2.0 DESCRIPTION OF THE PROPOSED ACTION

The FERC is the federal agency responsible for authorizing applications to construct and operate onshore LNG import and interstate natural gas transmission facilities. The Coast Guard is the federal agency responsible for determining the suitability of the waterway for LNG marine traffic. The Coast Guard is also the federal agency responsible issuing a LOR regarding the suitability of the waterway for LNG marine traffic.

The proposed action before the FERC is to consider issuing to Sempra a section 3 authorization for the LNG import facilities and a section 7 Certificate for a new natural gas pipeline. The proposed action before the Coast Guard is to consider issuing Sempra a Coast Guard Letter of Recommendation finding the waterway suitable for LNG Marine Traffic, with certain conditions. These conditions are delineated, in part, in the Coast Guard's March 20, 2006 letter to FERC (attached as Appendix H). Specifically these conditions require that all agencies that would be involved in navigation safety and maritime security aspects of LNG vessels transiting to and operating at the Port Arthur Terminal be adequately staffed, equipped and funded to fully implement the safety and security measures. These measures include, but are not limited to, security zones around the LNG carriers, a vessel traffic control plan, escorts by armed law enforcement vessels, a variety of waterway and shoreline surveillance measures, and multi-agency cooperation and communication. Specific details of these measures are further delineated in the Coast Guard's March 20, 2006 letter to FERC which has been designated Sensitive Security Information as defined in Title 49 CFR Part 1520. Because any unauthorized disclosure of these details could be employed to circumvent the proposed security measures, they are not releasable to the public.

2.1 PROPOSED FACILITIES

Sempra proposes to construct and operate a new LNG import, storage, and vaporization terminal on the Port Arthur Ship Canal, south of Port Arthur, Texas. It also proposes to construct two natural gas send-out pipelines to transport the imported natural gas from the LNG terminal to interconnections with the existing natural gas pipeline infrastructure. A 3-mile-long pipeline would be constructed in Jefferson County, Texas. This pipeline would end at NGPL facilities south of the proposed LNG terminal. A 70-mile-long pipeline would be constructed from the terminal, northeasterly, ending at the Transco pipeline downstream of Transco's Compressor Station No. 45, and traversing Jefferson and Orange Counties, Texas, and Cameron, Calcasieu, and Beauregard Parishes, Louisiana. These facilities are shown on the general project location map, **figure 2.1-1**, and in greater detail in **appendix C**. In addition, construction of the ship berth would require the relocation of 3.3 miles of SH 87 as well as existing pipelines and utilities that parallel the highway (see **appendix A**). The total length of the relocated highway and utility corridor would be 3.7 miles. Sempra would relocate the highway, pipelines, and utilities to property they own; no land owned or leased by other parties would be affected. This section describes the proposed Port Arthur LNG Project facilities, land requirements, construction procedures and schedule, environmental compliance and inspection monitoring, operation and maintenance procedures, and safety controls. Non-jurisdictional facilities, including the relocation project and the electric service facilities necessary to provide power to the terminal (transmission lines and substation), are addressed in **appendix A**.

2.1.1 LNG Terminal Facilities

The LNG terminal facilities would consist of a turning basin and two berths, six LNG storage tanks, and a vaporization system and vapor handling system. The terminal facility would be located on approximately 198 acres of a 540-acre site under Sempra ownership on the western shore of the Port Arthur Ship Canal, south of Port Arthur in Jefferson County, Texas. Of the 198 acres, approximately 116 acres would be

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Figure 2.1-1

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used for the marine facilities. An additional area of 65 acres outside of the LNG terminal site would be used for temporary construction areas (laydown, office, and parking). The plot plan of the LNG terminal is shown in **figure 2.1.1-1.**

2.1.1.1 Marine Facilities

The Port Arthur LNG Project would include the construction of marine facilities to berth and unload LNG ships. The marine facilities would consist of an LNG unloading slip with 2 berths and a turning basin approximately 1,700 feet in diameter. The marine facilities would be capable of unloading on the order of 180 ships per year during Phase I and a total (for both Phase I and II) of up to 360 ships per year. The actual number of ships would be dependent on the size of the ships calling on the terminal over time. Assuming an average LNG ship size of 140,000 m^3 during Phase I, a total of 186 ship arrivals would be required to meet the Phase I sustained natural gas send-out rate of 1.5 Bcf/d. If a 200,000 m^3 average ship size is assumed for Phase II, a total of 260 LNG ship arrivals would be required to meet the Phase II sustained natural gas send-out rate of 3.0 Bcf/d. A ship traffic study conducted by Lanier and Associates (2004) concluded that the additional LNG ship traffic associated with the Project can be accommodated in the SNWW. Some additional resources, such as tugs and pilots, may be required if all anticipated growth within the SNWW occurs as is currently contemplated.

The LNG ship unloading slip would be approximately 1,310 feet in length and 1,890 feet in width and dredged to match the depth of the channel. For purposes of estimating the amount of dredged material, a nominal depth of minus 40 feet mean lower low water (MLLW) was used. A turning basin with an approximate radius of 850 feet would be partially within the slip. Construction of the slip would require the dredging of approximately 5.3 million cubic yards (yd^3) of material and construction of the turning basin would require the dredging of approximately 1.4 million yd^3 for a total of 6.7 million yd^3

Each berth would be sized to handle LNG ships with capacities of 125,000 m^3 up to 250,000 m^3 and drafts up to 40 feet. Three breasting dolphins would be provided at each berth, consisting of reinforced concrete caps 15 feet in length and 15 feet wide constructed on steel piles. The breasting dolphins would be equipped with energy absorbing fenders capable of safely berthing the full range of ships being considered, as well as access ladders to the water and quick release mooring hooks with load monitoring systems. Access bridges would be provided at each berth to connect each breasting dolphin to the lower deck of the unloading platform and to the mooring dolphins. Six mooring dolphins would be provided at each berth, each consisting of reinforced concrete caps supported on piles. The caps would be approximately 15 feet long and 15 feet wide. Mooring dolphins would be provided with quick release mooring hooks with load monitoring systems, light poles, access ladders to the water, and protective hand railing, except on the mooring line faces. All mooring dolphins would be interconnected to the unloading platform by personnel bridges.

The unloading platform at each berth would be a two level structure. The lower deck of the unloading platform would comprise a reinforced concrete beam and slab deck structure, approximately 100 feet wide by 110 feet long, supported on piles. The deck would be sloped to discharge rainwater into the slip. The elevated unloading arm deck would be a reinforced concrete beam and slab deck structure, on steel columns, supported on the lower deck of the unloading platform. The upper deck would be curbed to confine LNG spillage and its surface would be sloped to a collection point. Drainage from this point would be via a LNG spill collecting trough to a LNG spill containment sump.

A total of five marine unloading arms would be installed on each unloading platform, three for unloading LNG to the terminal storage tanks, one for vapor return to the LNG ship, and one hybrid arm capable of unloading LNG to the terminal storage tanks or returning vapor to the ship. The unloading arms would be designed with swivel joints to provide the required range of movement between the ship and the shore

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Figure 2.1.1-1

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connections. Each arm would be fitted with powered emergency release coupling valves to isolate the arm and the ship in the event of an emergency separation. Each arm would be operated by a hydraulic system and a counterbalance weight would be provided to reduce the deadweight of the arm on the shipside connection and to reduce the power required to maneuver the arm into position. Additional unloading platform equipment would include a ship gangway, area lighting facilities, navigation aids, and firewater monitors.

The facilities would be designed to provide safe berths for the receipt and support of LNG ships and to ensure the safe transfer of LNG cargo from the ships to on-shore storage facilities. Design would be in accordance with applicable codes and standards, including but not limited to Oil Companies International Marine Forum, Society of International Gas Tanker and Terminal Operators (SIGTTO), American Petroleum Institute (API), and American Society of Civil Engineers (ASCE).

2.1.1.2 LNG Storage Tanks

The LNG would be stored in full containment LNG storage tanks designed to store 160,000 m^3 (1,006,000 barrels) of LNG at a temperature of -270 degrees Fahrenheit (°F) and a normal pressure of 1 to 4 pounds per square inch gauge (psig). Three LNG tanks would be constructed during Phase I and three during Phase II of the Project. Each tank would have a primary 9 percent nickel steel inner container and a secondary pre-stressed concrete outer container wall, a reinforced concrete outer container bottom, a reinforced concrete domed roof and an aluminum insulated support deck suspended from the outer container roof over the inner container (see **figure 2.1.1.2-1**). These tanks would be designed and constructed so that both the primary container and the secondary container would be capable of independently containing the stored LNG. The primary container would contain the cryogenic liquid under normal operating conditions. The secondary container would be capable of containing the cryogenic liquid and of controlling vapor resulting from product release from the inner container. The outside diameter of the outer container would be approximately 256 feet and the height of the top of the dome would be approximately 176 feet above grade. The LNG tank pile cap would be elevated with approximately 6 feet of clear space between the final grade and the bottom of the pile cap.

The space between the inner container and the outer container would be insulated with expanded perlite that would be compacted to reduce long-term settling. This insulation would allow the LNG to be stored at a temperature of -270°F while maintaining the outer container at near ambient temperature. The insulation under the inner container's bottom would be a cellular glass, load bearing insulation. The outer concrete container above the approximately 16-foot-high thermal corner protection system would be lined on the inside with carbon steel plates. This carbon steel liner would serve as a barrier to moisture migration from the atmosphere reaching the insulation inside the outer container. This liner also would form a barrier that prevents vapor from escaping from inside the tank during normal operations. To increase the safety of the tank, there would be no penetrations through the inner container or outer container sidewall or bottom below the maximum liquid level. All piping into and out of the tank would enter from the top of the tank.

The LNG storage tanks constructed during Phase I would be located within an area that would be enclosed by a storm surge/security barrier, approximately 7 feet high. The storm surge/security barrier would be designed to contain the contents of one 160,000 m^3 LNG storage tank. The LNG storage tanks constructed during Phase II also would be within an area enclosed by a similarly sized, but separate, storm surge/security barrier.

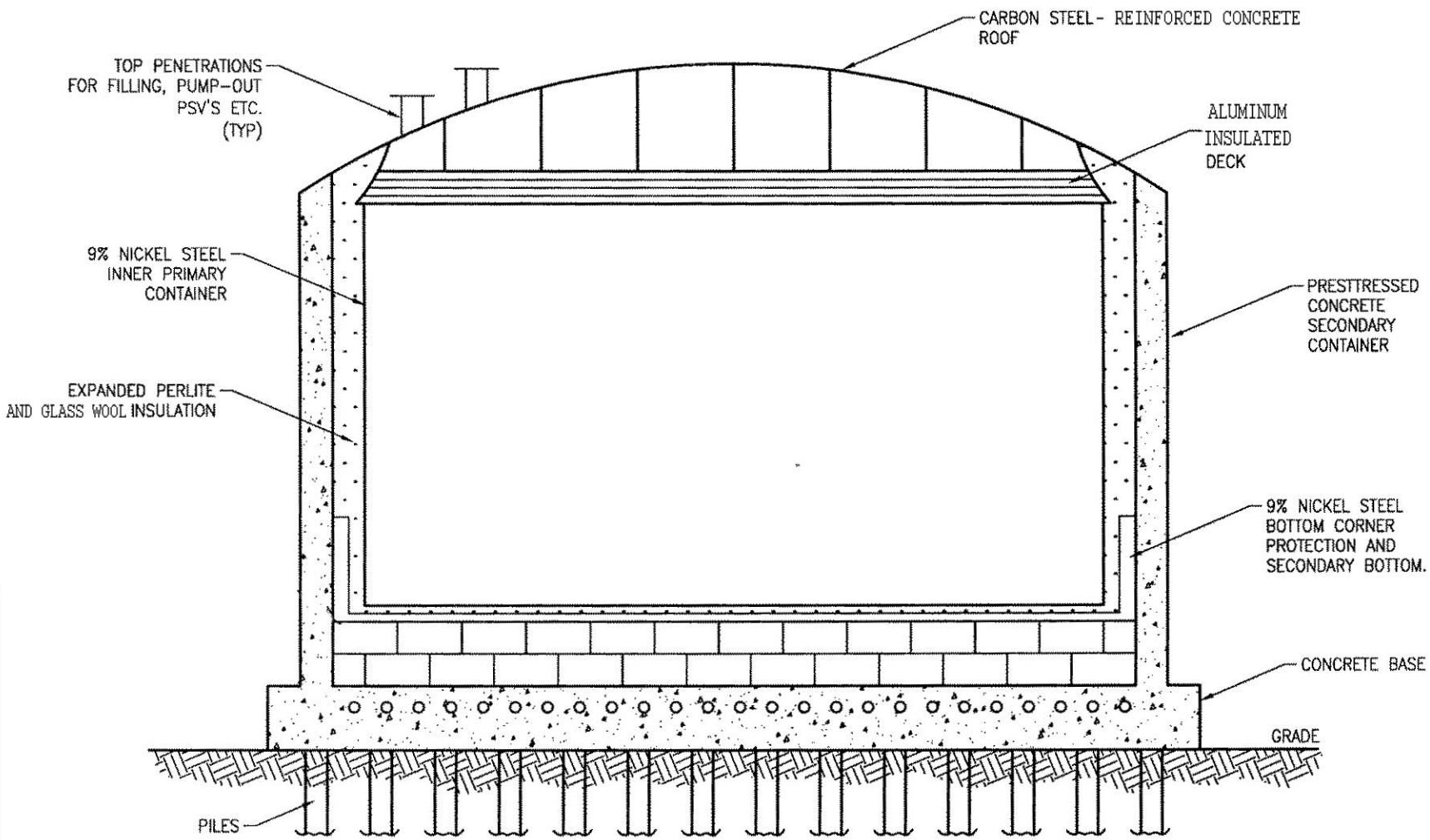

Figure 2.1.1.2-1
Conceptual Design of the LNG Storage Tanks
Port Arthur LNG Project

2.1.1.3 Vaporization System

LNG from the LNG storage tanks must be pressurized and vaporized so that natural gas can be sent out via the natural gas pipeline systems (**figure 2.1.1.3-1**). Each LNG storage tank would have three in-tank pumps. The in-tank pumps would deliver the LNG from the LNG storage tanks to the LNG booster pumps. During Phase I, a total of eight LNG booster pumps would be installed, with an additional eight LNG booster pumps installed during Phase II. A total of five in-tank pumps and seven LNG booster pumps would be required to achieve the Phase I design send-out rate of 1.5 Bcf/d and a total of 10 in-tank pumps and 14 LNG booster pumps would be required to achieve the Phase II send-out rate of 3.0 Bcf/d. The remaining non-operating pumps would be available as spares or for peaking service. The LNG discharged from the booster pumps would flow to the vaporizers.

During Phase I, six (five plus one spare) shell and tube vaporizers (STVs) would be used to vaporize the LNG. Each vaporizer would be capable of vaporizing approximately 0.305 Bcf/d of LNG, 0.3 Bcf/d as send-out natural gas and 0.005 Bcf/d routed to the LNG terminal fuel system. Heat for the LNG vaporization would be supplied from the burning of natural gas to heat water that would be circulated through the shell side of the vaporizers. The water heaters, each rated for an absorbed heat duty of 348 MMbtu/hr, would heat the water to 210°F. After leaving the vaporizers, the high pressure gas would pass through the metering station and then into the natural gas pipeline.

The Phase I and Phase II pumps and vaporizers would be installed within curbed spill collecting areas. Drainage from these curbed collecting areas would be conveyed via LNG spill collecting troughs to the LNG spill containment sump located towards the northern part of the LNG terminal site.

2.1.1.4 Vapor Handling System

During normal operation, ambient heat input into the LNG would cause a small amount of LNG to be vaporized. Some vaporization of LNG also would be caused by other factors, such as barometric pressure changes, heat input due to pumping, and ship flash vapor. The vapor handling system would recover and condense these vapors and combine them back with the send-out LNG. Vapor from the LNG storage tank would be compressed by the BOG compressors and then passed to the recondenser system where it would be condensed into the outgoing LNG prior to being pumped up to pipeline pressure in the LNG booster pumps.

During LNG ship unloading operations, vapors also are released from the LNG storage tanks due to simple displacement as the tanks are filled. A portion of this vapor would be returned to the ship to make up for the volume of liquid pumped out of the ship into the LNG storage tanks. This vapor would be returned to the ship using the return gas blowers. The vapor return system would include a desuperheating system at each unloading berth to ensure that the vapor is returned to the ships at an acceptable temperature. During an upset condition, vapor from the tanks would be directed to the vent to prevent over pressuring the LNG storage tanks.

2.1.1.5 LNG Ships

LNG is currently shipped from a variety of sources around the world, including such locations as Algeria, Australia, Brunei, Indonesia, Malaysia, Nigeria, Oman, Qatar, Trinidad, and United Arab Emirates. Sempra anticipates that LNG could be delivered to the proposed LNG terminal from any of these worldwide sources. Although LNG ships and their operation are directly related to the use of the proposed import terminal, they are not subject to the section 3 authorization sought in the FERC

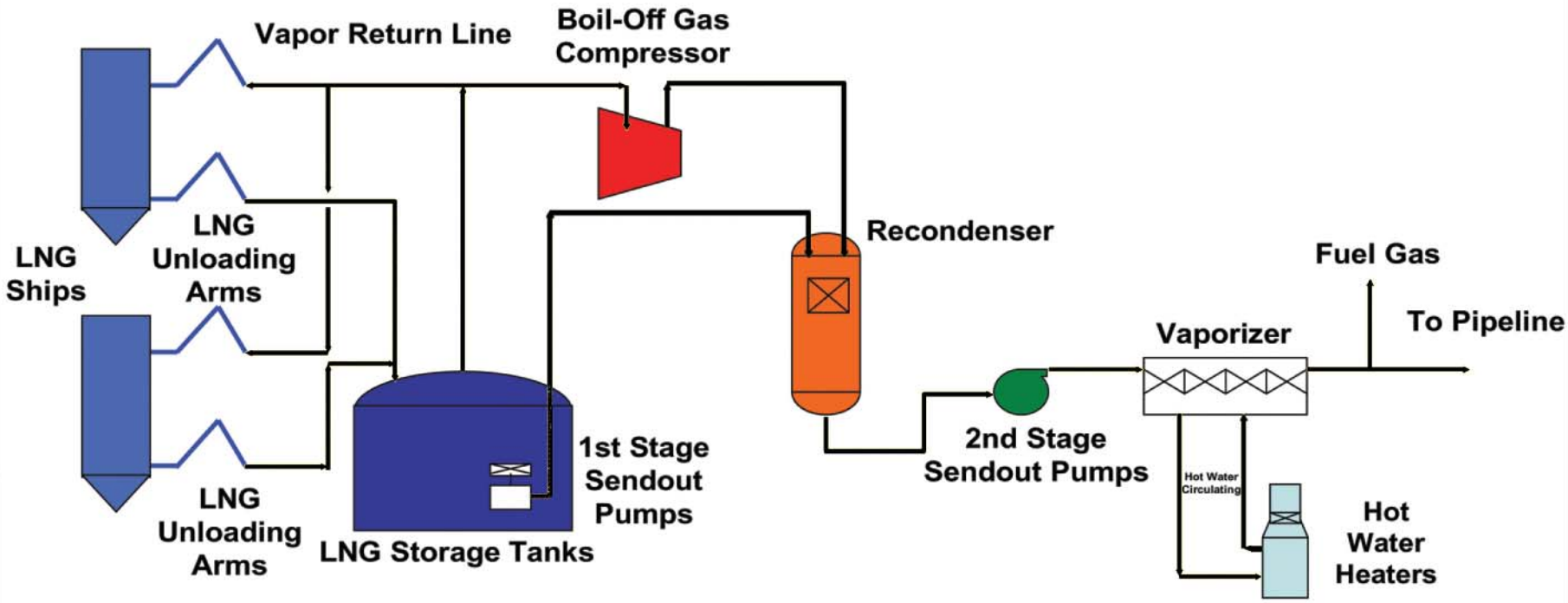

Figure 2.1.1.3-1
Block Flow Diagram of the LNG Terminal
Port Arthur LNG Project

application. However, the Coast Guard is responsible for determining the suitability of the Sabine/Neches Waterway for these LNG ships and must issue an LOR for the operation of the proposed facility. On March 20, 2006, the Coast Guard made a preliminary determination that the Sabine/Neches Waterway from the Gulf of Mexico to the proposed LNG terminal site, may be suitable for accommodating the type and frequency of LNG vessels proposed for the Port Arthur LNG Project.

The ships that transport LNG are specially designed and constructed to carry LNG for long distances. LNG ship construction is highly regulated and combines conventional ship design and equipment with specialized materials and systems designed to safely contain liquids stored at temperatures of -260°F.

The following sections present a brief overview of the main design and safety features of a typical LNG ship that may transport LNG to the Port Arthur LNG terminal.

Profile

LNG ships have a distinctive appearance compared with other transport ships. A LNG ship has a high freeboard (i.e., that portion of the ship above water), when compared with vessels such as an oil tanker, because of the comparatively low density of the cargo. Because of the high freeboard, wind velocity can adversely affect the maneuverability of the ship, particularly at slow speed, such as during docking.

Hull System

All LNG ships are constructed with double hulls while most other liquid transport ships presently in use have single-hull construction. Double-hull construction increases the structural integrity of the hull system and provides protection for the cargo tanks in case of an accident. The space between the inner and outer hulls is used for water ballast. The International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (Gas Tanker Code) and USCG regulations require that LNG ships meet a Type IIG standard of subdivision, damage stability, and cargo tank location.

The Type IIG standard requires that the LNG ship design withstand flooding of any two adjacent compartments without any adverse effect upon the stability of the ship. Type IIG design also requires that the cargo tanks must be a minimum of 30 inches from the outer hull and a minimum distance above the bottom of the ship equal to the beam of the ship divided by 15, or 6.5 feet, whichever is less. This distance is intended to prevent damage to the cargo tanks in case of low energy-type accidents that might occur in harbors and during docking. Most large LNG ships have a distance of 10 to 15 feet between the outer hull and cargo tank.

Containment Systems

The LNG containment system on the LNG ships consists principally of the cargo tank (sometimes called a primary barrier), the secondary barrier, and insulation. The containment system also includes cargo monitoring and control and safety systems.

Three basic tank designs have been developed for LNG cargo containment: prismatic free standing, spherical, and membrane. The earliest form of LNG containment is the prismatic free-standing tank. It consists of an aluminum alloy or 9 percent nickel steel, self-supporting tank that is supported and restrained by the hull structure. Insulation consists of reinforced polyurethane foam on the bottom and the sides, with fiberglass on the top. The spherical tank design uses an unstiffened, spherical, aluminum alloy tank that is supported at its equator by a vertical cylindrical skirt with the bottom of the skirt integrally welded to the ship's structure. This free-standing tank is insulated with multi-layer close-cell polyurethane panels. In the membrane containment system, the ship's hull constitutes the outer tank wall

with an inner tank membrane separated from it by insulation. Two forms of membrane are commonly used: the Technigaz membrane using stainless steel and the Gas-Transport membrane using Invar.

LNG tankers are of the double-hulled design regardless of the containment system used. A double bottom and double sides are provided for the full length of the cargo area and arranged as ballast tanks, independent of the cargo tanks. The double-hulled design provides greatly increased reliability of cargo containment in the event of grounding and collisions. Further, the segregated ballast tanks prevent ballast water from mixing with any residue in the cargo tanks.

Pressure/Temperature Control

A basic goal of all LNG containment systems is to maintain the LNG cargo at or near atmospheric pressure at the boiling temperature of the LNG (about -260°F). This is accomplished using "auto refrigeration," a phenomenon that results from the constant heat flow into the tank and the removal of the associated vapor.

The vapor generated during auto-refrigeration is known as boil-off. Typical boil-off rates of LNG ships range from 0.15 to 0.25 percent (by volume) per day. Currently, all LNG ships burn the boil off as fuel. The USCG does not permit routine venting of BOG to the atmosphere in the U.S. Thus, all LNG ships that trade in the U.S. are fitted with an internalized combustion energy system that allows the ship's boilers to consume all of the BOG to fuel the ship's steam propulsion system. As a result, LNG ships have reduced emissions of air pollutants when compared with conventional oil-fired ships.

Ballast Tanks

Sufficient ballast water capacity must be provided to permit the ship to return to the loading port safely under various sea conditions. LNG cargo tanks are not used as ballast tanks because these tanks must contain a minimal amount of LNG in them at all times, even when "empty" in order to keep the tanks cold in normal operation. Consequently, LNG ships must be designed to provide adequate ballast capacity in other locations.

Ballast water tanks are arranged within the LNG ship's double hull. Since it is essential that ballast water not leak into the LNG containment system, the ballast tanks, cofferdams, and void spaces are typically coated to reduce corrosion and the potential for leakage. LNG ships also are periodically inspected to examine the coating and to renew it as necessary.

A ballast control system, which permits the simultaneous intake of ballast during cargo transfer operations, also is incorporated into each LNG ship. This allows the LNG ship to maintain a constant draft during all phases of its operation to enhance performance. Under normal operating conditions, ballast water would be taken onto the ship during and after LNG offloading.to maintain the trim and stability of the ship. A 138,000 m^3 LNG ship would typically take on ballast water at a rate of about 5,200 cubic meters per hour (m^3/hr) (about 1.4 million gallons/hour) and a 200,000 m^3 ship would take on ballast water at a rate of about 7,500 m^3/hr (about 2 million gallons/hour). For both ships, the ballast water would be taken on over a 10-hour period, resulting in a total ballast water intake per ship of about 52,000 m^3 (13.7 million gallons) for a 138,000 m^3 ship and 75,000 m^3 (19.8 million gallons) for a 200,000 m^3 ship. Assuming a 10-hour reballasting period for a 138,000 m^3 ship, the average ballast water intake velocity would be about 1 foot per second. A portion of this ballast water would be taken on while at berth and the remaining amount would be taken on while in transit down the Sabine/Neches Waterway. Ballast water would not be discharged to the Sabine/Neches Waterway during unloading operations

Ship Safety Systems

The LNG vessels proposed for Project use would have to comply with all federal and international standards regarding LNG shipping. As such, ships that transport LNG to the Port Arthur LNG terminal would be fitted with an array of cargo monitoring and control systems. These systems would automatically monitor key cargo parameters while the ship is at sea and during the remote control phase of cargo operations at the marine terminal basin. The system includes provisions for pressure monitoring and control, temperature monitoring of the cargo tanks and surrounding ballast tanks, emergency shutdown of cargo pumps and closing of critical valves, monitoring of tank cargo levels, and gas and fire detection.

The LNG ships also would be fitted with many navigation and communication systems, including:

- two separate marine radar systems, including automatic radar plotting and radio direction finders;
- LORAN-C receivers;
- echo depth finders; and
- a satellite navigation system.

All LNG ships also have redundant, independent steering control systems that are operable from the bridge or steering gear room to maintain rudder movement in case of a steering system failure.

Fire Protection

All LNG ships arriving at the Port Arthur LNG terminal would be constructed according to structural fire protection standards contained in the International Convention for the Safety of Life at Sea (SOLAS). This would be done under the review and approval of the USCG.

The ships also would be fitted with active fire protection systems that meet or exceed design parameters in USCG regulations and international standards, such as the Gas Tanker Code and SOLAS, including:

- a water spray (deluge) system that covers the accommodation house and central room, and all main cargo control valves;
- a traditional firewater system that provides water to fire monitors on deck and to fire stations found throughout the ship;
- a dry powder fire extinguishing system for LNG fires; and
- a carbon dioxide (CO_2) system for protecting the machinery, ballast pump room, emergency generators, cargo compressors, etc.

Crew Qualifications and Training

All officers and crews of the LNG ships would comply with the International Convention Standards of Training, Certification and Watch Keeping for Seafarers. Key members of the crew must have specific training in the handling of LNG and the use of the safety equipment. Officers must receive simulator

training in the handling of the ship and the cargo systems specific to the conditions at the Project site. In addition, a local pilot from the port would board each ship and guide it through the SNWW.

Ship Selection

The specific identity of LNG ships that would offload at the Port Arthur LNG terminal would depend on the commercial terms of the LNG purchase agreements. Transportation could be provided by either the LNG buyer or supplier. The different contractual arrangements for LNG transport can result in ships of different sizes and countries of origin being used to transport LNG to the Port Arthur LNG terminal.

Table 2.1.1.5-1 shows the relative dimensions of the 125,000 m^3 to 145,000 m^3 ships typical of those presently in service; and the dimensions of future ships ranging from 165,000 m^3 to 250,000 m^3.

TABLE 2.1.1.5-1

Typical LNG Ship Characteristics

Specifications	Existing Ships		Future Ships		
Capacity (m^3)	125,000	145,000	165,000	200,000	250,000
Length Overall (feet)	936 - 950	905 - 936	982	1,033	1,128
Beam (feet)	135 - 145	142 - 158	151	164	177
Draft (feet)	35 - 36	37 - 38	38	39	39

Source: Cheniere Sabine's Vessel Maneuvering Simulation Study for Sabine Pass LNG Terminal (October 2003).

Ships using the terminal would also comply with the Coast Guard regulations for LNG ships. This compliance is demonstrated by the operator of the LNG ship having proper certificates authorizing the transport of LNG as follows:

- United States Flag LNG Ship - The Coast Guard Certificate of Inspection must be valid and endorsed for the ship to transport LNG (46 CFR 154, 1979). A Coast Guard Certificate of Inspection (COI) is issued for a period of 5 years and retention of the COI depends upon the continued maintenance of the vessel in a safe operating condition and satisfactory completion of required annual inspections during the 5-year COI period.

- Foreign Flag LNG Ship - The ship must have a valid Certificate of Compliance issued by the Coast Guard. The certificate is issued after the ship has proven that it complies with the Coast Guard regulations and after it has been satisfactorily inspected by a Coast Guard Marine Safety Office (46 CFR 154, 1979). A Certificate of Compliance (COC) is valid for a 2-year period and remains valid pending satisfactory completion of an annual mid-period examination between COC renewals

Both United States and foreign flagships must be annually inspected by the Coast Guard and the flag state. USCG officers from the Marine Safety Unit, Port Arthur, Texas, may board the LNG ships arriving in the SNWW to ensure safety standards are met. Sempra would continually monitor ship operations to ensure that operations are in accordance with its established procedures and that ships are maintained to all standards.

2.1.2 Pipeline Facilities

Sempra also proposes to construct two 36-inch-diameter natural gas pipelines; one pipeline would be approximately 70 miles in length, extending northeast from the proposed Port Arthur LNG terminal to the

existing Transco Compressor Station No. 45 in Beauregard Parish, Louisiana, and would be constructed during Phase I of the Project. The other pipeline, approximately 3 miles in length, extending from the LNG terminal to an existing NGPL pipeline that passes south of the terminal, would be constructed during Phase II. Potential interconnections with existing intrastate and interstate pipeline systems include Sabine, Florida Gas Transmission (FGT), Tennessee Gas, and Texas Eastern along the 70-mile-long route. The 70-mile-long pipeline would have a capacity to transport 1.5 Bcf/d of natural gas during Phase I of the project. The total capacity of the system would increase to 3.0 Bcf/d with the construction of the second pipeline during Phase II. The two pipelines would be designed for a maximum allowable operating pressure of 1,400 psig.

2.1.3 Aboveground Facilities

The proposed aboveground facilities associated with the pipelines are listed in **table 2.1.3-1**.

TABLE 2.1.3-1

Proposed Aboveground Pipeline Facilities

70-Mile-Long Pipeline to Transco Compressor Station No. 45	**Milepost**
Pig Launcher	0.0
MLV	19.2
MLV	29.9
MLV	40.3
MLV	50.0
MLV	58.4
Pig Receiver	69.9
3-Mile-Long Pipeline to NGPL Pipeline	**Milepost**
Pig Launcher	0.0
Pig Receiver	2.6

Launcher facilities would be located at the LNG terminal site (MP 0.0) and a receiver facility would be located at the pipeline termini, just downstream of the Transco Compressor Station No. 45 at MP 69.9 (70-mile-long pipeline) and MP 2.6 (3-mile-long pipeline). The launchers, receivers, and pipelines would be designed to allow for smart pigging capability.

For the 70-mile-long pipeline, Sempra would install five MLVs at MPs 19.2, 29.9, 40.3, 50.0, and 58.4. MLVs segment the pipeline for safety, operating, and maintenance purposes. Each MLV would be within a 30-foot by 30-foot (0.02-acre) fenced and graveled area, except the MLV at MP 19.2, which would be installed on a platform straddling the water/marsh border. The pig receiver at MP 69.9 would be within a 200-foot by 200-foot (0.92-acre) fenced and graveled area adjacent to Transco's Compressor Station No. 45. The pig launcher (MP 0.0) would be located on the LNG terminal facility within a 60-foot by 150-foot (0.2-acre) fenced and graveled area. The 3-mile-long pipeline would not require any MLVs between the terminal and the NGPL pipeline. The pig receiver would be located at the terminus of the pipeline (MP 2.6) within a 300-foot by 300-foot (2-acre) fenced and graveled area. The pig launcher (MP 0.0) would be located within the same 0.2-acre site used for the 70-mile-long pipeline's pig launcher.

Sempra is not proposing to construct any meter stations as part of the proposed project. If Sempra ties into another pipeline, metering and tie-in facilities would need to be constructed and would be subject to separate filings or permitting processes.

2.2 LAND REQUIREMENTS

A total of approximately 1,497 acres of land and open water would be required for construction of the Project. Operation of the LNG terminal would permanently impact about 198.2 acres of land, including about 82.5 acres of wetlands, which would be filled. Operation of the pipelines generally would require a 50-foot-wide permanent easement comprising approximately 404.7 acres; only about 3.22 acres (for the aboveground facilities, including MLVs and pig launchers and receivers) of which would be permanently precluded from its current use. An additional 65 acres (terminal) and 1,230.58 acres (pipelines, including extra workspace and staging yards) would be temporarily affected during construction of the Project as summarized in **table 2.2-1**, described in sections 2.2.1 and 2.2.2 below, and described in greater detail in section 4.8. No new access roads would be required for the project, but approximately 57.1 miles of existing roads would require improvement, such as grading, widening, and/or gravelling.

TABLE 2.2-1

Summary of Land Requirements Associated with the Proposed Facilities

Facility	Land Affected During Construction (acres)	Land Affected During Operation (acres)	Open Water (acres)
LNG terminal facilities and marine basin	263.2	198.2	38.3[a]
Pipeline:			
Pipeline rights-of-way	970.3[b]	404.7[c]	[d]
Temporary workspace	182.3	0.0	[d]
Staging areas	81.2	0.0	N/A
Access roads	[e]	0.0	N/A
Aboveground facilities	0.0[f]	3.22[h]	N/A
Forest	196.9[g]	87.2[h]	
Pipeline Subtotal	1,233.8	90.42[h]	[d]
Project Total	**1,497.0**	**602.9**[i]	**38.3**[a]

[a] Open water in the Port Arthur Ship Canal that would be deepened for the turning basin. As a result of the creation of the slip, 82 acres of land (accounted for in the first two columns) would become open water.
[b] Based on a 125-foot-wide construction right-of-way on land and a 150-foot-wide construction right-of-way in water (3-mile-long pipeline); and a 100-foot-wide construction right-of-way in upland areas, a 125-foot-wide construction right-of-way between MPs 19.2 and 35.4, and a 75-foot-wide construction right-of-way in wetlands between MPs 35.4 and 70.0 (70-mile-long pipeline).
[c] Based on a 50-foot-wide permanent right-of-way easement for both pipelines.
[d] Open water affected by construction of the pipelines is included in the land affected during construction totals.
[e] No new access roads would be required for the project. Approximately 57.1 miles (346.3 acres) of existing access roads would require some improvement (see **table 2.2.2-1**).
[f] All aboveground facilities would be constructed within the pipeline rights-of-way accounted for above.
[g] Included in the 970.3 acres of pipeline rights-of-way.
[h] Included in the 404.7 acres of pipeline rights-of-way.
[i] 198.2 acres would be permanently affected during operation of the LNG terminal; 3.22 acres would be permanently affected for pipeline-related aboveground facilities; and 87.2 acres of forest would be converted to non-forest during operation of the pipeline facilities. The remaining 313.46 acres would comprise permanent right-of-way easements that could return to current use.

2.2.1 LNG Terminal Facilities

Of the total property owned by Sempra in the Port Arthur area (2,900 acres), approximately 198.2 acres of a 540-acre parcel would be used for the permanent LNG terminal facilities, of which approximately 115.9 acres would be for the marine facilities. An additional area of 65 acres outside of the permanent LNG terminal site would be used for temporary construction areas (laydown, office, and parking). The plot plan for the LNG terminal facilities is shown in **figure 2.1.1-1**. The land requirements for the terminal are summarized in **table 2.2-1**.

The area that would be occupied by the LNG storage tanks is 30.7 acres and 23.0 acres for Phase I and Phase II, respectively. The area that would be occupied by the proposed process plant facilities (vaporizers, pumps, compressors, blowers, condenser, heaters, etc.) is 17.9 acres. The Entergy substation would occupy approximately 5.2 acres. The remaining property would be used for administration, electrical, vent, etc., and would occupy 5.5 acres. Sempra also would require use of a dredge material placement area (DMPA) for placement of the material to be dredged for the slip and turning basin (see sections 2.5.1.2 and 3.4).

2.2.2 Pipeline Facilities

Construction of both proposed pipelines would affect a total of approximately 1,233.8 acres of land (**table 2.2-1**). Sempra proposes to use a nominal 100-foot-wide temporary construction right-of-way in upland areas. In most wetland areas, Sempra would use a 75-foot-wide temporary construction right-of-way. In areas requiring special construction techniques, Sempra proposes to use a wider construction right-of-way, such as 150-foot-wide temporary construction right-of-way in Sabine and Keith Lakes and a 125-foot-wide temporary construction right-of-way in the marsh area north of Sabine Lake. After construction, Sempra would retain a 50-foot-wide permanent easement in most areas. Typical proposed temporary construction right-of-way cross-sections are shown in **figure 2.2.2-1.**

2.2.2.1 3-Mile-Long Pipeline

Construction of the proposed, approximately 3-mile-long pipeline would affect a total of about 47.9 acres of land of which 41.6 acres would be construction right-of-way and 6.3 acres would be additional temporary workspace[1]. Approximately 2.2 acres of land would be permanently affected by the proposed pig launchers and pig receiver. All proposed access roads to be used for construction of both pipelines are existing dirt, gravel, or paved roads. The dirt and some gravel roads would require grading and/or improvement, to move equipment and materials to the construction right-of-way. **Table 2.2-1** lists land requirements for the construction and operation of the pipelines, associated aboveground facilities, extra work spaces, and staging areas.

2.2.2.2 70-Mile-Long Pipeline

Construction of the approximately 70-mile-long pipeline would affect a total of approximately 1,185.9 acres of land, of which about 928.7 would be construction right-of-way; 176 acres would be used as additional temporary workspace; and 81.2 acres for temporary staging yards (see **table 2.2-1**). Approximately 1.02 acres of land would be permanently affected by the aboveground facilities (pig receiver and MLVs). The pig launcher for the 70-mile-long pipeline would be within the same 0.2-acre fenced and graveled area as the launcher for the 3-mile-long pipeline. A total of approximately 57.1 miles of access roads would require some improvements. The access roads are primarily existing dirt or gravel roads, which would be improved by grading, widening, and/or gravelling to allow the movement of equipment and materials to the construction areas. **Table 2.2.2-1** lists the existing access roads that would require improvement.

[1] Additional temporary workspaces would be required for construction at wetland, waterbody, road, and pipeline crossings. These workspaces also would be required for the construction of aboveground facilities. The locations, sizes, and land use of the known additional temporary workspaces are identified in **appendix I**, **table I-1**.

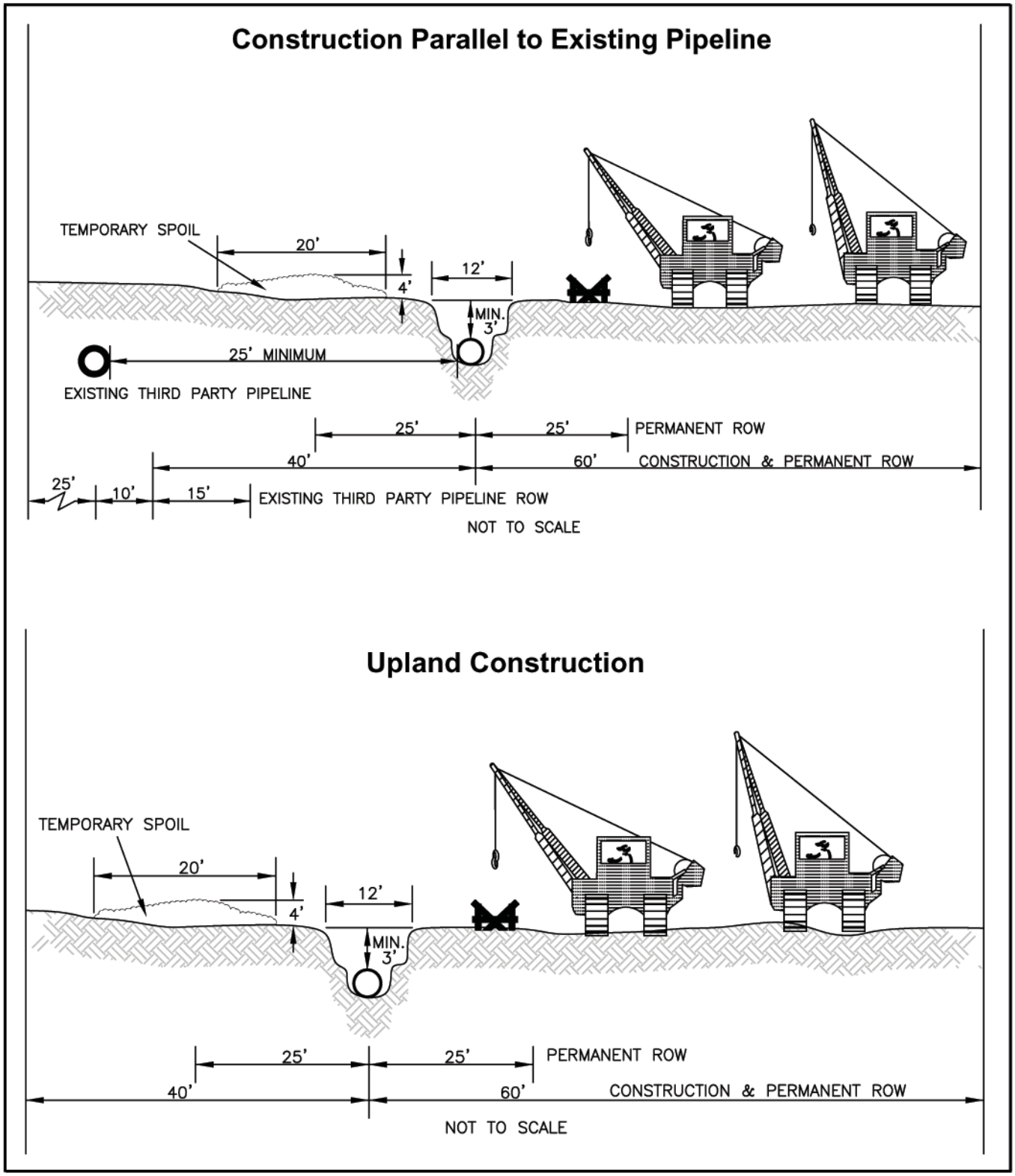

Figure 2.2.2-1
Typical Construction Cross Sections
Construction Parallel to Existing Pipeline
Upland Construction
Port Arthur LNG Project

Not to Scale
Sheet 1 of 3

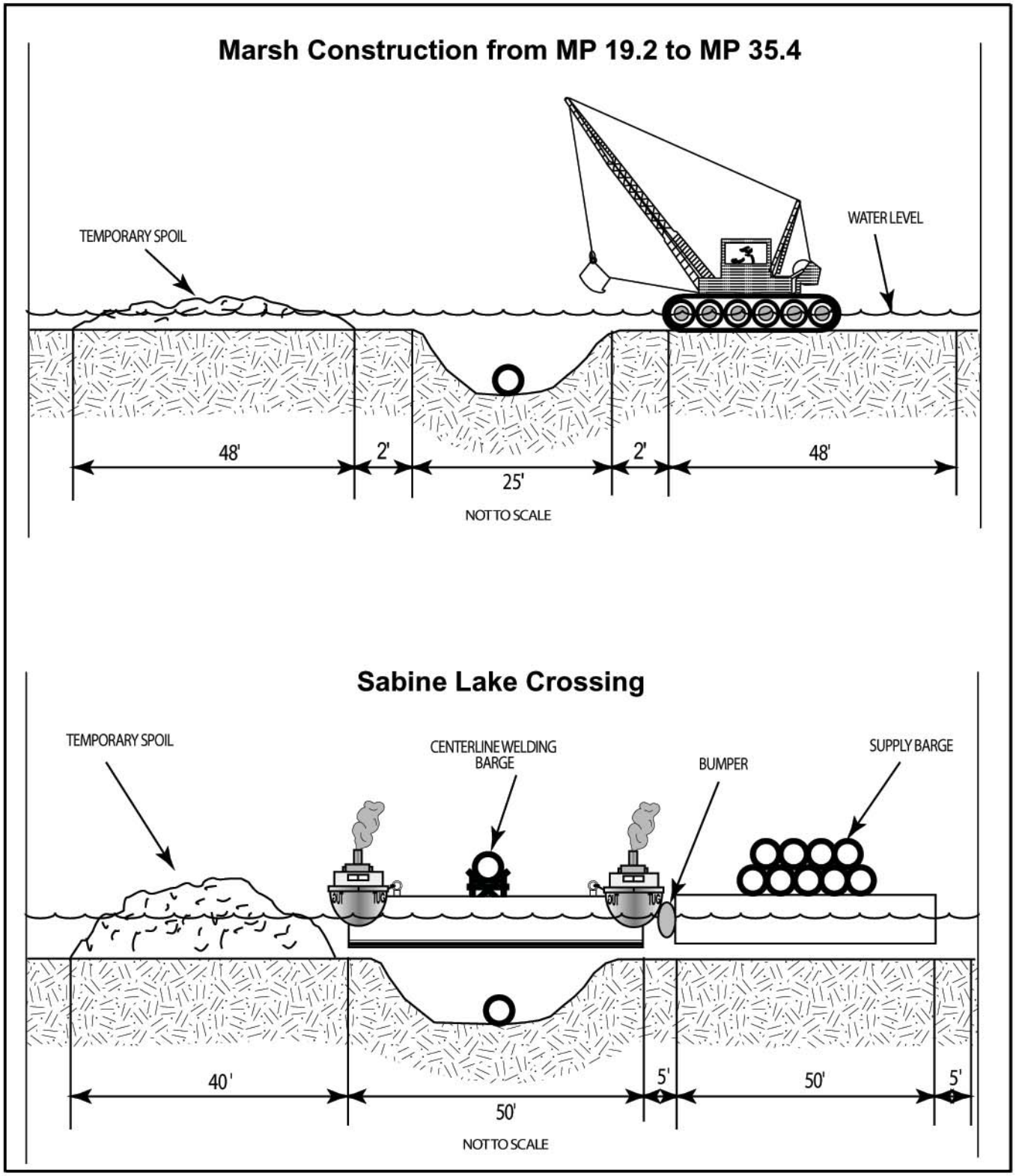

Figure 2.2.2-1
Typical Construction Cross Sections
Marsch Construction from MP 19.2 to MP 35.4
Sabine Lake Crossing
Port Arthur LNG Project

Not to Scale
Sheet 2 of 3

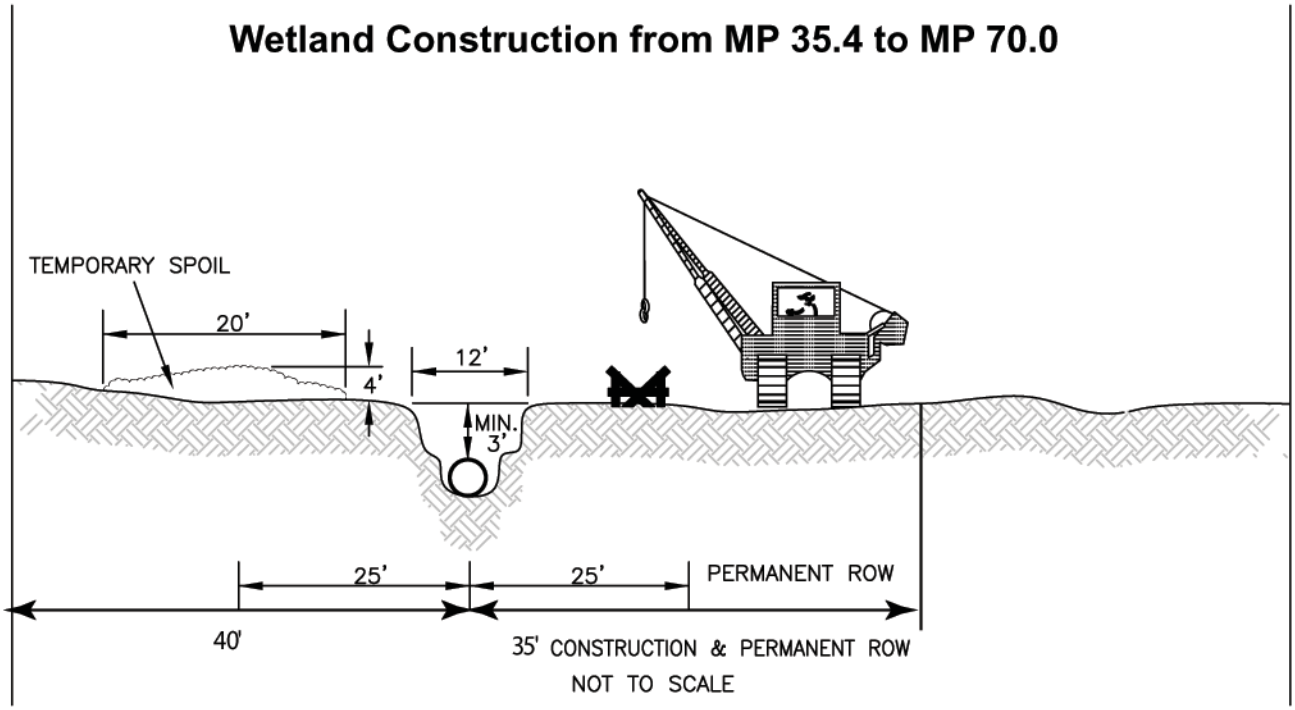

Figure 2.2.2-1
Typical Construction Cross Sections
Wetland Construction from MP 35.4 to 70.0
Port Arthur LNG Project

Not to Scale
Sheet 3 of 3

TABLE 2.2.2-1

Summary of Access Roads Requiring Improvement[a] for the Port Arthur LNG Project Pipelines

Access Road	MP	Type	Length (feet)	Width (feet)	Area Affected (acres)
1	[b]	Dirt	3,549	50	4.1
5	[b]	Gravel	13,354	50	15.3
6	[b]	Dirt	5,178	50	5.9
7	[b]	Dirt	4,178	50	4.8
8	[b]	Gravel	6,150	50	7.1
11	[b]	Dirt	28,973	50	33.3
12	[b]	Dirt	1,699	50	2.0
14	36.0	Dirt	5,223	50	6.0
21	38.1	Dirt	575	50	0.7
26	40.3	Gravel	3,212	50	3.7
34	43.8	Dirt	7,000	50	8.0
35	44.1	Dirt	10,529	50	12.1
36	45.7	Dirt	9,730	50	11.2
40	47.0	Dirt	300	50	0.3
44	51.3	Dirt	11,920	50	13.7
45	[b]	Gravel	2,327	50	2.7
46	[b]	Gravel	10,921	50	12.5
50	48.8	Dirt	7,388	50	8.5
51	50.1	Dirt	13,346	50	15.3
52	50.8	Dirt	2,848	50	3.3
53	[b]	Dirt	5,643	50	6.5
54	52.7	Dirt	13,226	50	15.2
55	[b]	Dirt	7,872	50	9.0
56	53.6	Dirt	1,699	50	2.0
57	54.0	Dirt	1,031	50	1.2
59	55.0	Dirt	3,383	50	3.9
61	55.5	Dirt	2,418	50	2.8
62	55.9	Dirt	9,183	50	10.5
64	56.8	Dirt	4,921	50	5.6
65	57.5	Gravel	6,559	50	7.5
68	[b]	Dirt	1,702	50	2.0
70	60.7	Dirt	14,419	50	16.6
73	62.1	Dirt	4,251	50	4.9
74	62.3	Dirt	6,559	50	7.5
75	[b]	Dirt	4,858	50	5.6
78	63.2	Dirt	10,907	50	12.5
79	[b]	Dirt	14,574	50	16.7
81	[b]	Dirt	946	50	1.1
82	[b]	Dirt	6,044	50	6.9
83	64.9	Dirt	11,699	50	13.4
84	[b]	Gravel	12,067	50	13.9
85	66.8	Dirt	1,858	50	2.1
91	69.7	Dirt	1,577	50	1.8
92	68.5	Dirt	5,889	50	6.8
TOTAL			**301,685**		**346.3**

[a] Improvements may include grading, widening, and/or gravelling.
[b] Access roads without a MP reference would not directly intercept the proposed pipeline routes, but would provide access to the right-of-way.

2.3 CONSTRUCTION SCHEDULE

2.3.1 LNG Terminal

Sempra has proposed an in-service date of November 2008 for Phase I of the Project. Construction of the LNG storage tanks would likely take up to 36 months. The timing for Phase II construction would be

dependent upon market demand, but could begin as early as October 2007 to meet the proposed in service date of November 2010. Construction may occur over a period of up to 10 years to complete both phases.

2.3.2 Pipelines

Sempra proposes to construct the first 1.1 miles of both pipelines during the relocation project since they share the same corridor. Construction of the remaining portion of the 70-mile-long pipeline would begin in February 2008 and take approximately 10 months to complete. Construction of the remaining portion of the 3-mile-long pipeline would begin in June 2010 and take approximately 4 months to complete. Restoration of the pipeline rights-of-way would begin within 10 days of, or as soon as possible after, backfilling the trench.

2.4 ENVIRONMENTAL COMPLIANCE AND MITIGATION MONITORING

Sempra would employ a Chief Inspector for the LNG facilities construction and one for the pipeline construction. In addition, two or more Craft Inspectors and Environmental Inspectors (EI) would assist the Chief Inspectors. All Port Arthur LNG Project inspectors would have access to relevant compliance specifications and other documents contained in the construction contracts.

The EI(s) duties would include ensuring compliance with the environmental conditions attached to all permits and authorizations and having stop-work authority and the authority to require corrective action(s) to achieve environmental compliance.

Sempra would develop an environmental training program tailored to the construction of the LNG terminal and pipelines. The program would be designed to ensure that:

- qualified environmental training personnel provide thorough and well-focused training sessions regarding the environmental requirements applicable to the trainees' activities;
- all individuals receive environmental training before they begin work;
- adequate training records are kept; and
- refresher training is provided as needed to maintain high awareness of environmental requirements.

Sempra would incorporate post-construction environmental requirements into Operation and Maintenance Plans and Emergency Plans and Procedures for the LNG terminal and the send-out pipelines. These documents would identify relevant requirements and establish responsibilities for compliance.

2.5 CONSTRUCTION PROCEDURES

This section describes the general construction procedures proposed by Sempra for construction of the LNG terminal and pipeline facilities. Chapter 4.0 contains more detailed discussions of proposed construction, mitigation, and restoration procedures, as well as additional measures that we are recommending to mitigate environmental impacts.

2.5.1 LNG Terminal Facilities

Sempra would construct the LNG facilities in accordance with the Upland Erosion Control, Revegetation, and Maintenance Plan (Plan) and the Wetland and Waterbody Construction and Mitigation Procedures

(Procedures) dated January 2003 (with any approved variances). Sempra also has developed a Spill Prevention, Control, and Countermeasures Plan (SPCC Plan). The SPCC Plan addresses potential spills of fuels, lubricants, and other hazardous materials and describes spill prevention practices, spill handling and emergency notification procedures, and training requirements. These three plans for the LNG facility are included in **appendix D**.

2.5.1.1 Site Preparation

Sempra has conducted geotechnical studies to determine the soil properties of the existing subsurface materials at the proposed terminal location and to identify the design criteria for ground improvements and foundations. Based on the results of these studies, the foundations for settlement-sensitive equipment and structures, such as the LNG storage tanks, process equipment, and pipe racks, would require support by concrete piles. Foundations would be constructed on top of the piles. The tops of the concrete foundations for all critical process equipment and structures would be installed at an elevation of plus 16 feet above mean sea level (amsl).

Construction site preparation would require clearing and filling of the site to an approximate elevation of plus 5 feet amsl for the LNG storage tank area and plus 16 feet amsl for the process areas. Following clearing and grading of the site, the soft areas would be over-excavated and filled with structural fill. Temporary ditches, sediment fences, and silt traps would be installed as necessary. Individual excavations would be made for equipment foundations. All settlement-sensitive equipment, buildings, and structures would be supported on piles, as specified in the Geotechnical Report (PSI 2004). Piles would be installed to a depth of approximately 110 feet for the LNG storage tanks and to a depth of approximately 60 feet for the remaining foundations. Following completion of foundations, the site would be filled, compacted, and brought up to final grade. Final grading and landscaping would consist of gravel surfaced areas, asphalt surfaced areas, concrete paved surfaces, and grass areas.

Materials and Equipment Delivery

Materials and equipment may be shipped; however, final transportation to the site would be by truck or rail. Sempra does not anticipate constructing a barge dock to be used for material or equipment shipment during construction. Sempra would develop a plan to ensure that safe and expedient unloading is achieved. Where practical, skid mounted equipment would be utilized to minimize the pieces that must be erected at the site.

2.5.1.2 Marine Terminal Basin

The construction of the marine facilities would involve the use of a barge-mounted hydraulic dredge and dual marine construction spreads, made-up of a crane and supply barges with tug boat support. The crane barges would likely carry 80-ton- and 140-ton-capacity cranes; pile drivers; welding, cutting and grinding machines; and sand blasting and painting equipment.

Construction of the marine facilities would start with dredging. Approximately 6.7 million cubic yards (yd^3) of sands and clays would be dredged for the slip and the turning basin in the Port Arthur Ship Canal. Sempra proposes to initially use DMPA 1-2 (see **section 3.4**, **figure 3.4-1**) on Sempra-owned land for interim dredged material placement. Sempra is considering several restoration, enhancement, and protection projects for beneficial reuse of a portion of the dredged material. The J.D. Murphree Wildlife Management Area (WMA) is located immediately to the west of the proposed terminal location. The Texas Parks and Wildlife Department (TPWD) has expressed an interest in receiving some of the dredged material for restoration projects in the WMA (see **section 3.4.5**).

Once dredging operations have reached the extent necessary, the marine construction spreads would start construction of the first berth. One marine construction spread would install the piles and decking for the unloading platform and the breasting dolphins, and set the unloading arms. The second marine construction spread would install piles, decks, and equipment for the mooring dolphins. Upon completion of the first berth, the second berth would be installed in a similar manner.

Once the dredging of the slip is completed, dredging of a turning basin would start. The 1,700-foot-diameter turning basin would allow LNG ship maneuvering in the Port Arthur Ship Canal in order to dock at the facilities. This turning basin would be dredged to a nominal – 40 feet MLLW. The top of the dredged slope would be a minimum of 80 feet from the restored shoreline. Once all dredging is complete, the dredging spread would be demobilized.

The specific construction sequences are summarized as follows:

- Installation of the loading platform and approach trestle
  - Drive piling to design penetration and cut off heads;
  - Set pre-cast concrete caps and weld out;
  - Install pre-cast concrete deck units and pour deck surface slab; and
  - Install piping and equipment, hookup and commission.
- Installation of the mooring dolphins
  - Drive piling to design penetration and cut off heads;
  - Set pre-cast concrete caps with mooring hooks and weld out;
  - Hookup and commission mooring hooks; and
  - Install walkways.
- Installation of the breasting dolphins
  - Drive piling to design penetration and cut off heads;
  - Set pre-cast concrete caps with mooring hooks and fenders and weld out;
  - Hookup and commission mooring hooks; and
  - Install walkways.

Actual installation of berth piping and equipment and hookup and commissioning of the unloading system and utilities would follow. Installation of both unloading berths would require about 18 months. The overall duration of dredging and installation of both berths would require about 25 months.

2.5.1.3 LNG Storage and Vaporization Facilities

<u>Storage Tank Construction</u>

The construction of the LNG storage tanks could take up to 36 months for each Phase of construction. Each tank would be built on a reinforced concrete slab foundation supported on pre-cast concrete piles driven to a depth of approximately 110 feet below grade. Sempra has not indicated that any additional temporary areas would be needed to drain the soils before the tanks could be constructed. Sempra has not selected a tank contractor and although the timing and sequence of the construction activities may vary somewhat among contractors, the process would generally be as follows:

- preparation of subgrade by removing soil at the surface and replacing it with cement stabilized sand or lean concrete to a suitable depth;
- casting of reinforced concrete bottom slabs with a thickness of 4 feet at the perimeter and 18 inches at the center of the tanks;
- preparation of the outer wall forms;

- pouring of pre-stressed concrete walls and installation of a bottom carbon steel vapor liner;
- construction of a steel dome roof and suspended deck using temporary supports inside the outer container. The suspended deck and dome roof would be raised with blowers into final position during the air-raising operation and secured to the embedded compression ring;
- installation of roof nozzles, other penetrations, and steel reinforcement studs in the steel dome roof, which would then be covered with concrete;
- installation of an inner tank, including vapor barriers, on the inside face of the concrete container; placement of base insulation up the inside face of the outer concrete container vapor barrier to a height of approximately 15 feet to provide thermal protection for the bottom corner of the concrete wall and base slab; 9 percent nickel steel "secondary bottom," 9 percent nickel inner container annular and bottom plates; and construction of the inner tank shell;
- installation of tank internal accessories such as pump columns, bottom and top fill, instrument wells, and purge and cool-down piping, along with roof platforms, walkways, and piping;
- hydrostatic testing and cleaning of the tank followed by placement of instrumentation inside the tank and annular space;
- placement of perlite insulation into the tank annular space along with the suspended deck blanket insulation and external piping insulation;
- visual inspection and cleaning of tanks; and
- installation of LNG pumps and purging of tanks with nitrogen.

Construction of Other Facilities

Almost all of the foundations required for the facility equipment, buildings, and pipe racks would be constructed on piles. Pilings used in the process area would be primarily pre-cast concrete driven piles with depths ranging up to 60 feet below final ground surface.

Construction of the foundations, pipe racks, and terminal buildings together with installation of major mechanical equipment, process and utility piping, and electrical and instrumentation would occur once tank construction is underway. These facilities would be completed and pre-commissioned in readiness for mechanical completion of the LNG tanks. The process would consist of the following steps:

- the underground pipe would be installed for the firewater and potable water systems;
- construction of foundations, including piling as required for the buildings, major equipment, and pipe racks;
- delivery of major LNG terminal equipment and placement directly on its foundations; installation of process and utility piping and cable tray;
- installation of piping, electrical, and instrumentation;
- insulation of the piping systems; and
- instrumentation and electrical loop testing and pre-commissioning activities would be completed concurrent with the LNG tanks.

Final Grading and Site Restoration

After the installation of the equipment and piping has been completed, the final road paving, grading of gravel surfaced roads, general gravel surfacing of the site, application of top soils, seeding and mulching for grass areas, and clean-up would be done. The temporary construction facilities would be demobilized on a progressive basis as they are no longer needed.

2.5.2 Pipeline Facilities

The proposed send-out pipelines would be designed, constructed, operated, and maintained in accordance with federal safety standards that are intended to ensure adequate protection for the public and to prevent natural gas pipeline accidents or failures. These regulations include Department of Transportation (DOT) regulations in 49 CFR Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. Among other design standards, 49 CFR Part 192 specifies pipeline material selection; minimum design requirements; protection from internal, external, and atmospheric corrosion; and qualification procedures for welders and operations personnel. In addition, Sempra would comply with the siting and maintenance requirements in 18 CFR Part 380.15 and other applicable federal and state regulations.

2.5.2.1 General Pipeline Construction Techniques

Figure 2.5.2.1-1 shows the typical steps of cross-country pipeline construction. Standard pipeline construction proceeds in the manner of an outdoor assembly line composed of specific activities that make up the linear construction sequence. These operations collectively include survey and staking of the right-of-way, clearing and grading, trenching, pipe stringing and bending, welding and coating, lowering-in and backfilling, hydrostatic testing, and cleanup.

In addition to standard pipeline construction methods, Sempra would use special construction techniques where warranted by site-specific conditions. These special techniques would be used when constructing across residential areas, waterbodies, wetlands, agricultural areas, and roads and railroads.

Survey and Staking

Before construction, crews would survey and stake the centerline and boundaries of the construction right-of-way. The boundary stakes would mark the limit of approved disturbance areas and would be maintained throughout the construction period. Utility lines would be located and marked to prevent accidental damage during pipeline construction, and any special agricultural drainage systems would be noted. During this period, equipment involved in pipeline construction would be moved onto the right-of-way using existing roads for access.

Clearing and Grading

The construction right-of-way and additional temporary work areas would be cleared of shrubs and trees and other obstructions. Any cut trees would be treated in accordance with agency regulations or the preferences of private landowners, and stockpiled to the side or removed from the right-of-way before any soil disturbance activities. Various clearing methods would be employed depending on vegetation, the contour of the land, the ability of the ground to support clearing equipment, and water conditions. Grading would not take place in wetlands unless topographic or other features make the right-of-way unsafe for construction equipment. Temporary erosion controls would be installed immediately after initial disturbance of the soils to minimize erosion, and would be maintained throughout construction.

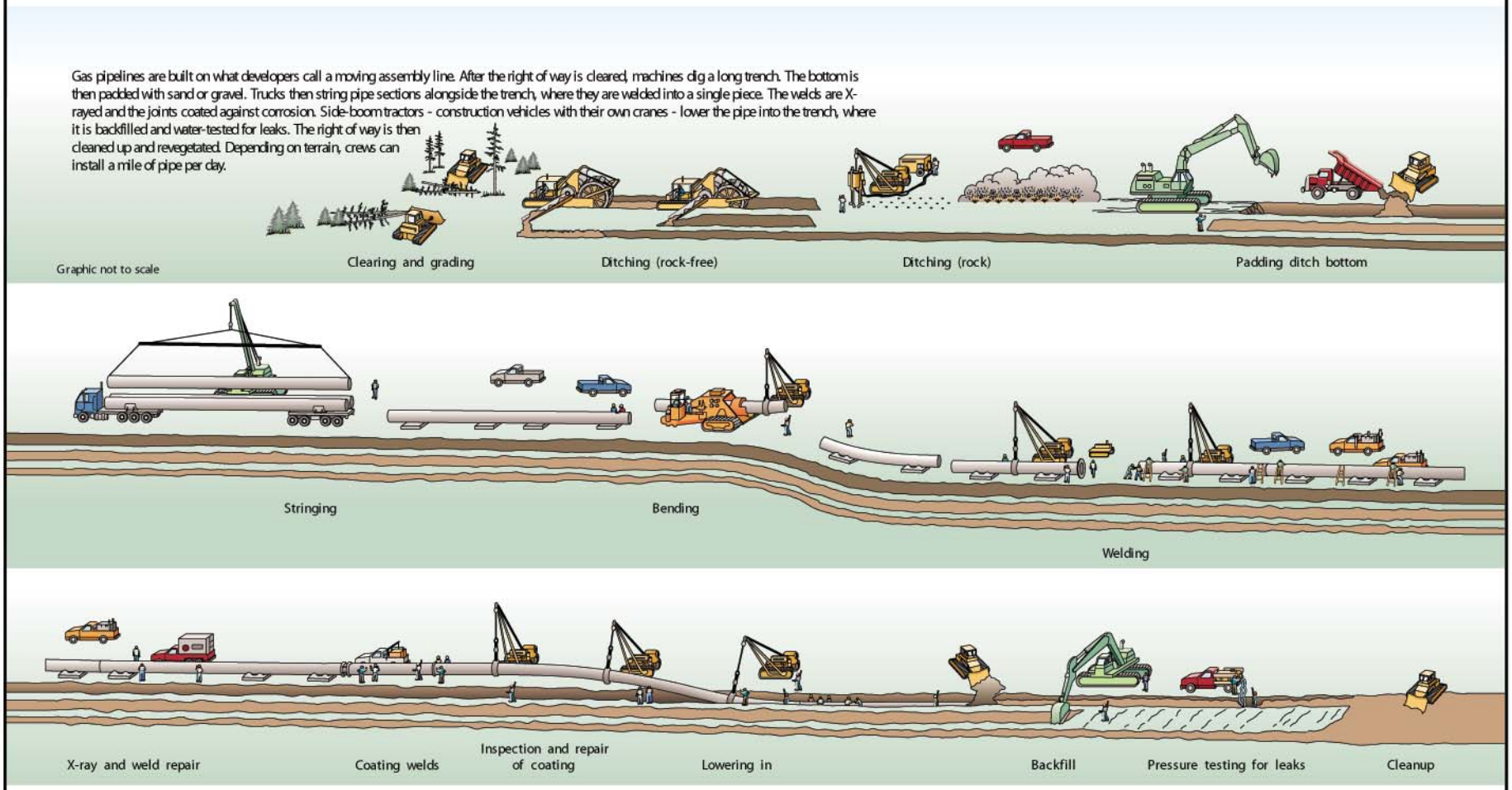

Figure 2.5.2.1-1
Conventional Overland Pipeline Construction
Port Arthur LNG Project

Graphic Not to Scale

Trenching

Hydraulic backhoes would be used to excavate a trench approximately 6.5 feet deep and 12.5 to 25 feet wide to provide a minimum 3-foot depth of cover. Spoil material excavated during trenching operations would be piled temporarily to one side of the right-of-way adjacent to the trench. In areas where topsoil stripping is required, the topsoil and subsoil would be stored in separate windrows on the construction right-of-way and would not be allowed to mix. Where trench dewatering is needed, water would be discharged directly to the ground if there is adequate vegetation adjacent to the right-of-way to function effectively as a filter medium. Where vegetation is sparse or absent, or in environmentally sensitive areas (e.g., adjacent to streams or wetlands), hay bale filters or suitable filtering alternatives would be used to limit siltation.

Stringing and Bending

Individual joints of pipe would be strung along the right-of-way adjacent to the excavated trench and arranged to be accessible to construction personnel. This operation typically involves specially designed stringing trucks to deliver pipe from the pipeyard to the right-of-way. Small portable cranes and/or side-boom tractors are used to unload the stringing trucks and place the pipe along the trench line. A hydraulic pipe-bending machine would bend individual joints of pipe to the desired angle to accommodate changes in the trench contour or pipeline alignment. In certain areas, prefabricated fittings would be used where field bending is not practicable. In upland areas, the pipe would be placed along the right-of-way in a staggered pattern to allow for the preparation of the exposed ends of the pipe. In wetland areas, the pipe would be stored at the staging area.

Welding and Coating

After stringing and bending are complete, pipe sections would be aligned, welded together, and placed on temporary supports along the edge of the trench. This would involve both automatic and manual welding processes. All welds would be inspected, both visually and radiographically, and repairs would be made, if necessary. The pipe is typically delivered with a factory coating of fusion-bonded epoxy or similar material.

Lowering-in and Backfilling

After welding and coating are completed, the pipe would be lowered into the trench by side-boom tractors. Bladed equipment or a specially designed backfilling machine would be used to backfill the trench. No construction debris, including wooden supports, welding rods, containers, brush, trees, or refuse of any kind, would be permitted in the backfill.

Hydrostatic Testing

After backfilling, the pipeline would be hydrostatically tested in accordance with DOT regulations to ensure that the pipeline can operate safely at the design pressure. The testing process involves filling a segment of the pipeline with water and maintaining a prescribed pressure for a specified amount of time. If a leak or break in the line were to occur during testing, that section of pipeline would be repaired and retested until DOT specifications are met.

The length of individual test segments would be determined by topography and water availability. Water withdrawals used to fill and test the pipeline would be consistent with state regulations and the Plan and Procedures. In some cases, water used to test one segment may be pumped into the next segment and reused. After testing is completed, the water would be discharged, typically to either an upland area or

directly to a waterbody, in accordance with the Plan, Procedures, and permits issued by the appropriate state agencies. This is further discussed in section 4.3.3.2.

Cleanup/Restoration

After hydrostatic testing is completed, the construction work areas would be regraded and restored as nearly as practicable to the original contour of the land. In wetlands, any excess spoil that remains after the area is restored to its original contours would be removed and disposed of in approved disposal areas. Segregated topsoil would be respread over all areas from which it was originally removed. Permanent soil stabilization efforts would primarily include revegetation of the right-of-way. Fences that were removed to install the pipeline would be reconstructed across the right-of-way.

Disposal of slash would be in accordance with desires of the landowner and consistent with local regulations and the Plan and Procedures. Slash would be left in place to provide habitat diversity (with landowner consent), hauled offsite, or burned onsite in accordance with local regulations.

Post-Construction Monitoring

All areas disturbed by construction would be monitored to identify any areas that require additional restoration work, noxious weed treatment, or erosion controls. In all areas crossed by the pipeline, Sempra would work with the landowners to ensure any claims, drainage problems, or property damage related to pipeline construction are fairly settled. Sempra would repair and correct any areas identified as needing additional work in consultation with the landowner, FERC staff, or the appropriate regulatory agencies.

2.5.2.2 Special Construction Techniques

Residential Land

Three residences are located within 50 feet of the 70-mile-long pipeline temporary construction right-of-way at MPs 46.8, 47.0, and 68.5. Sempra has developed specific residential construction plans for each of these locations. To minimize disruption and to maintain access to residences, Sempra would require that land agents and construction contractors coordinate with property owners before and throughout the construction process to minimize impacts on the landowners. Owners of residential property crossed by or within 50 feet of proposed work areas would be contacted individually by land agents to notify them of the approximate time that construction would take place on their property and would be kept informed of any special construction activities that might concern them.

Agricultural Land

Approximately 0.1 mile of annually cultivated cropland would be crossed between MPs 66.8 and 66.9 in Beauregard Parish, Louisiana. In this area, the topsoil would be stripped from over the trench line only, as requested by the landowner, to a minimum of 12 inches, or to the depth of the topsoil, if less than 12 inches deep. Other agricultural areas, such as pasture and pine plantations, also would be crossed by the 70-mile-long pipeline. In these areas, the topsoil would be stripped from over the full work area or from the trench and subsoil storage area, unless the landowner or land management agency specifically approves otherwise.

Wetland Crossings

Construction of the proposed pipelines would affect approximately 308.3 acres of wetlands (see section 4.4.1). Sempra has requested several variances from the Procedures; most of which involve requests for additional temporary right-of-way to facilitate construction in wetlands and marsh areas (see section 4.3, **table 4.3.3.1-2**).

Sempra proposes to use the push method construction technique and the HDD technique to install the pipeline across select wetlands and marsh areas, as well as waterbodies, along the proposed pipeline routes. With the push method, concrete-coated or weighted pipe segments are welded together and fitted with flotation devices. As each new length of pipe is welded on, the pipeline would be incrementally pushed (and floated) out into the open, water-filled trench and, at the appropriate time, the flotation would be removed, which would allow the concrete-coated or weighted pipeline to settle into the trench. The trench would then be backfilled and the right-of-way restored. The HDD construction technique involves drilling a pilot hole underneath the water or wetland feature, and then enlarging that hole through successive reamings until it is large enough to accommodate the pipe. Pipe sections long enough to span the entire crossing would be staged, welded, and hydrostatically tested along the construction work area and then pulled back through the drilled hole. Use of both the push method and the HDD technique would help to minimize impacts on wetlands and marshes by limiting the amount of heavy equipment needed to operate within wetland and marsh areas. Additional details regarding the locations where Sempra proposes to use special wetland and marsh construction techniques and where Sempra has requested variances from the Procedures are provided in sections 4.3 and 4.4.

Waterbodies

The pipelines would cross 37 perennial streams, 2 lakes, 3 ponds, and 42 intermittent streams. Of these, 67 would be crossed using the open cut crossing method and 17 would be crossed using the HDD technique (see section 4.3.3). The waterbody crossings would be constructed in accordance with the Procedures, any approved variances to the Procedures, and applicable permits. The open cut crossings would involve excavation of the pipeline trench across the waterbody, installation of the pipeline, and backfilling of the trench with no effort to isolate flow from construction activities. Excavation and backfilling of the trench would be accomplished using backhoes or other excavation equipment. Trench spoil would be stored at least 10 feet from the stream banks (topographic conditions permitting). Sediment barriers, such as silt fencing and staked straw bales, would be installed to prevent spoil and sediment-laden water from entering the stream.

Additional details regarding the locations where Sempra proposes to use special waterbody construction techniques and where Sempra has requested variances from the Procedures are provided in section 4.3.3.

Roads and Railroads

Construction across paved roads, highways, and railroads would be in accordance with requirements of applicable permits or approvals. Where open-cutting is not permissible, Sempra generally proposes to cross railroads, highways, and paved roads by boring underneath the crossing (bored crossing) and installing the pipe without a casing unless one is required by the permitting authority. There would be little or no disruption of traffic on road crossings that are bored. Other roads and driveways may be bored or crossed by trenching across the road (open-cut crossing). Sempra would either fence or cover with steel plates any trenches that remain open during all non-working hours. A list of the roads that Sempra proposes to open cut is provided in **table 2.5.2.2-1**.

Prior to construction, Sempra would meet with local road and law enforcement authorities to share specific construction schedule and road use plans, and would adopt the recommendations/requirements of these authorities, as appropriate.

TABLE 2.5.2.2-1

Summary of Roads To Be Open Cut for the Port Arthur LNG Project Pipelines

Road Name	Milepost	Type
Unnamed Road	38.22	Dirt
LeDoux Road	44.15	Dirt
Unnamed Road	45.78	Dirt
Unnamed Road	47.07	Dirt
Unnamed Road	51.39	Dirt
Unnamed Road	48.81	Dirt
Unnamed Road	50.10	Dirt
Unnamed Road	51.91	Dirt
Unnamed Road	52.79	Dirt
Unnamed Road	53.79	Dirt
Unnamed Road	54.10	Dirt
Kendrick Road	54.78	Dirt
Unnamed Road	55.69	Dirt
Tillie LeDoux Road	56.36	Dirt
Unnamed Road	56.95	Dirt
Unnamed Road	57.77	Gravel
Unnamed Road	60.98	Dirt
Unnamed Road	62.10	Dirt
Unnamed Road	62.31	Dirt
Unnamed Road	63.46	Dirt
Bushnell Road	64.94	Dirt
Unnamed Road	66.96	Dirt
Unnamed Road	69.97	Dirt
Unnamed Road	68.44	Dirt

Non-jurisdictional Facilities

The relocation of SH 87 and associated utility corridor, as well as the installation of electrical service facilities associated with the proposed Project are addressed in **appendix A**.

2.6 OPERATION AND MAINTENANCE PROCEDURES

2.6.1 LNG Terminal Facilities

Imported LNG would be obtained from locations throughout the world and delivered via LNG ships to the LNG terminal. The LNG ships would enter Sabine Pass under the command of a local pilot. The pilot would decide whether the water current and wind conditions would allow safe entry to the Sabine Pass Channel and on up the SNWW into the Port Arthur Ship Canal. The pilot would direct the maneuvering of the LNG ship in the harbor using the Project's dedicated tugboats. Sempra proposes to use three dedicated tractor tugs, each with 70 tons bollard pull. The pilot would direct the securing of the lines and return the command back to the captain when the ship is secured.

The unloading arms would be coupled to the ship manifolds by shore-side operators. Connecting the ship-to-shore cable would connect the ship and the shore-side instrument control systems. This essentially would create one control system for the entire unloading operation. The emergency shutdown system would be tested before unloading could begin.

The shore-side operators would open the required valves after performing the required safety checks and procedures so that the LNG tank(s) are ready to receive the LNG. The ship operator would then start the in-tank pumps on the ship. The BOG blower would return cold LNG vapors created during the unloading process to the ship through the vapor return arm to maintain a vapor balance within the ship's LNG tanks. During unloading, the ship's manifold would be visually monitored by a ship operator on deck and by video cameras mounted on the dock that transmit pictures to the dock and the main control rooms.

LNG vaporization would not be interrupted during the unloading operation. LNG can enter an LNG tank and be withdrawn at the same time. The control room operator would verify that the planned vaporization rate is maintained. LNG stored in the tanks would be pumped to the vaporizers using a series of in-tank and send-out pumps. The LNG would be vaporized in shell and tube LNG vaporizers (STVs) and discharged into the interior plant piping that would connect the vaporization trains to the metering facility, which would measure the total natural gas output of the LNG terminal.

All operations and maintenance personnel at the terminal would be trained to properly and safely perform their jobs. The terminal operators would be trained in the potential hazards associated with LNG, cryogenic operations, and the proper operations of all the equipment. The operators would meet all the training requirements of the USCG, DOT, Port Arthur Fire Department, and other regulatory entities.

The full-time terminal maintenance staff would conduct routine maintenance and minor overhauls. Major overhauls and other major maintenance would be handled by bringing in specialized maintenance personnel specifically trained to perform the maintenance. All scheduled and unscheduled maintenance would be entered into a computerized maintenance management system (CMMS). The system would print out work orders every morning. These work orders would then be distributed to the maintenance personnel during morning meetings. Scheduled maintenance, such as preventive and predictive maintenance, would be input to the system to automatically print out work orders either on a time basis or on an hours-of-operation basis, depending on the requirement. In addition to rotating equipment, scheduled maintenance also would include safety and environmental equipment, instrumentation, and any other maintenance that would be required on a routine basis.

Unscheduled maintenance would be entered into CMMS as required. When a problem is detected that requires maintenance attention, the person that detects the problem would enter it into CMMS. All personnel (operations, maintenance, and others) would be trained on the use of CMMS. If the problem requires immediate attention, the appropriate person would be notified and the problem would be input into CMMS.

The normal flow of maintenance work orders would be as follows:

- scheduled preventive and predictive maintenance would be input to CMMS when a piece of equipment is installed and placed in operation;
- unscheduled maintenance would be input to CMMS by the person that detected the problem when the problem is detected;
- CMMS would print out work orders every morning;
- the work orders would be distributed to the appropriate maintenance personnel in their morning meetings;

- hard copy back ups would be made of all maintenance work orders; and
- maintenance logs would be updated and maintained.

The person that completes the maintenance work would close out the work order on CMMS.

Operating procedures would be prepared after final design is completed and extensive training would be provided for operational personnel to ensure that the facility personnel are familiar with and understand the importance of adherence to safe procedures. These procedures would address safe startup, shutdown, cool down, purging, etc., as well as routine operation and monitoring. Particular attention would be taken to coordinate with and involve appropriate local officials in the vicinity of the LNG terminal.

2.6.2 Pipeline Facilities

Sempra would operate and maintain the pipelines in accordance with all applicable federal and state regulations. The pipelines would be monitored and controlled 24 hours a day by a remote dispatch center located at the LNG terminal. A locally-based, full-time staff would be assigned to operate and maintain the natural gas pipelines. Sempra also would retain a local contractor to assist in routine maintenance services and respond to emergency situations.

The pipelines would be routinely inspected by air or on the ground to observe right-of-way conditions and identify indications of leaks, evidence of pipeline damage, and damage to erosion controls resulting from erosion or washouts, and right-of-way encroachments. All inspections would be done in accordance with DOT standards. Any erosion or unstable conditions would be repaired as necessary.

2.7 SAFETY CONTROLS

2.7.1 LNG Terminal Facilities

The LNG terminal facilities would be sited, designed, constructed, operated, and maintained in compliance with federal safety standards. Federal siting and design requirements for LNG facilities are summarized in **table 2.7.1-1**.

2.7.1.1 Spill Containment

The LNG spill containment systems for the new facility would be designed and constructed to comply with DOT regulations 49 CFR Part 193 Sections 193.2149 through 193.2185. These regulations require that each LNG container and each LNG transfer system be provided with a means of secondary containment which has been sized to hold the quantity of LNG that could be released as a result of the design spill which is appropriate for the area and LNG equipment. The design spills are defined in the NFPA 59A.

Sempra would provide a spill containment system consisting of a system of concrete collection troughs that would direct any spillage to an LNG spill containment basin. The spill containment sump would be 92 feet long by 50 feet wide by 29 feet deep with a maximum usable depth of 22.5 feet. The usable volume of the sump would provide for containment of a 10-minute spill from a single pipe rupture that would produce the highest release rate in accordance with NFPA requirements.

A stormwater drainage system would be provided consisting of low lift stations for the collection and transfer of stormwater runoff within the diked LNG storage tank areas, plus a system of swales, ditches,

and culverts for collection of clean stormwater from areas outside of the LNG storage tank diked areas. All collected clean stormwater runoff would be discharged to an outfall that would drain to the slip.

The transfer piping spill containment system would be sized to contain the volume of LNG that could be released in 10 minutes from a single pipe rupture that would produce the highest release rate. The LNG spill containment system would consist of spill collecting troughs that drain to a central LNG spill containment sump. The sump would be sized to contain a ten minute spill from the LNG unloading line at the design unloading rate.

The LNG storage tank concrete outer container would be designed to contain 110 percent of the nine percent nickel steel inner container. The storm surge/security barrier dike would be designed to hold the contents of one 160,000 m^3 LNG storage tank.

TABLE 2.7.1-1

Federal Siting and Design Requirements for LNG Facilities

Requirement	Description
Thermal Radiation Protection (49 CFR Part 193.2057 and section 2.2.3.2 of National Fire Protection Association [NFPA] 59A)	This requirement is designed to ensure that certain public land uses and structures outside the LNG facility boundaries are protected in the event of an LNG fire.
Flammable Vapor-Gas Dispersion Protection (49 CFR Part 193.2059 and sections 2.2.3.3 and 2.2.3.4 of NFPA 59A)	This requirement is designed to prevent a flammable vapor cloud associated with an LNG spill from reaching a property line of a property suitable for building.
Wind Forces (49 CFR Part 193.2067)	This requirement specifies that all facilities be designed to withstand wind forces of not less than 150 miles per hour without the loss of structural integrity.
Impounded Liquid (section 2.2.3.8 of NFPA 59A)	This requirement specifies that liquids in spill impoundment basins cannot be closer than 50 feet from a property line of a property suitable for building or a navigable waterway.
Container Spacing (section 2.2.4.1 of NFPA 59A)	This requirement specifies that LNG containers with capacities greater than 70,000 gallons must be located a minimum distance of 0.7 times the container diameter from the property line or buildings.
Vaporizer Spacing (section 2.2.5.2 of NFPA 59A)	This requirement specifies that integral heated vaporizers must be located at least 100 feet from a property line of a property suitable for building and at least 50 feet from other select structures and equipment.
Process Equipment Spacing (section 2.2.6.1 of NFPA 59A)	This requirement specifies that process equipment containing LNG or flammable gases must be located at least 50 feet from sources of ignition, a property line of a property suitable for building, control rooms, offices, shops, and other occupied structures.
Marine Transfer Spacing (33 CFR Part 127.105)	This requirement specifies that each LNG unloading flange must be located at least 985 feet from any bridge crossing a navigable waterway.

2.7.1.2 Hazard Detection/Control System

Sempra would install hazard detectors throughout the facilities to give operations personnel a means for early detection and location of released flammable gases and fires. The hazard detection system would consist of separate detection units for combustible gas, fire, smoke, high and low temperature, and would

be hard-wired to the main control system for alarm. Smart area gas detectors would be provided to monitor flammable gases within the LNG terminal.

Low temperature sensors would be located in the spill impoundment basin to shut down and/or prevent the storm water pumps from starting in the event of an LNG spill. Smart ultraviolet/infrared (UV/IR) fire and flame detectors also would be located throughout the LNG terminal and high temperature detectors would be located to detect a fire on the vent pipes of the LNG storage tank relief valves.

Several different types of fire suppression agents would be available for fighting fires within the LNG terminal. The type of agent that would be used in a specific situation would depend on the characteristics of a particular event and on the relative effectiveness of the various agents on that particular type of fire. A high expansion foam system would be provided for the LNG spill containment sump. High expansion foam concentrate would be metered or proportioned into the firewater system by means of a typical balanced pressure foam proportioning system. The resulting foam solution would be delivered via underground piping to the high expansion foam generator installed in the LNG spill impoundment sump. The high expansion foam generator, ANGUS or equivalent, would be water-motor powered, thus no electrical power would be required. The foam generator would produce nominal 500:1 high expansion foam, that is, 500 parts air for every part foam solution. This foam would be applied to LNG spills, whether ignited or un-ignited. Applied to ignited spills, the foam would control the fire, greatly reducing the level of radiant heat to the surroundings. If the spill remains un-ignited, the foam would serve to reduce the downwind distance to the lower flammability limit (LFL) by warming the LNG vapors. High expansion foam systems would be in accordance with NFPA 11A.

Dry chemical fire suppression systems would be provided for the LNG storage tank relief valves and would be automatically activated to extinguish any potential fires at the valves. Manually operated dry chemical units would be strategically located throughout the facilities.

2.7.1.3 Fire Protection System

Firewater System

The LNG terminal would have firewater supply and distribution systems for extinguishing fires, cooling structures and equipment exposed to thermal radiation, and dispersing flammable vapors. Hydrants, manual monitors, automatic sweep monitors, and hose reels would be located throughout the LNG terminal. Internal building water sprinkler systems would be located in the main control room, warehouse, and office.

The main components of the firewater distribution system would include:

- freshwater storage tank with a storage capacity of approximately 360,000 gallons;
- two electric motor-driven firewater “jockey” pumps, having a rated capacity of 200 gpm at 125 psig discharge pressure;
- three diesel engine-driven freshwater fire pumps, each with a rated capacity of 1,000 gpm at 150 psig discharge pressure. Freshwater firewater pumps would be designed and installed in accordance with NFPA 20. Per NFPA 20, diesel engine-driven firewater pumps would have individual fuel tanks permitting up to eight hours of continuous pump operation;

- two diesel engine-driven sea water fire pumps, each rated for 1,500 gpm at 75 psig discharge pressure, would be provided as a back-up system;

- nineteen firewater monitors and four elevated firewater monitors would be provided. Two elevated monitors on each of the marine unloading berths would be remotely operated from a safe distance with a view of the unloading berth. Firewater monitor nozzles would be adjustable from straight stream to full fog and, in general, would be rated for 500 gpm. In locating firewater monitors, an effective coverage range of 100 feet would be assumed;

- dry barrel, compression-type fire hydrants, would offer the opportunity for direct action by means of 2.5-inch hose lines, as well as the capability to deliver pressurized firewater to automotive fire apparatus equipped with a fire pump. Hydrant spacing around the process area would be approximately 300 and 500 feet around LNG storage tanks, offsite, and administration areas. Each fire hydrant would be provided with a 6-inch gate valve installed in the lateral between the hydrant and fire main. The valve would be fitted with a two-piece adjustable roadway box, with cover at grade, to permit T-wrench access to the valve's operating nut;

- hose reels, each mounting, including 100 feet of hard rubber non-collapsible 1.5-inch fire hose and adjustable fog nozzle for a rapid first response with firewater would be provided;

- an automatic sprinkler system in accordance with NFPA 13 would be installed in the administration and warehouse/workshop buildings. In addition, hose reels would be mounted on building vertical steel members; and

- an underground firewater piping distribution system would be installed, with strategically located post indicating isolation valves, located in order to minimize system impairment due to maintenance or repair. The firewater piping material would be high density polyethylene for all underground piping and carbon steel for all aboveground piping. The system would be designed and installed in accordance with NFPA 24.

Fail Safe Shutdown System

The LNG terminal would have an emergency shutdown (ESD) system with shutdown and control devices designed to leave the facility in a safe state. The ESD system would be used for major incidents and would result in either total plant shutdown, shutdown of ship unloading, and/or individual pieces of equipment, depending on the type of incident. Three levels of shutdown would be configured for the Project as follows:

- Level 1 – shutdowns would be used for a major incident and would carry out a total Project shutdown.

- Level 2 – shutdowns would only shutdown the appropriate jetty unloading area and could be initiated manually, automatically by local instrumentation, by a Level 1 shutdown, or by ship to-shore operation.

- Level 3 – shutdowns for shutting down individual pieces of equipment would be initiated automatically by trip input signals to the safety instrumented system.

Security System

Sempra would prepare a security procedures manual and plan in close coordination with the USCG, FERC, and the DOT's Office of Pipeline Safety (OPS). The manual/plan would establish a written program for physical security for all facilities at the proposed LNG Terminal. The plan, which would comply with DOT regulations, would provide for risk-based levels of security carried out by trained personnel during all operation shifts and, if necessary, by governmental law enforcement offices to respond to serious threats.

The LNG terminal would include sirens that would be audible in all locations. The sirens would have a distinctive tone for easy differentiation between alarms and emergency events.

2.7.2 Pipeline Facilities

The pipeline would be constructed, operated, and maintained in accordance with all applicable federal, state, and local laws and regulations, including but not limited to the DOT regulations in 49 CFR Part 192.

2.7.2.1 Cathodic Protection

Corrosion Detection and Prevention Systems

External corrosion control measures would include the protective coating on the exterior of the pipelines and use of cathodic protection systems. These systems are designed to meet the minimum requirements established by the DOT for protection of metallic facilities from external, internal, and atmospheric corrosion. The planned method of cathodic protection would be to design an impressed current system using deep-well anodes placed in areas where they would provide the required negative induced potential to resist external corrosion. Aboveground facilities would be painted with a suitable anti-corrosion coating. Internal corrosion is not expected to be a factor. Sempra would monitor the interior of the pipelines through the use of internal corrosion probes, on-line pigging tools, or a combination thereof. Deep well anodes, used for cathodic protection, would be located within the pipeline rights-of-way.

Pipe Wall Classifications

DOT regulations define area classifications based on population density in the vicinity of the pipeline and on an area that extends for 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. The four area classifications are defined as:

- Class 1 – A location with 10 or fewer buildings intended for human occupancy;
- Class 2 – A location with more than 10 but fewer than 46 buildings intended for human occupancy;
- Class 3 – A location with 46 or more buildings intended for human occupancy or where the pipeline lies within 100 yards of any building, or small well-defined outside area occupied by 20 or more people during normal use; and
- Class 4 – A location where buildings with four or more stories aboveground are prevalent.

Each class location requires a minimum safety design factor. For the natural gas pipelines, Sempra would use all Class 1 pipe for all areas except the road crossings where Class 2 would be used to allow for a greater margin of safety.

2.7.2.2 Emergency Response Procedures

Pipeline system emergencies can include gas leaks, fire or explosion, and/or damage to the pipeline or pipeline facility. In an emergency, the main inlet valve could be closed remotely from the terminal or manually at the site. MLVs would be activated manually under an emergency scenario. Additional MLVs would be included at accessible locations to isolate portions of the pipeline that cross navigable waterbodies. In accordance with DOT regulations, Sempra would establish guidelines and procedures to be followed in the event of a pipeline emergency on the natural gas pipelines. These would include training of employees on emergency procedures; establishing liaisons with appropriate fire, police, and other community officials; and informing the public on how to identify and report an emergency condition. The community liaison program would identify the responsibility and resources of each governmental organization that could respond to a gas pipeline emergency, familiarize public officials with Sempra's plan for responding to an emergency and minimizing hazard to life or property, and provide training to designated community response personnel. The program would be reviewed yearly with local agencies to ensure that the emergency plan is current and that all personnel understand the plan and their responsibilities.

2.8 FUTURE PLANS AND ABANDONMENT

2.8.1 LNG Terminal Facilities

Sempra has indicated that it has no plans for the expansion of the LNG terminal facilities beyond what has been described in this document. The design basis of the LNG terminal is approximately 30 years, after which time there are several options that would be considered regarding the disposition of the LNG terminal. These options would include: reuse of the facility or selective facility components in the same or alternative service, in-place deactivation or closure that would follow the placement of the facilities in a safe and stable condition with regard to potential risks to the environment and public safety, the complete removal of the facilities and restoration of vegetated or affected areas, or some combination thereof.

2.8.2 Pipeline Facilities

Sempra has indicated that it has no plans for the expansion of the pipeline facilities beyond what has been described in this document. If and when Sempra plans to expand or abandon any currently proposed pipeline facilities, the expansion or abandonment would be subject to approval of the Commission under Section 7(c) of the NGA. The appropriate level of environmental review would be completed at the time of application for any such proposed expansion or abandonment. See **appendix A** for details regarding the existing, non-jurisdictional pipelines along SH 87 that are to be abandoned (rather than relocated) as part of the relocation project.