for future corridor development. The hypothetical projects include the following types of energy transport systems:

- Three 500-kV electricity transmission lines:
  - Two AC transmission lines (overhead).
  - One DC transmission line (overhead).
- Two liquid petroleum product pipelines.
- Two gaseous product pipelines.

Although the number and types of energy transport systems that have been included in this reference scenario are hypothetical, the systems themselves nevertheless collectively reflect the entire array of energy transport systems that may be proposed for installation within the next 20 years under any of the alternatives evaluated in this PEIS. This scenario does not identify the actual developments that may occur within the designated energy corridors. Figures G-1 and G-2 depict various electricity transmission and pipeline systems, respectively. Although these photographs and illustrations accurately portray energy transport systems and represent standard industry practices with respect to their construction and installation, the images do not necessarily represent the appearances of transport systems that potentially may be installed in any designated energy corridor.

Technologies for transmitting electricity and liquid and gaseous energy commodities are constantly changing, with advancements replacing older technologies in commercial systems. While some technologies now under development offer the promise of substantial benefits in costs, efficiencies, and lessened environmental impacts, their development schedules are often ill defined, and the dates by which they would see widespread commercial application are unknown. Accordingly, the reference scenario does not include such new and emerging technologies unless published forecasts, together with professional judgment, suggest that they could be introduced into energy corridors within a 20-year planning horizon. As with all project-specific developments that may occur in the future in designated energy corridors, such introductions would be accompanied by appropriate levels of NEPA analyses.

Electricity Transmission System

Towers; lattice (left) and monopole

Transmission lines leaving substation

Towers under construction

Vegetation management for transmission lines crossing North Ogden Notch, Ogden, Utah

IH90605

Transmission lines heading over a mountain pass

FIGURE G-1 Possible Visual Impacts of Electricity Transmission Systems

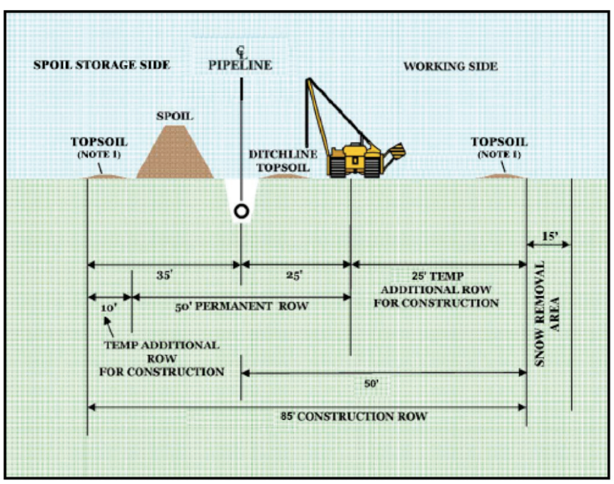
Natural Gas and Liquid Product Pipelines

Trenching in preparation for installation of gas pipeline

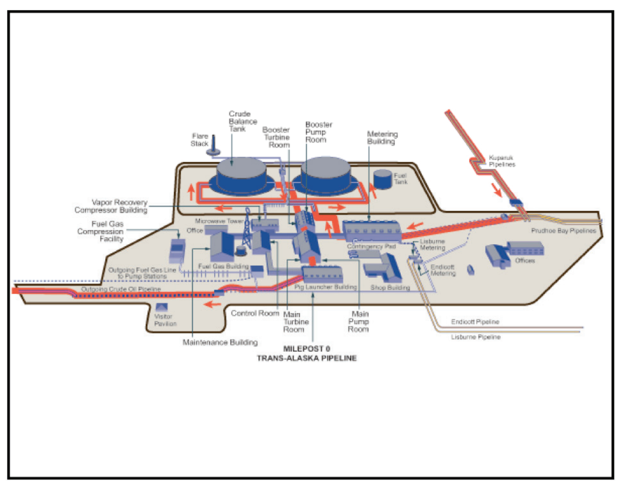
Natural gas control valve
(note vegetation clearing that distinguishes pipeline location)

Typical natural gas compressor station

Typical natural gas city gate



Typical construction cross-section



Schematic of pumping station

IH90606

FIGURE G-2 Possible Impacts of Natural Gas and Liquid Product Pipelines

Although it is technically feasible to transmit both DC and AC by underground (buried or vaulted) lines, such installations are not currently considered likely over long distances because of their substantially higher costs relative to conventional overhead lines. Transmission of electricity over long distances by high-temperature superconductivity is in its early stages of technological development, and its commercial application within a 20-year planning horizon is considered unlikely. Therefore, two of the three electricity transmission systems considered consist of conventional overhead AC transmission lines, each having as many as two circuits. The third involves overhead DC transmission lines having a maximum of two circuits.

Transport of liquefied natural gas (LNG) by pipeline over long distances is not considered to be a likely development within a 20-year planning horizon.[6] Likewise, transport of liquefied hydrogen by pipeline over long distances is considered technically infeasible at this time, and long-distance liquefied hydrogen pipelines are not likely to be installed within the next 20 years. Accordingly, only the transport of liquid petroleum was considered. Liquid petroleum can include crude oil; crude or partially upgraded bitumen (including Syncrude produced from tar sand deposits and shale oils); partially refined petroleum feedstocks (secondary feedstocks); and refined petroleum distillates, including fuel oils, gasoline, diesel fuel, jet fuel, and kerosene. Liquid petroleum also includes LPG.[7] Gaseous products considered include natural gas, raw gas produced from conventional gas wells, fuel gas derived from oil shale and/or tar sand production, and hydrogen.[8]

The assumptions and quantitative values contained in the hypothetical scenario are purposely conservative, and in some cases overly conservative, in order to reflect the possible worst-case scenario with respect to potential impacts from the implementation of the energy transport systems within Section 368 corridors. Consequently, the probability is low that all facets of the scenarios described below would actually materialize.

Assumptions about the size and capacity of energy transport systems are based primarily on historical precedent, as well as on a consideration of probable energy developments within or otherwise affecting the 11 western states. Thus, while electricity transmission lines have been constructed in the United States that operate at voltages as high as 765 kV, the maximum (and predominant) size of transmission lines in the 11 western states is 500 kV, so that value was selected for anticipated future developments. DC transmission of electricity results in less line loss than does AC transmission; consequently, DC lines, if constructed, are also unlikely to be operated at voltages greater than 500 kV.

The largest crude petroleum feedstock pipeline in operation in the United States is the

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6 Currently, seven LNG terminals are being planned for locations along the West Coast of the United States. Although many of these facilities will become operational within a 20-year planning horizon, it is assumed that liquefied natural gas received at these facilities by ship will be converted back to its gaseous state before being transported by pipeline. Additional information on LNG terminals is available on the FERC website: http://www.ferc.gov/industries/lng/indus-act/terminals/exist-term.asp.

7 Here, the term LPG is intended to mean commercially available propane or butane, as well as all varieties of LPG generally available in commerce, including mixtures that also contain propylenes and butylenes that liquefy when compressed and are typically transported as a liquid under pressure.

8 Although they would be eligible for installation within an energy corridor, materials transported by pipeline expressly for the purpose of energy production (e.g., carbon dioxide gas used for enhanced crude oil recovery) are not considered in the following impact assessments.

48-inch Trans-Alaska Pipeline System (TAPS) that extends from the North Slope to Valdez, Alaska, having a design capacity of over 2 million barrels per day (bpd). However, it is unlikely that production rates for crude petroleum feedstock within a concentrated geographic area in the 11 western states would attain such production values within the 20-year planning horizon to require such a large-capacity pipeline. Likewise, facilities (terminals and/or refineries) with the capacities to receive crude feedstock or deliver products at such volumetric rates do not now exist within the 11 western states, and no published forecasts indicate that they are likely to come into existence within the next 20 years. Thus, future feedstock and product pipeline capacity requirements are likely to be less than TAPS.

The estimated pipeline dimensions for the hypothetical scenario are based upon a maximum hypothetical flow between any two geographic locations of 500,000 barrels per day (bpd) of crude feedstock. Such a volume of flow can be accommodated easily by a pipeline with a diameter of 32 inches.[9] Further, for the purpose of analysis, it is reasonable to assume that pipelines carrying refined petroleum products of lesser viscosity (i.e., higher API gravities) also will not need to be greater than 32 inches in diameter. Typical diameters of interstate pipelines for natural gas can be as high as 42 inches, and natural gas pipelines of such dimensions already exist within the 11-state study area. Thus, for analysis purposes, gaseous product pipelines that might be built within designated energy corridors are assumed to have diameters as large as 42 inches.

An oil and gas pipeline network already exists within the 11 western state study area. Within the planning horizon, the collective capacity of raw natural gas pipelines can be expected to expand in the study area, with new or expanded pipelines transporting not only the raw gas produced from the rapidly expanding conventional oil and gas industry in Colorado's Piceance Basin, but also the "fuel gas" expected to be produced at oil shale facilities exploiting the Green River Shale Formation basins in Colorado, Utah, or Wyoming. Likewise, the crude oil pipeline network that now supports the ongoing conventional oil production in Colorado, Utah, and Wyoming and also delivers Syncrude from Canada to refineries in the 11 western states can be expected to expand in order to handle not only the expanding volume of Canadian Syncrude, but also crude or partially upgraded shale oil from production facilities in Colorado, Utah, and Wyoming. Bitumen from tar sands can also be expected to be produced in the special tar sands areas in Utah and will likely be transported by this expanded pipeline network to refineries within the 11 western states. In the later years of the 20-year planning horizon, if oil shale and tar sand facilities in Colorado, Utah, and Wyoming become fully operational at projected commercial scales as those industries mature, pipelines to transport their products to refineries within and outside of the 11 western states will probably be built.

To further ensure that worst-case conditions are analyzed, all seven developments that are considered are assumed to be contemporaneous, thus simultaneously imposing their individual impacts on surrounding receptors.[10] Although contemporaneous, the developments are further presumed to occur without a high degree of

[9] The actual throughput of a liquid pipeline is dependent on numerous factors, including the specific gravity and viscosity of the commodity and design factors such as operating pressure. In general, however, a good approximation of throughput for most liquid petroleum results from multiplying the square of the pipeline's internal diameter by 500. Thus, a 32-inch pipeline will delivery approximately 512,000 bpd.

[10] It can be argued that consecutive rather than simultaneous construction schedules would extend the period of potential environmental impacts, thus creating greater overall impacts to some natural resources. However, simultaneous construction periods were selected to maximize the potential impacts on local infrastructures and economies.

coordination between the individual project operators. Thus, the impacts assigned to each project are those that would occur if the project was the sole occupant of the specified corridor and mitigation dividends resulting from consolidation opportunities (e.g., shared access roads) were not taken.[11]

Although the cumulative ROW widths of the seven energy transport projects is less than half the nominal corridor width, the entire width of a corridor is thought to be available for development, thus allowing each ROW to meander within the corridor boundaries to avoid unique conditions within the corridors that might otherwise increase environmental impacts, increase the severity of unavoidable impacts, increase the technological complexity, or reduce the operational reliability of the transport system. Although it can be anticipated that multiple ROWs would remain generally parallel to each other throughout the length of the portion of the corridor over which they travel, when it is technically feasible and/or necessary to do so, ROWs may cross each other within a corridor.[12] Portions of the corridor where overlapping or crossing ROWs exist may be subject to additional design and/or operating requirements to ensure that all potential interferences between individual projects are adequately addressed by both parties, as well as any public safety or system reliability issues.

The project parameters reflected in the assumptions below are derived from standards of practice extant within the respective industries. Whenever possible, the extremes of the ranges of project parameters were selected, since they could be expected to create maximum impacts during construction or operation, or off-normal events such as spills or leaks. Even so, unique project-specific features could generate additional impacts during construction, operation, or decommissioning.

Finally, for any given future development, myriad other design and operating decisions as well as site-specific factors could introduce additional impacts during construction, operation, or decommissioning. The issues addressed below are considered to collectively represent the majority of major impactive factors for each of the technologies addressed.

G.2.2 What General Assumptions Does the Hypothetical Scenario Make?

- To the greatest extent feasible, corridors would be developed from their centerlines outward, preserving outmost buffer areas to the greatest extent and longest possible periods of time; however, the entire designated width of a corridor would be available for ROW meandering, when necessary.[13]

- Each project developer and/or operator would utilize accepted industry practices and standards in the design, installation, and operation of the energy transport project and would conform to all applicable or relevant federal, state, and local regulations.

- Construction and decommissioning ROWs would be 50 to 100% wider than operation ROWs (unless specified otherwise in the technology-specific assumptions below) and would exist only for the period necessary to support construction. Temporary use permits (TUPs) may be necessary for extra

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11 However, simultaneous construction activities on adjacent ROWs would still be limited by safety factors and by the natural limitations of supporting logistical systems (e.g., railroad transport of construction materials to the general area).

12 However, it is incorrect to assume that ROWs that are parallel to one another necessarily share a common boundary. It is altogether possible that federal land managers may chose to keep fallow portions of the corridor lying between granted ROWs.

13 Although possible, the granting of a ROW that extends beyond the boundaries of a designated energy corridor is considered to be unlikely.

ROW widths. ROW widths would reduce to operational widths, and rehabilitation of the construction ROW would commence once construction is completed.

- Staging areas for components and construction equipment and materials would be located on nonfederal lands.

- Access roads from existing paved roads to the ROW would have an average distance of 5 miles or less and would be gravel; access roads would be constructed of gravel pack, meet the specifications for a minimal 100-ton load, have a nominal width of 15 feet, and exist within the center of a nominal 25-foot-wide ROW. All access roads critical to operation would be authorized under a ROW or TUP prior to any road building and/or use.

- Access roads of the type minimally necessary to support operation and maintenance would be maintained along the mainline ROW throughout the operating period.

- Access roads to critical support facilities located along the mainline ROW, such as pump stations, compressor stations, and electric substations, would be maintained in gravel throughout the operating life of the transport system; vegetation at these facilities would be continuously managed for security, operational expediency, and fire safety purposes.

- All energy transport systems would be installed over the entire length of a given energy corridor.

- All energy transport systems would run at or near design capacity on a continuous basis.[14]

- The rates at which each energy transport system project would be constructed are dependent on myriad local factors; for the sake of consistent analyses and to allow comparisons with baseline data for one particular year, it is assumed that each of the projects would be installed in each corridor at the rate of 150 miles in any given year and would become fully operational in the following year.[15]

- Technological interferences and instabilities have been identified when certain energy transport technologies exist adjacent to one another; the ROW widths specified below, together with other specific design modifications and/or additions, are considered to be sufficient to adequately address and eliminate those interferences and maintain sufficient reliability for adjacent energy transport systems.

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[14] Continuous operation is selected to produce the maximum possible impact; however, it is recognized that the actual impacts of operation may be less, since each of the energy transport systems under consideration would be shut down (or de-energized) periodically for maintenance, upgrading, and/or repair.

[15] For the sake of analysis, “installation” begins with the activity that first causes disturbance of one or more resources. Thus, initial surveys and testing are not considered “installation,” whereas site preparation (clearing and grading) is.

G.2.2.1 What Electricity Transmission Line Assumptions Does the Hypothetical Scenario Make?

- Transmission lines would have nominal voltages of 500 kV; two lines would carry AC, and one would carry DC.[16]
- Nominal mainline ROW width would be 400 feet, based on the following:
  - Nominal tower height would be 150 feet.[17]
  - Nominal tower designs/materials would be lattice/metal (predominates) and monopole/ metal.
  - Only one three-phase circuit would be installed on each tower, together with the required aerial ground wire (or static wire).[18]
  - Nominal tower width (the width of a cross-arm, if present) would be 100 feet.[19]
  - Clear space to each side of the line would be maintained at a minimum of 150 feet to ensure that a tower would not impact an adjacent tower or transmission line if it were to fall in the direction of that other tower or line.
- Tower spacing on level ground without special concerns for wind or ice loading on the power cables would be 1,000 to 1,200 feet for lattice towers and 800 feet for monopole towers. Different spacings can be expected over radical changes in grade or with changes in direction; towers might be either closer together or father apart, with some extra-tall towers used on severe slopes to ensure adequate ground clearances.[20]
- Tower construction/erection would require special ROW construction considerations:[21]

[16] Power (voltage × current) is not specified because the voltage of a line determines the majority of the parameters of interest to the environmental impact analysis; however, transmission lines intended to carry exceptionally large amounts of current may be designed with larger (heavier) conductors, and thus may require a closer tower spacing.

[17] Substantially taller towers may be required for crossing valleys.

[18] Additional circuits likely could be accommodated on typical lattice towers. However, the added cable weight and wind and ice loading may dictate closer tower spacing than is presumed here. Ground wires are not insulated from the towers and are intended to bond the towers electrically to enhance protection against lightning.

[19] Although the typical maximum width of tower "arms" is 75 feet or less, a dimension of 100 feet was selected to maximize potential visual impact and to ensure that safe distances are maintained between energized conductors, regardless of transmission line configurations and voltages or the presence of adjacent transmission lines.

[20] A change in direction would necessitate a differently designed tower (known as a diversion tower); however, changes to tower design have little effect on the nature or degree of construction or operation impacts over a conventional lattice tower. For DC transmission, power cables would be lighter weight than AC power cables operating at equivalent voltages; thus, support towers for DC transmission could be less substantial in design and placed at greater spacings, notwithstanding similar unique requirements for severe grades.

[21] See ANL (2007a) for additional details.

- Each tower would require a tower assembly area of at least 100 feet × 200 feet.[22]

- Lattice towers would require at least 80,000 square feet per tower for construction.[23]

- Grades within tower construction/ erection areas would be made level to facilitate lifting-equipment placement and operation.

- Tower construction area needs would be reduced by 25% for impact calculations because of overlapping assembly areas.

- At any given time during construction, two cable-pulling sites of 37,500 square feet each (150 feet × 250 feet) would be in use or in preparation.[24]

• Tower installation would utilize conventional construction equipment; however, tower erection in very remote and rugged areas where conventional equipment could not be used would include the use of airlift helicopters.

• Tower foundations would be constructed in accordance with good engineering practice and in consideration of local conditions.

- Foundations for towers would be installed at a nominal depth of 14 to 35 feet, after consideration of climate and local soil and subsurface conditions. At least four such foundations would be required for each typical lattice-type tower, while only one foundation would be required for each monopole tower; however, the monopole foundation typically would be deeper (by as much as 20%) and wider than the corresponding dimensions of a lattice tower's foundation installed in the same subsurface conditions.

- Each typical foundation would utilize as much as 10 cubic yards of concrete.

- Typical working time for ready-mixed concrete would be 45 minutes or less, depending on weather conditions; special tactics may be necessary to conduct concrete work in remote areas.[25]

- Foundations would likely utilize steel-reinforced annular concrete rings of nominal widths of 4 feet and nominal thicknesses of 8 inches, the centers of which would be backfilled with indigenous soils[26]; excess excavation materials would be disposed of off the ROW.

• In addition to tower construction/ erection areas, material laydown areas

22 Tower sections are typically assembled on the ground and lifted into place by cranes.

23 This 80,000 square foot area would be sufficient to support both tower assembly and tower erection. Monopole towers would require 31,415 square feet per tower for construction.

24 However, cable installation tasks are greatly influenced by circumstantial factors that may result in substantially higher area requirements (e.g., 200 ft × 500 ft for cable tensioning and 200 ft × 200 ft for cable pulling).

25 Special tactics may include separate delivery of water and dry cement/aggregate mix to the site and mixing on-site, construction of a temporary cement plant near the site, or delivery of ready-mixed concrete by helicopter.

26 Foundations for monopole towers are typically wider at their base to help resist the tipping/lifting actions imposed by cables reacting to wind. For the purpose of impact analysis, however, foundations are considered cylindrical.

would be located every 10 miles along the construction ROW.

   – Laydown areas would be nominally 3 acres in size.

   – Laydown areas would be maintained free of vegetation throughout the construction period for fire safety.

   – Minimal grade alterations would be made.

   – Temporary roads would be constructed for access to laydown areas by haul vehicles. Laydown areas for substations would be located entirely within the footprint granted in the lease for the substation.

   – Laydown areas would not be used for long-term storage of equipment or materials (except that such storage would occur at substations).

   – Laydown areas would be reclaimed at the end of the construction period, or as soon as the need for each laydown area has ended.

- Substations, switchyards, and other facilities integral to the operation of the transmission line would be located on the mainline ROW; expansions to ROW dimensions would be made to accommodate such essential facilities when necessary.

   – Transformers, capacitors, switches, bushings, and other electrical devices typically containing dielectric fluids would be free of polychlorinated biphenyls (PCBs).

   – Electrical equipment containing liquid dielectric fluids would be installed within adequate secondary containment features.

   – Substations would have a nominal footprint of 20 acres; for fire safety, safety of the operators, and to provide all-weather access, the entire footprint of the substation would be compacted gravel and maintained free of all vegetation throughout the operating period.

   – Substations would be underlain with grounding grids generally extending over the entire aerial extent of the substation; in arid areas, grounding grids may need to extend beyond the substation footprint or, alternatively, wells would be drilled to the nearest aquifer for the purpose of establishing adequate electrical ground.

- Other support facilities such as maintenance or repair facilities, material storage yards, administrative buildings, and operational control centers would be located off the mainline ROW on nonfederal property, whenever possible.

- Natural gas or propane and conventional air-conditioning equipment would be used for heating or cooling any facility or enclosure located on the mainline ROW that requires such temperature controls.

- No maintenance-related wastes would be disposed of within the mainline ROW.

- Vegetation would be maintained along the ROW using a combination of herbicides and physical clearing/cutting.

- Decommissioning would be initiated immediately after the end of the operating period.

   – Decommissioning would involve removal of all above-ground facilities and gravel workpads and roads; subsurface facilities (grounding rods and grids, tower and building foundations, natural gas pipelines, etc.) would be removed to a depth of 3 feet from the surface and otherwise abandoned in place.

– Laydown areas, each nominally 3 acres in size, would be established to support decommissioning; some may be located on the laydown areas used during construction.

– Dismantled components would be staged at laydown areas for only as long as necessary to arrange for their removal to disposal, reclamation, or recycling facilities.

– All spills and contaminated soils would be remediated.

– All gravel packs would be removed.

– Reclamation of laydown areas, substations, access roads, and other "deconstruction" areas would commence immediately upon completion of the dismantlement of the system.

G.2.2.2 What Liquid Petroleum Pipeline Assumptions Does the Hypothetical Scenario Make?

- Pipe inside diameter (ID) would be 32 inches.[27]

- Nominal mainline ROW width would be 50 feet; nominal construction ROW width may be as much as 100% larger than the operating ROW.

- Material laydown areas would be located every 10 miles along the mainline within the construction ROW.

  – Laydown areas would be nominally 3 acres in size.

  – Laydown areas for pump stations would be contained entirely within the footprint for the pump station.

  – Vegetation would be cleared from laydown areas for fire safety.

  – Minimal grade alterations would be made.

  – Temporary gravel access roads may be installed to facilitate haul vehicle access to laydown areas.

  – Laydown areas would not be used for long-term storage of equipment or materials (except that such storage would occur at pump stations).

  – Laydown areas would be reclaimed immediately after the end of the construction period or as soon as the need for each laydown area has ended.

- In any given segment, pipelines would be buried unless subsurface features make excavation prohibitively expensive or technologically infeasible; no more than 10% of mainline pipe length would be above ground in any given segment.

[27] The largest pipe that can be produced in the United States or Canada has a 42-inch outer diameter (OD). Larger diameter pipes would involve purchase of the pipe from overseas sources. The maximum volume expected to be produced in any existing or future single point or consumed (refined) at any single destination would be 500,000 bpd. An accepted pipeline rule of thumb, which estimates flow = (pipeline diameter)^2 × 500, yields a pipeline size of 32 inches to support 500,000 bpd flow (as also highlighted in Footnote 8). Substantially different operating pressures from the norm and the use of drag-reducing agents could greatly influence this size requirement.

- Ancillary facilities such as pump stations, electrical substations, break-out tanks, and pig launch/recovery facilities that are integral to pipeline operation would be located on the mainline ROW; expansions of ROW widths (but within corridor boundaries) would be made to accommodate such facilities, when necessary.

- Other support facilities such as maintenance or repair facilities, material storage yards, administrative facilities, and control centers would be located off the mainline ROW and energy corridor, on nonfederal land, to the greatest extent possible.

- Pump stations would be located within the mainline ROW.

  – Pump stations would be 50 miles apart[28] (assuming the average API gravity of the product being moved to be °25 [at 140°F]).[29]

  – Pump stations would occupy a nominal area of 25 acres, including a cleared perimeter maintained for security and fire safety; the industrial area would be maintained in compacted gravel for all-weather access and fire safety.

  – Pump station structures and any storage tanks would be no more than 30 feet high.

  – Mainline pumps would be powered predominantly by electric motors, with power supplied from commercial sources and occasionally by gas supplied from commercial sources; when electric motors are used, substations may exist at the pump station for power management.

  – Nominal power of each pump would be 5,500 brake horsepower (bhp).

  – For reliability and to facilitate repairs or maintenance without mainline shutdown, three pumps would be installed in a parallel array and two pumps would operate at all times.

  – Pig launch/recovery facilities would always be colocated at pump stations.

- Control valves and check valves would be installed on the mainline pipe in accordance with technological

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[28] Long-distance lines can be expected to have pump station spacings up to 200 miles, whereas short-distance pipelines would have a closer pump station spacing. The 50-mile spacing is taken to be a predictable average spacing, given the variety of lengths of pipelines that could be installed in the designated corridors. This pump station spacing also anticipates that the pipelines would include a number of associated facilities and interconnections, all of which would require an increased number of pump stations.

[29] API °25 approximates the viscosity and bulk density of a heavy fuel oil distillate such as #6 oil or bunker fuel. Pump stations at this spacing and operating at typical power ratings that are sufficient to move materials of that API gravity would easily be capable of moving lighter weight refined distillates that have higher API gravity values (e.g., gasoline API is about °55) and less bulk density and exhibit less frictional drag against the inner walls of the pipe. This API gravity was also selected to ensure that the pump station spacing was adequate to deliver crude shale oil to existing refineries from facilities within Colorado, Utah, and Wyoming after only moderate degrees of upgrading or mixing with diluents at the mine sites. Pipelines that are designed to convey petroleum products with greater viscosities (i.e., lower API gravities) would require pump stations at closer spacings or pump stations at this spacing with increased power capacities. Adding drag-reducing agents to the material (a technique often employed with the long-distance movement of crude oils) would also reduce pump station demands.

requirements and applicable regulations and standards of practice; all valves would have remote-operation capabilities; valves would be located such that the mainline pipe would never contain more than 50,000 barrels of product between valves (assuming a full face of liquid product in the pipeline).

- Vegetation along the mainline would be maintained to the extent necessary to provide for fire safety and to protect system reliability; woody plants whose roots may compromise the integrity of the buried pipe would be controlled; both clearing activities and herbicide applications would be performed.

- In rocky soils, explosives (typically, ammonium nitrate/fuel oil [ANFO]) would be used for trench excavations.[30]

- Excavations for pipe burials would provide for 1.5 feet of bedding material below the pipe and a minimum of 3 feet of overburden above the pipe, resulting in a trench depth of 4.5 feet in addition to the outside diameter of the pipe — that is, 7.25 feet in the case of a 32-inch pipe.

- Widths of excavation trenches would be nominally twice the diameter of the pipe, allowing for stable side slopes during construction and the ability to lay the pipe in a serpentine fashion when necessary to accommodate thermal distortions, resulting in a nominal minimum trench width of 5.25 feet for a 32-inch pipe.[31]

- In no more than 10% of the length of a given segment, excavated indigenous soils or rocks would not be suitable for bedding materials, and appropriate sands or gravels would be imported to the site from the nearest available location, or excavated rock would be crushed to a uniform size on-site.

- Original grades would be reestablished after pipe burial; excess soils would be disposed of off the ROW.

- In arid regions, wells would be dug to the nearest groundwater aquifer for the purpose of installing adequate and reliable electrical grounding for all elements of the pipeline that exist above ground.[32]

- No solid or liquid wastes associated with the operation and maintenance of the pipeline would be disposed of on the ROW.

- Pipeline would undergo hydrostatic testing at the completion of construction and before being put into service and on every occasion thereafter when the pipeline is opened for repairs or replacements. Hydrostatic test water would be obtained from local resources or commercial suppliers; hydrostatic test water would be disposed of along the ROW (including discharge to the ground surface or to surface waterbodies) under the auspices of state-issued permits.

- River crossings would occur beneath the water with the depth of burial beneath the streambed (to the top of the pipe) dictated by regulation plus 10% additional thickness to allow for river scouring over the entire operating period

[30] Rock cutters are also sometimes used in lieu of explosives; however, explosives were selected for the model system to maximize impact.

[31] However, for the purpose of impact calculations, the sides of the trench are presumed to be vertical; thus, the cross-sectional area is the nominal depth multiplied by the nominal width, without correction for the slope angle of the sides.

[32] As is customary, segments of the pipeline that exist above ground would be electrically isolated from segments that are buried for the purpose of corrosion control.

of the pipeline[33]; trench burial of the pipeline in the streambed would occur only in nonnavigable watercourses.

- Decommissioning would begin immediately after the end of the operating period.
  - Decommissioning would involve removal of all above-ground features, gravel workpads, and gravel access roads, and the removal of subsurface equipment to a depth of 3 feet.
  - Mainline pipe existing at depths of 3 feet or greater would be emptied, cleaned, plugged, and abandoned in place; wastes from pipe cleaning would be disposed of off the ROW.
  - Original laydown areas would be reestablished or new laydown areas would be established to support decommissioning/dismantlement.
  - Laydown areas would be maintained clear of vegetation throughout the decommissioning period.
  - All tanks would be emptied and cleaned prior to dismantlement or movement to recycling or salvage facilities off the ROW.
  - Materials and equipment would remain in the laydown area only for as long as required to relocate the materials and equipment to salvage or recycling facilities.
  - All spills and contaminated soils would be remediated.
  - Original grades would be reestablished.

G.2.2.3 What Gaseous Product Pipeline Assumptions Does the Hypothetical Scenario Make?

- Pipe diameter is assumed to be 42 inches.
- Nominal mainline ROW width would be 50 feet; nominal construction ROW may be as much as 120% of the operating ROW.
- Operating pressure would be as high as 1,400 psig.
- Material laydown areas would be located every 10 miles along the mainline within the construction ROW.
  - Laydown areas would be nominally 3 acres in size.
  - Laydown areas for compressor stations would be contained entirely within the footprint for the pump station.
  - Vegetation would be cleared from laydown areas for fire safety.
  - Minimal grade alterations would be made.
  - Temporary gravel access roads may be installed to facilitate haul-vehicle access to laydown areas.
  - Laydown areas would not be used for long-term storage of equipment or materials (except that such storage would occur at compressor stations).
  - Laydown areas would be reclaimed immediately after the end of the

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33 The DOT's Office of Pipeline Safety specifies a depth of burial ranging from 36 inches to 48 inches (see Title 40, Part 195.248, of the *Code of Federal Regulations* [40 CFR 195.248]).

construction period or as soon as the need for each laydown area has ended.

- Compressor stations would be located within the mainline ROW.

  – Compressor stations would be nominally 40 miles apart.

  – Compressors would be powered by natural gas drawn from the pipelines they serve or drawn from commercial sources.

  – Compressor stations would be have a maximum footprint of 20 acres, including a cleared perimeter for security and safety; the industrial footprint would be compacted gravel for fire safety and to provide all-weather access.

  – Average compressor station total power capacity would be 13,000 bhp.

  – For reliability and to facilitate repairs or maintenance without mainline shutdown, compressor station design allows three compressors to be installed in parallel, with two compressors operating at all times.

  – Compressor station structures would be no more than 20 feet high, except for the exhaust stacks for each compressor, which would be 50 feet high.

  – Pig launch/recovery facilities would be located on the mainline ROW, but may not be located at compressor stations.

- Other facilities that are integral to the operation of the pipeline, such as city gates and pig launch/recovery facilities, would be located on the mainline ROW. Expansions of ROW widths would be made to accommodate such facilities, when necessary; the nominal size of pig launch/recovery facilities not located at compressor stations would be 0.5 acres; the nominal size of city gates would be 3 acres.

- Other support facilities, such as maintenance facilities, material storage yards, administrative facilities, and operational control centers, would be located off the mainline ROW on nonfederal land to the greatest extent possible.

- In any given segment, pipelines would be buried unless subsurface features make excavation prohibitively expensive or technologically infeasible (e.g., seismically active zones); no more than 10% of mainline pipe length would be above ground in any given segment.

- Control valves and check valves would be installed on the mainline pipe in accordance with technological requirements, applicable regulations, and standards of practice; all valves would have remote operation capability. Each transmission line would have sectionalizing block valves spaced as follows, unless it is determined that an alternative spacing would provide an equivalent level of safety:

  – Each point on the pipeline in a Class 4 location must be within 2.5 miles of a valve.

  – Each point on the pipeline in a Class 3 location must be within 4 miles of a valve.

  – Each point on the pipeline in a Class 2 location must be within 7.5 miles of a valve.

- Each point on the pipeline in a Class 1 location must be within 10 miles of a valve.[34]

- Control valves would be installed on either side of a river crossing (as per standard industry practice).

- Compressor stations, city gate stations, ground valves, and other above-ground features of the pipeline would be secured by fencing; compressor stations and city gate stations would have security lighting and remote surveillance features.

- The entire lengths of buried sections of metallic pipelines would have cathodic protection in accordance with DOT regulations (49 CFR 192, Appendix D).

- Portions of the pipeline above ground would be electrically isolated from belowground segments, appropriately coated for corrosion control, and protected against lightning; in arid areas, wells may be dug to the nearest aquifer to allow a ground rod to reach adequate grounding conditions.

- Blowdown valves would be located within each pipeline segment (between mainline valves); when pipelines are adjacent to electrical transmission lines, gas venting from blowdown valves would be directed away from the electrical conductors.

- Vegetation along the mainline would be maintained in accordance with applicable regulations and standards of practice utilizing a combination of clearing/cutting and herbicide application; woody plants whose roots may compromise the integrity of the buried pipe would be controlled.

- In rocky soils, explosives (typically, ANFO) would be used for trench excavations.[35]

- Excavations for pipe burials would provide for 1 foot of bedding material below the pipe and a minimum of 3 feet of overburden above the pipe, resulting in a nominal trench depth of 7.5 feet for a 42-inch-diameter pipe.

- Widths of excavation trenches would be nominally twice the diameter of the pipe, allowing for stable side slopes during construction and access to the sides of the pipe as it is being installed, for the purpose of installing corrosion-control coatings and devices, resulting in a nominal minimum trench width of 7 feet for a 42-inch-diameter pipe.[36]

- In no more than 10% of the length of pipe in a given segment, excavated indigenous soils or rocks would not be suitable for bedding materials, and appropriate sands or gravels would be imported to the site from the nearest available location, or excavated rock would be crushed and sized on-site so it can be used as bedding.[37]

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[34] As per Office of Pipeline Safety regulations, 40 CFR 192. Class locations are defined in 40 CFR 192.5. See http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=192a5d9ec2f41944f3af0dc1af118227&rgn=div8& view=text&node=49:3.1.1.1.3.4.10.22&idno=49 for valve location requirements.

[35] Rock cutters are sometimes used in lieu of explosives for trench excavations. Explosives were selected for the model facility in order to maximize the potential for environmental impact.

[36] However, for the purpose of impact calculations, trench sides are presumed to be vertical.

[37] Heavy clay soil that retains water and unevenly sized rock with sharp edges would be considered unsuitable for bedding material. Using unevenly sized materials as fill would introduce the potential for later subsidence.

- Original grades would be reestablished after pipe burial; excess soils would be disposed of off the ROW.

- Pipeline would undergo hydrostatic testing at the completion of construction and before being put into service and on every occasion thereafter when the pipeline is opened for repairs or replacements. Hydrostatic test water would be obtained from local resources or commercial suppliers; hydrostatic test water would be disposed of along the ROW (including discharge to the ground surface or to surface waterbodies) under the auspices of state-issued permits.

- No solid or liquid wastes associated with the operation and maintenance of the pipeline would be disposed of on the ROW or within the designated corridor.

- River crossings would occur beneath the water with the depth of burial beneath the streambed (to the top of the pipe) dictated by regulation plus 10% additional thickness to allow for river scouring over the entire operating period of the pipeline[38]; trench burial of the pipeline in the streambed would occur only in nonnavigable watercourses.

- Decommissioning would begin immediately after the end of the operating period.

  – Decommissioning would involve removal of all above-ground features, gravel workpads, and gravel access roads, and removal of subsurface equipment to a depth of 3 feet.

  – Mainline pipe existing at depths of 3 feet or greater would be emptied, cleaned, plugged, and abandoned in place; wastes from pipe cleaning would be disposed of off the ROW.

  – Original laydown areas would be reestablished or new laydown areas would be established to support decommissioning/dismantlement.

  – Laydown areas would be maintained clear of vegetation throughout the decommissioning period.

  – Materials and equipment would remain in the laydown area only for as long as required to relocate the materials and equipment to salvage or recycling facilities.

  – All spills and contaminated soils would be remediated.

  – Original grades would be reestablished.

[38] DOT's Office of Pipeline Safety specifies a depth of burial ranging from 36 inches to 48 inches (see 40 CFR 195.248).