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# Report to the Congress on Candidate Sites for Expansion of the Strategic Petroleum Reserve to One Billion Barrels

Submitted In Response to the Senate Report Accompanying the Department of the Interior and Related Agencies Appropriations Act for Fiscal Year 1991

**March 1991**

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# EXECUTIVE SUMMARY

This report has been prepared in response to the Senate Report No 101-534 accompanying the bill which was enacted as the Department of the Interior and Related Agencies Appropriations Act for Fiscal Year 1991 (P.L. 101-512). Senate Report 101-534 requested the Department of Energy to initiate construction planning for an expansion of the Strategic Petroleum Reserve to one billion barrels and to report to the Committees on Appropriations by March 15, 1991, regarding recommended storage sites, the proposed method of storage, a conceptual plan for storage and distribution facilities, and preliminary construction cost estimates. The Department of Energy's 1989 Report to the Congress entitled *Report to Congress on Expansion of the Strategic Petroleum Reserve to One Billion Barrels* provides a background and point of departure for this report.

An analysis of expansion of the Strategic Petroleum Reserve has been directed toward the expected U.S. petroleum market and likely crude oil distribution systems in the Year 2000. The projections in this report do not assume implementation of the National Energy Strategy (NES). In general, the projected U.S. and regional crude oil import dependence has not changed since 1989. The US is projected to be approximately 63 percent dependent on foreign crude in Year 2000, with the highest imports in the Gulf Coast, Midwest and East Coast regions, respectively. The crude oil pipeline infrastructure from the Gulf Coast to the Midwest and Midcontinent is projected to increase by 700,000 barrels per day as inland demands for Gulf Coast imports increase. The Department expects that all increases in pipeline capacity to meet inland crude oil demands will originate in the Houston and Freeport areas of Texas which are currently served by the Reserve's Seaway System. Within the Gulf Coast, the Capline and Seaway areas stand out as the largest centers of projected demand and distribution potential for the Reserve.

In the 1989 Report, the Department discussed the possibility of a 100-million-barrel site on the East Coast utilizing an inground concrete storage technology as an alternative to a second Gulf Coast location. Since then, several studies have been performed to further assess the East Coast storage concept in terms of siting, technical feasibility, environmental feasibility and cost. From siting and constructibility studies, the development of a 100-million-barrel inground concrete oil storage facility was found to be technically feasible. However, the estimated East Coast site development cost would be roughly double the cost of a Gulf Coast site and, environmentally, the project would likely encounter significant problems associated with siting, spill prevention and control, air quality standards and distribution. Since East Coast refiners are marine-accessible from the Reserve's Gulf Coast facilities, East Coast siting has been deleted from the Reserve's candidate site list.

The Energy Policy and Conservation Act Amendments of 1990 (P.L. 101-383) stated that in assessing alternatives for the expansion of the Reserve "the Secretary shall consider leasing privately owned storage facilities". Based on the analysis presented in this report and the Department's

Alternative Financing Report, the Department believes that "leasing" might be a reasonable alternative for developing or financing crude oil storage facilities, but only in a situation where storage becomes available to the Government as a result of a commercial storage project.

The Department has initiated an environmental review process in accordance with NEPA and completed an analysis of the 1976 Programmatic Environmental Impact Statement (EIS) and its 1979 Supplement which addressed expansion of the Reserve to one billion barrels. The analysis concludes that another supplement to the Reserve's Programmatic EIS likely will not be required to support its expansion to one billion barrels. The appropriate site-specific NEPA document will be prepared.

Eight Gulf Coast salt domes have been identified as candidates for an expansion of the Reserve to one billion barrels. Chacahoula, Cote Blanche, Napoleonville, and Weeks Island are candidates for a 150-million-barrel site in Louisiana; and Boling, Big Hill, Hawkinsville, and Stratton Ridge are candidates for a 100-million-barrel site in Texas. The report presents the geological characteristics, facility development requirements, distribution plans and environmental aspects for each candidate site. These candidates are the alternatives proposed to be assessed under NEPA. The scoping process may identify additional alternatives for assessment. Subsequent to completion of the NEPA process, a Strategic Petroleum Reserve Plan Amendment will be submitted which will provide decisions regarding the recommend storage sites to be developed.

The total construction cost for the expansion of the Reserve to one billion barrels is estimated to cost between 1.4 billion and 1.9 billion dollars depending on the sites selected for development. This expansion would require at least nine years to complete including the NEPA review process. Alternative schedules for implementation will be assessed as part of the Strategic Petroleum Reserve Plan Amendment in September 1992.

# SECTION I
## INTRODUCTION

**A. Congressional Requirements for A Strategic Petroleum Reserve Expansion Report and Plan Amendment.**

During 1990, Congress took actions on two bills to cause the Department of Energy to undertake planning activities associated with the expansion of the Strategic Petroleum Reserve (SPR) to one billion barrels: the Energy Policy and Conservation Act Amendments of 1990 (P.L. 101-383) and the Department of the Interior and Related Agencies Appropriations Act for Fiscal Year 1991 (P.L. 101-512).

The Senate Report accompanying the bill which was enacted as Public Law 101-512 requests the Department of Energy to provide a report to the Committees on Appropriation before March 15, 1991, addressing recommended sites for storage of an additional 250-million-barrel increment to the SPR, the proposed method of storage, a conceptual plan for storage and distribution facilities for the additional oil, and a preliminary cost estimate for the construction plan. This report has been prepared in response to that requirement.

Public Law 101-383 directs the Department of Energy, within 24 months of the date of enactment (September 15, 1990), to amend the SPR Plan to prescribe plans for completion of storage of one billion barrels of petroleum products in the Reserve. The Department is to submit detailed plans for the design, construction, leasing or other acquisition, and fill of storage and related facilities of the Reserve to achieve one billion barrels of storage. Environmental, geotechnical and engineering studies have been initiated to satisfy that requirement.

**B. Expansion Report Background and Scope**

On April 1, 1989, the Department forwarded a report to Congress entitled *Report to the Congress on Expansion of the Strategic Petroleum Reserve to One Billion Barrels*. That report, prepared in response to the Department of Interior and Related Agencies' Appropriations Act for 1989 (P.L. 100-446), presented U.S. petroleum supply and import projections for the year 2000, the likely SPR expansion configuration, eight potential storage site candidates, and the estimated cost and schedule to achieve one billion barrels of storage capacity by the year 2000.

With the 1989 Report to the Congress as background, this current report is structured to address:

- Major changes in U.S. and regional crude supplies and distribution systems projected for the year 2000.

- An in-depth analysis of the feasibility of an East Coast storage facility.

- An analysis of leasing privately-owned storage facilities in lieu of Government ownership.

- A description of the current eight candidate sites for storage of the additional 250 million barrels being evaluated under the National Environmental Policy Act of 1969 (NEPA) review process.

- The current environmental review process including an analysis of the SPR's 1976 Programmatic Environmental Impact Statement (PEIS) and its 1979 Supplement which addressed expansion of the SPR to one billion barrels.

- An updated cost estimate and schedule for expanding the Reserve to one billion barrels.

This report does not present definitive recommendations on the sites for the expansion to one billion barrels since the formal NEPA review process has not been completed. The SPR Plan Amendment, which is scheduled to be submitted in September 1992, will provide final decisions regarding the recommended storage sites to be developed and engineering-level cost estimates and schedules.

# SECTION II
## U.S./Regional Crude Supply and Distribution Systems

This section presents the forecasted U.S. petroleum market situation in the year 2000 as an analytical basis for establishing SPR expansion and distribution plans. This section describes the U.S. petroleum supply and demand situation, the estimated regional crude oil import dependences and the expected U.S. inland crude oil pipeline supply infrastructure for the year 2000. These projections are based on the Energy Information Administration's (EIA) *Annual Energy Outlook 1991* and do not assume implementation of the National Energy Strategy (NES). These projections will be updated in the SPR Plan Amendment.

### A. U.S. Petroleum Supply and Demand Projections

Based on EIA's *Annual Energy Outlook 1991* (AEO 1991) projections for U.S. petroleum supply and demand over the next ten years:

- U.S. oil consumption will increase slowly.
- Domestic oil production will decline significantly.
- Petroleum imports, particularly crude oil, will increase greatly to meet the nation's net petroleum supply requirements.

Figure II-1 presents historic U.S. petroleum import data and the outlook for the U.S. petroleum market through the Year 2000. These data include Puerto Rico and the U.S. Virgin Islands because, under the Energy Policy and Conservation Act (EPCA), the U.S. Caribbean region is defined as part of the U.S. and thus is a refining region intended to be supplied by the SPR during an energy supply emergency.

Changes in petroleum product supplies also are expected to occur over the 1990 to 2000 period. The use of alcohol fuels, although small in comparison to total petroleum supplies, is expected to grow steadily. Refined product imports are also projected to increase. As both of these liquids substitute for U.S. refinery product output, they reduce U.S. refinery requirements for crude oil, and their growth leads to a slower increase in imported crude oil requirements.

Nevertheless, by the year 2000, crude oil requirements of U.S. refineries are projected to be 14.5 million barrels per day. Since domestic production is expected to provide only 5.3 million barrels per day, imported crude oil will have risen to 9.2 million barrels per day, or 63 percent of U.S. refiners' supply of crude oil. These projections are detailed in Appendix A.

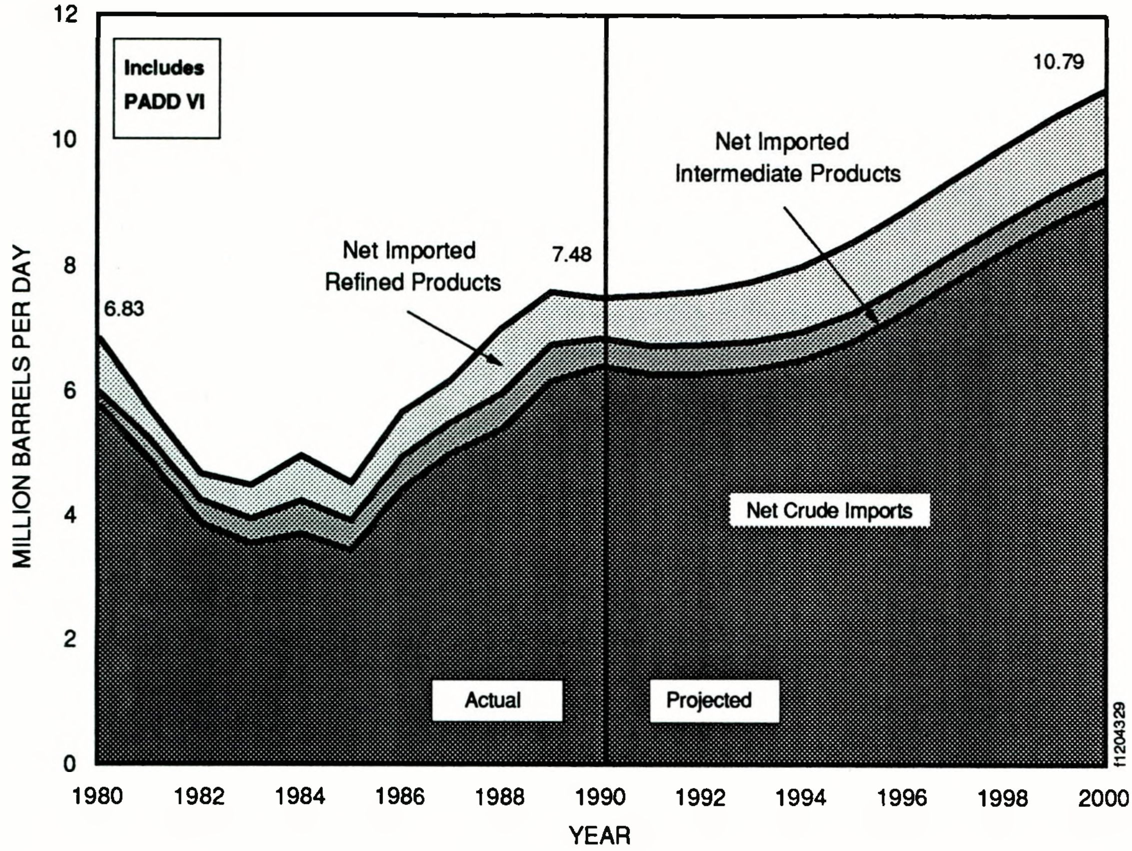


**Figure II-1. HISTORIC AND PROJECTED U.S. PETROLEUM IMPORTS**

Figure II-2 presents estimated Year 2000 imports of crude oil by PADD[1/] region of entry and shows the changes relative to 1990. Imports from Canada are shown separately because Canadian imports are more secure than imports from the rest of the world; the enactment of the U.S.-Canada Free-Trade Agreement has resulted in an integrated North American energy market that makes Canadian imports much like domestic production from a supply planning perspective. The advent of offshore Eastern Canadian production by 2000 should lead to a substantial increase in Canadian imports into the U.S. East Coast.

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1/ PADD = Petroleum Administration for Defense District, the standard regional aggregations in which petroleum data are usually published.

Figure II-2 shows that crude oil imports will be required in all regions of the United States. The largest volume of crude oil imports (68 percent) is projected to enter via the U.S. Gulf Coast where they will supply Gulf Coast refineries and move inland. Non-Canadian imports are projected to increase significantly on both the West and U.S. Gulf Coasts over the next 10 years: on the West Coast by 130 percent, and on the Gulf Coast by 63 percent.

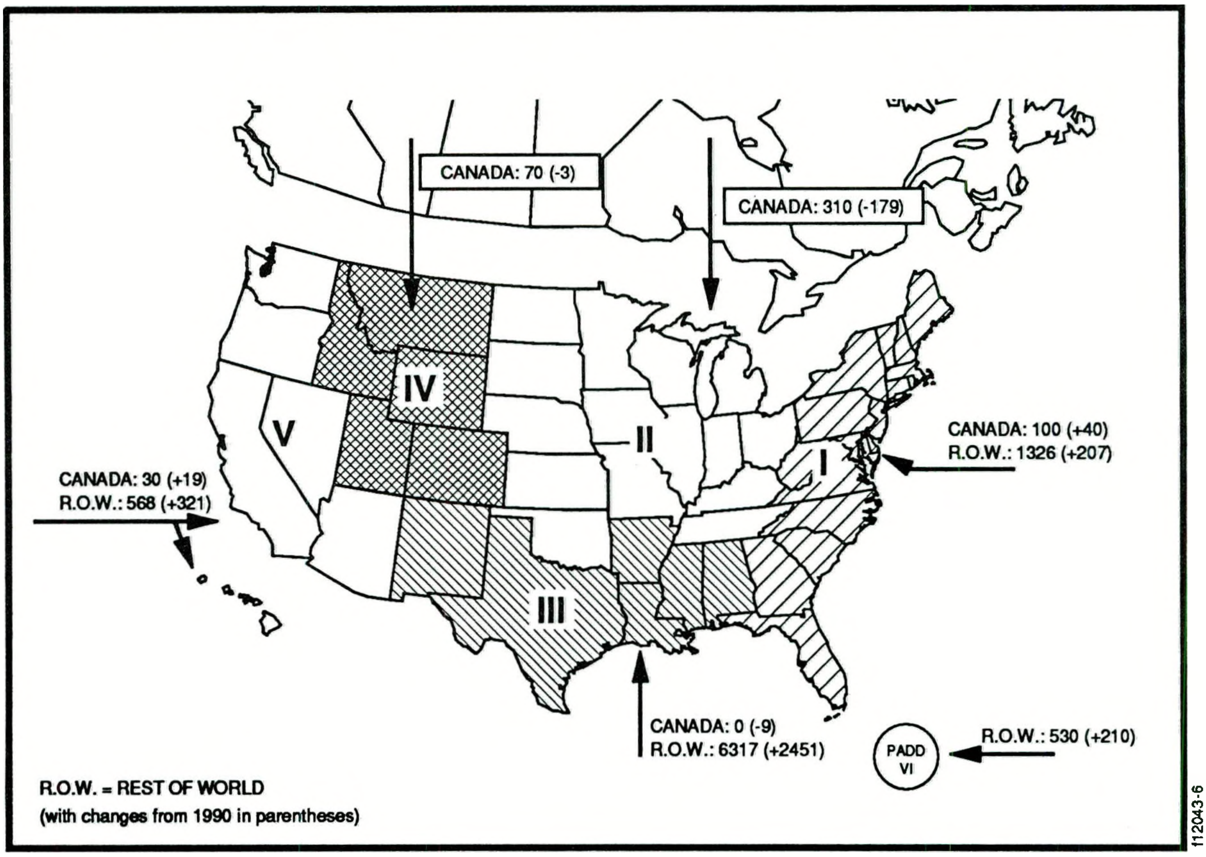


**Figure II-2. YEAR 2000 U.S. CRUDE IMPORTS BY PADD OF ENTRY (MBD)**

## B. Projected Regional Imports and Dependencies

Table II-1 shows estimates of crude oil consumption, imports and percent of import dependence for the six PADDs. These projections are described in detail in Appendix A. The data in Table II-1 indicate that all regions of the United States are expected to be at least partially import-dependent.

**TABLE II-1**
**Year 2000 Projected U.S. Refiner Dependence on Crude Oil Imports**
**(thousand barrels per day)**

| PADD | Crude Con-sump-tion | Domestic Crude | | Imports | | Import Dependence | |
|---|---|---|---|---|---|---|---|
| | | Lower-48 | Alaska | Canada | Other | Total | Non-Cana-dian |
| I (East Coast) | 1,368 | 0 | 0 | 100 | 1,268 | 100% | 93% |
| II (Midwest) | 3,098 | 1,014 | 0 | 310 | 1,774 | 67% | 57% |
| III (U.S. Gulf) | 6,304 | 1,761 | 0 | 0 | 4,543 | 72% | 72% |
| IV (Rockies) | 437 | 367 | 0 | 70 | 0 | 16% | 0% |
| V* (West Coast) | 2,793 | 1,345 | 850 | 30 | 568 | 21% | 20% |
| Subtotal | 14,000 | 4,487 | 850 | 510 | 8,153 | 62% | 58% |
| VI** (U.S. V.I./P.R.) | 530 | 0 | 0 | 0 | 530 | 100% | 100% |
| TOTAL | 14,530 | 4,487 | 850 | 510 | 8,683 | 63% | 60% |

* Includes Hawaii
** U.S. Virgin Islands/Puerto Rico.

East Coast (PADD I) refiners are projected to remain completely dependent on imported crude oil. By the year 2000, however, the region is expected to be receiving 100,000 barrels per day of crude oil from new offshore production in Eastern Canada. As a result, the region will be marginally less dependent on imports from less secure sources.

The Midwest (PADD II) is projected to become increasingly dependent on crude oil from outside North America as domestic crude oil production declines. Although some imports from Canada should still be available, an increasing amount will be required from overseas. As described below, the nation's crude oil pipeline system likely will be altered to respond to the increasing amount of imported crude oil supplied to the region via ports in the U.S. Gulf Coast. By the year 2000, PADD II is projected to be 57 percent dependent on non-Canadian imported crude oil.

The largest change in crude import dependence is projected for the U.S. Gulf region (PADD III). Even in the region that historically has been the nation's principal crude oil production area, refiners will be heavily dependent on imported crude oil from overseas. The level of crude imports will rise in part due to higher projected U.S. Gulf refinery throughput, but principally the increased imports will be replacing declining domestic crude supplies.

The lowest level of crude import dependence is projected for the Rockies (PADD IV). Although there is a possibility that pipelines may be reversed to bring in crude from PADD III, the Department projects that PADD IV's import requirements will continue to be met over the next decade by Canadian pipeline deliveries.

PADD V, the West Coast, is faced with increasing crude import dependence as Alaskan production declines. Based on EIA projections, the West Coast crude import dependence will increase to 21 percent by the year 2000. Other recent production estimates prepared by ICF Resources, Inc. project much greater production of Alaskan, California offshore, and California onshore from enhanced oil recovery as shown in Table II-2. At this higher level of domestic production, West Coast import dependence would be reduced to 9 percent; imports would be limited to those crudes that are needed to meet West Coast requirements for light crude oil. This higher level of Alaskan production has been further supported by a recent study of Alaskan oil reserves by the Department of Energy and the State of Alaska.[2/] This study projects the most likely forecast for production for Alaska's North Slope in the year 2000 to be 1,009,000 barrels per day and a potential for production using enhanced oil recovery techniques to be 1,159,000 barrels per day.

**TABLE II-2**
**Alternative Projections of PADD V Import Dependence (MBD)**

| | **Crude Require-ments** | **PADD V Production** | | | **Crude Imports** | **Import Depen-dence** |
|---|---|---|---|---|---|---|
| | | **Alaska** | **Other** | **Total** | | |
| EIA: Base Case | 2,793 | 850* | 1,345 | 2,195 | 598 | 21% |
| ICF Resources: Production Estimates | 2,793 | 1,175* | 1,516 | 2,691 | 260** | 9% |

* Excludes ANS exports of 50 MBD to Canada (allowed under the US-Canada Free-Trade Agreement).
** Minimum required to meet PADD V light crude oil requirements.

2/ US Department of Energy/State of Alaska, *Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity*, January 1991.

Estimates of future West Coast imported crude oil requirements are complicated, however, by large uncertainties over tightening environmental constraints. These constraints will affect petroleum product demand, production, domestic pipeline flows and, over the long term, the economic viability of the smaller refineries.

PADD VI, the U.S. Caribbean refining region, is projected to be entirely dependent on imported crude supplies by the year 2000. The current shipments of Alaskan crude to the region are projected to end once the West Coast no longer has a domestic crude supply surplus.

**C. Projected Gulf Coast Crude Oil Infrastructure Changes**

In the mid-1970's, when the SPR was established, its crude oil storage facilities located in U.S. Gulf Coast sites had access to three major interstate crude oil pipelines serving the Midcontinent of the U.S. These three pipelines were the Seaway Pipeline, the Texoma Pipeline and the Capline Pipeline.

In the period after the establishment of the SPR and continuing up until the mid-1980's, petroleum market trends in the Midwest led to a declining demand for non-Canadian imported crude oil. PADD II crude oil production increased as did Canadian imports into that region. Transport of imported foreign crude oil inland from the Gulf Coast declined significantly. As a result, both the Seaway and Texoma Pipelines were underutilized and eventually converted to natural gas transmission. Only the Capline Pipeline system remains as a crude carrier.

Between 1985 and 1990, this trend reversed when PADD II crude oil production began declining and the level of Canadian imports stabilized. Demand for West Texas and imported crude supplies from the Gulf Coast began to grow. As a result, West Texas-to-Oklahoma pipelines became bottlenecked, and the utilization of the Capline Pipeline system doubled.

Industry began responding to the tight pipeline capacity situation in 1988 when the ARCO Pipe Line Company reversed its 20-inch pipeline to transport crude oil from Houston to Cushing, Oklahoma. In December 1989, Texas Pipe Line Company followed suit and reversed its 16-inch crude pipeline from Houston to Cushing. From Cushing, a central node of the inland crude oil pipeline infrastructure, pipeline capacity is sufficient to move crude to most points in the Midwest. In 1990, two additional smaller pipelines were reversed between Port Arthur and Longview, Texas to transport crude oil imports inland.

Two studies are known to have been performed in 1990 to analyze 1990-2000 demand for foreign crude oil imports into PADD II, and the need for additional pipeline capacity to transport the imported crude inland from the Gulf Coast. The first study, entitled *Inland Crude Transportation Study*, was organized by the AMOCO Pipeline Company. This study found that without further pipeline expansions, existing pipeline systems would be unable to meet inland refiner demand for imported crude by 1993. The study estimated that, without additional pipeline capacity, the existing pipeline capacity shortfall from PADD III to PADD II would be about 329,000 barrels per day by 1995 and about 526,000 barrels per day by the year 2000.

The second study, which was performed by Purvin and Gertz Inc., came to similar conclusions. Purvin and Gertz concluded that PADD II refiners' reliance on foreign crude oil imports from the Gulf Coast would be likely to double by the year 2000. Imports from the Gulf Coast into PADD II were projected to rise to about 1.74 million barrels per day. Purvin and Gertz concluded that increased pipeline capacity would be required to serve these inland needs.

To meet this growing demand for non-Canadian foreign crude oil imports in PADD II, three pipeline projects are known to have been initiated to increase pipeline capacity from the Houston area to Cushing:

- ARCO Pipe Line has an expansion project underway to increase its Houston-to-Cushing pipeline capacity from 70,000 barrels per day to 120,000 barrels per day by April 1991, and possibly to 200,000 barrels per day in the future.

- Texaco Pipe Line is considering an expansion of its pipeline capacity from Houston to the Midcontinent from 65,000 barrels per day to 120,000 barrels per day.

- Phillips Pipe Line is studying the reconversion of the original Seaway Pipeline System from natural gas to crude oil transmission. The Seaway pipeline was originally constructed with a capacity to move 300,000 barrels per day of crude oil from Freeport, Texas to Cushing, and its capacity can be increased to 600,000 barrels per day.

The increased demand for U.S. Gulf crude oil imports also has implications for marine port requirements. Phillips Pipe Line, on behalf of 15 companies, is directing a feasibility study of the construction of a Texas Offshore Oil Port (TEXPORT) near Freeport. TEXPORT would be designed to unload 1-2 million barrels of crude oil per day from ultra large crude carriers and deliver it to an onshore storage terminal for pipeline deliveries to Cushing (via Seaway Pipeline) and Houston/Texas City refineries. Phillips expects to make a decision during 1991 on whether to pursue licensing for TEXPORT.

The Gulf Coast pipeline infrastructure envisioned to meet the crude oil supply needs of the Midcontinent and Midwest refiners in the year 2000 is presented in Figure II-3. The Department expects that all increases in pipeline capacity to meet inland crude oil demand will originate in the Houston/Freeport region served by the SPR's Seaway Complex. The Department projects that the

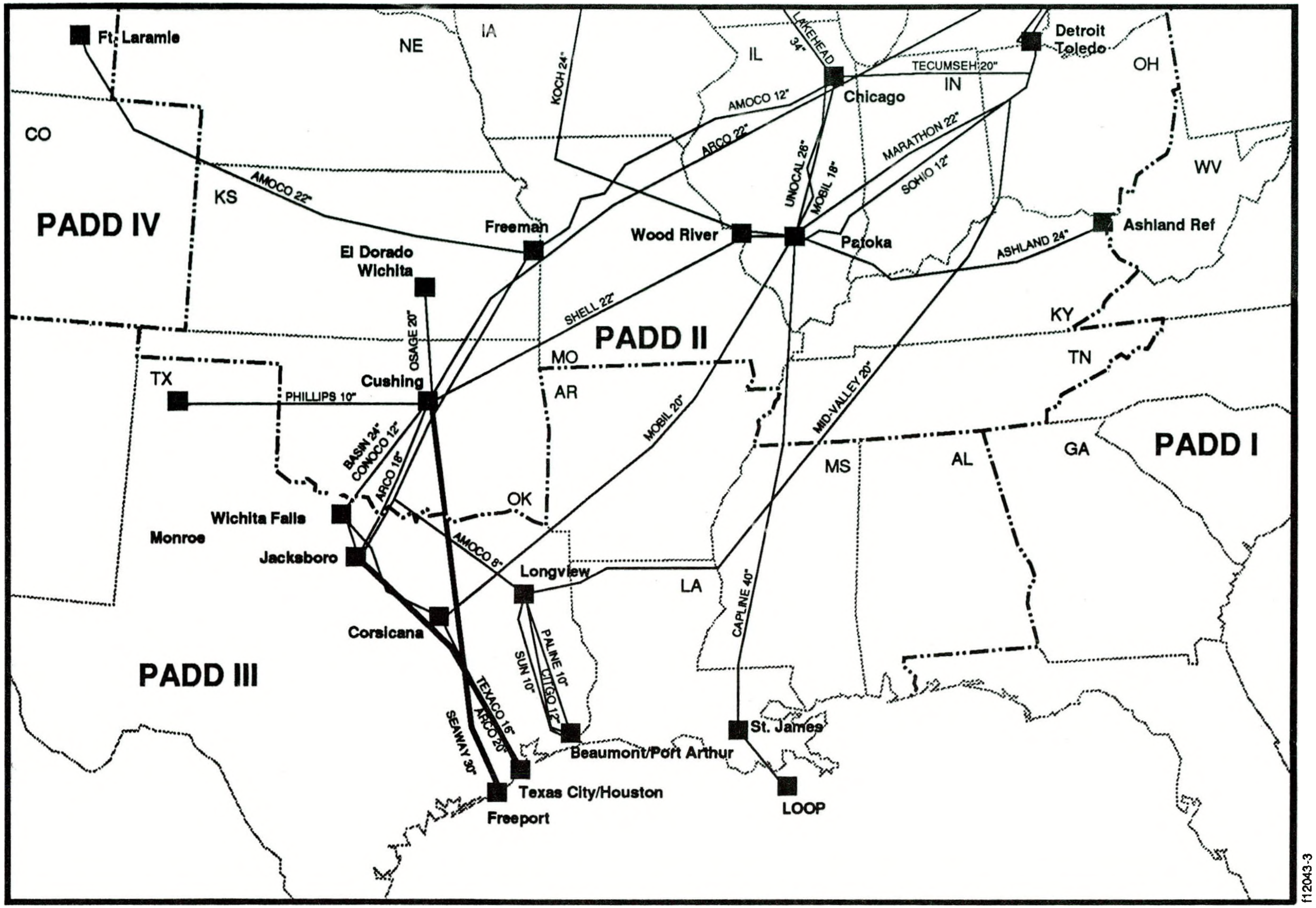


**Figure II-3. YEAR 2000 PROJECTED INLAND CRUDE OIL PIPELINES**

Seaway Pipeline will be returned to crude oil service and will become the dominant pipeline into the Midcontinent area.

**D. Conclusions**

Projected regional import trends indicate that the Gulf and East Coasts will be the U.S. regions with the greatest dependence on imported crude. The Gulf Coast in particular is projected to receive 68 percent of total U.S. crude imports in the year 2000, with almost one-third of that delivered inland to satisfy PADD II demands. These import dependence trends suggest that, all other things being equal, the Gulf and East Coasts would be the most appropriate regions in which to site storage facilities for SPR expansion.

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# SECTION III
## SPR Expansion and Distribution Plan

This section presents an in-depth analysis of the feasibility of an SPR storage site on the East Coast, and of the potential siting and distribution capabilities for SPR storage facilities on the Gulf Coast, in order to establish the best expansion configuration for the Reserve. It also includes an analysis of leasing storage facilities as an alternative to Government development and ownership.

**A. SPR Expansion Plan of 1989**

The Department's 1989 report to the Congress on expansion of the Strategic Petroleum Reserve to one billion barrels concluded that the most desirable expansion configuration for the SPR would be:

- Government owned and controlled.
- Crude oil storage only.
- Located in the Gulf Coast in underground storage in salt domes.
- Drawdown capability of 6.0 million barrels per day.

The Department's proposed expansion configuration consisted of two sites: a 150-million-barrel storage site in the Gulf Coast (Capline Complex) and a 100-million-barrel storage site to be located in either the Gulf Coast or the East Coast.

The 150-million-barrel site was proposed for the Gulf Coast Capline Complex based on projected Gulf Coast demand and distribution analyses. The Capline Complex offered the greatest projected demand and the best distribution potential by way of the LOOP Terminal at Clovelly, the Capline Interstate Pipeline and the Department's St. James marine terminal.

Due to its high level of crude oil imports, the East Coast offered the next best siting; however, due to the lack of salt domes on the East Coast for economical storage development, a 100-million-barrel storage site in the Gulf Coast with waterborne distribution capabilities was proposed.

A 100-million-barrel site on the East Coast utilizing an inground concrete storage technology was proposed as an alternative to a second Gulf Coast location. However, the 1989 report concluded that if an East Coast site is pursued, there must be further evaluation of the inground storage concept in terms of siting, technical feasibility, environmental feasibility and cost.

## B. East Coast Site Feasibility

Due to the lack of salt domes and suitable mines, storage technology associated with the East Coast is essentially limited to above-ground steel tanks and inground concrete tanks. The inground concrete tank concept for a 100-million-barrel East Coast site was identified in the April 1989 report as potentially being more advantageous than above-ground steel tanks in terms of cost, land usage, safety and other factors. Additional feasibility, cost and environmental analyses have been done to determine whether the inground concept is a reasonable alternative.

### Siting Feasibility

In December 1990, the Department initiated an East Coast siting feasibility study through the U.S. Army Corps of Engineers. The preferred location would be in the Delaware-New Jersey area along the lower Delaware River between Philadelphia, Pennsylvania and Delaware City, Delaware, where approximately 80 percent of the East Coast's refining capacity is concentrated. Along this 35-mile stretch of the river, eight of the East Coast's fourteen operating refineries account for approximately one million barrels per day of refining capacity. In its January 1991 report, the Corps of Engineers identified twenty preliminary sites in the Lower Delaware River area which may be suitable for locating an East Coast storage facility. Figure III-1 shows the location of these sites. The Corps' selection of these locations was based on required acreage, proximity to the navigable section of the Delaware River (i.e., downriver of Trenton, New Jersey), current land use and zoning, and site elevation and contours.

### Technical Feasibility

Based on preliminary engineering design and analysis, the development of a 100-million-barrel inground concrete crude oil storage facility in the Lower Delaware River area is technically feasible. This conclusion is based on a conceptual design report completed in April 1989 by PB-KBB, Inc. of Houston, Texas under contract to the Department, and a further technical assessment of that conceptual design by ICF Kaiser Engineers of Oakland, California in January, 1991.

A conceptual drawing of an inground concrete storage facility is presented in Figure III-2. The storage facility would encompass an area of approximately 640 acres or one square mile, with the rectangular polyethylene-lined concrete tank compartments almost entirely underground and covered and sealed with precast concrete roof slabs. Construction of the facility would be an immense undertaking involving approximately 580,000 cubic yards of earth excavation, 47,000 cubic yards of poured-in-place concrete, and the driving of nearly 800 piles.

There is little or no U.S. experience in the construction and operation of a facility of this type. The concept is based on a similar but much smaller oil storage facility currently in operation in South Africa, and concrete construction techniques used in building aqueducts in California. The

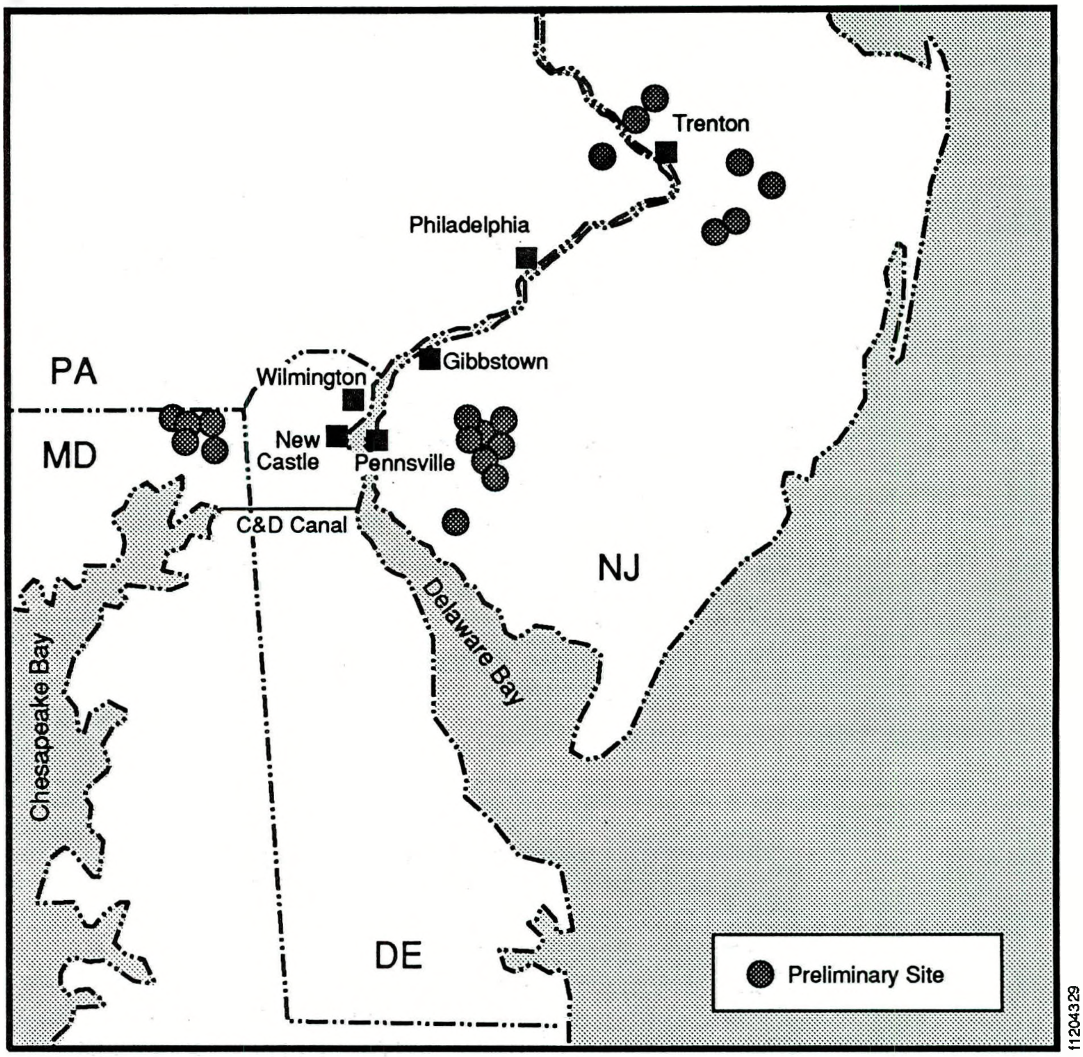


**Figure III-1. POTENTIAL EAST COAST STORAGE LOCATIONS**

lack of prior experience with this technology presents an inherent risk to completing an operable facility within estimated costs and schedule that will be technically and environmentally sound. Of particular concern are the large number of penetrations through the polyethylene liner necessitated by the pile foundation. Although all such penetrations would be sealed insofar as practicable, every penetration through a seal is a potential failure point which could result in some leakage.

Distribution

A major impediment associated with an East Coast storage site is the lack of relevant infrastructure for crude oil transport and distribution. Petroleum transportation facilities and operations on the Delaware River are oriented toward tank barges and rail tank cars. There is much reliance on lightering, bunkering and associated handling operations. Most facilities are for the

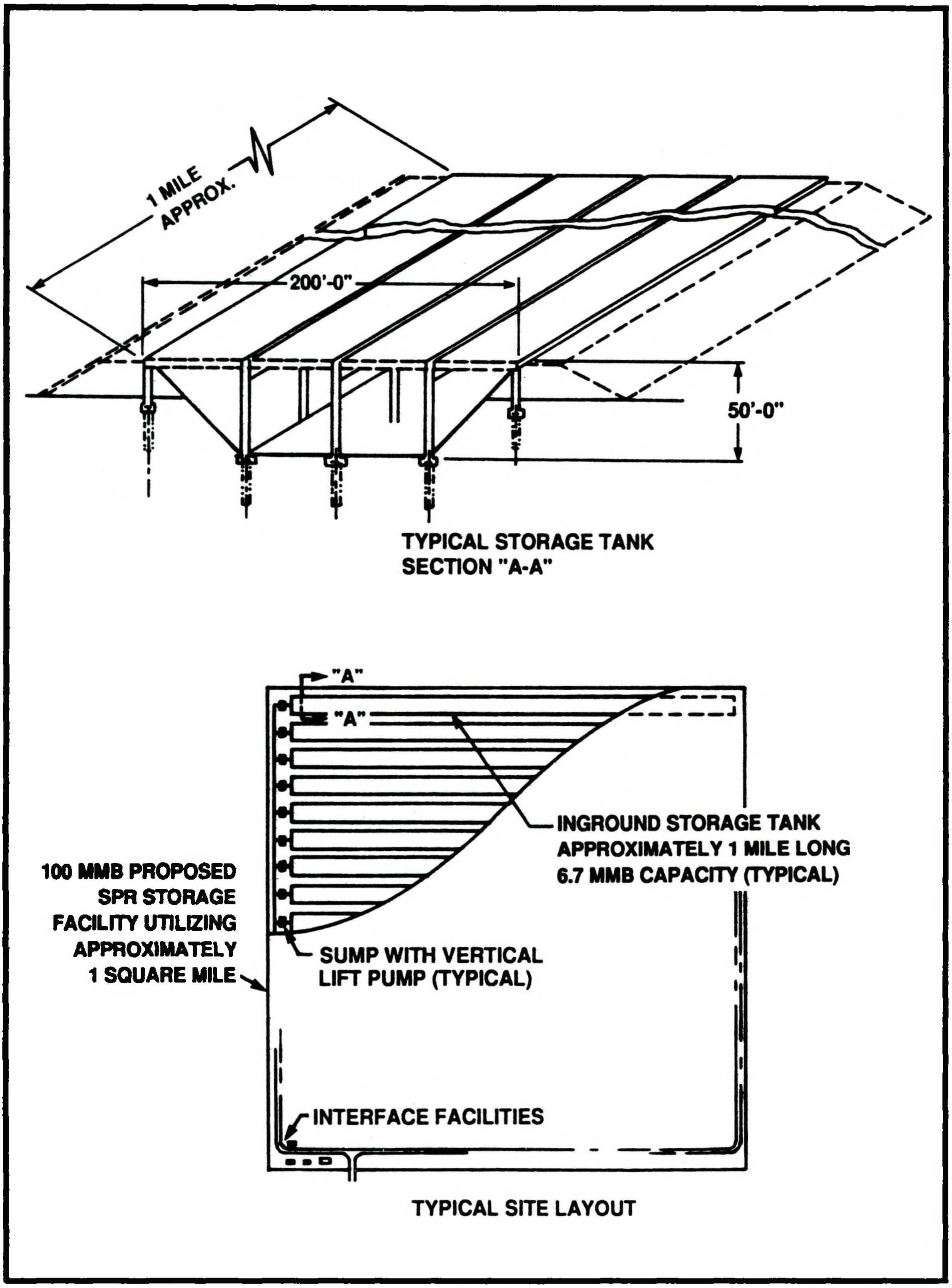


**Figure III-2. INGROUND CRUDE OIL STORAGE CONCEPT**

distribution of fuel oil and petroleum products in regional commerce or for local plant consumption. There are no commercially operating marine terminals. There are private tanker berths at Delaware City, Delaware, Marcus Hook and Philadelphia, Pennsylvania, and Paulsboro and Westville, New Jersey, but these are integrated with refining operations and, based on our experience, would not likely be available for modification and use by the SPR.

Since there is no crude oil pipeline infrastructure on the East Coast, distribution would be 100 percent waterborne, and construction of a new Government-owned marine terminal would most likely be required. Potential sites for a new marine terminal capable of handling oceangoing tankers appear to be confined to a 20-mile stretch of New Jersey shoreline between Gibbstown and Pennsville, and an 8-mile stretch of Delaware shoreline between New Castle and the Chesapeake and Delaware Canal.

Cost and Schedule

The development of an inground concrete storage facility is projected to be more costly and require more time than an equivalent Gulf Coast salt dome site. The total estimated cost of an East Coast facility in constant (unescalated) 1991 dollars is $1,134,331,000 or $11.34 per barrel of storage capacity (Table III-1). The estimated site development costs include design, land acquisition, storage site construction, construction management, and distribution system costs which include a new, two-dock marine terminal and a 20-mile, 36-inch pipeline. This cost can be compared to the estimated cost of $545,000,000 or $5.45 per barrel for an equivalent 100-million-barrel Gulf Coast salt dome site (average cost of four candidate sites, see Section VI). Construction of a 100-million-barrel inground concrete storage facility on the East Coast is estimated to take at least 9 years including detailed design and land acquisition following completion of NEPA environmental activities (see Section IV).

The costs shown in Table III-1 do not include operation and maintenance costs. There exists no prior U.S. experience in the operation and maintenance of a facility of this nature, but it is thought that such recurring costs could be significantly higher than an equivalent salt dome. For example, although the polyethylene lining system is designed to preclude leakage and require minimal maintenance, 100 percent performance cannot be guaranteed. Repairing the polyethylene liner material would be a significant cost which would require completely emptying and cleaning the affected portion of the storage container. Under long term storage conditions, sludge would also accumulate which would require internal mixing or removal and disposal. Salt caverns on the other hand, require virtually no maintenance and sludge accumulation is minimal due to convection in caverns.

Significant delays and cost growth were encountered in the early stages of Gulf Coast SPR development due to regulatory requirements in the permitting process. Contributing factors included lack of familiarity of state agencies with SPR systems, activities, and procedures, and public suspicion of large-scale development employing technology that, at the time, was unproven for crude oil storage in this country. For similar reasons, there is a significant risk to the program of major delays and cost growth associated with implementing an untried concept, large-scale inground concrete storage tanks, in a region, the East Coast, that has no experience with the SPR program.

**TABLE III-1**
**Estimated Development Cost**
**100-Million-Barrel Inground Concrete Storage Facility**

| Activity | Estimated Cost |
|---|---|
| Land Acquisition | $17,971,000 |
| Construction | $768,785,000 |
| Engineering and Construction Management | $196,689,000 |
| Subtotal-Storage Facility | $983,445,000 |
| Marine Terminal | $87,711,000 |
| Distribution Pipeline | $63,175,000 |
| Subtotal-Distribution System | $150,886,000 |
| Total Development Cost | $1,134,331,000 |

Environmental Considerations

Siting and constructing an inground storage facility on the East Coast would raise serious environmental questions. Development of a 100-million-barrel inground tank storage facility would result in the extreme disturbance of a 640-acre site; this represents an irreversible and irretrievable loss of resources. The facility could pose serious environmental risks during operations through the potential for large crude oil leaks to groundwater and releases to land and surface water. These risks, however, would be mitigated in accordance with existing Departmental orders through an extensive groundwater monitoring program and spill prevention and control designs, procedures, and countermeasures. Although the inground approach necessarily requires siting the storage facility to avoid wetlands and to be above the water table, wetland involvement may be unavoidable in siting a marine terminal or in routing a pipeline between the docks and the storage facility.

Aside from the public concern that would be anticipated with such a project, there is heightened public sensitivity to siting industrial facilities throughout the Delaware River basin. Accordingly, the affected States have imposed stringent regulations, including prohibition of undesired facilities. For example, Delaware prohibits siting of any new heavy industrial facilities or new offshore liquid transfer facilities in the coastal zone; consequently, siting a marine terminal may be unrealistic.

The States of New Jersey, Delaware, and Maryland all have extensive regulations covering construction in or disturbance of, the areas' wetlands and coastal zones. Because the pipeline and marine terminal would likely impact these areas, requirements for permits, mitigation measures (e.g., replacement of wetlands), and determinations that no alternative sites exist, would raise additional questions.

A further concern is the increased risk of oil spills on the Delaware River, given typical oil-handling operations. The replacement of 100 million barrels of lost imports from a local storage facility could effectively triple the petroleum handling operations on the waterway: the transfer from tanker to terminal during fill of the storage facility; the transfer from terminal to tanker during a drawdown; and the transfer from the tanker to local refinery docks. This handling problem is particularly important given public concern over recent oil spills and resulting adverse impacts on the Delaware River.

The most serious environmental issue would likely involve the air quality impacts of siting a new marine terminal. The stretches of the Delaware River under consideration for a marine terminal are located in a nonattainment area for the ozone National Ambient Air Quality Standard (NAAQS). Releases of hydrocarbons, such as those anticipated during loading and unloading of crude oil, increase the formation of atmospheric ozone. Therefore, siting a marine terminal in an ozone nonattainment area would be difficult if not impossible. Such siting could only be accomplished in accordance with the Clean Air Act's offset policy. Under the offset policy, before a permit can be issued for a new source in a nonattainment area, legally enforceable emission reductions are required for all existing sources. Extensive negotiations with all existing sources would be necessary to achieve this requirement and financial compensation would likely be required. In addition, as a new source, the marine terminal would be required to install state-of-the-art control technology which would be very expensive. The risk of cost growth and schedule delay that could result from the offset policy is unknown at this time, but it is deemed to be significant and possibly insurmountable.

Summary

Strategic storage along the lower Delaware River could offer some transportation or distribution advantages to East Coast refineries in that area, in comparison to Gulf Coast storage. From an East Coast site, crude delivery would take one to two days; from the Gulf Coast, transit and delivery time would be six to eight days. Nonetheless, Gulf Coast distribution accessibility to the East Coast is considered quite adequate.

In terms of projected costs and technical and environmental risks, there is little question that salt dome storage in the Gulf Coast is preferable. The small distribution advantage offered by East Coast storage does not justify the additional costs, technical risks, and potential environmental problems. Therefore, the Department has concluded that inground concrete tank storage is not a reasonable alternative at this time and an East Coast storage facility will not be considered further for expansion of the SPR to one billion barrels.

### C. Gulf Coast Siting and Distribution

The dominant role of the U.S. Gulf Coast in receiving crude oil imports is clearly reflected in Figure III-3 which shows, schematically, imports by region and for various refining centers for the year 2000 as forecast by the Department. More than 70 percent of all non-Canadian imports will be received at the Gulf Coast. Of that amount, approximately 30 percent will enter via the Capline region of the lower Mississippi River, principally through the Louisiana Offshore Oil Port (LOOP), where they will be consumed by local refineries or distributed to the Great Lakes region through the Capline Pipeline.

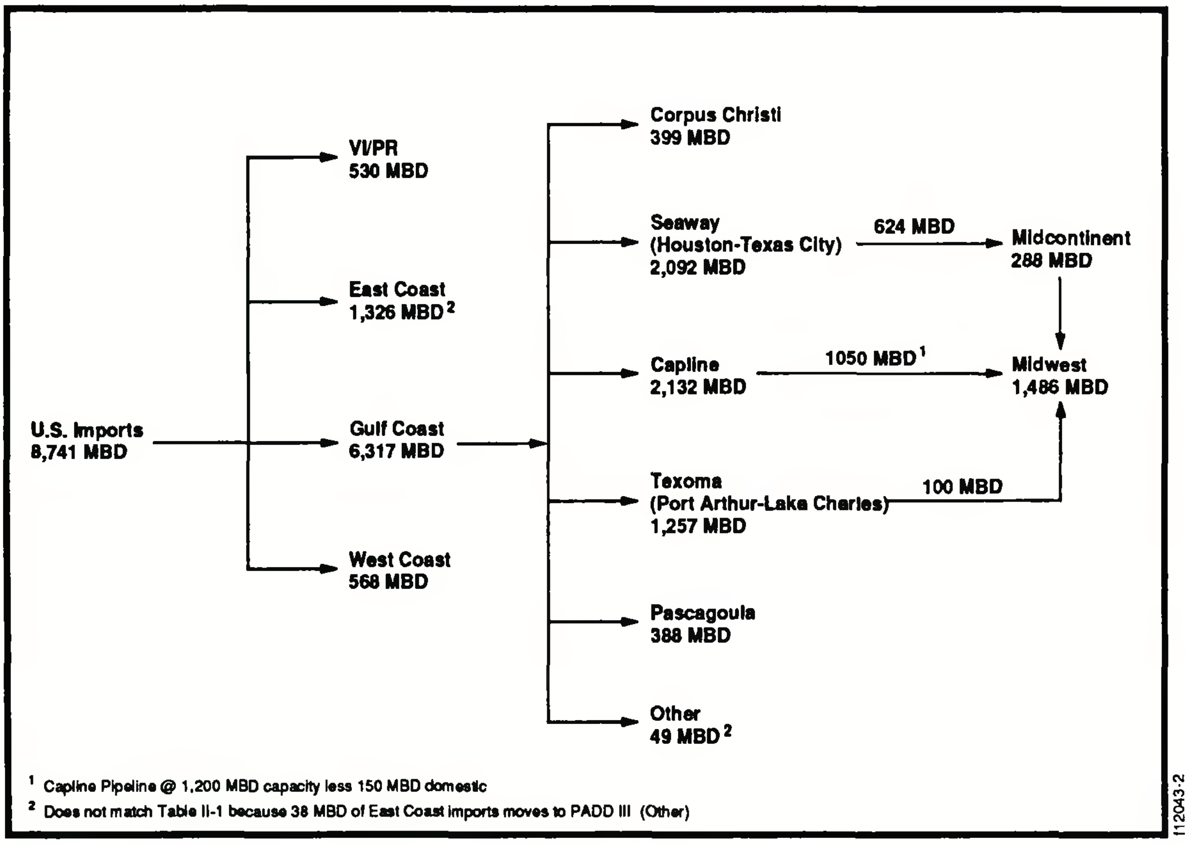


**Figure III-3. PROJECTED RECEIPTS OF NON-CANADIAN CRUDE OIL IMPORTS BY U.S. REGIONS AND REFINING CENTERS IN THE YEAR 2000**

The most significant change from today's crude oil import logistics picture is the new inland distribution of foreign crude to the Midcontinent and Midwest, principally from the Seaway region and to a minor extent from the Texoma region, resulting from the changes to the commercial distribution infrastructure described in Section II.

The distribution capability of each of the SPR complexes, as currently authorized in the 750-million-barrel Reserve, is compared in Figure III-4 to actual 1990 imports and to the projected year 2000 imports. The dramatic increase in imports forecast in the Seaway, Texoma, and Capline areas is due primarily to declining domestic production within PADD II and PADD III and the disappearance of Alaskan crude oil from the Gulf Coast market when the West Coast crude surplus ends.

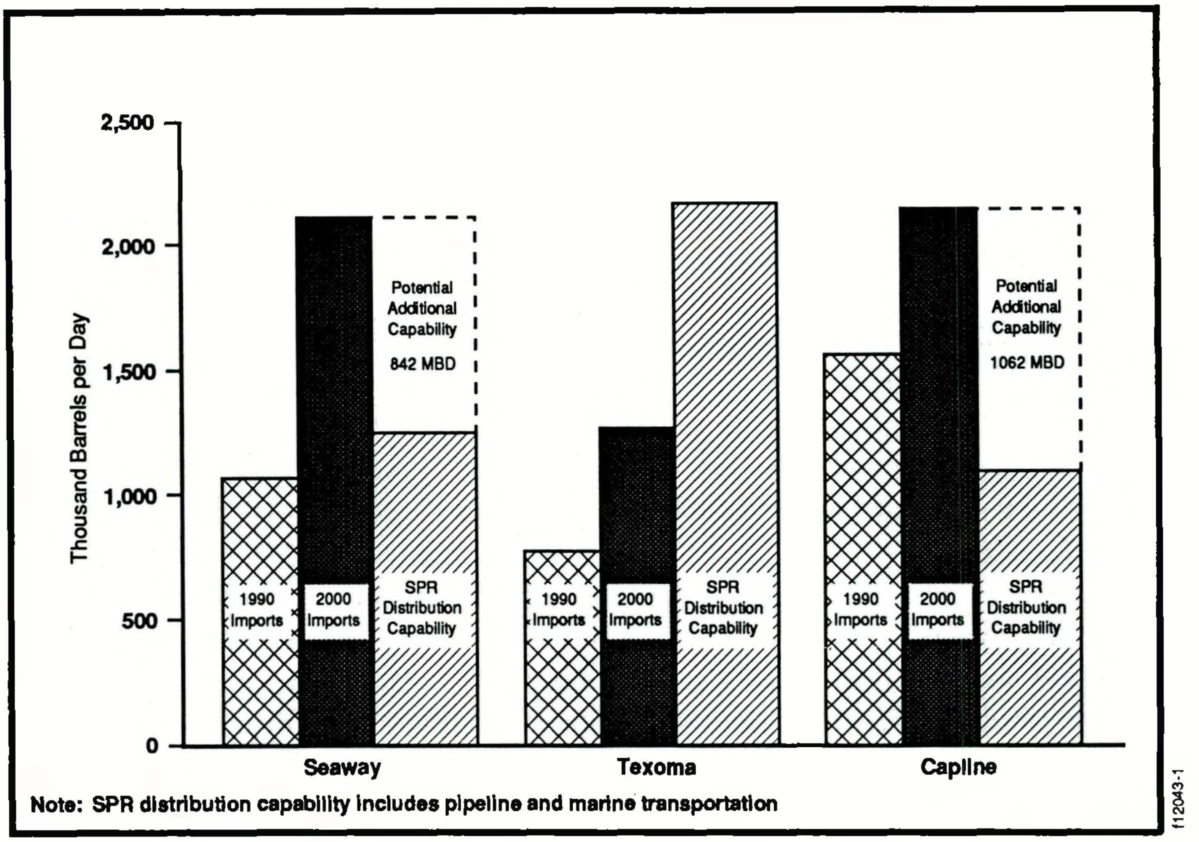


**Figure III-4. NON-CANADIAN CRUDE OIL IMPORTS vs. SPR DISTRIBUTION CAPABILITY**

In addition to the effects of declining domestic production, the demand for imports via Seaway, and thus potentially the SPR oil delivered through Seaway, will grow by one million barrels per day primarily as a result of the connection of the Midwest refiners and the Midcontinent refiners of Oklahoma and Kansas through the reversed ARCO and Texaco systems and a recommissioned Seaway Pipeline. These new connections are shown in Figure III-5. Consequently, expansion of the SPR's Seaway complex appears to have considerable potential benefits.

The drawdown capabilities of the SPR Texoma complex currently saturate the local refinery demand for imported crude oil and the local commercial marine distribution capability. This condition is projected to persist in spite of a large expected increase in local crude oil import demand (Figure III-4). Expanded storage capacity in the Texoma complex, with a concomitant higher drawdown rate, therefore would require Departmental construction of a pipeline to the Houston area in order to increase the SPR distribution capability.

The Capline Complex offers substantial distribution expansion potential (see Figure III-4). The PADD II demand for non-Canadian imported oil that is served by the Capline pipeline is expected to more than double by year 2000 as a result of declining domestic production and Canadian imports. Figure III-6 is a schematic of existing refinery connections accessible through LOOP and LOCAP in the Capline Complex area. By connecting additional SPR storage capacity to the LOOP pipeline terminal at Clovelly salt dome, the SPR could increase its distribution capability by connecting to five additional refineries of the lower Mississippi River, as well as serve the growing PADD II demand.

In conclusion, from the perspective of refiner demand and the related SPR distribution infrastructure, a 250-million-barrel expansion of the SPR would logically be concentrated in the Seaway and Capline complexes. Between the two complexes, a larger Capline storage site would be more desirable for two reasons. First, the Capline Complex is projected to have a larger distribution potential than the Seaway Complex and is also expected to be the dominant import carrier to the Midwest due to its more direct route and lower tariffs. Secondly, because the Capline Complex was never developed to the level of storage capacity envisioned in the original SPR Plan, the SPR's storage in the Capline area is only 20 percent of the current Reserve (145 million of 750 million barrels) and is insufficient to sustain a 150 to 180-day drawdown at design rates. Therefore, the most desirable expansion configuration for the one billion barrel program would be:

- A 150-million-barrel storage site in the Capline Complex connected to the LOOP Clovelly terminal for distribution.

- A 100-million-barrel storage site in the Seaway Complex connected to the Seaway Pipeline Terminal or Houston pipeline terminals serving the Midcontinent and Midwest.

The drawdown capability of the one billion barrel Reserve will most likely be 5 to 6 million barrels per day. Assuming, for planning purposes, a 6-million-barrel per day drawdown rate, the 150-

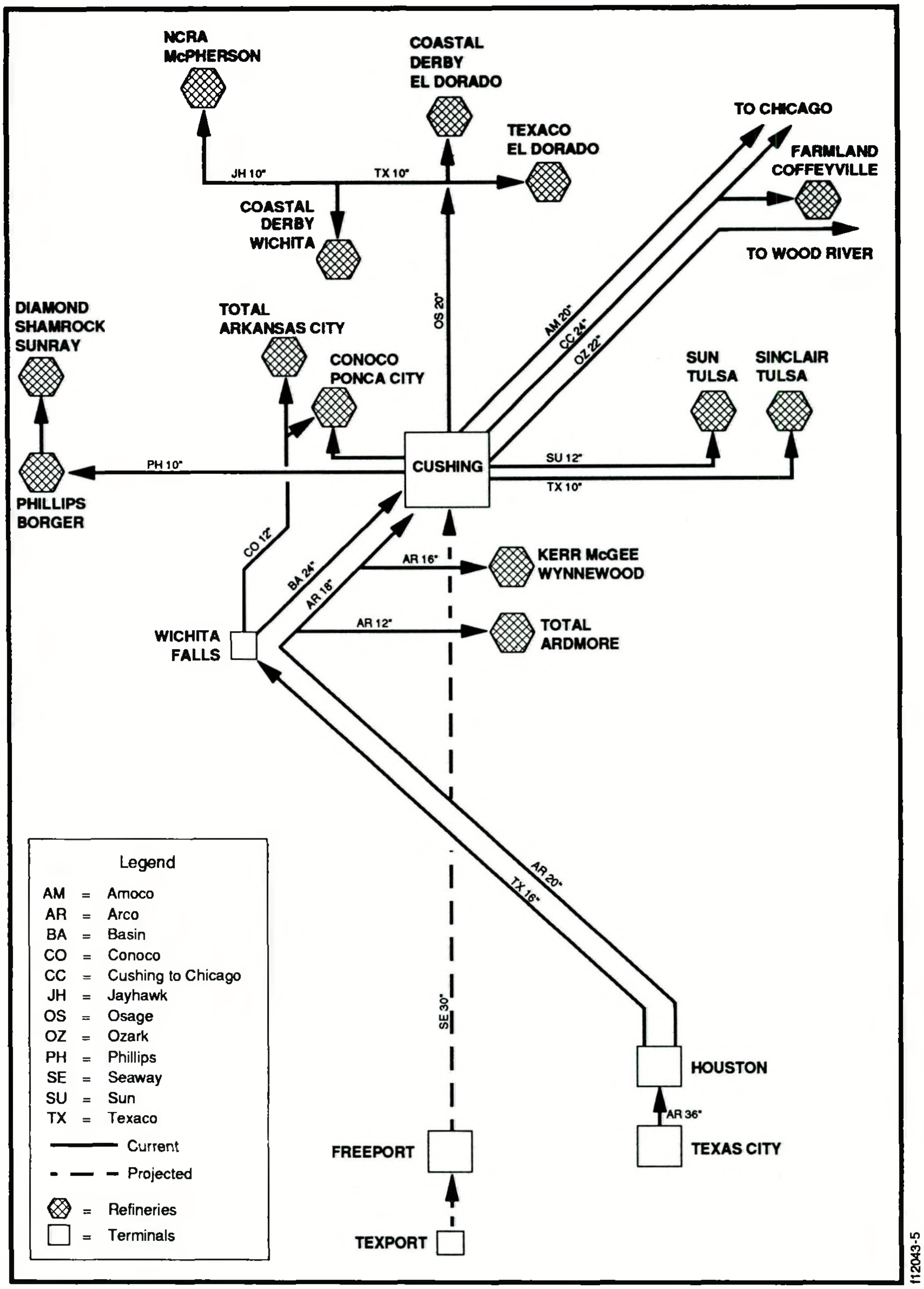


**Figure III-5. MIDCONTINENT DISTRIBUTION CAPABILITIES FROM THE FREEPORT/HOUSTON AREAS**

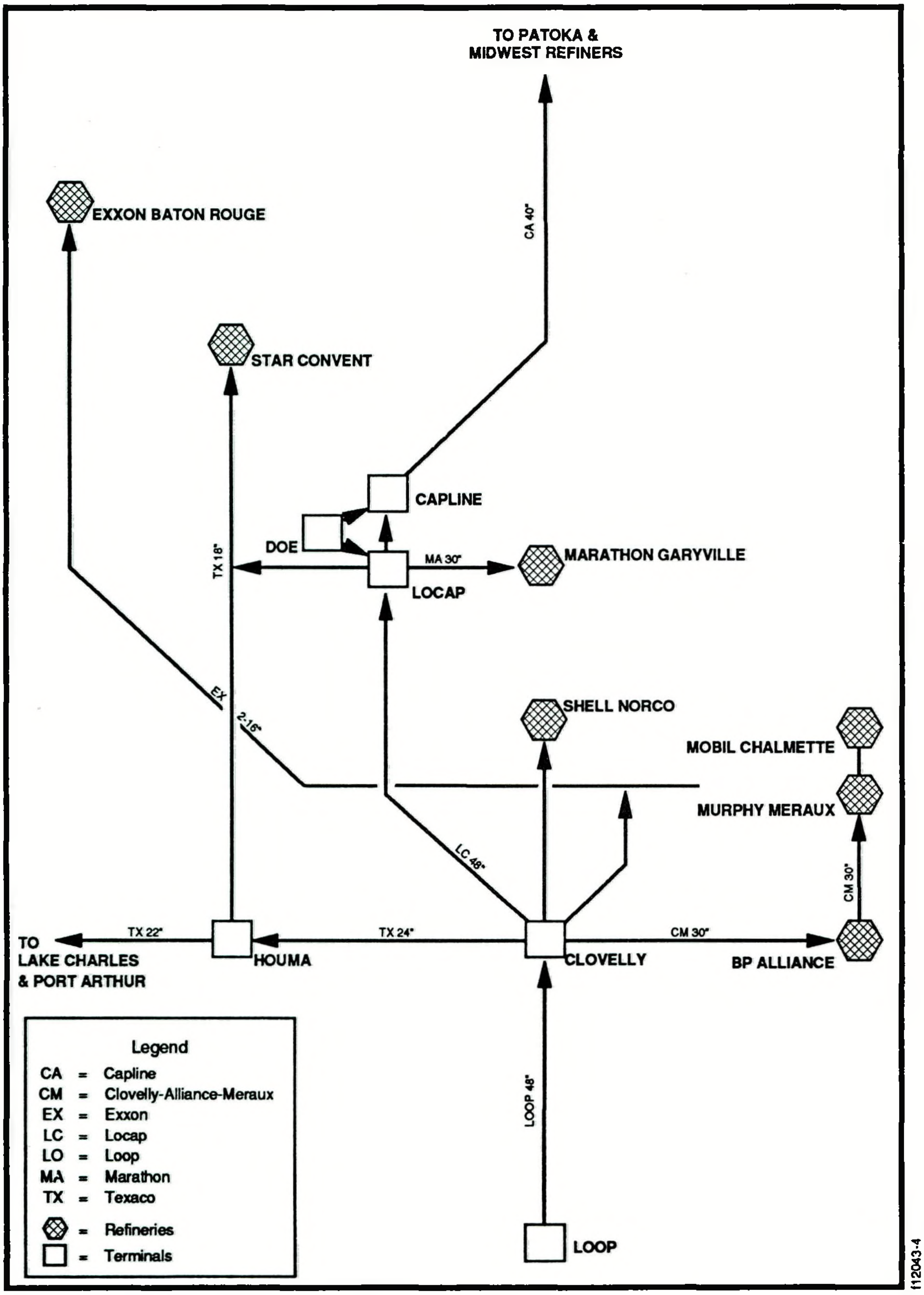


**Figure III-6.** **LOWER MISSISSIPPI RIVER DISTRIBUTION CAPABILITIES FROM THE LOOP CLOVELLY TERMINAL**

million-barrel Capline Storage site would have a drawdown/distribution rate of 900,000 barrels per day and the 100-million-barrel Seaway storage site would have a drawdown/distribution rate of 600,000 barrels per day. The required drawdown capability for the expansion will be reanalyzed and discussed in the SPR Plan Amendment.

The proposed expansion configuration of a 150-million-barrel Capline storage site and a 100-million-barrel Seaway storage site would provide a balancing of the storage and drawdown capabilities of the three SPR storage complexes as shown in Table III-2.

**TABLE III-2**
**SPR Complex Storage and Drawdown Capabilities**

| | Current 750 MMB Program | | Expanded 1000 MMB Program | |
|---|---|---|---|---|
| | Storage (MMB) | Drawdown Rate (MBD) | Storage (MMB) | Drawdown Rate (MBD) |
| Seaway | 226 | 1,250 | 336 | 1,850 |
| Texoma | 379 | 2,180 | 379 | 2,180 |
| Capline | 145 | 1,070 | 295 | 1,970 |
| Total | 750 | 4,500 | 1,000 | 6,000 |

**D. Leasing Storage Facilities**

All of the existing SPR storage facilities are Government-owned and have been financed by the U.S. Treasury out of general tax revenues. This section examines the feasibility of leasing privately owned storage facilities as a means of expanding the Reserve by another 250 million barrels.

Leasing of facilities was addressed in the Department of Energy's *Report to the Congress on Alternative Financing Methods* of February 1, 1990. Based on the analysis presented in that report, the Department found that "leasing" and comparable arrangements generally are not attractive options for financing long-term strategic crude oil storage facilities. Some of the more significant technical and financial problems associated with leasing are discussed below.

**Technical Issues**

As a nationally important strategic project intended to respond to energy emergencies with a high probability of success, SPR facilities must meet rigorous design and construction specifications for maximum reliability, safety, and security. SPR design and performance requirements are typically much more stringent than those applied to commercial storage facilities, and understandably so.

During long periods of standby, the SPR is expected to maintain readiness to begin drawdown of crude oil within fifteen days, and then to operate under emergency conditions with minimal downtime.

Industry representatives have asserted that cost savings could be achieved if a lessor is permitted to design a site to meet performance specifications rather than design specifications, with only minimal design and construction criteria specified. However, at the same time, they are disinclined to guarantee the integrity of storage caverns against the loss of oil. In any case, without the more stringent design and construction specifications, there could be a significant risk to the SPR's mission capability.

The maintenance and operation of a leased facility could also be a significant problem, as it is critical to continued reliability and assurance of performance capability. Technical assurance over the entire term of the lease will depend heavily on the operator's maintenance, repair and spare parts programs, periodic system tests and cavern recertifications and operator training. All of the existing SPR sites are operated and maintained by one contractor who answers directly to the Government and is subject to continual monitoring. This contract with the Government is structured to provide performance incentives and, as a reimbursable-type contract, effectively eliminates the natural tendency to maximize profits by minimizing maintenance expenditures. In a lease-type arrangement, the contractual and working relationship among the lessor, lessee, and operator could be difficult to manage and the maintenance of required performance likely difficult to control.

SPR facilities also require a strict security program consistent with its perceived attraction as a potential terrorist target. The security program, mandated by DOE criteria, includes 24-hour armed protective forces and extensive physical detection, assessment, and access control systems, as well as frequent inspections and tactical exercises for protective forces. Some industry representatives have indicated that the DOE's special security requirements could cause them to decline to lease facilities to the Government. Those with existing facilities who might entertain a collocation arrangement also viewed DOE's security requirements as a serious problem. Even if the perceived problems are resolved, however, it is uncertain whether the SPR could maintain the desired level of confidence and reliability in a security program at a leased site.

Existing SPR facilities have been subjected to a continuing program of capital improvements over the years as a result of changes in DOE and industry regulations, such as stricter fire protection requirements, and modifications to a site's drawdown and distribution capabilities. Thus, under a lease-type arrangement, the Government could find itself in a situation of having to pay for improvements to a privately-owned facility.

Finally, there are the numerous inspections and audits which SPR facilities, whether owned or leased, would be subjected to under DOE practice. These include, but are not limited to, Inspector General and General Accounting Office (GAO) audits, Technical Assurance audits, Environmental, Safety and Health inspections, Fire Protection inspections, and Internal Control

Reviews. The prospect of having to deal with these types of activities further disinclines private firms from entering into a long-term relationship with the Government.

**Economic and Financial Issues**

The initial interest in SPR facility leasing arose in response to the constrained federal budget situation because Government reliance on short-term leases of an asset can reduce near-term budget outlays. Nevertheless, in this case, economic and financial issues are an obstacle to strategic storage facility leasing.

OMB Circular A-104 requires that an economic analysis be undertaken to determine whether to purchase or lease capital assets for Federal agency use. That Circular requires that the interest rate on Treasury securities (plus one-eighth of a percent) be used as the discount rate to compare lease and purchase alternatives because the Treasury rate represents the Government's cost of capital for financing its own investments. Except for short-term use of an asset, the use of the Treasury's discount rate generally leads to Government financing rather than leasing because the Government's interest rate is the lowest market interest rate available. The Department's analysis indicates that purchase of a storage facility would have lower discounted costs than leasing.

Additionally, a Federal agency may not enter into a lease agreement unless it has budget authority to cover the payments required over the life of the lease. Since even a short-term lease of a strategic storage facility contains an obligation to make payments that cover the entire cost plus interest of construction of the facility, the budget authority required for leasing a facility would exceed the authority required for Federal purchase of the facility. So, even though near-term budget outlays might be lower with a lease, required near-term budget authority would be higher.

Over the life of a long-term lease, the total budget authority required could be up to three times the requirement for purchase because, while the lease payments include the interest to cover investment, the cost of Treasury financing of a facility is not included in the budget authority calculation when an agency purchases a capital asset. This asymmetry in budget comparisons further works against the attractiveness of leasing as an SPR facility financing option.

An exception could arise, as noted in the February 1, 1990 report (Executive Summary pages 26 and 27): "...leasing could be economically attractive if it provided the Government with access to storage arrangements that could not be obtained through direct acquisition. For example, collocation of strategic and commercial storage could create the potential for economies to scale or support attractive oil acquisition opportunities." Such an alternative, involving a true "Lease" or a comparable arrangement such as a storage "services" contract, could result as a by-product of a producer nation's or other individual's decision to develop storage capacity for his own commercial purposes; however, at this time the Government has no knowledge of any producer nation's or other person's plan to develop commercial storage capacity in or reasonably accessible to the United States, and it is inappropriate to speculate on what such a plan might entail.

# SECTION IV
## ENVIRONMENTAL REVIEW AND SITE SELECTION

This section provides an overview of the process for NEPA compliance of the SPR expansion. Further, this section summarizes an analysis to determine whether another Supplement of the Programmatic Environmental Impact Statement (PEIS) is indicated and provides the overall schedule for performing site-specific environmental assessments of the SPR expansion.

### A. NEPA Review Process

National policy under NEPA ensures that consideration is given to environmental values and factors in Federal planning and decision making. To ensure that environmental factors are considered in the decision-making process and to promote environmentally responsible decisions, the Department incorporates NEPA requirements early into the planning process for proposed actions.

The initial NEPA document prepared for the SPR was the 1976 PEIS, a broad-scope EIS that identified and assessed the environmental impacts of the proposed SPR program assuming a total storage capacity of 500 million barrels. This PEIS was supplemented in 1979 to address an increase in the oil storage capacity to one billion barrels.

The Department has recently completed a Supplement Analysis (SA) of the PEIS and its 1979 Supplement to identify any changes in the overall program that may be relevant to environmental concerns or any significant new circumstances or information relevant to environmental concerns that might bear on the proposed expansion or its impacts. The SA will form the basis for a determination by the Department whether a second supplement to the PEIS is required at this time.

In addition to the PEIS, 17 site-specific EISs were prepared between 1976 and 1981 for the existing crude oil storage facilities and pipelines. To support the expansion of the reserve to one billion barrels, an additional site-specific EIS will be prepared. The schedule for preparation of this EIS is outlined in Section IV.C.

The Department recently issued a Proposed Rule for NEPA Implementing Procedures (55 **FR** 46444, November 2, 1990). As proposed, 10 CFR 1021.331(b) requires an SA of site-wide NEPA documents at least every five years, based on which the Department will decide whether additional site-specific NEPA documentation is required. If the rule is finalized as proposed, SAs will be prepared for all of the existing SPR site-specific EISs.

## B. Programmatic Environmental Impacts

In preparing the SA of the PEIS, the Department reviewed numerous existing SPR site environmental documents and reports, relevant technical studies and research efforts, and current legislative and regulatory records. This was done to determine whether all environmental issues and program alternatives were adequately covered in the PEIS, as well as to determine whether the conclusions drawn about impacts remain valid, especially given the SPR operating experience in the intervening years.

The areas of major emphasis in the analysis included the following:

Technical Issues

- Oil Spill Impacts and Mitigation
- Water Quality Impacts
- Air Quality Impacts
- Ecological Impacts (including wetlands)
- Geological Impacts

Regulatory Issues

- Water (e.g., Clean Water Act and amendments, Safe Drinking Water Act, Oil Pollution Act).

- Air (Clean Air Act and amendments).

- Waste Management (e.g., Resource Conservation and Recovery Act, Comprehensive Environmental Response, Compensation and Liability Act).

- Sensitive Environments (e.g., wetlands, wild and scenic rivers, coastal zone management, coastal barrier resources, critical habitat for threatened and endangered species, marine mammals, historical and archaeological considerations).

- Other (e.g., noise control, national flood insurance, involvement of prime farmland, land use programs).

Overview of Technical Issues

Oil Spill Impacts and Mitigation - The review of oil spill impacts and mitigation addressed in the PEIS concentrated on: 1) frequency of oil spills; 2) adequacy of oil spill scenarios; 3) spill fate and transport; 4) biological and ecological impacts; 5) control and cleanup regulations; and 6) oil spill cleanup costs.

In general, the spill incident and exposure assumptions and data used in the PEIS to estimate the risk of accidental spills during oil transport proved to be conservative, in the sense that s· "! experience has been better than anticipated. Although the movement of oil by sea has increased nearly 10 percent between 1971 and 1989, the estimated total amount of oil spilled from marine transportation has decreased by approximately 70 percent over the same time period. Pipeline spills have also decreased significantly although the total amount of crude oil and product moved by pipeline has remained fairly constant.

The oil spill risk assessments were also conservative in that only 13 percent of the SPR oil has actually come from the Middle East, whereas a worst-case 100 percent was assumed in the PEIS. With the availability of a deepwater port, the risk of spillage in transit is reduced even further.

The discussion in the PEIS of potential impacts of oil spills was relatively accurate regarding the importance of weathering of oil in spill cleanups and the gross effects of spills on land and aquatic ecosystems. In fact, a review of data gathered from major spills in the Gulf region over the past ten years confirms that no major irreversible damage has occurred.

As one would expect, spill cleanup costs have escalated over the past 15 years. The PEIS estimated a cost range of $1.34 to $1,300 per barrel; a survey of costs from recent spills indicates a range from $0.76 to $7,560 per barrel (including the Exxon Valdez spill). Liability has become a major cost component and in some cases has greatly exceeded the total cleanup costs.

Water Quality Impacts - An extensive review and analysis showed that the SPR has effective site-specific water quality monitoring programs and is in compliance with its National Pollutant Discharge Elimination System (NPDES) permits for discharges such as brine to the Gulf, stormwater runoff, and sewage treatment plant effluent. An appropriate number of surface water monitoring stations at each site is monitored for pH, Total Suspended Solids (TSS), Total Organic Carbon (TOC), temperature, dissolved oxygen, and oil and grease. Groundwater is monitored for salinity and other indicator parameters.

In general, the overall water quality record at SPR sites has been excellent. There have been spill events (as anticipated in the 1979 PEIS Supplement) that have had adverse environmental impacts, the most notable being the brine spill at the Bryan Mound site in 1989. Vegetation was killed in the impacted area, but natural flushing allowed for rapid dispersion of the brine to the

Intercoastal Waterway and vegetation recovered quickly in all but the most severely affected areas. Other potential water quality issues identified have been site-specific rather than programmatic in nature and have been dealt with on a site-by-site basis.

Extensive study of brine disposal into the Gulf has demonstrated that the adverse ecological impacts predicted in the PEIS have not taken place. However, the actual plumes at Bryan Mound and West Hackberry are detectable over a greater areal extent and at greater distances from the diffuser than was predicted. Although the brine dispersion model used in the PEIS was recognized as being less than adequate and was replaced by a new model in later site-specific EISs, the overall conclusions of the PEIS regarding the potential impacts of brine disposal in the Gulf of Mexico were conservative (i.e., overestimated impacts) and, therefore, remain valid.

Air Quality Impacts - The PEIS focused on evaporative hydrocarbon emissions from transport and transfer operations. Estimated maximum emissions at the St. James terminal were 1,856 and 2,234 pounds per hour for tanker unloading and loading operations, respectively. Subsequent estimates, based in part on performance data obtained in 1980, 1981 and 1982, were 1,326 and 577 pounds per hour for unloading and loading, respectively, which are well within the original conservative estimates. The estimated annual emissions for tanker loading and unloading at a typical salt dome as well as from surge and storage tanks, pump seals, and pipeline valves also appear to be conservative compared to more recent estimates based on actual experience at the St. James terminal.

The PEIS concluded that emissions during tanker loading and unloading may, under worst-case conditions, result in violation of the National Ambient Air Quality Standard (NAAQS) for hydrocarbons. The NAAQS for hydrocarbons was revoked in 1983.

Ecological Impacts - Since there have been no major changes in SPR construction methods and operating practices, ecological impacts from construction, waste disposal, dredging operations, excavation and devegetation are believed to be comparable to those projected in the PEIS. There has been no significant new information in the technical literature on ecological impacts from large oil spills that would raise new concerns. Case studies on oil spills that document vulnerability of marine organisms to oil spills and biological recovery from oil spills are still valid and provide a suitable basis for accurate assessments of potential ecological impacts from an accidental spill.

There have been several changes to the threatened and endangered species lists in the States of Texas and Louisiana; however, these do not alter the findings of the PEIS.

The potential impacts of the SPR program on wetlands identified in the PEIS are still relevant even though the degree of damage and extent of recovery within a specific area appear to be more variable than first estimated. The brine leak from the Bryan Mound brine disposal pipeline in 1989 described earlier provides a case study on the impact of brine on wetlands. The recovery of the vegetation in the impacted coastal marsh has been variable although a study in 1990 indicated that the measurable surface water and soil impacts were relatively short term because frequent and severe tidal and precipitation events provided excellent natural flushing to the marsh. However, the most severely impacted area is expected to be extremely slow to recover naturally.

Geological Impacts - Potential geological impacts from the SPR program identified in the PEIS included halokinesis or cavern "creep" (i.e., the tendency of caverns to close as a consequence of the plastic flow of salt under heat and pressure), subsidence (i.e., subsidence of the surface resulting from cavern contraction), and seismic stability (i.e., local likelihood of earthquakes). The development and filling of salt domes in the Gulf region has progressed much as projected in the PEIS and the analysis of potential impacts conducted at that time is still judged to be sufficient and valid.

Subsidence is an important geologic issue concerned not only with cavern stability but also with the contribution to loss or gain of wetlands. There have been no problems relating to cavern collapse or structural failure associated with the SPR program. Much research has been conducted in this area since the PEIS, and the general issues of cavern stability have largely been resolved by engineering design of the cavern and roof and implementation of conservative leaching procedures. The contribution of cavern creep to the overall local subsidence is being monitored closely at certain SPR facilities.

Overview of Regulatory Issues

Since the PEIS and the Supplement were prepared in 1976 and 1979, respectively, environmental regulations have become increasingly stringent and have expanded substantially in scope. Specific aspects of SPR operations that are subject to increasingly stringent regulation under the Resource Conservation and Recovery Act (RCRA) include standards for underground storage tanks used for on-site storage (e.g., gasoline tanks), and disposal restrictions for wastes generated on-site by operations (e.g., spent solvents). NPDES permits for such discharges as brine to the Gulf, stormwater runoff, and sewage treatment plant effluent are effective regulatory tools for limiting the discharge of any pollutants that could have adverse environmental consequences. Since 1979, regulations for the NPDES permit program, including stormwater discharge permits, have become more comprehensive. NPDES regulating parties (i.e., the States) have been given more authority to mitigate effects of future potential problems through revision of the regulations.

The most significant regulatory development affecting future oil spills will result from the landmark Oil Pollution Act of 1990 (OPA). The new law has several provisions directed towards preventing oil spills from vessels, including tanker navigation safety studies, provisions on personnel policies, and tug escort requirements. New oil tankers must have double hulls and certain existing tankers must be retrofitted by the year 2015. Other OPA provisions address mitigating the effects of spills that do occur. Coast Guard regulations governing operational discharges from vessels have also been strengthened. Thus, it is likely that more stringent regulations will contribute to a reduction both in frequency of oil spills and in related environmental impacts, compared to those estimated in the 1979 PEIS.

It is likely that additional initiatives will result in regulations that provide even more mitigation of impacts. For example, under the Clean Air Act Amendments of 1990, standards are required for the maximum concentration of VOCs (volatile organic compounds) that can be released during tanker loading and unloading; there are also likely to be more restrictive requirements at the State level for hydrocarbon emissions related to tanker loading and unloading activities. In addition, Congressional initiatives providing comprehensive wetland legislation and reauthorizing the RCRA program, if passed, would likely result in regulations that place more stringent requirements on the operations of the SPR.

At this time, the existing Gulf Coast SPR storage sites are in compliance with current regulations.

Conclusions of Supplement Analysis

Overall, only minor changes have been identified concerning technical and legislative issues since the completion of the PEIS. In general, these changes have further enhanced or strengthened environmental safety and represent no compliance problems for SPR facilities. Based on these findings, the Department has determined that no supplement to the PEIS is required to support the expansion of the SPR to one billion barrels.

**C. Site-Specific Environmental Documentation Plan**

The Department has developed a preliminary schedule for the preparation and publication of site-specific environmental documents necessary to meet NEPA requirements for the expansion of the SPR to the one-billion-barrel level. Work has begun on planning the scoping process and a Notice of Intent to prepare an EIS will be issued shortly. Public meetings to be held at appropriate locations are being planned for spring 1991. Once the scoping process has been completed, a draft EIS will be prepared for the sites considered to be expansion alternatives. Draft documentation is scheduled to be ready for Departmental review and approval by November 1, 1991. The review and approval process is expected to take about two months followed by publication and filing of the documentation with EPA in January, 1992. Comments and questions should be addressed and final documentation prepared by May, 1992. Following two months for Departmental review and approval, the documentation would be published and filed and a Record of Decision finalized by September 15, 1992. This proposed schedule is presented in Figure IV-1.

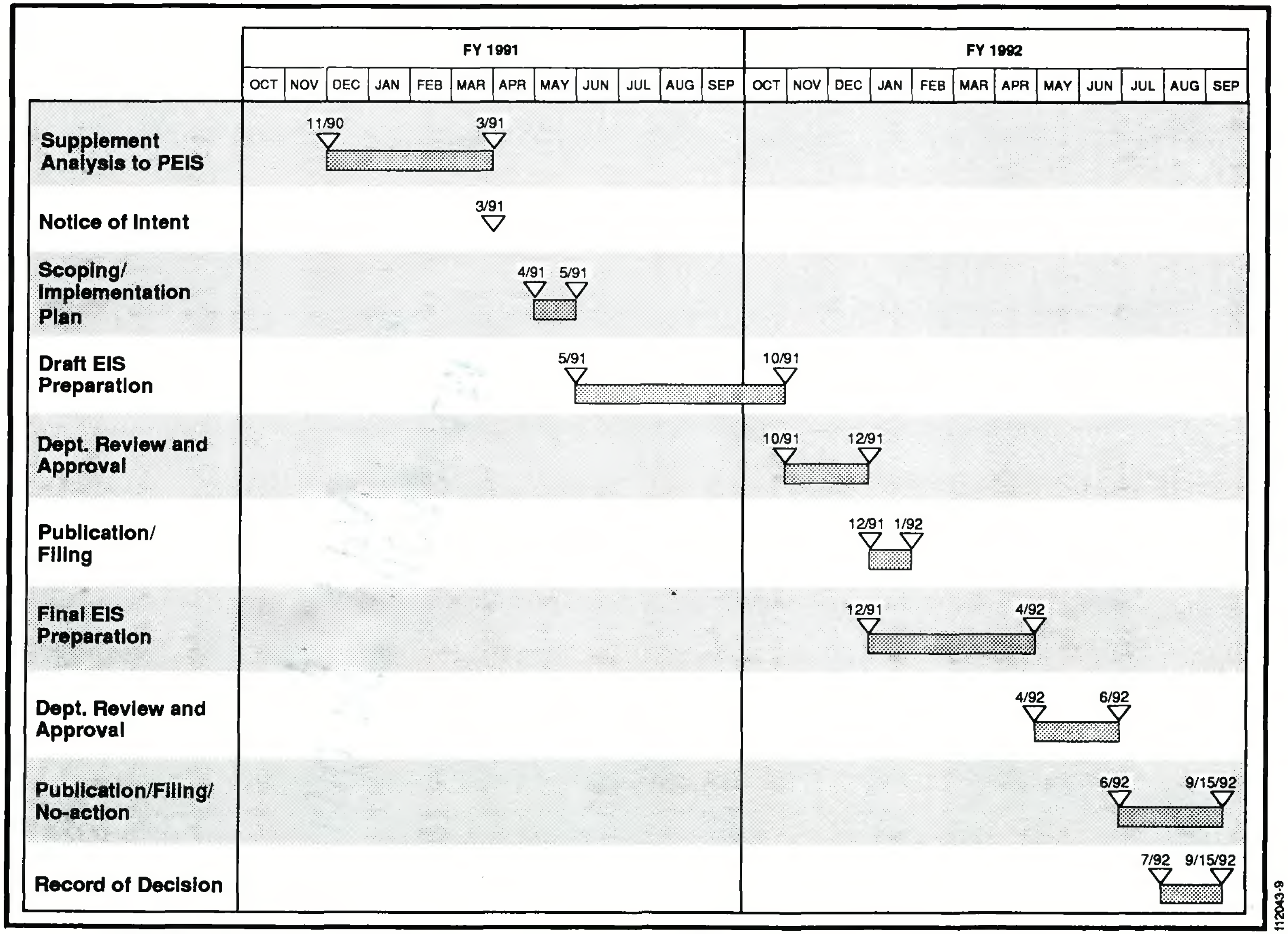


**Figure IV-1. EIS FOR EXPANSION TO ONE BILLION BARRELS**

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# SECTION V

## Candidate Storage Sites and Descriptions

This section identifies eight candidate Gulf Coast salt domes, four in Louisiana and four in Texas, for expansion of the SPR. For each candidate site, summary descriptions of site location, surface characteristics, geological characteristics, planned facilities, distribution plans and alternatives, general environmental characteristics and existing commercial operations on the salt dome are included.

### A. Candidate Sites

The 1989 report to Congress identified seven Gulf Coast candidate sites for expansion of the SPR and for future environmental assessment under the NEPA. The comprehensive candidate site selection and screening procedure followed in the 1989 report is summarized in Appendix C. This process reduced over 550 Gulf Coast salt domes to 30 candidates and ultimately to the "best" seven candidates.

For this report, the 30 candidate sites of 1989 were reevaluated. These 30 candidates were reassessed in terms of revised siting and distribution objectives, given the potential enhanced distribution capability associated with the projected conversion of the Seaway Pipeline. As a result, three new SPR expansion candidates, the Boling, Hawkinsville and Stratton Ridge salt domes, have been added.

Two salt dome candidates nominated in the 1989 Report to the Congress, Clemens and Gyp Hill domes in Texas, are no longer considered to be among those most desirable for expansion of the SPR to one billion barrels. In the case of Clemens dome, analyses of recently acquired data indicates that: available maps were inaccurate and not up to date; earlier sulfur mining extended over a larger portion of the dome than previously thought, which affected the proposed location of several SPR caverns; on the basis of drilling logs, the -1000 foot contour area was significantly smaller than shown on maps, and in fact, provided space for only three versus ten to twelve potential SPR caverns; and finally, significant salt overhangs exist which would also affect SPR cavern spacing and locations. Consequently, available data indicate that there is insufficient space and salt mass for 100 or even 50 million barrels of cavern development.

Gyp Hill salt dome in southern Texas was dropped from further consideration as a candidate site due to its remote inland location and its distribution potential. Gyp Hill is approximately 70 miles from the Corpus Christi refining center and any existing marine facilities. Distribution potential within the Corpus Christi area is limited by the small local refinery demands and by a limited pipeline infrastructure. In light of the current and projected pipeline and marine distribution capability within the Seaway Complex, Gyp Hill became significantly less desirable.

Table V-1 lists the current eight salt dome candidate sites according to their distribution area, location, maximum estimated storage capacity and planned drawdown/distribution capabilities. Figure V-1 shows the location of these sites relative to the existing SPR sites and major distribution facilities. These eight candidate sites are considered the "best" candidates at this time for achieving the current Gulf Coast siting and distribution objectives. This list provides four alternatives within each complex for evaluation under the NEPA process.

**TABLE V-1**
**Salt Dome Candidate Sites**

| Complex | Salt Dome Site | Location | Maximum Storage Capacity (MMB)* | Planned Drawdown Distribution (MBD)** |
|---|---|---|---|---|
| Capline Sites (150 MMB) | Chacahoula | Louisiana | 250 | 900 - Loop Terminal |
| | Cote Blanche | Louisiana | 250 | 900 - Loop Terminal |
| | Napoleonville | Louisiana | 150 | 900 - Loop Terminal |
| | Weeks Island | Louisiana | 150 | 900 - Loop Terminal |
| Seaway Sites (100 MMB) | Big Hill | Texas | 120 | 600 - Houston & Inland/Pipeline |
| | Boling | Texas | 250 | 600 - Seaway Pipeline |
| | Hawkinsville | Texas | 100 | 600 - Seaway Pipeline |
| | Stratton Ridge | Texas | 150 | 600 - Seaway Pipeline |

* MMB: millions of barrels.
** MBD: thousands of barrels per day.

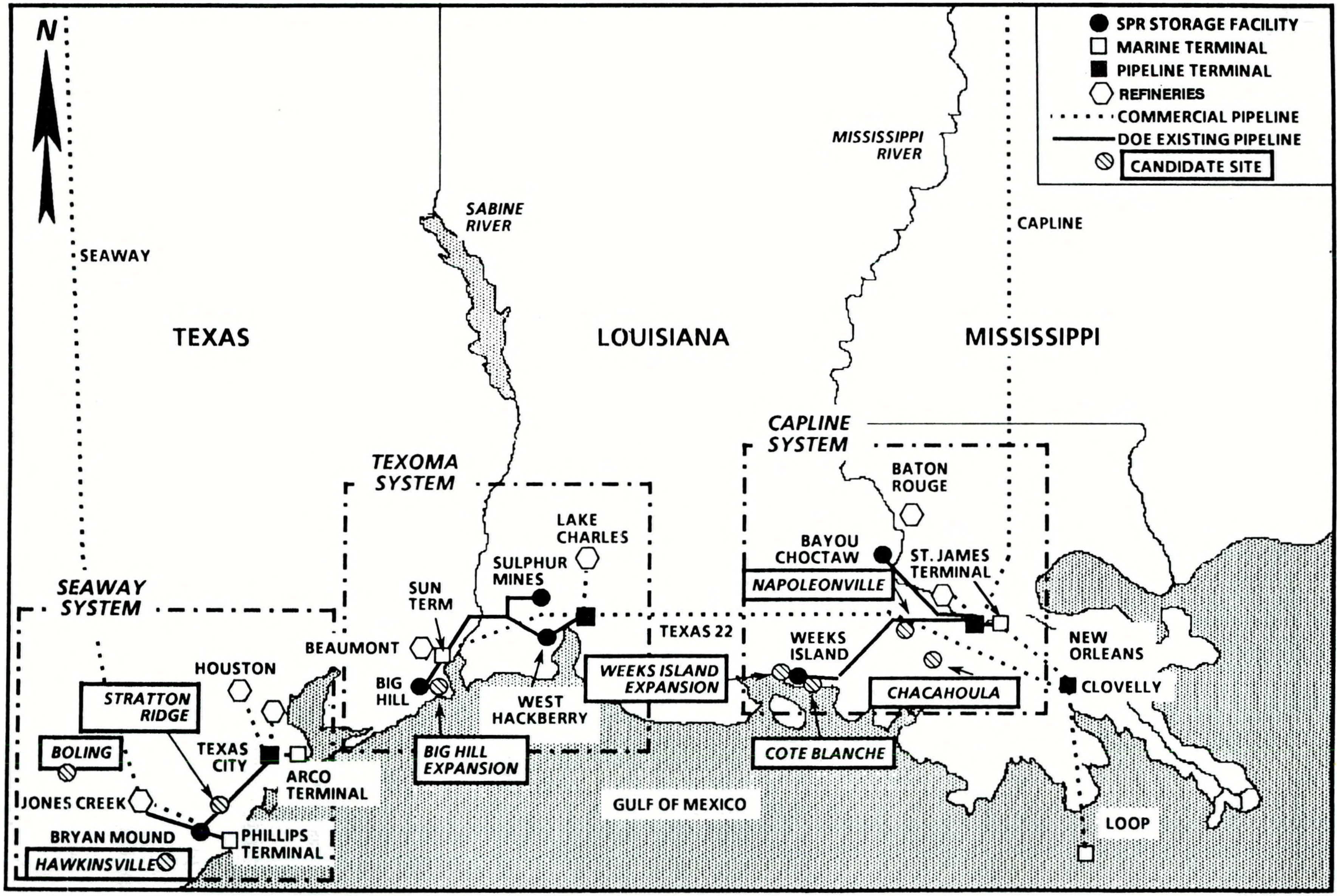


**Figure V-1.** LOCATION OF CANDIDATE SITES FOR STRATEGIC PETROLEUM RESERVE (SPR) RELATIVE TO EXISTING SPR AND COMMERCIAL FACILITIES.

## B. Candidate Site Descriptions

### Chacahoula Salt Dome

The Chacahoula salt dome is located in northwestern Lafourche Parish, Louisiana, approximately 72 miles south and east of Baton Rouge, and 66 miles west and south of New Orleans (Figure V-2) . The dome is 20 miles south of the Department of Energy's St. James Terminal on the Mississippi River and 40 miles north of the Gulf of Mexico.

Texas Brine Company currently operates three brine caverns at depths of -6,500 feet below sea level on the south-central part of the dome. The total volume of brine production was approximately ten million barrels in 1990, according to State of Louisiana records. Sun Oil Company made the first discovery of petroleum in 1938 and production of oil and gas on the flanks of the dome continues today. With the exception of the brining operations, there are presently no activities within the -2,000 feet below mean sea level (MSL) salt contour.

Geological Characteristics[1/]

Chacahoula is among the largest of the some 550 known Gulf Coast domes; the dome is nearly 3 miles long (E-W) and 1.6 miles wide (N-S) inside the -5,000 foot salt contour. Inside the -2,000 foot salt contour there are some 1,200 contiguous acres, which would support more than 250 million barrels of SPR cavern storage development.

Caprock is thin or absent over much of the dome, but where present, occurs at a depth of approximately -875 feet. In the northeast corner of the salt dome, the caprock is sufficiently thick to have permitted minor sulfur mining. There is sufficient available land for SPR cavern development at the west end of the dome which would enable one to avoid the former sulfur-mining area.

The top of the salt occurs at approximately -1100 feet on the dome. A minor salt overhang occurs at the eastern edge of the dome between -5,000 to -10,000 feet, and is delineated by penetration of five wells. There is no indication that the overhang would have any impact on possible storage areas of the dome located inside the -2,000 foot salt contour.

Facilities Development

SPR facilities would be located on approximately 300 acres on the salt dome as shown in Figure V-3. Onsite facilities would consist of 15 storage caverns of 10 million barrels each, a raw water leaching/drawdown system, a brine settling and disposal system, a crude oil injection/distribution

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1/ *Preliminary Geological Site Characterizations for Strategic Petroleum Reserve Candidate Sites: Chacahoula Salt Dome, Louisiana*, Sandia National Laboratories, SNL/6257-91 CH.

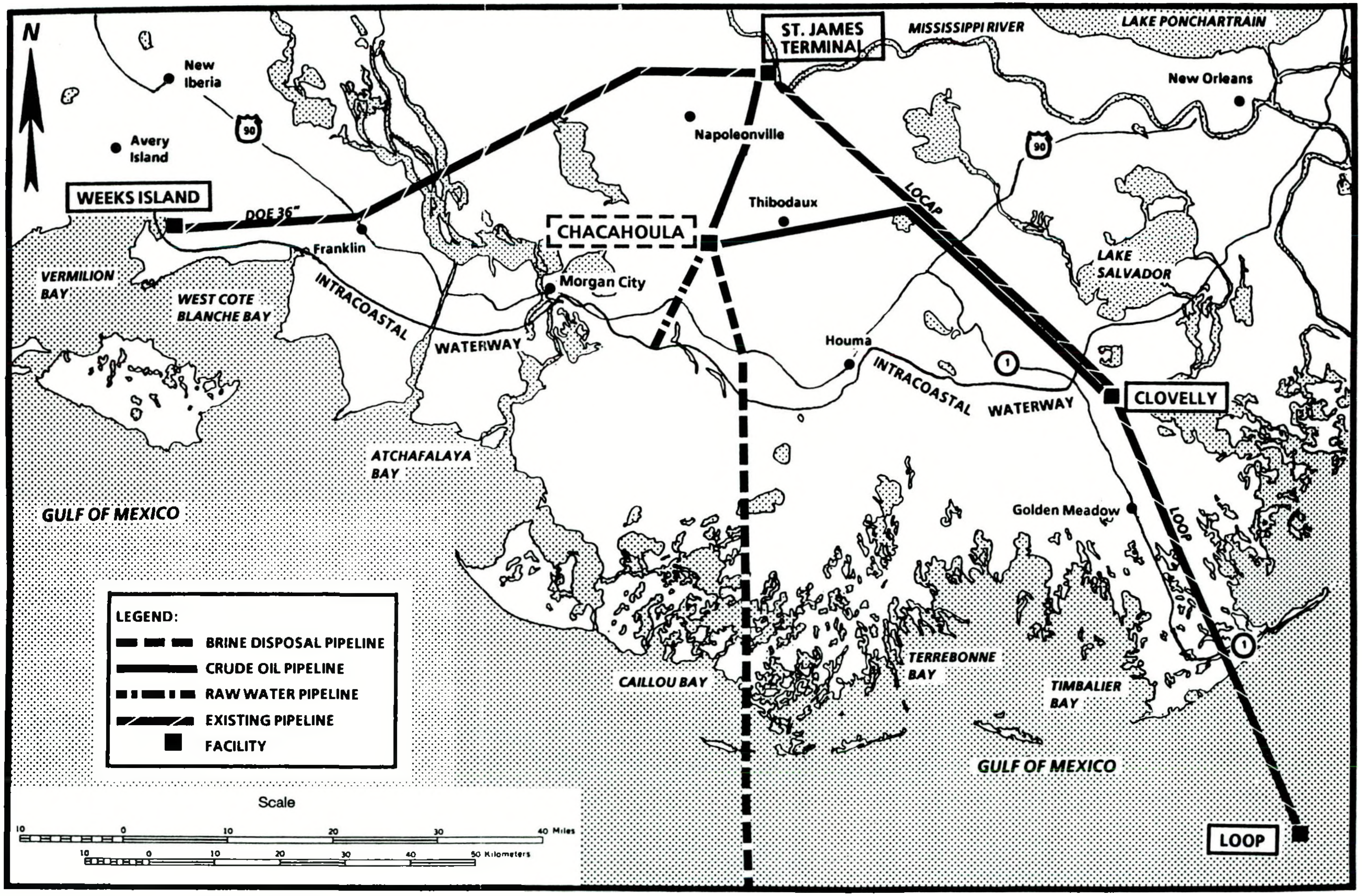


Figure V-2. CHACAHOULA STORAGE SITE WITH PROPOSED CRUDE OIL, BRINE AND RAW WATER PIPELINES

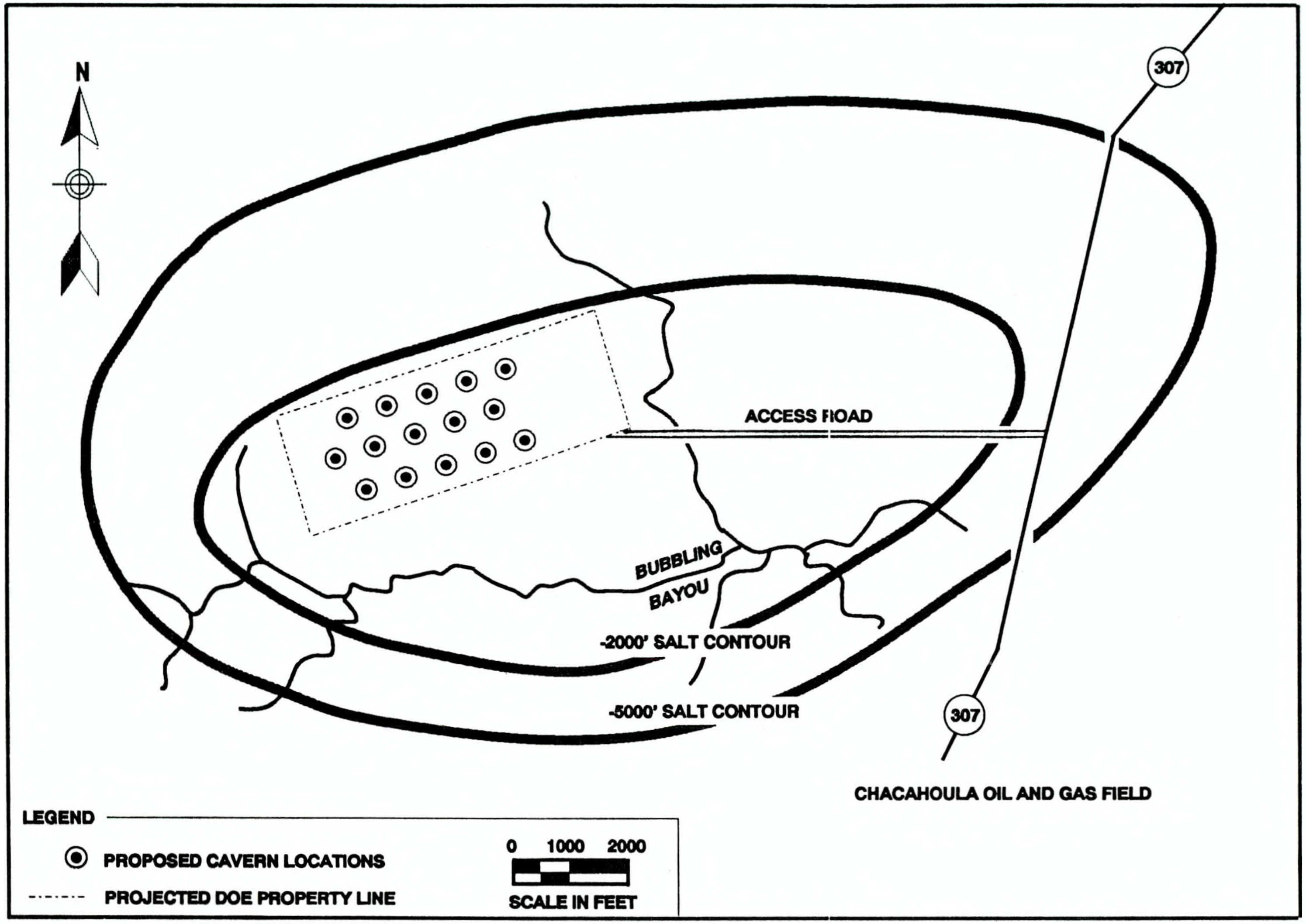


**Figure V-3. PROPOSED SPR STORAGE FACILITY LOCATION ON CHACAHOULA SALT DOME**

system, and operations, maintenance and security buildings. Offsite facilities would include a raw-water intake structure on the Gulf Intracoastal Waterway, located 11 miles southwest of the site, and interconnecting pipelines for raw water, brine disposal, and crude oil receipt and distribution. The water and brine systems would be sized for leaching caverns at a rate of one million barrels per day and the crude oil system designed for drawdown at 900,000 barrels per day.

Brine disposal would be accomplished by laying a 60-mile, 48-inch pipeline southwest into the Gulf of Mexico to a 30-foot water depth (Fig. V-2). The brine pipeline could be buried in the bottom of barge and pipeline canals, which enter the site from the southwest, across the Atchafalaya Basin to the Gulf of Mexico. The route would follow these pipeline canals to Gibson and Bayou Black, thence to Bayou Chene; both bayous are navigable waterways.

Oil Fill/Distribution

A new 150-million-barrel storage site at the Chacahoula salt dome would be pipeline connected to the DOE St. James Terminal for oil fill and to the LOOP Clovelly Terminal for drawdown/distribution. This site would primarily serve the LOOP-connected lower Mississippi River refiners, while the existing DOE Capline distribution system would be realigned to primarily serve the Capline Pipeline to the midwest and waterborne distribution (Figure V-2).

From the Chacahoula salt dome, DOE would construct a 43-mile, 36-inch pipeline to LOOP's Clovelly Terminal. This pipeline would have a distribution capacity of 900,000 barrels per day, which is equivalent to the projected import demands of the six LOOP-connected refiners on the lower Mississippi River. At St. James, the DOE's existing distribution capabilities would be realigned and expanded to compensate for two refiners now to be served through LOOP. DOE would increase its marine distribution at St. James from 400,000 to 800,000 barrels per day through the construction of two additional docks at DOE's terminal or contracting for commercial marine distribution services.

For oil fill, DOE would construct a 22-mile, 36-inch crude oil pipeline from DOE's St. James Terminal to the Chacahoula storage site with a capacity of 400,000 barrels per day. This pipeline could also be used for distribution and as such, would provide the SPR Capline distribution system with additional flexibility.

Environmental Aspects

The site is a cypress swamp wetland, which, depending on facility placement, would probably require a reasonable amount of mitigation for approximately 405 acres. Ponded swamp water is present in the entire area and several feet of rock fill would be required for construction of roads, well pads, and surface facilities similar to those at other existing SPR sites in Louisiana.

The site is in an area classified as a nonattainment area for ozone and would be subject to special conditions and provisions affecting design and construction. The site could be subject to maximum achievable control technology under the Clean Air Act.

The rights-of-way for raw water, brine disposal, and crude oil pipelines would require restoration of approximately 1,610 acres (660 acres of which would be for the brine disposal pipeline right-of-way) disturbed by construction of these pipelines. Water control structures would be required to segregate fresh and brackish waters on the brine disposal and crude oil pipelines.

Potential hazards at the Chacahoula site are hurricanes and associated flooding, and possibly some subsidence resulting from solution mining. Because of the dome's low 6- to 7-foot elevation above MSL, it could be vulnerable to 100-year hurricane storm surges. Subsidence of the surrounding area would require elevation of the roadways serving this area and elevation of all on-site supporting structures (roads, well pads, etc.).

**Cote Blanche Salt Dome**

The Cote Blanche salt dome is located 8 miles southeast of the SPR's Weeks Island site and 18 miles southeast of New Iberia in St. Mary Parish, Louisiana (Figure V-4).

The Cote Blanche salt dome rises from the north shore of Cote Blanche Bay to about 75 feet above MSL. The dome is surrounded on three sides by brackish water and marsh and forms an "island" that is separated from the mainland by the Gulf Intracoastal Waterway; access to the dome is presently via cabled ferry across the Intracoastal Waterway. A conventional salt mine on the west side of the dome is operated by North American Salt Company, and is serviced by a ferry from Highway 83. North American Salt Company operates a single-level, mechanically-mined, room and pillar salt mine at a depth of 1,365 feet in the salt dome beneath Cote Blanche "island". The southern half of the dome lies beneath West Cote Blanche Bay and would be unsuitable for SPR development.

Geological Characteristics[2/]

The Cote Blanche salt dome is moderately large, generally elliptical, 2.7 miles (N-S) by 1.6 miles (E-W) within the -5,000 foot salt contour, with a major salt overhang on the north side having a dip of 60 degrees south. About half of the salt dome lies beneath West Cote Blanche Bay. The nature of the salt on the east edge of the mine is considered to be an anomalous zone manifested by gas outbursts and oil seeps which effectively define the eastern extent of further salt mining operations. Adequate separation from this probable shear zone, and from the existing mine would be required for safe SPR cavern development. The southeastern extent of the salt mass between -2000 and -5000 feet is somewhat uncertain but further study might indicate additional available cavern development potential.

There are approximately 450 contiguous acres available on the dome which would support SPR storage cavern development up to 250 million barrels within the -2,000 foot salt contour. These 450 acres do not include the area above the operating mine; that area would not be used for SPR development. Because of the shallow salt depth, the majority of SPR-developed caverns would be constructed in the 2,000-4,000 foot depth range.

The area over the mine has shown some local subsidence but the effect on surface relief has been minimal. Subsidence that could result from cavern operations is not considered a problem.

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2/ *Preliminary Geological Site Characterizations for Strategic Petroleum Reserve Candidate Sites: Cote Blanche Salt Dome, Louisiana*, Sandia National Laboratories, SNL/6257-91 CB.

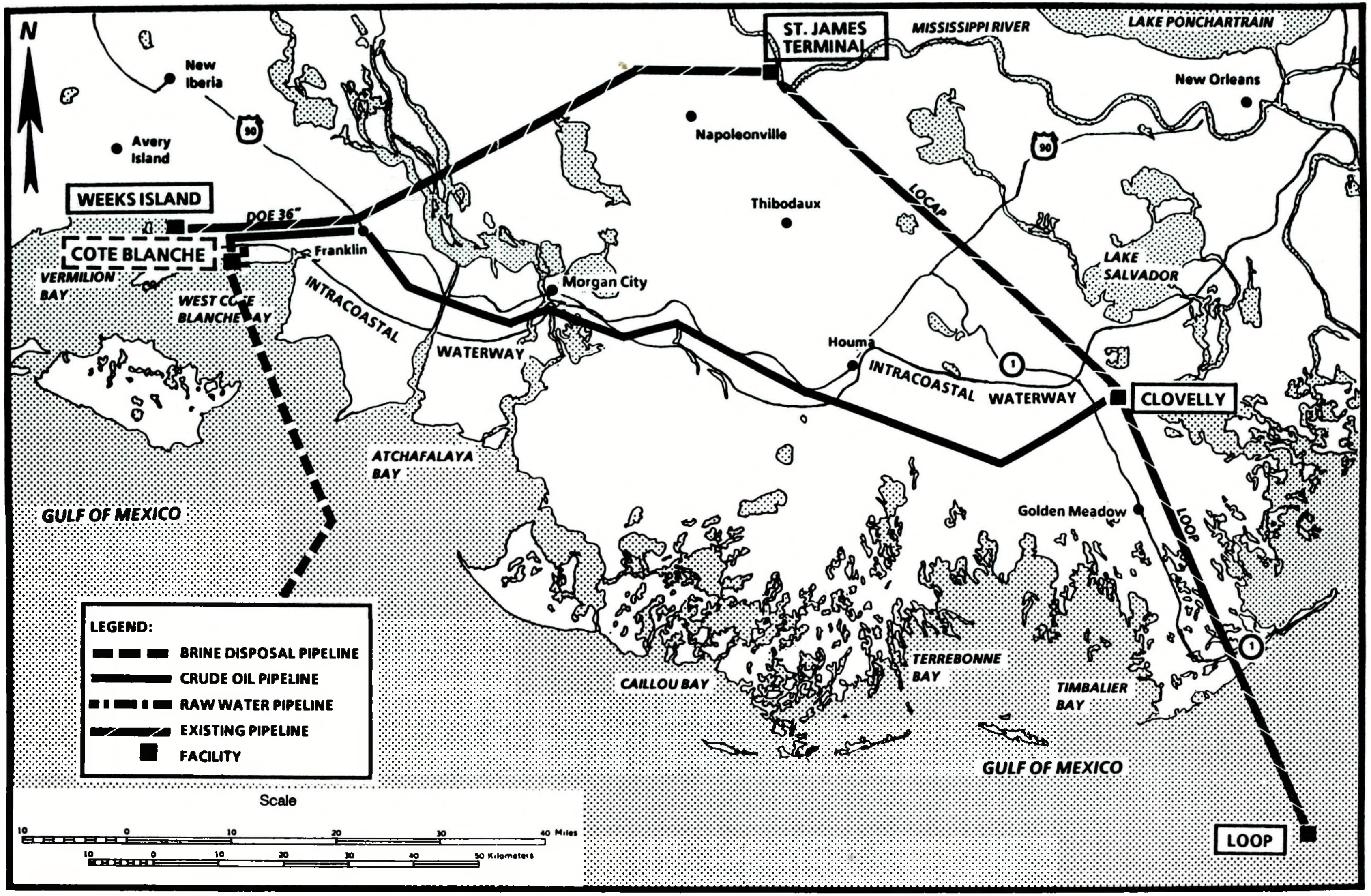


**Figure V-4.** **COTE BLANCHE STORAGE SITE WITH PROPOSED CRUDE OIL, BRINE AND RAW WATER PIPELINES**

Facilities Development

SPR facilities would be located on approximately 300 acres on the salt dome as shown in Figure V-5. Onsite facilities would consist of 15 storage caverns of 10 million barrels each, a raw water leaching/drawdown system, a brine settling and disposal system, a crude oil injection/distribution system, and operations, maintenance and security buildings. Offsite facilities would include a raw water intake structure on the Gulf Intracoastal Waterway located one mile north of the site and interconnecting pipelines for raw water, brine disposal, and crude oil receipt and distribution. The water and brine systems would be sized for leaching caverns at a rate of one million barrels per day and the crude oil system designed for drawdown at 900,000 barrels per day.

As access to the island is presently via cabled ferry, alternative access would require a bridge or tunnel to support fire, security and site personnel. A pivot/push barge could be used for all other heavy equipment.

Brine disposal would be accomplished by laying a 46-mile, 48-inch pipeline southwest into the Gulf of Mexico to a 30-foot water depth. The route of the brine line would not threaten any environmentally sensitive land area.

Oil Fill/Distribution

A new 150-million-barrel storage site at the Cote Blanche salt dome would be pipeline connected to the DOE St. James Terminal for oil fill and to the LOOP Clovelly Terminal for drawdown/distribution. This site would primarily serve the LOOP-connected lower Mississippi River refiners, while the existing DOE Capline distribution system would be realigned to serve the Capline Pipeline to the midwest and waterborne distribution (Figure V-4).

From the Cote Blanche salt dome, DOE would construct a 94-mile, 42-inch pipeline to LOOP's Clovelly Terminal. This pipeline would have a distribution capacity of 900,000 barrels per day, which is equivalent to the projected import demands of the six LOOP-connected refiners on the lower Mississippi River. At St. James, the DOE's existing distribution capabilities would be realigned and expanded to compensate for two refiners now to be served through LOOP. DOE would increase its marine distribution at St. James from 400,000 to 800,000 barrels per day through the construction of two additional docks at DOE's terminal or contracting for commercial marine distribution services.

For oil fill, DOE would construct a 2-mile, 30-inch crude oil pipeline spur from DOE's existing Weeks Island-to-St. James Pipeline to the Cote Blanche storage site with a capacity of 400,000 barrels per day.

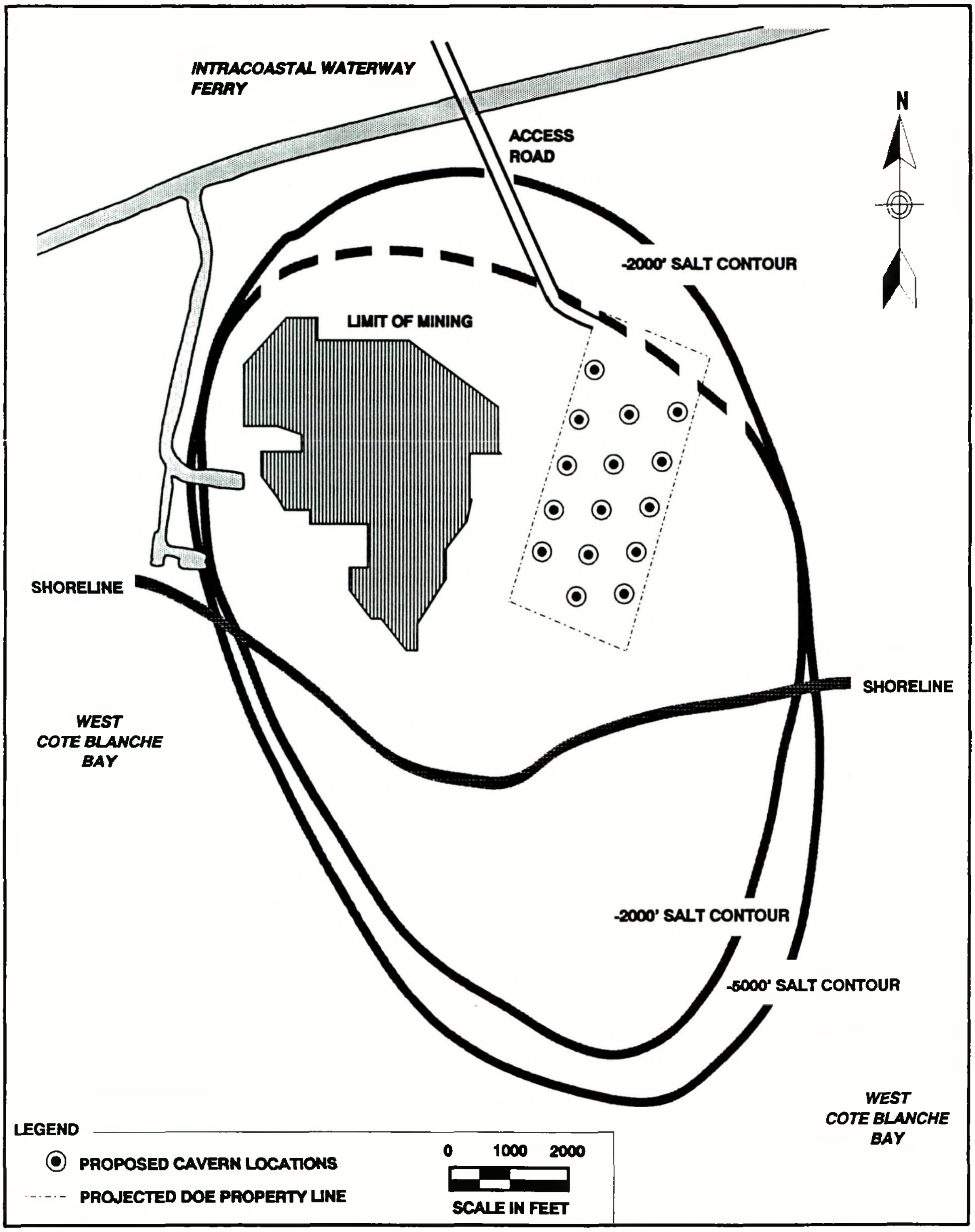


**Figure V-5. PROPOSED SPR STORAGE FACILITY ON COTE BLANCHE SALT DOME**

Environmental Aspects

No apparent adverse impact to the south Louisiana environs would result from SPR development on the Cote Blanche dome, and minimal mitigation would be required. Some oyster beds could be affected which would require mitigation.

The site is in an area classified as a nonattainment area for ozone and would be subject to special conditions and provisions affecting design and construction. The site could be subject to maximum achievable control technology under the Clean Air Act.

The brine disposal line would skirt Marsh Island, with minimal disturbance to wetlands and other environmentally sensitive land masses. The crude oil pipeline from Cote Blanche to Clovelly would require restoration of 1,710 acres of wetlands. This routing would be along non-SPR rights-of-way, primarily paralleling the Texaco 22-inch pipeline. Water control structures would be required to segregate fresh and brackish waters along this route. The oil fill pipeline spur from Cote Blanche to the existing Weeks Island - St. James crude oil pipeline would require restoration of approximately 40 acres.

The surface elevation of 75 feet above MSL is sufficient so that flooding is of little concern, even during the most severe hurricanes, except perhaps in the marshy areas on the southeast side which would not affect the area designated for cavern development. According to estimates made by the Louisiana Geological Survey, the progressive loss of coastal wetlands in south Louisiana will eventually, in about 50 years, lead to the loss of marshland surrounding Cote Blanche Island, unless mitigation action is taken; however, there is considerable uncertainty as to the rate of marshland loss.

**Napoleonville Salt Dome**

The Napoleonville salt dome is located in Assumption Parish, 30 miles south of Baton Rouge, Louisiana. The dome is 17 miles west of St. James Terminal, just off Louisiana State Highway 70, and 7 miles northwest of Napoleonville (Figure V-6).

There are five ongoing commercial operations on the dome, including 45 caverns used for LPG storage and brine storage/production. There is some hydrocarbon production on the flanks of the dome, and several pipelines cross over and run around the dome. A network of well-maintained roads exists over the dome.

<u>Geological Characteristics</u>[3/]

The Napoleonville salt dome is elliptical in shape and is approximately 1.3 miles (N-S) by 2.4 miles (E-W) within the -5,000 foot salt contour. A cavern depth interval of 2,000 - 4,000 feet is suitable for SPR caverns; however, the dip of the salt slopes at the edges of the dome are uncertain at this time. There are, however, steep salt dips and possible overhangs on the west and southwest sides of the dome. The salt contours on the south side, adjacent to the potential SPR cavern field, require further refinement, and additional seismic work is warranted. The top of the salt has a relief of about 100 feet and salt is encountered at an average depth of 700 feet. Top of caprock is at -415 feet below MSL while information on the extent of the caprock over the edge of the dome is limited. Although this dome has extensive commercial cavern development, little information is available at this time on the internal structure and salt properties.

<u>Facilities Development</u>

SPR facilities would be located on approximately 300 acres on the southwestern part of the salt dome as shown in Figure V-7. Onsite facilities would consist of 15 storage caverns of 10 million barrels each, a raw water leaching/drawdown system, a brine settling and disposal system, a crude oil injection/distribution system, and operations, maintenance and security buildings. A conceptual cavern layout is shown in Figure V-7. Offsite facilities would include a raw water intake structure on the Gulf Intracoastal Waterway, located 27-miles south of the site, and connecting pipelines for raw water, brine disposal, and crude oil receipt and distribution. The water and brine disposal systems would be sized for leaching caverns at a rate of one million barrels per day and the crude oil system designed for drawdown at 900,000 barrels per day.

Brine disposal would be accomplished by laying an 80-mile, 48-inch pipeline into the Gulf of Mexico to a 30-foot water depth (Fig. V-6). The brine disposal pipeline could cross the Atchafalaya

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3/ *Preliminary Geological Site Characterizations for Strategic Petroleum Reserve Candidate Sites: Napoleonville Salt Dome, Louisiana*, Sandia National Laboratories, SNL/6257-91 NA.

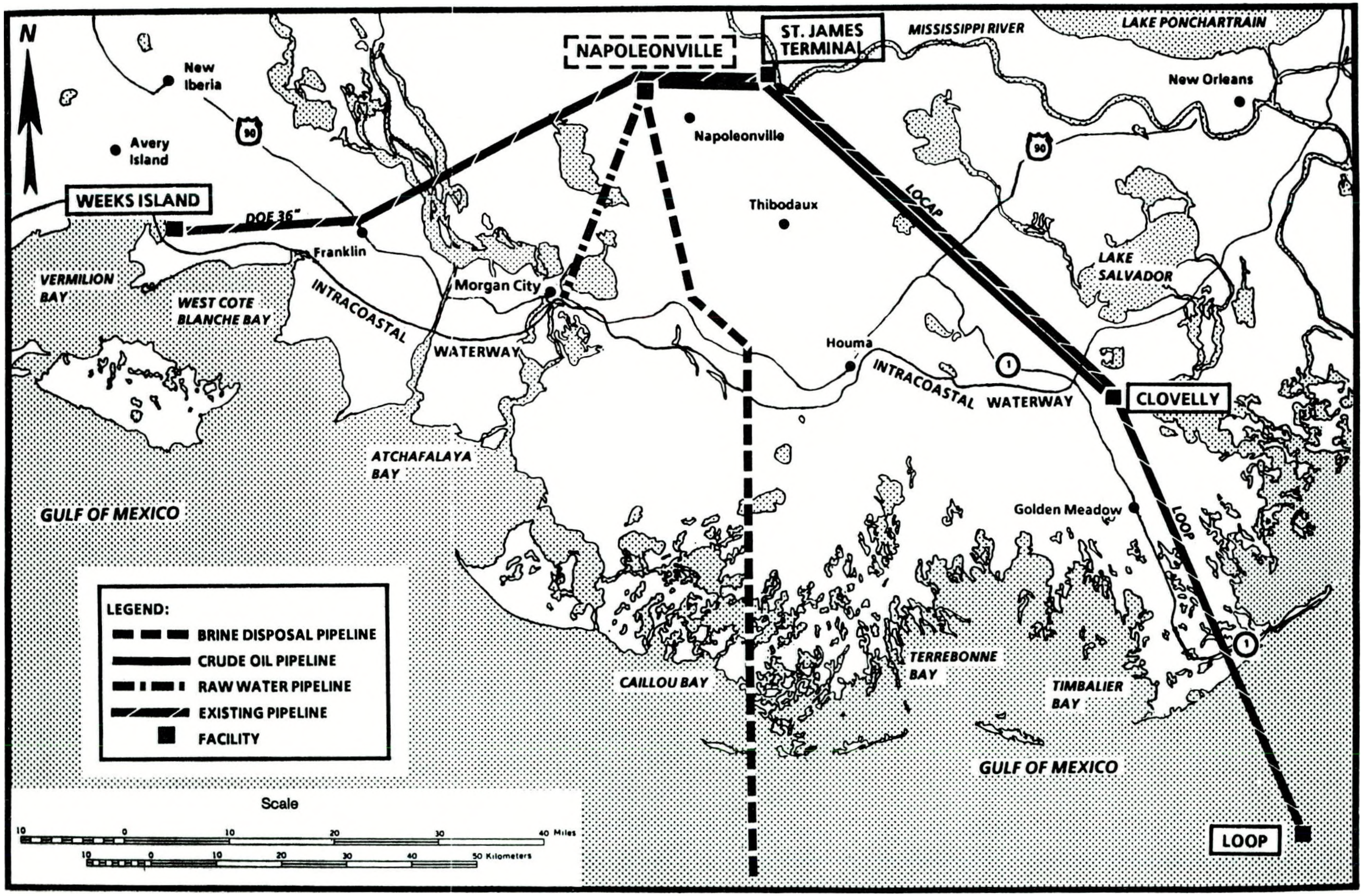


**Figure V-6. NAPOLEONVILLE SALT DOME WITH PROPOSED CRUDE OIL, BRINE AND RAW WATER PIPELINES**

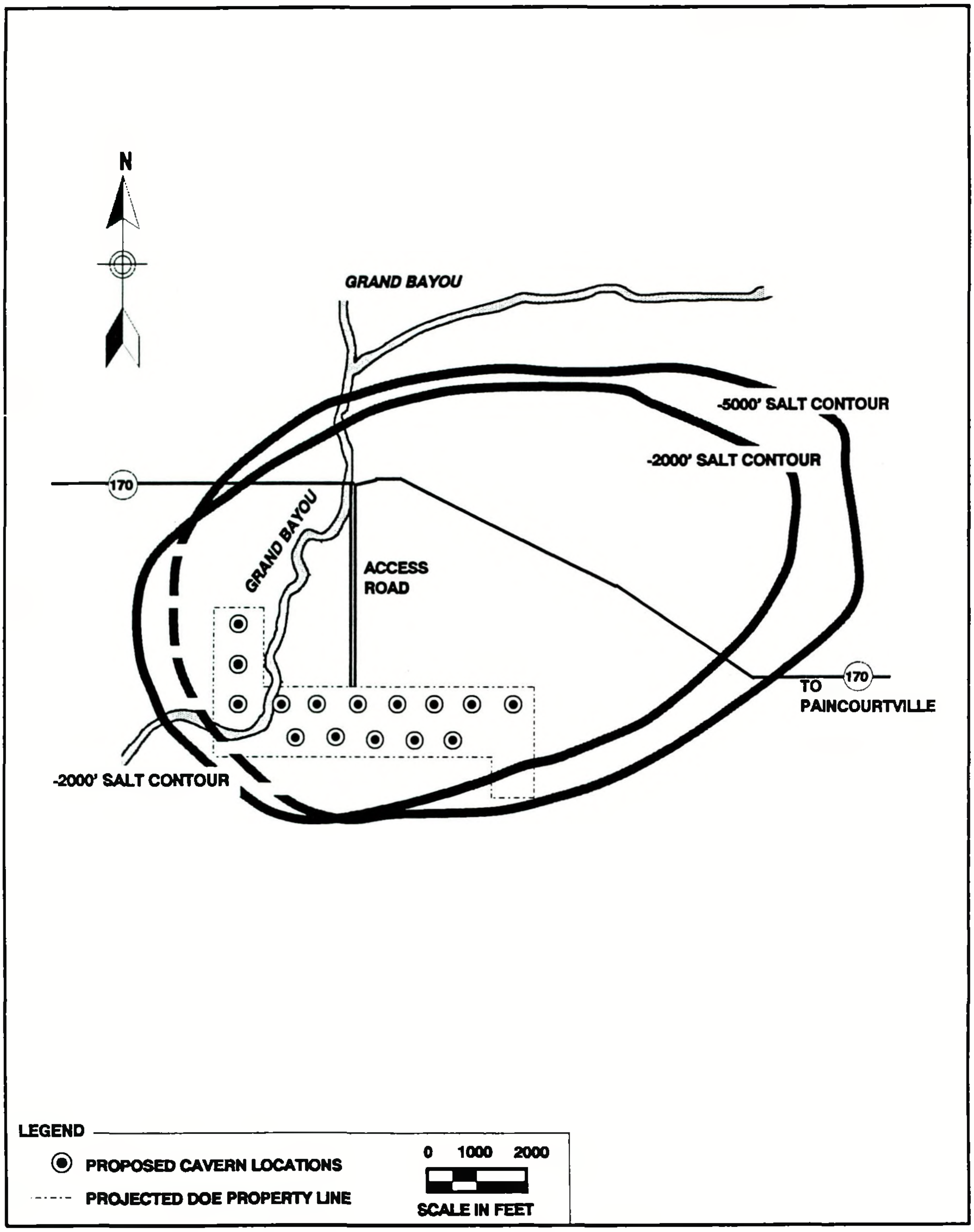


**Figure V-7. PROPOSED SPR STORAGE FACILITY LOCATION ON NAPOLEONVILLE SALT DOME**

Basin where mitigation would be required.

Oil Fill/Distribution

A new 150-million-barrel storage site at the Napoleonville salt dome would be pipeline connected to the DOE St. James Terminal for oil fill and to the LOOP Clovelly Terminal for drawdown/distribution. This site would primarily serve the LOOP-connected lower Mississippi River refiners, while the existing DOE Capline distribution system would be realigned to serve the Capline Pipeline to the midwest and waterborne distribution (Figure V-6).

From the Napoleonville salt dome, DOE would construct a 62-mile, 36-inch pipeline to LOOP's Clovelly Terminal. This pipeline would have a distribution capacity of 900,000 barrels per day, which is equivalent to the projected import demands of the six LOOP-connected refiners on the lower Mississippi River. At St. James, the DOE's existing distribution capabilities would be realigned and expanded to compensate for two refiners now to be served through LOOP. DOE would increase its marine distribution at St. James from 400,000 to 800,000 barrels per day through the construction of two additional docks at DOE's terminal or by contracting for commercial marine distribution services.

For oil fill, DOE would construct a one-mile, 30-inch crude oil pipeline connection from the proposed Napoleonville-to-Clovelly pipeline to DOE's St. James Terminal with a capacity of 400,000 barrels per day. This pipeline could be used for distribution as well as fill which would provide the SPR with additional distribution flexibility.

Environmental Aspects

The site is a cypress swamp wetland, which, dependent on facility placement, would require some degree of mitigation of up to 405 acres.

The site is in an area classified as an attainment area for ozone. However, it is located adjacent to an area classified as a Severe II nonattainment area and may require the maximum achievable control technology under the Clean Air Act.

The rights-of-way for raw water, brine disposal, and crude oil pipelines would require restoration of approximately 1,778 acres disturbed by these pipelines, 985 acres of which would be for the brine disposal pipeline right-of-way. For the crude oil pipeline, only 50 acres of new swamp land would be disturbed; the remaining acreage is along existing pipeline rights-of-way.

The surface elevation is 5 to 7 feet above MSL; consequently, the site would be vulnerable to flooding resulting from 100-year storms. Expected continued subsidence over the commercial cavern field will cause the already low surface elevation to experience periodic and, perhaps ultimately, permanent inundation.

**Weeks Island Salt Dome**

The Weeks Island salt dome is located 15 miles south of New Iberia along the north shore of Vermilion Bay in Iberia Parish, Louisiana (Figure V-8).

The Weeks Island salt dome rises more than 150 feet above MSL and is the highest elevation in south Louisiana. The proposed SPR site development area is approximately 50 feet above MSL. The salt is of culinary grade but is not being considered for future salt mining at this time by Morton International, Inc., which currently operates a mechanically-mined room and pillar salt mine at a depth of about 1,300 feet. Morton International, Inc. retains surface rights in the area proposed for the SPR development; however, other interests own mineral rights to the salt. Other activities on the dome include: the SPR's Weeks Island crude oil storage mine; two leached caverns which produce table salt, located on the Northeast corner of the dome, also owned and operated by Morton International, Inc.; and hydrocarbon production on the north salt overhang where production will ultimately exceed one billion barrels, making Weeks Island one of the top three salt dome oil fields in the world.

Geological Characteristics[4/]

The Weeks Island salt dome is generally circular, with a diameter of 2 miles within the -5,000 foot salt contour. The dome has a major salt overhang on the north side and thin caprock occurs only on the dome periphery. Approximately 500 contiguous acres are potentially suitable for SPR crude oil storage cavern development of more than 150 million barrels within the -2,000 to -5,000-ft. depth range. Several small shallow water ponds occur on the east side of the dome; these could limit the SPR cavern development area to some degree.

The average rate of subsidence over the SPR's oil storage area since 1983 has been 1.4 inches per year; subsidence is expected to continue at that rate. Some tilting of the vertical shafts to the SPR's oil storage mine has also occurred over the years due to salt creep closure.

According to the Louisiana Geological Survey, within 50 years or less, at currently projected rates of broad subsidence in the Gulf Coast area, the progressive loss of coastal marshland in south Louisiana will, if not mitigated, lead to Weeks Island becoming a true island in the Gulf of Mexico.

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4/ *Preliminary Geological Site Characterizations for Strategic Petroleum Reserve Candidate Sites: Weeks Island Salt Dome, Louisiana*, Sandia National Laboratories, SNL/6257-91 WI.

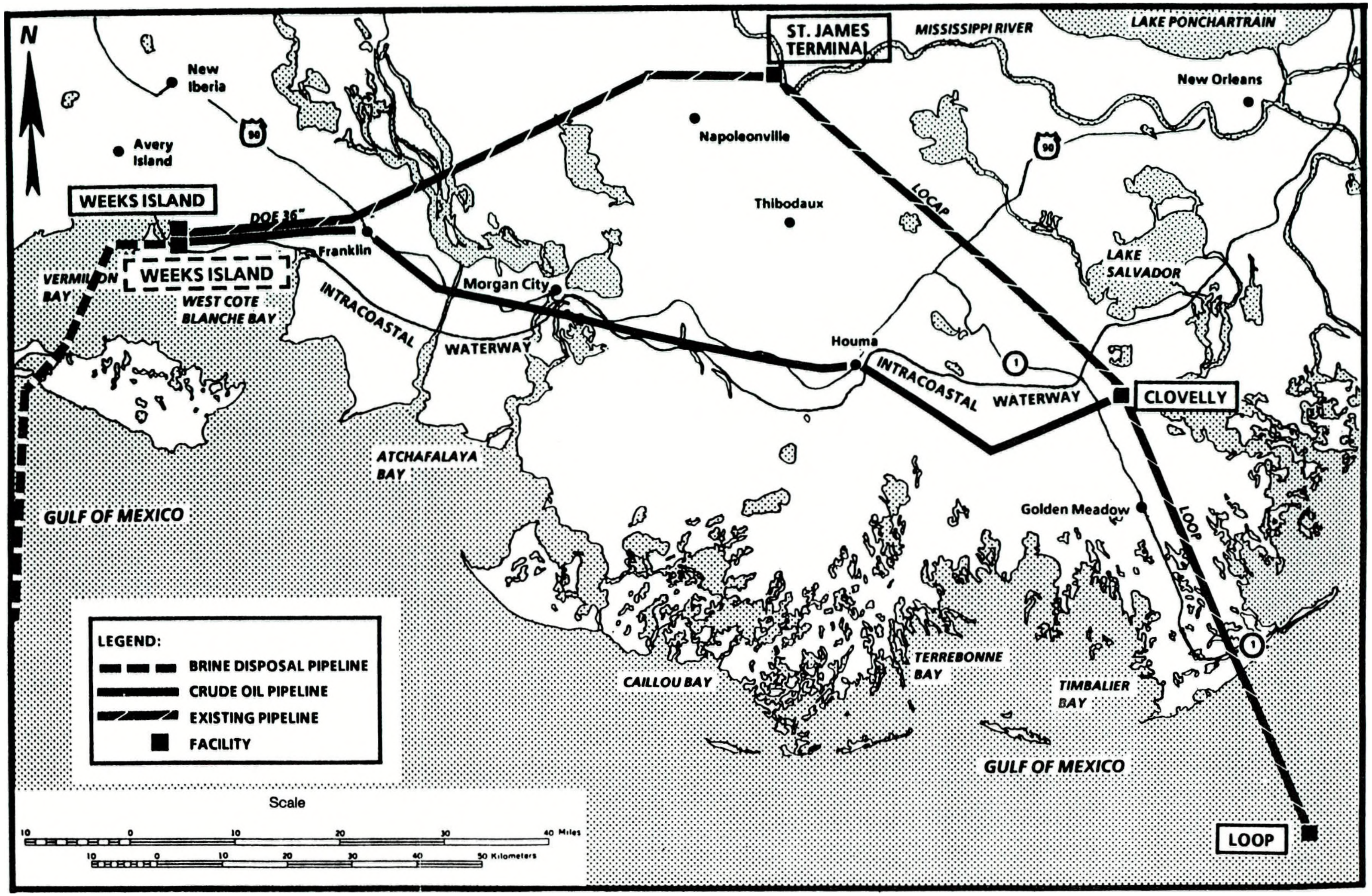


**Figure V-8. WEEKS ISLAND SALT DOME WITH PROPOSED CRUDE OIL, BRINE AND RAW WATER PIPELINES**

Facilities Development

SPR facilities would be located on approximately 300 acres on the eastern part of the salt dome as shown in Figure V-9. Onsite facilities would consist of 15 storage caverns of 10 MMB each, a raw water leaching/drawdown system, a brine settling and disposal system, a crude oil injection/ distribution system, and operations, maintenance and security buildings. Offsite facilities would include a raw water intake structure on the Gulf Intracoastal Waterway located one mile north of the site and interconnecting pipelines for fresh water, brine disposal, and crude oil receipt and distribution. The raw water and brine systems would be sized for leaching caverns at a rate of one million barrels per day and the crude oil system designed for drawdown at 900,000 barrels per day.

Brine disposal would be accomplished by construction of a 48-mile, 48-inch brine pipeline skirting around Blue Point and other land masses, through Southwest Pass skirting Marsh Island to a 30-foot water depth in the Gulf of Mexico. This route would not threaten any environmentally sensitive land mass.

Oil Fill/Distribution

A new 150-million-barrel storage site at the Weeks Island salt dome would be pipeline connected to the DOE St. James Terminal for oil fill and to the LOOP Clovelly Terminal for drawdown/distribution. This site would primarily serve the LOOP-connected lower Mississippi River refiners, while the existing DOE Capline distribution system would be realigned to serve the Capline Pipeline to the midwest and waterborne distribution (Figure V-8).

From the Weeks Island salt dome, DOE would construct a 100-mile, 42-inch pipeline to LOOP's Clovelly Terminal. This pipeline would have a distribution capacity of 900,000 barrels per day, which is equivalent to the projected import demands of the six LOOP-connected refiners on the lower Mississippi River. At St. James, the DOE's existing distribution capabilities would be realigned and expanded to compensate for two refiners now to be served through LOOP. DOE would increase its marine distribution at St. James from 400,000 to 800,000 barrels per day through the construction of two additional docks at DOE's terminal or by contracting for commercial marine distribution services.

For oil fill, DOE would construct a 1-mile, 30-inch crude oil pipeline spur from DOE's existing Weeks Island-to-St. James pipeline to the new Weeks Island expansion site.

Environmental Aspects

Siting at Weeks Island should not require mitigation of wetlands; however, construction of water retention/disposal facilities for storm, rain, or run-off water will be required as this water must be collected and delivered to the brine pond for disposal. No SPR water can cross Morton

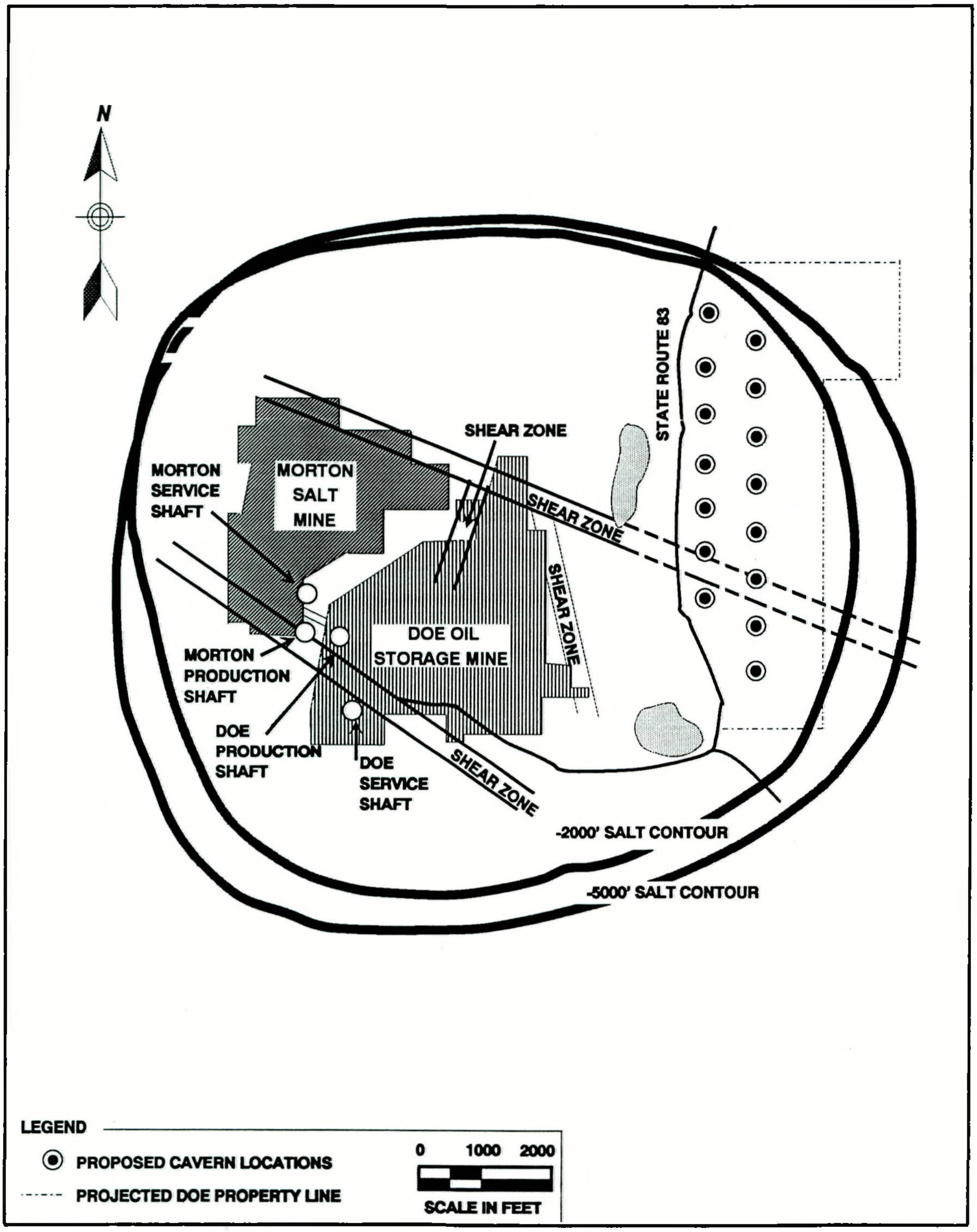


**Figure V-9. PROPOSED SPR STORAGE FACILITY LOCATION ON WEEKS ISLAND SALT DOME**

International's land as Morton is out of compliance with its state discharge permits and cannot be licensed by Louisiana for run-off disposal due to the high salinity of their surface areas.

The site is in an area classified as an attainment area for ozone and should not be subject to special conditions and provisions affecting design and construction.

The Weeks Island-to-Clovelly crude oil pipeline route would require restoration of approximately 1,900 acres. The route would be through fresh and brackish waters, requiring special water control structures to maintain water separation.

The surface elevation varies from 5 to 75 feet above MSL; consequently, fill would be required to raise the low elevations significantly above a 100-year hurricane storm surge.

**Big Hill Salt Dome**

The Big Hill salt dome is located 17 miles southwest of Port Arthur in Jefferson County, Texas, 5 miles north of the Intracoastal waterway, and 9 miles from the Gulf of Mexico (Figure V-10). The dome rises to about 37 feet above MSL. The Department is currently developing a 160-million-barrel storage facility on land acquired in 1982/1983. The current SPR site consists of 269 acres and is in the Texoma Distribution Group. On the northern part of the dome, UNOCAL owns two 0.5-million-barrel LPG caverns; these storage caverns are north of the SPR's proposed storage expansion area. No other operators are on the dome.

The SPR's current storage facilities on Big Hill site are connected to the Sun Terminal in Nederland, Texas, by a DOE-owned 24-mile, 36-inch crude oil pipeline which has a distribution capability of 930,000 barrels per day.

Geological Characteristics[5/]

The Big Hill salt dome is moderately elliptical, 1.25 miles (N-S) by one mile (E-W) within the -5,000-foot salt contour. The dome has a minor salt overhang on the western edge, and major salt overhangs on the southern and eastern margins. The proposed SPR expansion area north of the SPR's existing storage caverns would not be affected by the overhangs. The top of the caprock is encountered at a depth of about 300 feet and the thickness varies between 850 and 1350 feet, one of the thickest of Gulf Coast salt domes. The caprock is vugular and previous SPR drilling encountered several zones of lost circulation. The dome has additional storage potential of perhaps up to 300 million barrels.

A surface fault is manifested by 100 feet of caprock displacement which likely extends into the salt mass, but not necessarily with adverse consequences of salt shearing or bad salt. Geophysical mapping of this fault trace through the caprock would be required for additional SPR cavern development north of the existing SPR caverns. Salt coring to determine salt properties would also be required for those caverns that would be developed adjacent to the shear zone.

Facilities Development

SPR facilities would be located on approximately 232 acres on the salt dome, north of the existing SPR facilities as shown in Figure V-11. Onsite facilities would consist of 10 storage caverns of 10 million barrels each, expansion of the existing raw water drawdown system, a sacrificial alum treatment and brine settling pond and existing disposal system, enhancements to the existing crude oil injection/distribution systems, and expansion of existing operations, maintenance and security

5/ *Preliminary Geological Site Characterizations for Strategic Petroleum Reserve Candidate Sites: Big Hill Salt Dome, Texas*, Sandia National Laboratories, SNL/6257-91 BH.

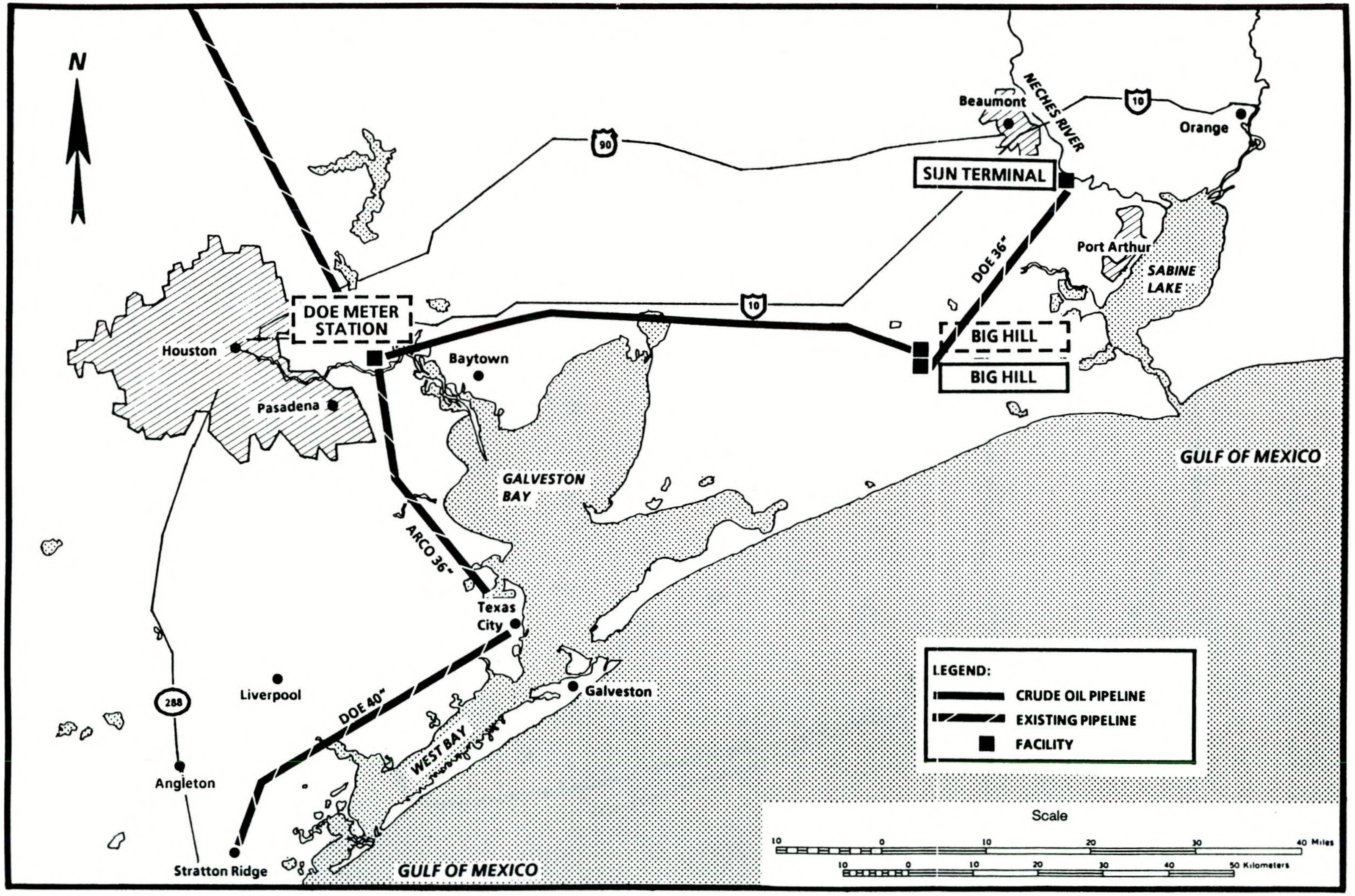


Figure V-10. BIG HILL SALT DOME WITH PROPOSED CRUDE OIL PIPELINE

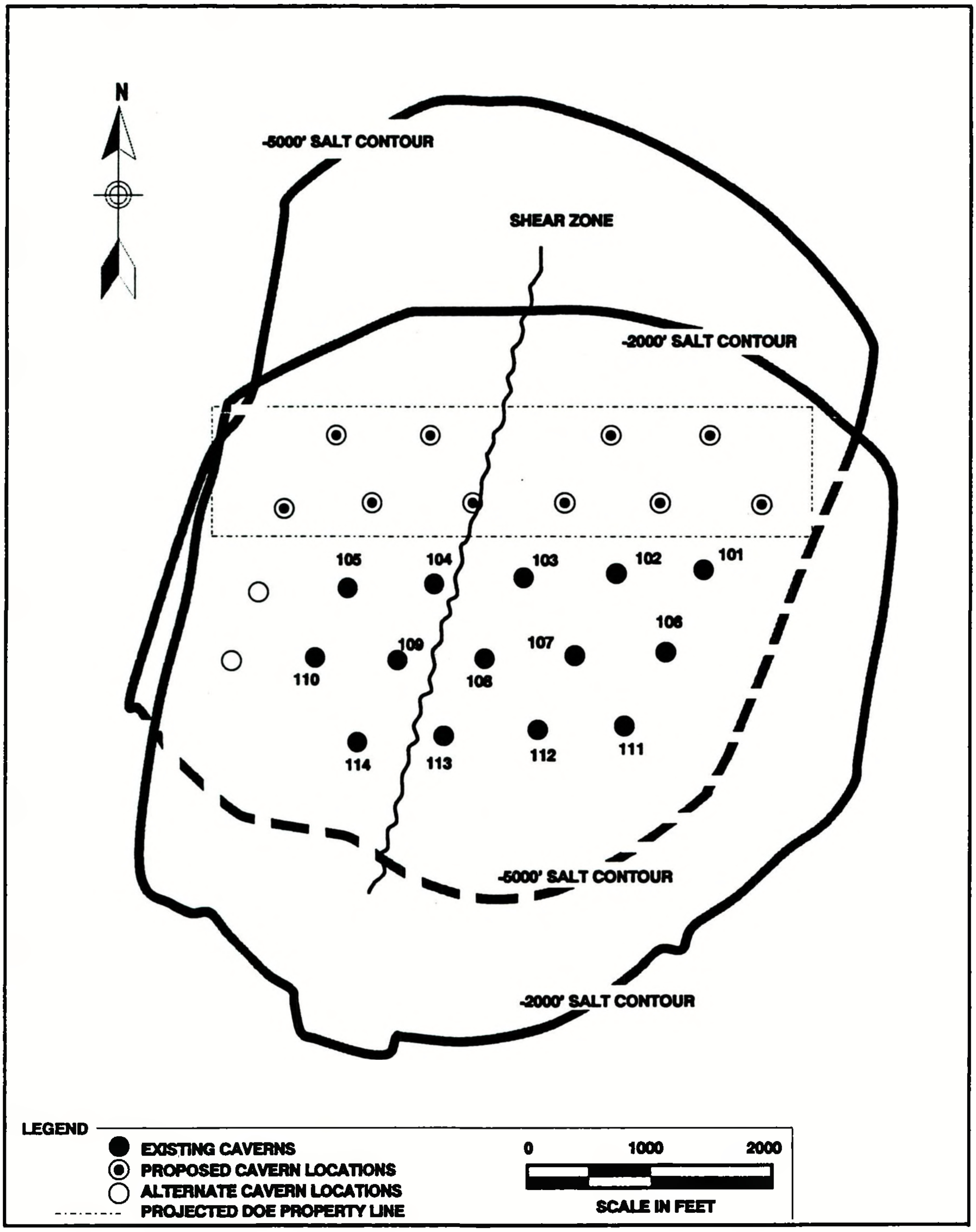


**Figure V-11. PROPOSED SPR STORAGE FACILITY LOCATION ON BIG HILL SALT DOME**

buildings. A conceptual cavern layout is shown in Figure V-12. Existing SPR facilities would be utilized in this expansion by means of interconnecting pipelines for fresh water, brine disposal, and crude oil receipt and distribution. The water and brine systems are sized for leaching caverns at a rate of one million barrels per day. The existing crude oil system would be expanded to provide an additional 600,000 barrels per day. A new oxygen scavenging system would be required for water and brine treatment, and the existing brine disposal pipeline will require special care to minimize erosion during standby operations.

Brine disposal would be accomplished utilizing the existing SPR 14-mile long, 48-inch brine disposal pipeline to the Gulf of Mexico. Raw water would be obtained from the Intracoastal Waterway, via the existing SPR 5-mile, 48-inch raw water pipeline.

Oil Fill/Distribution

A new 100-million-barrel expansion of the Big Hill Storage facility would require additional distribution since existing distribution facilities in the Beaumont/Port Arthur area are used to capacity by the 750-million-barrel Reserve.

From the Big Hill salt dome, DOE would construct a 58-mile, 36-inch pipeline to the East Houston refining center where connections would be made to the ARCO and Texaco pipeline terminals for inland distribution and to a commercial marine terminal on the Houston Ship Channel for waterborne distribution (Figure V-10). This pipeline would have a distribution capacity of 600,000 barrels per day and could be used for both oil fill and drawdown operations. This would allow Bryan Mound to service Seaway/TEXPORT via a new 4-mile, 36-inch pipeline to the Jones Creek Tank Farm. Bryan Mound would provide a 600,000-barrel per day capability to Jones Creek and a 650,000-barrel per day capability to ARCO and/or Phillips Marine Terminal (current distribution channels).

Environmental Aspects

The site is an upland area requiring little or no mitigation.

The site is in an area classified as a Severe II nonattainment for ozone and would be subject to the maximum achievable control technology requirements anticipated under the new Clean Air Act.

Raw water and brine disposal pipelines are in-place. The proposed crude oil pipeline to the Houston, Texas area would require restoration of an estimated 90 acres.

The dome's elevation, about 37 feet above MSL, is sufficient to maintain a minimum risk of flooding even during 100-year storm surges.

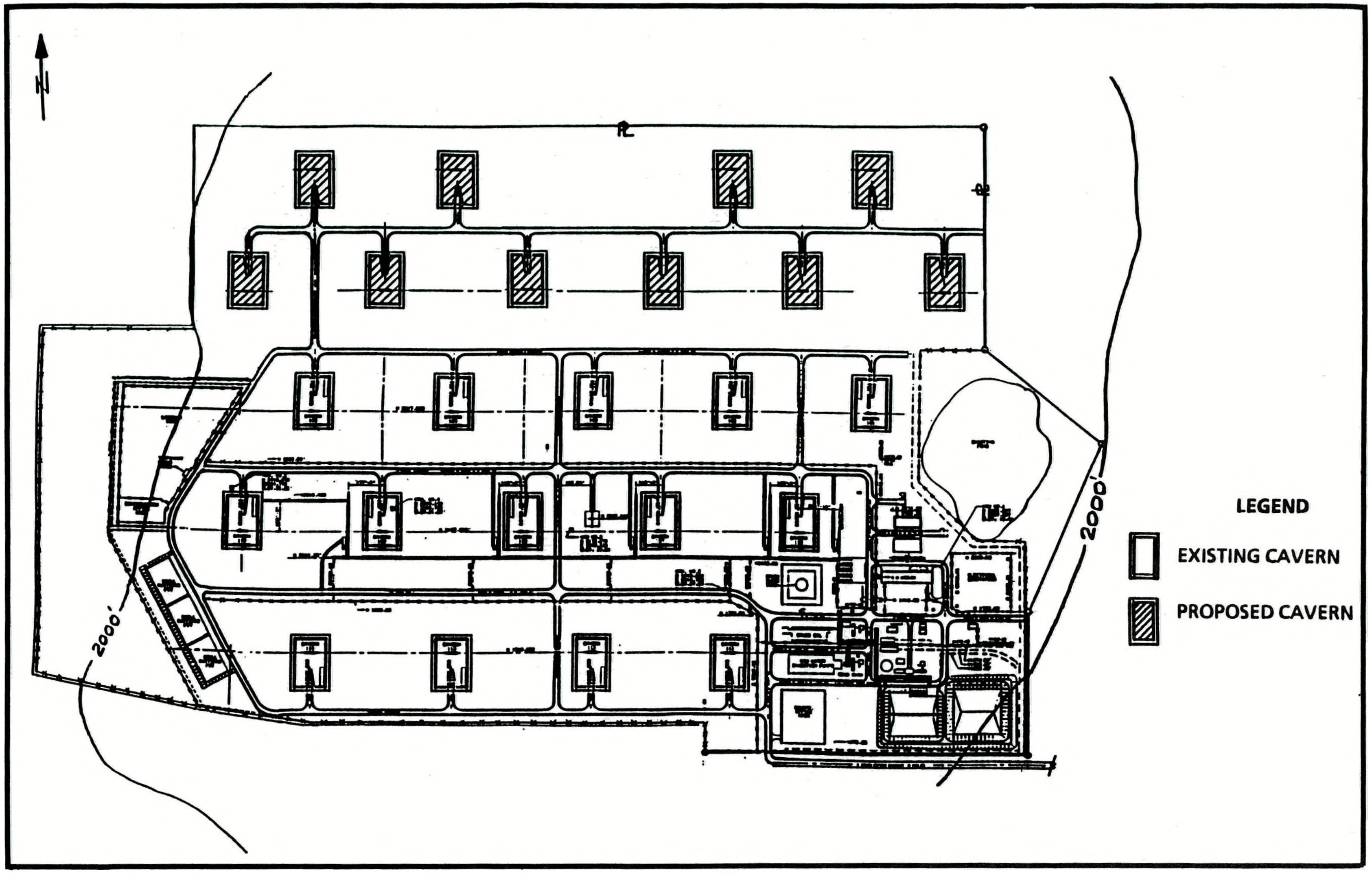


Figure V-12. BIG HILL--CONCEPTUAL LAYOUT OF EXISTING AND PROPOSED SPR CAVERNS

**Boling Salt Dome**

The Boling salt dome (also known as Newgulf) is in Wharton County, 9 miles east of Wharton, Texas, just north of the villages of Boling, Newgulf, and Iago (Fig. V-13).

Several commercial operations are ongoing on this dome. Sulfur mining, initiated in 1928, has produced over 82 million tons to date and is expected to continue for another ten years according to Texas Gulf Sulphur. Another company operates four gas storage caverns with a total storage volume of 13 million barrels on a 285-acre tract, with space for up to 20 additional caverns. Several brine wells are also operating on the dome. A permit for storage of solidified hazardous waste has been requested by another company; the permit was denied but is under appeal.

Geological Characteristics[6/]

The Boling salt dome is quite large relative to all other Gulf Coast domes; the dome is elliptical, 4 miles (N-S) by 5.5 miles (E-W) within the -5000-foot salt contour. The dome is well-mapped as some 8000 wells have been drilled on and around this dome. No overhangs are known and the top of the caprock is at a depth of 385 feet ending at the top of the salt at a depth of 975 feet. Due to extensive sulfur mining, lost circulation zones could be encountered in drilling operations. Anomalously high geothermal gradients, even beyond the sulfur mining areas, suggest widespread void connections.

Facilities Development

SPR facilities would be located on approximately 200 acres of the dome as shown in Figure V-14. Onsite facilities would consist of 10 storage caverns of 10 million barrels each, a raw water leaching/drawdown system, a brine settling and disposal system, a crude oil injection/distribution system, and operations, maintenance and security buildings. Offsite facilities would include a raw water intake structure on the Gulf Intracoastal Waterway, located 40 miles southeast of the site, and interconnecting pipelines for fresh water, brine disposal, and crude oil receipt and distribution. The water and brine systems would be sized for leaching caverns at a rate of one million barrels per day and the crude oil system designed for drawdown at 600,000 barrels per day.

Brine disposal would be accomplished by construction of a 44-mile, 48-inch pipeline southeast into the Gulf of Mexico at a water depth of 30 feet (Fig. V-13). Raw water would be obtained from the Gulf Intracoastal Waterway via a 40-mile, 48-inch pipeline.

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6/ *Preliminary Geological Site Characterizations for Strategic Petroleum Reserve Candidate Sites: Boling Salt Dome, Texas*, Sandia National Laboratories, SNL/6257-91 Bo.

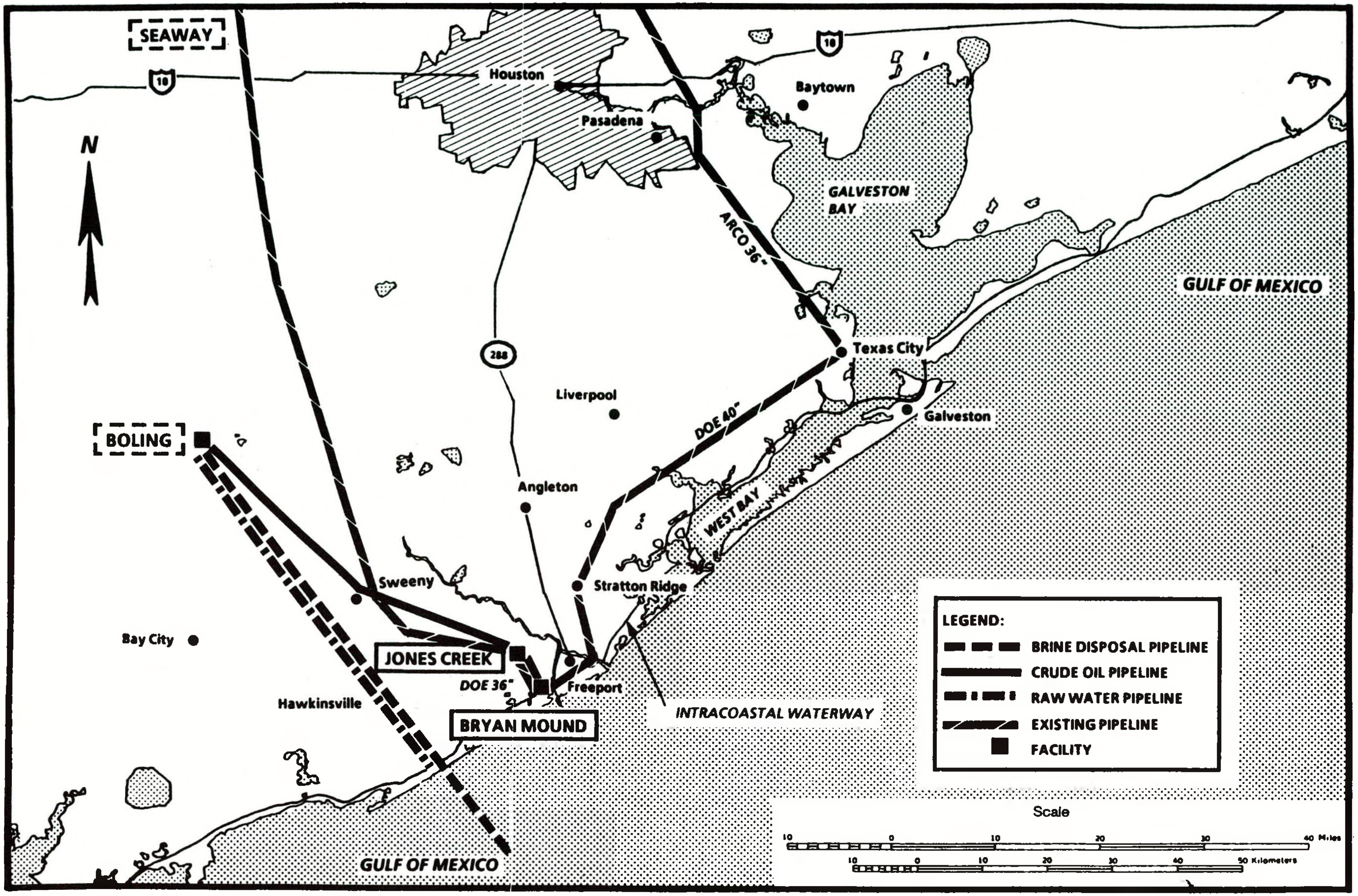


**Figure V-13. BOLING SALT DOME WITH PROPOSED CRUDE OIL, BRINE AND RAW WATER PIPELINES**

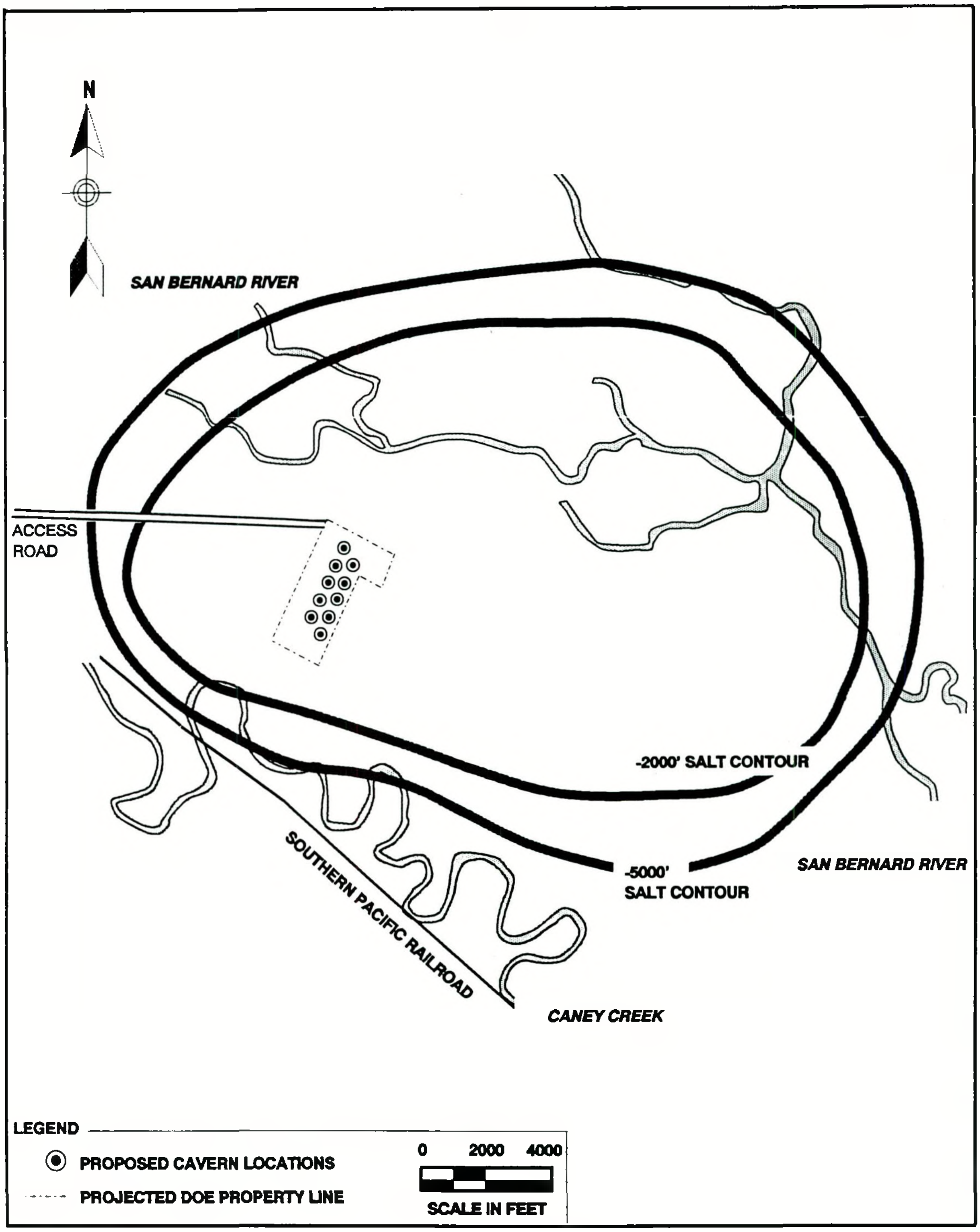


**Figure V-14. PROPOSED SPR STORAGE FACILITY LOCATION ON BOLING SALT DOME**

Oil Fill/Distribution

There are two distribution options for a 100-million-barrel storage site at the Boling salt dome depending on the reconversion of the Seaway pipeline to crude oil distribution.

Seaway Pipeline Option: From the Boling salt dome, DOE could construct a 38-mile, 36-inch pipeline to the proposed Seaway Pipeline Terminal near Freeport, Texas (Figure V-13). This pipeline would have a distribution capacity of 600,000 barrels per day which is equivalent to the projected capacity of the Seaway Pipeline System into the midcontinent. For oil fill, DOE would construct a short 4-mile, 36-inch pipeline connection from the Boling-to-Seaway Terminal pipeline to the SPR Bryan Mound storage site. This pipeline would provide for oil fill, inter-site crude transfers, and distribution flexibility.

Houston Pipeline Option: From the Boling salt dome, DOE could construct a 60-mile, 36-inch pipeline to the East Houston refining center where connections would be made to the ARCO and Texaco pipeline terminals for inland distribution and to a commercial marine terminal on the Houston Ship Channel for waterborne distribution. This pipeline would have a distribution capacity of 600,000 barrels per day and would be used for both oil fill and drawdown operations.

Environmental Aspects

The site is in an upland area requiring little or no mitigation.

The site is located in an area classified as an attainment area for ozone. However, due to its proximity to Brazoria County (Severe II nonattainment area), it may require some special provisions during construction and operation.

The rights-of-way for raw water and brine disposal pipelines will require restoration of approximately 110 acres. These pipelines would be built at the same time and placed in the same right-of-way. Crude oil pipelines are planned to transverse upland areas requiring little or no restoration.

Lost circulation zones resulting from past and present sulfur mining would present difficulties in drilling through the caprock and probably accelerate casing corrosion. Further, also due to sulfur mining, collapse sinkholes have occurred as recently as 1983 and can be expected to be a problem where sulfur mining has occurred near proposed SPR caverns.

Although surface elevation is 75-80 feet above MSL, the surface subsidence has lowered the surface to 50 feet or less in some places. These areas, particularly on the eastern side of the dome, are susceptible to flooding during heavy rainfall. Subsidence over or near areas of sulfur mining is expected to continue.

**Hawkinsville Salt Dome**

The Hawkinsville salt dome is located 18 miles west of the Bryan Mound salt dome and one mile north of Hawkinsville village in Matagorda County, Texas (Fig. V-15). The surface land on the dome is partly cultivated with the remainder in brush. Existing facilities and operations appear to be limited oil production on the flanks of the dome with no known mining.

Geological Characteristics[7/]

The Hawkinsville dome is generally circular, with a diameter of about one mile within the -5000-foot salt contour. There is a major overhang on the northeast side. The top of caprock is at a depth of 95 feet and has a thickness of 325 feet, while the top of salt is at a depth of 420 feet. The shape of the dome is poorly defined because of limited subsurface data. Sufficient space and salt for 100 million barrels of SPR storage development is likely available, but considerable geological and geophysical investigations would be required. The nature of the caprock and salt is not well known.

Facilities Development

SPR facilities would be located on approximately 200 acres on the dome as shown in Figure V-16. Onsite facilities would consist of 10 storage caverns of 10 million barrels each, a raw water leaching/drawdown system, a brine settling and disposal system, a crude oil injection/distribution system, and operations, maintenance and security buildings. Offsite facilities would include a raw water intake structure on the Gulf Intracoastal Waterway, located 9 miles southeast of the site, and interconnecting pipelines for fresh water, brine disposal, and crude oil receipt and distribution. The water and brine systems would be sized for leaching caverns at a rate of one million barrels per day and the crude oil system designed for drawdown at 600,000 barrels per day.

Brine disposal would be accomplished by construction of a 13-mile, 36-inch pipeline, to a water depth of more than 30 feet in the Gulf of Mexico (Fig. V-15). Brine diffusers would have to extend beyond the 30-foot water depth to avoid affecting Matagorda Bay.

Oil Fill/Distribution

There are two distribution options for a 100-million-barrel storage site at the Hawkinsville salt dome, depending on the reconversion of the Seaway pipeline to crude oil distribution.

Seaway Pipeline Option: From the Hawkinsville salt dome, DOE could construct an 18-mile, 36-inch pipeline to the proposed Seaway Pipeline Terminal near Freeport, Texas (Figure V-15). This

7/ *Preliminary Geological Site Characterizations for Strategic Petroleum Reserve Candidate Sites: Hawkinsville Salt Dome, Texas*, Sandia National Laboratories, SNL/6257-91 Ha.

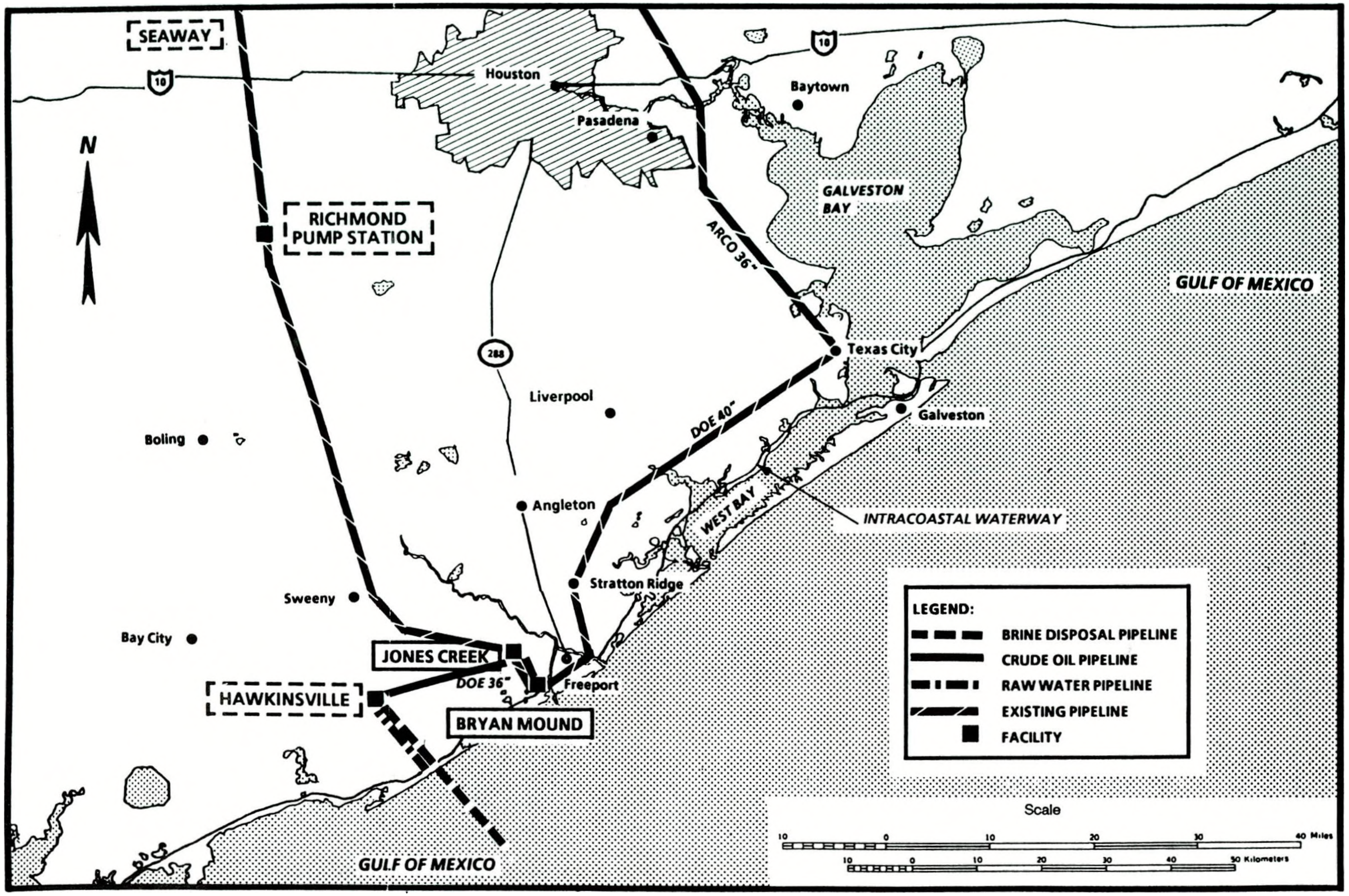


**Figure V-15. HAWKINSVILLE SALT DOME WITH PROPOSED CRUDE OIL, BRINE AND RAW WATER PIPELINES**

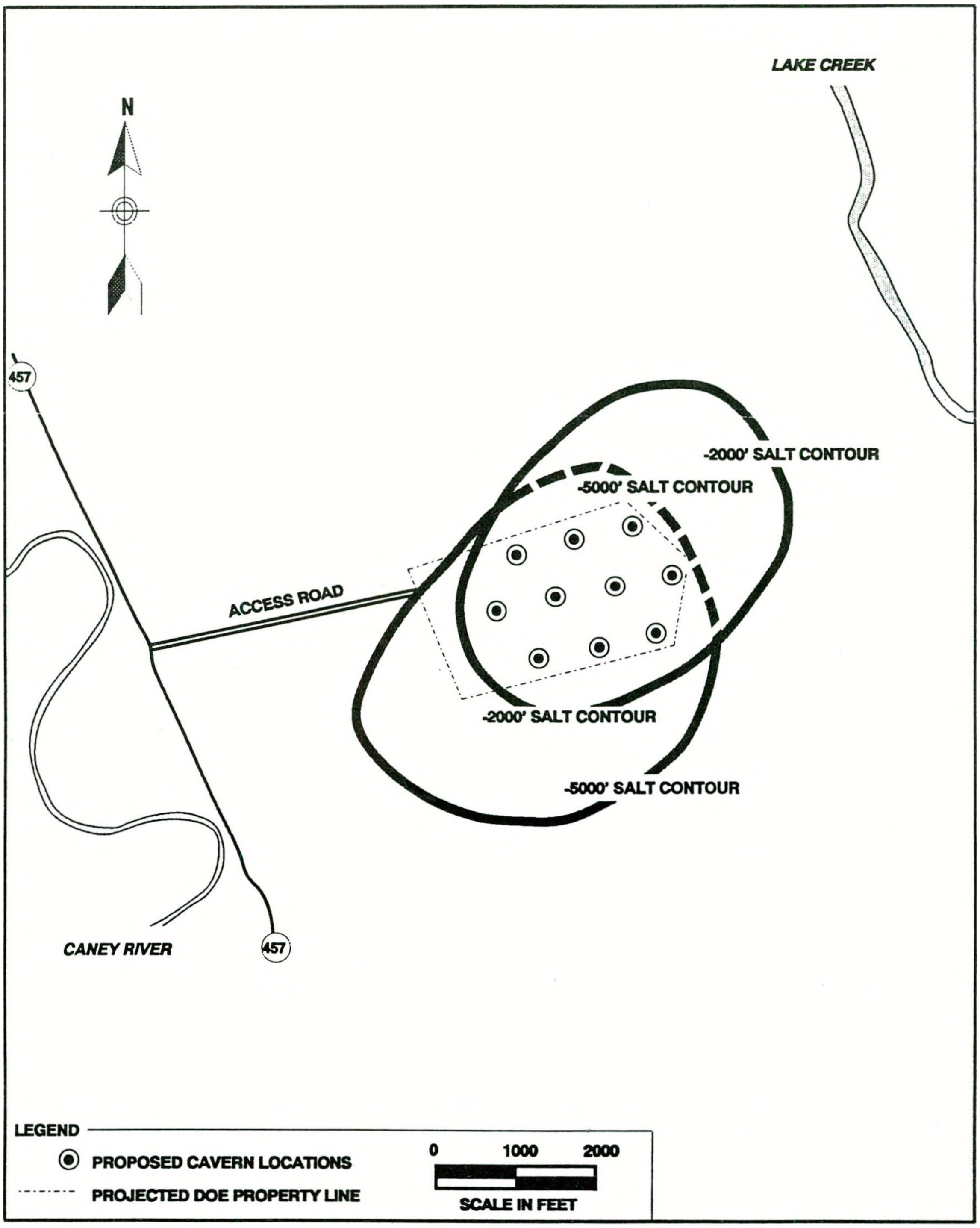


**Figure V-16. PROPOSED SPR STORAGE FACILITY LOCATION ON HAWKINSVILLE SALT DOME**

pipeline would have a distribution capacity of 600,000 barrels per day which is equivalent to the projected capacity of the Seaway Pipeline System into the midcontinent. For oil fill, DOE would construct a short 4-mile, 36-inch pipeline connection from the Hawkinsville-to-Seaway Terminal pipeline to the SPR Bryan Mound storage site. This pipeline would provide for oil fill, intersite crude transfers, and distribution flexibility.

Houston Pipeline Option: From the Hawkinsville salt dome, DOE could construct a 72-mile, 36-inch pipeline to the East Houston refining center where connections would be made to the ARCO and Texaco pipeline terminals for inland distribution and to a commercial marine terminal on the Houston Ship Channel for waterborne distribution. This pipeline would have a distribution capacity of 600,000 barrels per day and would be used for both oil fill and drawdown operations.

Environmental Aspects

The site is in an upland area requiring little or no mitigation.

The site is in an area classified as an attainment area for ozone. However, it is adjacent to Brazoria County (Severe II nonattainment area) and may require some special provisions during construction and operation.

The raw water and brine disposal pipelines would be constructed at the same time in the same right-of-way, and would require restoration of approximately 110 acres of wetlands. The crude oil pipeline to Jones Creek should require little or no restoration. The other proposed pipeline from Hawkinsville to the Houston Ship Channel would require little or no restoration.

The site is sufficiently inland and has an elevation of 10-15 feet; consequently, flooding would not be expected during a 100-year storm.

## Stratton Ridge Salt Dome

Stratton Ridge dome is located in Brazoria County, Texas, approximately 11 miles north of Bryan Mound, 6 miles north of Freeport and 2.5 miles northeast of Clute, Texas (Fig. V-17).

Several commercial operations are ongoing on this dome. Approximately 57 brine and petroleum product storage caverns with a wide range of sizes are currently in use.

### Geological Characteristics[8/]

Stratton Ridge salt dome is relatively large, about 3 miles (N-S) by 4 miles (E-W), and irregular in shape within the -5000-foot (below mean sea level) salt contour. The top of caprock is at a depth of 870 feet, and the top of the salt is at a depth of 1270 feet. There is an overhang on the southeastern corner of the dome but it is not likely to affect the proposed location of SPR caverns.

A trough-like depression extending generally in a north-south direction, on the east-central part of the dome (Fig. V-18), most likely a result of an active slump fault, is an area to be avoided for storage cavern development. Caprock shifting and associated casing failures are known to have occurred in the area of this suspected fault.

Subsidence has occurred in the areas of current cavern operations but the degree varies and predictions are uncertain in the area of proposed SPR cavern development where up to 400 or more contiguous acres are potentially available for cavern development.

### Facilities Development

SPR facilities would be located on approximately 200 acres on the salt dome as shown in Figure V-18. Onsite facilities would consist of 10 storage caverns of 10 million barrels each, a raw water leaching/drawdown system, a brine settling and disposal system, a crude oil injection/distribution system, and operations, maintenance and security buildings. Offsite facilities would include a raw water intake structure on the Gulf Intracoastal Waterway, located 8 miles southwest of the site, and interconnecting pipelines for fresh water, brine disposal, and crude oil receipt and distribution. The water and brine systems would be sized for leaching caverns at a rate of one million barrels per day and the crude oil system designed for drawdown at 600,000 barrels per day.

Brine disposal would be accomplished by construction of an 11-mile, 36-inch pipeline southwest into the Gulf of Mexico to a water depth of 30 feet (Fig. V-17). Raw water would be

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8/ *Preliminary Geological Site Characterizations for Strategic Petroleum Reserve Candidate Sites: Stratton Ridge Salt Dome, Texas*, Sandia National Laboratories, SNL/6257-91 SR.

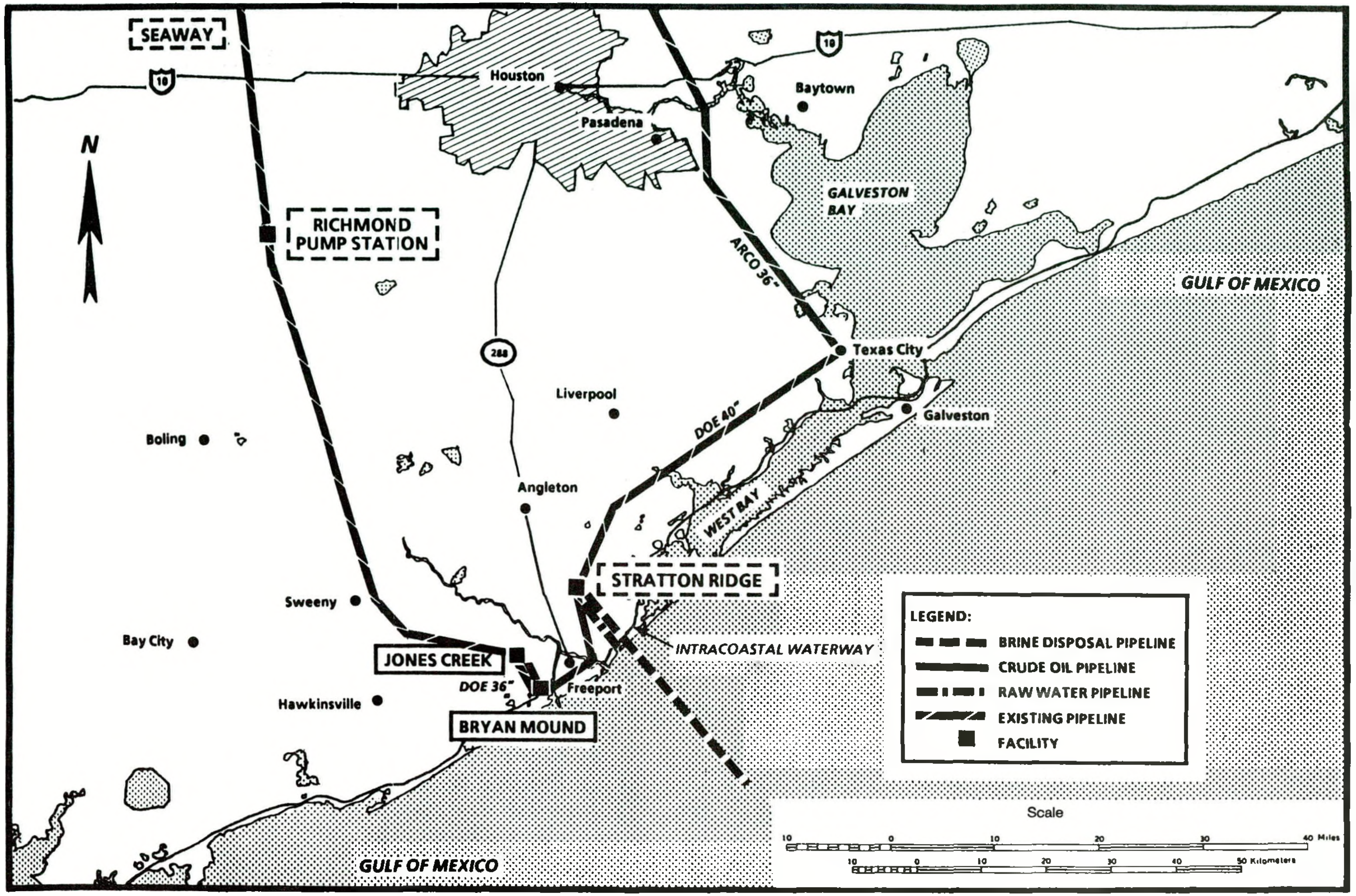


**Figure V-17. STRATTON RIDGE SALT DOME WITH PROPOSED CRUDE OIL, BRINE AND RAW WATER PIPELINES**

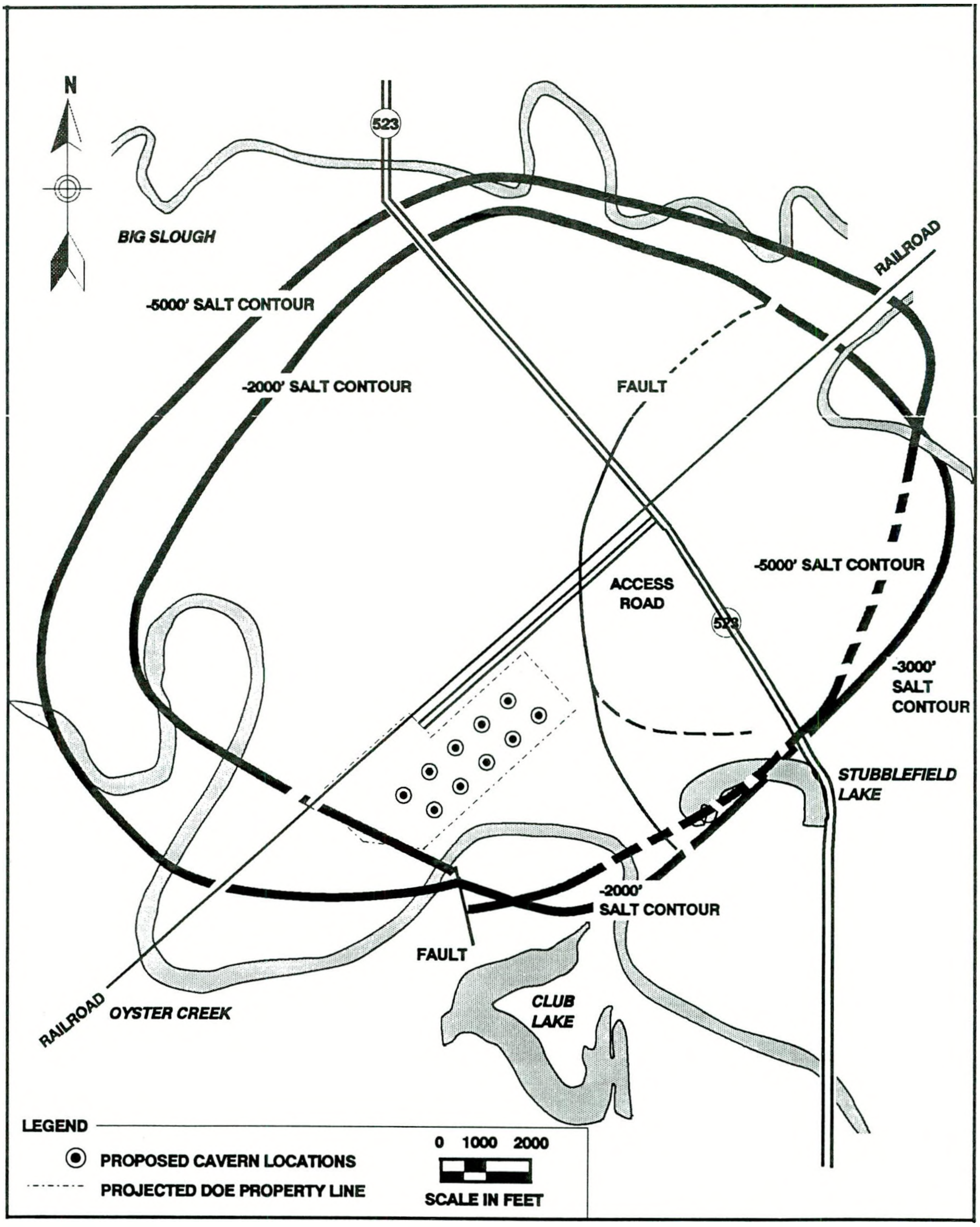


**Figure V-18. PROPOSED SPR STORAGE FACILITY LOCATION ON STRATTON RIDGE SALT DOME**

obtained from the Gulf Intracoastal Waterway by constructing an 8-mile, 36-inch pipeline.

Oil Fill/Distribution

There are two distribution options for a 100-million barrel storage site at Stratton Ridge, depending on the reconversion of the Seaway pipeline to crude oil distribution.

Seaway Pipeline Option: Under this option, the Stratton Ridge site would be configured to serve the Houston/Texas City refining center, and the current Bryan Mound site would be realigned to serve, via a new 4-mile, 36-inch pipeline, the planned Seaway Pipeline System into the Midcontinent (Figure V-17). From the Stratton Ridge salt dome, DOE would construct a short 1-mile, 36-inch pipeline tie-in to the existing Bryan Mound-to-Texas City pipeline with a capacity of 600,000. This pipeline connection would provide for oil fill, intersite crude transfers and distribution.

Houston Pipeline Option: From the Stratton Ridge salt dome, DOE could construct a 50-mile, 36-inch crude oil pipeline to the East Houston refining center where interconnections would be made to the ARCO and Texaco pipeline terminals for inland distribution and to a commercial marine terminal on the Houston Ship Channel for waterborne distribution. This pipeline would have a distribution capacity of 600,000 barrels per day. DOE would also construct a short 1-mile, 36-inch pipeline tie-in to the existing Bryan Mound-to-Texas City pipeline for oil fill, intersite crude transfers and distribution flexibility.

Environmental Aspects of Development

The site is an upland area requiring little or no mitigation.

The site is in an area classified as a Severe II nonattainment area for ozone and would be subject to the maximum achievable control technology requirements anticipated under the new Clean Air Act.

The rights-of-way for raw water, brine disposal, and crude oil pipelines would require restoration of approximately 220 acres.

The 100-year storm surge elevation predicted at Stratton Ridge is 3 feet. The site ranges from 10 to 15 feet above MSL. Subsidence is expected to continue over the extensive cavern area, and could present additional flooding problems in the future.

# SECTION VI

## Preliminary Cost and Schedule Estimates

This section provides preliminary cost and schedule estimates for expansion of the Strategic Petroleum Reserve to one billion barrels.

### A. Preliminary Construction Cost Estimates

Construction cost estimates have been developed for each of the eight candidate storage sites using a computerized parametric cost estimating program. Site development costs for a 150-million-barrel site in the Capline complex and a 100-million-barrel site in the Seaway complex are presented in Table VI-1. Site development costs include the cost of land, design, drilling, site construction, pipeline construction and site operations during cavern leaching. The cost range is principally driven by pipeline construction requirements associated with the candidate sites' locations with respect to fresh water for cavern leaching, the Gulf of Mexico for brine disposal and crude oil distribution facilities. The reason Capline storage sites are more expensive to develop than the Seaway sites is due to their larger size and inland distance from the Gulf of Mexico, which requires the construction of very long, large-diameter pipelines for brine disposal.

**TABLE VI-1**
**Projected Cost Ranges for Storage Site Developments**
**(Constant 1991 Dollars)**

| Activity | Capline Storage Sites 150 MMB (Costs in Millions) | Seaway Storage Sites 100 MMB (Costs in Millions) |
|---|---|---|
| Land Acquisition | $ 56 - 57 | $ 33 - 41 |
| Engineering | 113 - 122 | 40 - 89 |
| Site Construction | 225 - 237 | 136 - 171 |
| Pipeline Construction | 397 - 477 | 121 - 304 |
| Cavern Development | 171 - 204 | 98 - 127 |
| Total | $962 - 1,097 | $428 - 732 |
| Average Cost/Barrel | $6.42 - 7.31 | $4.28 - 7.32 |

The total facility development cost for the expansion of the Reserve to one billion barrels is estimated to be between $1.4 and $1.9 billion in 1991 dollars. This cost includes the cost of storage site developments, and the cost of accessing, modifying, and in some cases expanding oil distribution terminals for SPR use.

**TABLE VI-2**
**Total Project Development Costs**
**(Constant 1991 Dollars)**

| | Cost in Millions | Average Cost/Barrel |
|---|---|---|
| Capline Storage Site | $ 962 - 1,097 | $ 6.42 - 7.31 |
| Seaway Storage Site | 428 - 732 | 4.28 - 7.32 |
| Government/Commercial Terminal Distribution Mods | 70 - 91 | |
| Total Project Cost | $1,460 - 1,920 | $ 5.84 - 7.68 |

## B. Development Schedule

Expansion of the Reserve to one billion barrels storage capacity would require at least nine years to complete, including the NEPA environmental review and site selection process. This schedule is subject to the availability of appropriations and could extend longer. The actual schedule will be proposed in the SPR Plan Amendment to Congress in September 1992.

The Department of Energy initiated environmental, geotechnical and engineering planning studies in December 1990, and completed a Supplement Analysis of the SPR's 1976 Programmatic Environmental Impact Statement in February 1991. The Department anticipates completion of the NEPA environmental review and site selection, and the submission of a SPR Plan Amendment to Congress on the expansion to one billion barrels by September 15, 1992.

Subject to appropriations, the Department could commence engineering design and land acquisition activities as early as FY 1993. Land acquisition for the SPR program is performed by the U.S. Army Corps of Engineers through an Interagency Agreement. Land Acquisition activities normally require 18 to 24 months; however, the Corps of Engineers will be required to identify land ownership and perform preliminary title searches as part of the SPR Plan Amendment requirements (EPCA Section 154(e)(g)). Engineering design will be performed simultaneous with land acquisition and is not normally a critical path activity. However, an Architect-Engineer (A/E) firm must be competitively selected pursuant to P.L. 92-582, Brooks Architect-Engineering Act to perform the required Title I, II and III engineering services. The procurement process for acquisition of an A/E contractor requires 9 to 12 months.

Construction of each site will be phased and performed by a specialty drilling contractor, a general contractor for each phase of site development, and pipeline contractors. The construction contracts will be structured to complete the well drilling and construction of all facilities required for cavern leaching in 24 months and to complete all remaining facilities, i.e., security and oil distribution systems, in 45 months.

The cavern development program would be based on the same cavern leaching plans used to develop the SPR's Big Hill storage facility. Plans would be for both sites to commence cavern leaching at the same time and stagger cavern completions in order to complete the first cavern in 30 months and the last cavern in 36 months for the 100-million-barrel site, and in 48 months for the 150 million barrel site. The storage capacity development could be accelerated by approximately 6 to 12 months if Big Hill is selected for expansion because of its existing site infrastructure for cavern leaching.

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# *APPENDIX A*

# *NORTH AMERICAN PETROLEUM SUPPLY AND DEMAND PROJECTIONS FOR YEAR 2000*

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# APPENDIX A

## North American Petroleum Supply and Demand Projections For Year 2000

This Appendix presents the regional North American petroleum supply and demand outlook in the year 2000 used for SPR crude oil distribution planning. The market outlook includes an analysis of petroleum product consumption, crude oil and NGL production, product imports, refinery capacity and capacity utilization, and crude oil consumption and imports.

The market analyzed for SPR supply planning purposes includes the U.S. Caribbean Territories, Puerto Rico and the U.S. Virgin Islands, and Canada. Puerto Rico and the U.S. Virgin Islands (PADD VI)[1/] are included because they are important US refining centers and are considered as such under the EPCA. Canada is included because the passage of the US-Canada Free-Trade Agreement has resulted, to a large extent, in a North American free market in crude oil and petroleum products.

The main source of data and projections used to develop the Year 2000 scenario was the EIA *Annual Energy Outlook 1991* (AEO 1991). In the past, Canadian data and projections have been obtained from the National Energy Board of Canada (NEB). The NEB is presently updating its projections of Canadian energy supply and demand and the results will not be available until mid summer. An alternative 1989 projection entitled *2020 Vision* was obtained from the Canadian Department of Energy, Mines and Resources, and was used.

The AEO 1991 projections were published March 13, 1991 and are thus the most current EIA projections. Table A-1 compares the AEO 1991 with both the National Energy Strategy (NES) current policy and strategy implementation projections. The NES Current Policy Baseline was constructed from the prior AEO 1990 projections and its purpose was not to project the future but to simply establish a baseline for the NES analysis. The AEO 1991 is based on the same methodology as the NES Current Policy Base case but reflects the most recent 1990 information, somewhat lower oil price projections through the 1990s as a result of the Persian Gulf war, and slightly higher U.S. economic growth assumptions. The differences can be seen in the relationships between domestic production and net imports. The AEO 1991 projects lower domestic production by 2000 and consequently higher net petroleum imports.

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1/ PADD = Petroleum Administration for Defense District, the standard regional aggregations in which petroleum data are usually published.

**TABLE A-1**
**Comparison of AEO 1991 and NES Projections**
**(million barrels per day)**

| | AEO 1991 * | | | NES I ** | | | NES II *** | | |
|---|---|---|---|---|---|---|---|---|---|
| | **1990** | **1995** | **2000** | **1990** | **1995** | **2000** | **1990** | **1995** | **2000** |
| Domestic Production[1/] | 9.5 | 9.2 | 8.0 | 9.8 | 8.8 | 8.4 | 9.8 | 8.8 | 10.1 |
| Petroleum Imports[2/] | 7.3 | 8.1 | 10.5 | 7.6 | 9.9 | 11.3 | 7.6 | 8.9 | 8.3 |
| Petroleum Consumption | 17.0 | 17.3 | 18.5 | 17.4 | 18.6 | 19.7 | 17.4 | 17.7 | 18.4 |

* AEO 1991 Base Case
** NES Current Policy Base Case
*** NES Strategy Implementation
1/ Includes all U.S. liquids (crude, NGLs, alcohols) and refinery gain.
2/ Net crude and products; includes SPR imports.

**Regional Projections**

EIA only develops national oil market projections. EIA's national projections were disaggregated to a PADD and sub-PADD level by means of the North American Crude Oil Distribution Model (NACOD). NACOD is a regional model that was developed by ICF Resources for the DOE's Office of Strategic Petroleum Reserve. It is a Linear Programming Optimization model designed to disaggregate national product demand and then meet demand at least cost from a supply perspective, subject to a number of transportation, refining, import, and export constraints. There are 19 regions in the model:

- 13 United States Regions
- 1 Caribbean Region (Puerto Rico/U.S. Virgin Islands)
- 2 Canadian Regions (East/West)
- 1 import supply region
- 2 SPR supply regions

Figure A-1 shows all the regions with the exception of the import supply region and the 2 SPR supply regions. The SPR supply regions are not used except to simulate SPR supply during a drawdown.

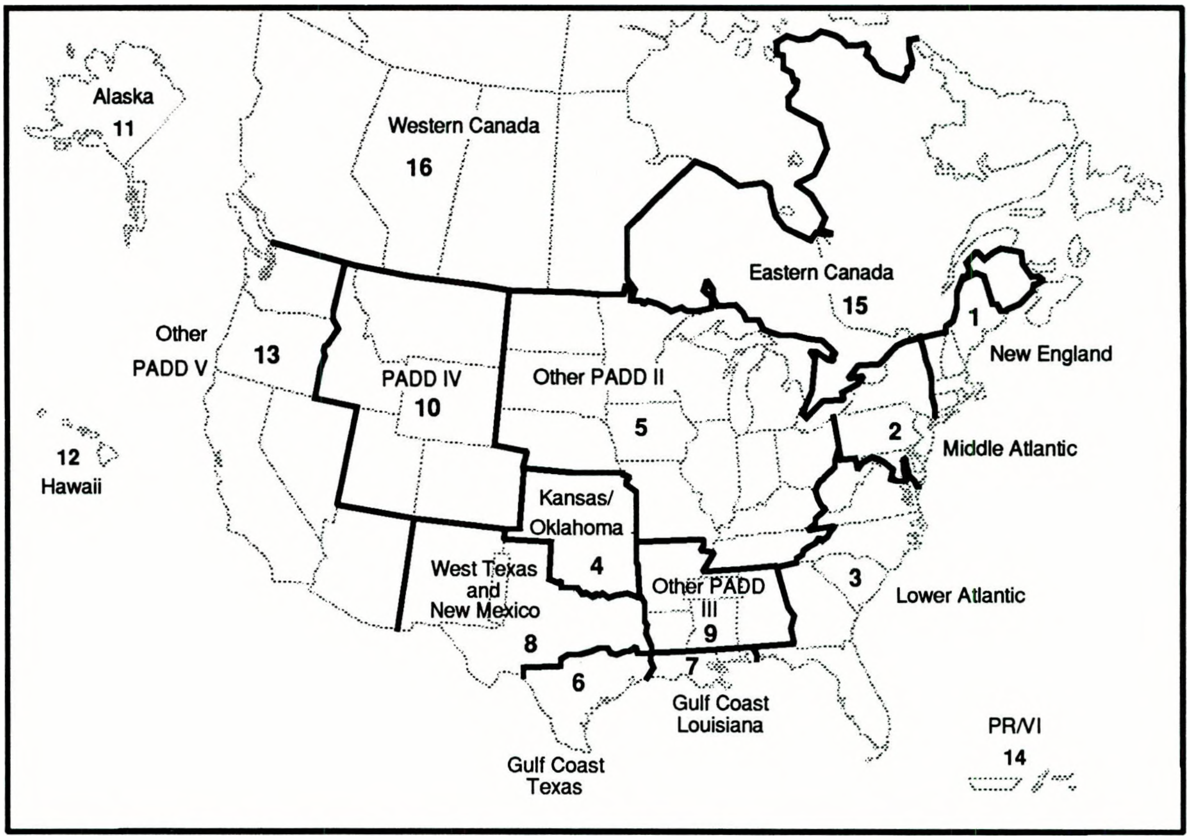


**Figure A-1. NORTH AMERICA CRUDE OIL DEMAND MODEL (NACOD) REGIONS**

The NACOD model distributes national petroleum supply and demand into regions based on several data sets: regional crude oil and NGL field production shares, regional consumption ratios for various products, regional refinery capacity gains and utilization costs, crude oil and product pipeline networks and marine movements, and regional population projections. Figure A-2 diagrams the input requirements and the output of the NACOD model.

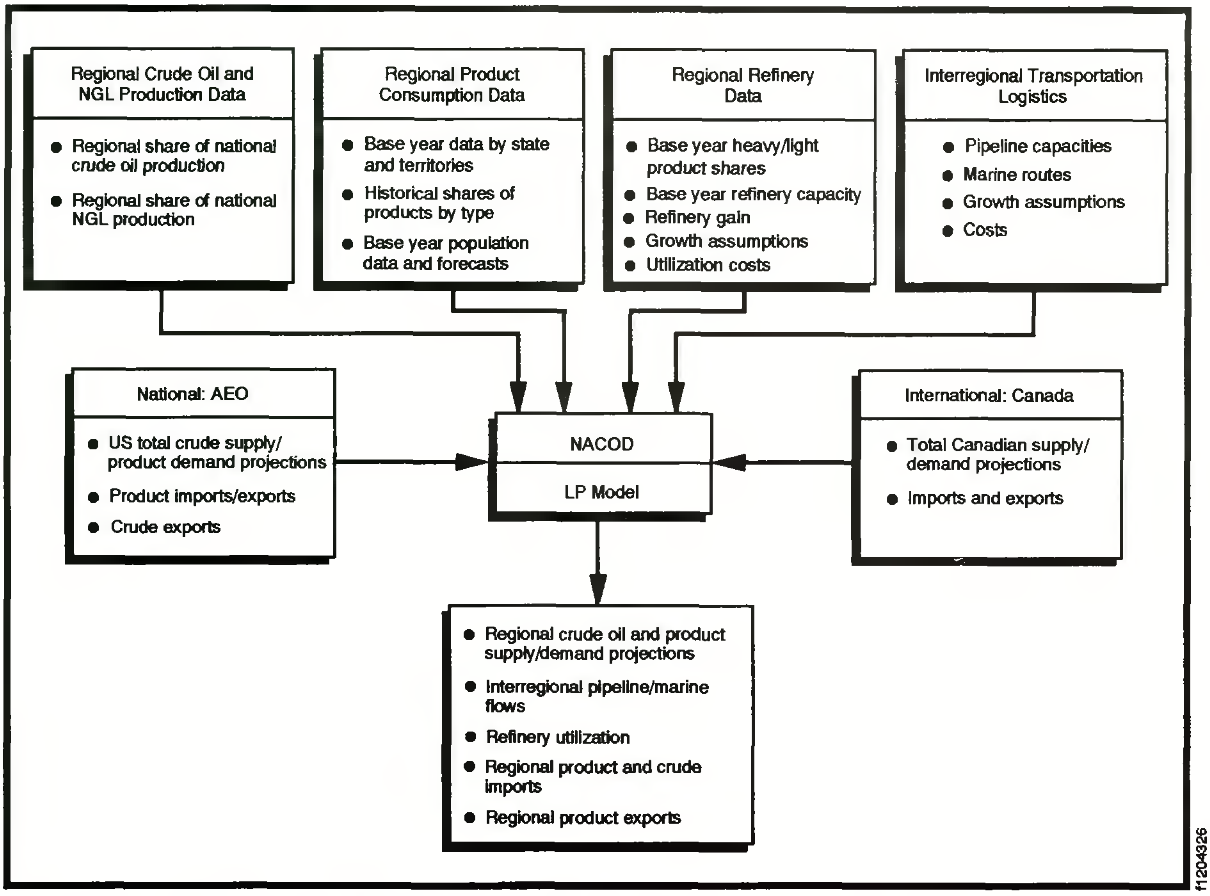


**Figure A-2. NORTH AMERICA CRUDE OIL DEMAND MODEL (NACOD)**

The rest of this Appendix discusses the details of the regional projections. The Year 2000 projections are compared to 1990 data. The 1990 numbers are preliminary as final numbers will not be available until later this year.

### Petroleum Product Consumption Projections

Total product consumption in the United States is expected to rise from 16.98 million barrels per day in 1990 to 18.53 million barrels per day in 2000. Consumption in PADD VI rises from 281,000 barrels per day in 1990 to 298,000 barrels per day in 2000. Product consumption in the United States rises in most product categories during this period with the exception of distillate fuel oils. Consumption of residual fuel oil rises the most, closely followed by jet fuel.

Figure A-3 shows product consumption for the United States by PADD region. As can be seen from the figure, product demand is expected to rise principally in the South and West due to projected population shifts and growth in those regions.

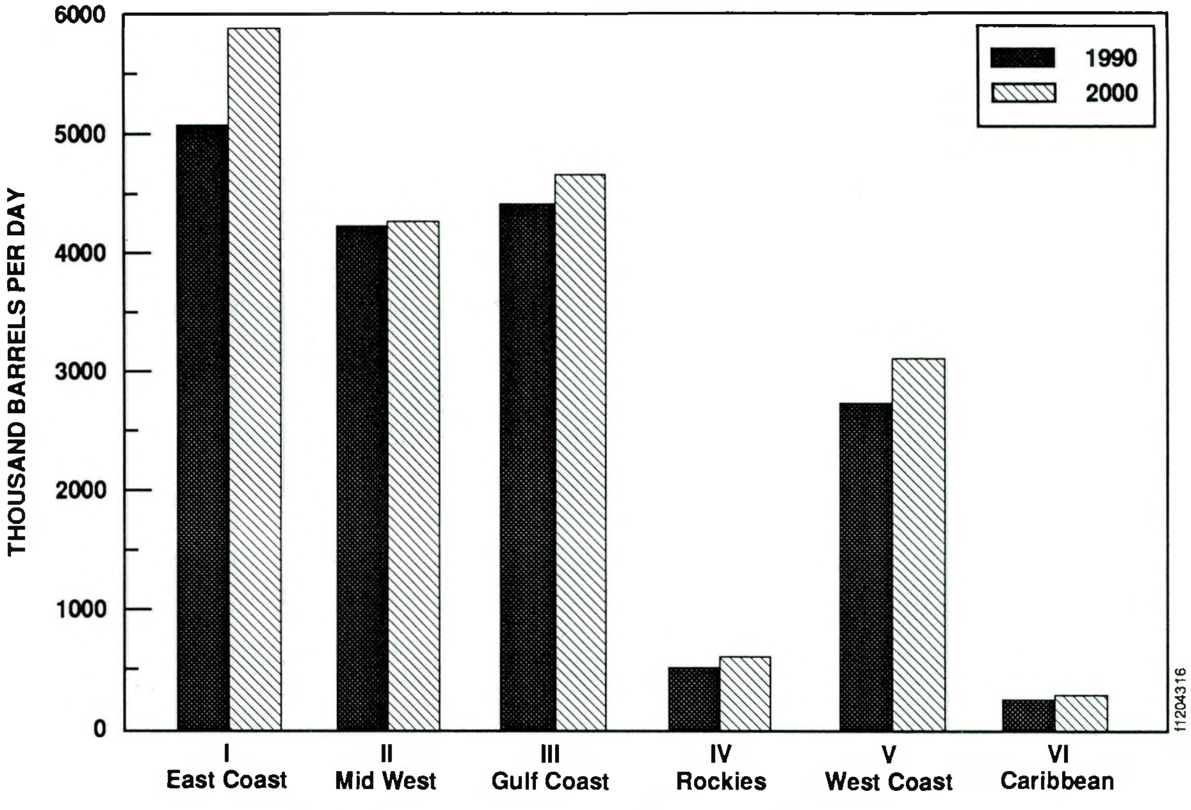


**Figure A-3. PRODUCT CONSUMPTION BY PETROLEUM ADMINISTRATION FOR DEFENSE DISTRICTS: 1990 VS 2000 BASE CASE**

### Crude Oil and NGL Production Projections

U.S. domestic crude oil production is projected to decline steadily at the national level over the next ten years. Disaggregation to the PADD level reveals a more varied picture. PADD II (Midwest) shows a marked decline of over 30 percent compared to 1990 production; PADDs III (Gulf Coast) and IV (Rockies) show a decline at a somewhat lesser rate, (when compared to 1990 production) somewhat over 20 percent for PADD III and a little under for PADD IV; and PADD I (East Coast), which has little production, shows a slight decline but essentially remains stable. The PADD V (West Coast) changes are more complex. Overall, there is a production decline in the PADD, but this is driven by a sharp decline in Alaska. No major new discoveries are projected in Alaska. Even if these were to occur during the next ten years, the lead time to production is so long in the harsh Arctic environment that production would only occur after 2000.

The lower-48 West Coast portion of PADD V, on the other hand, shows an increase in production by 2000. Growth of production in PADD V is directly related to an increase in enhanced oil recovery (EOR) production. Figure A-4 shows estimated year 2000 crude oil production levels by PADD region with the changes from 1990.

Figure A-5 shows estimated NGL production in 2000. NGL production is a by-product of natural gas production and, as such, is slated to increase steadily from now to the year 2000. The increase is concentrated in PADDs III and IV, with the rest of the country showing small declines. It should be noted that Alaskan numbers are based on the assumption that North Slope gas will not be produced by 2000.

Canadian crude oil production in 2000, which is shown in Table A-2 by category, is projected to increase on the national level when compared to 1990; however, there are also some major shifts in crude supply location. Eastern Canadian production increases by the year 2000, due in large part to the offshore Hibernia and Terra Nova fields which are expected to be producing by 1996 and 1998 respectively. In addition, offshore production from the Beaufort Sea becomes available in 2000. Offshore crude oil is expected to be light, and at least in the case of Hibernia, will have a high wax content. Crude production in Western Canada, the major producing area, is projected to decline. Conventional light crude (including pentanes) production in Western Canada will decrease to 42 percent of Canadian production in 2000 compared to an estimated 61 percent in 1990. An additional 14 percent of crude production will be heavy crude upgraded to synthetic light crude. The remaining proportion of Western Canadian crude oil production will be heavy crude, and of that, an increasing amount will be bitumen produced from tar sands.

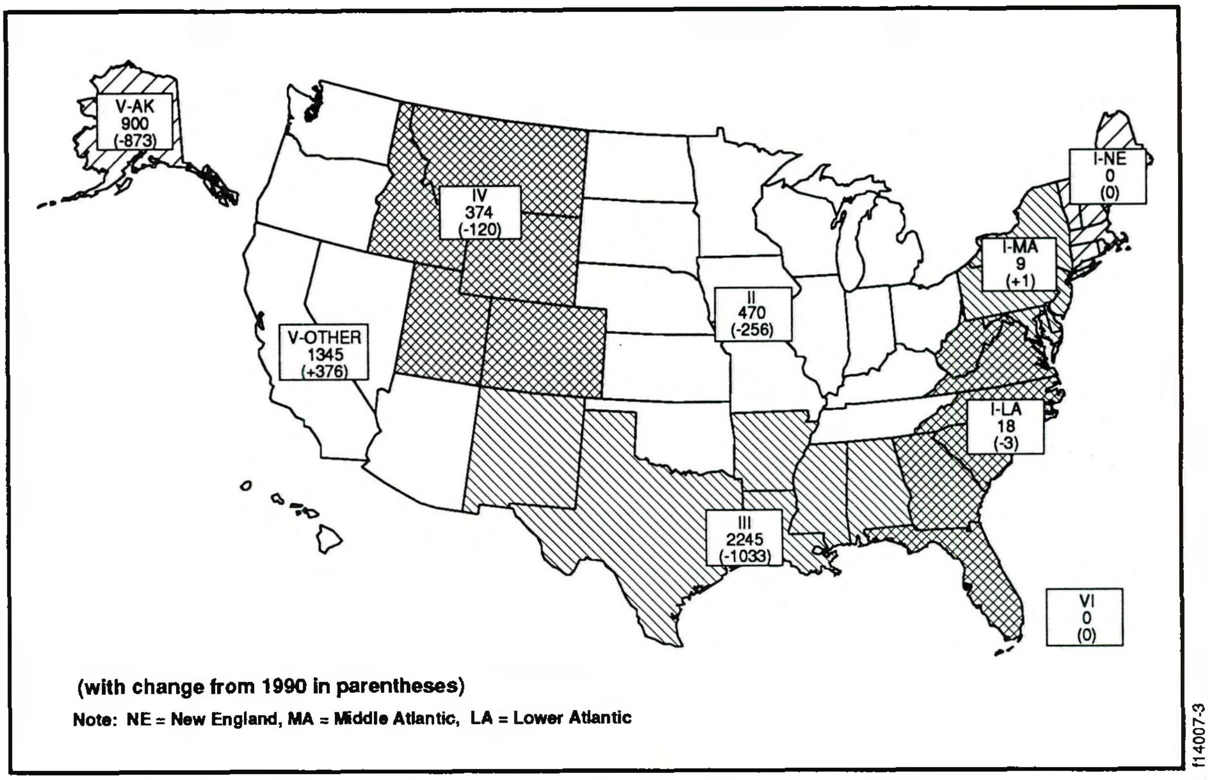


**Figure A-4. UNITED STATES CRUDE OIL PRODUCTION BY PADD AND SUB-PADD - 2000 BASE CASE (MBD)**

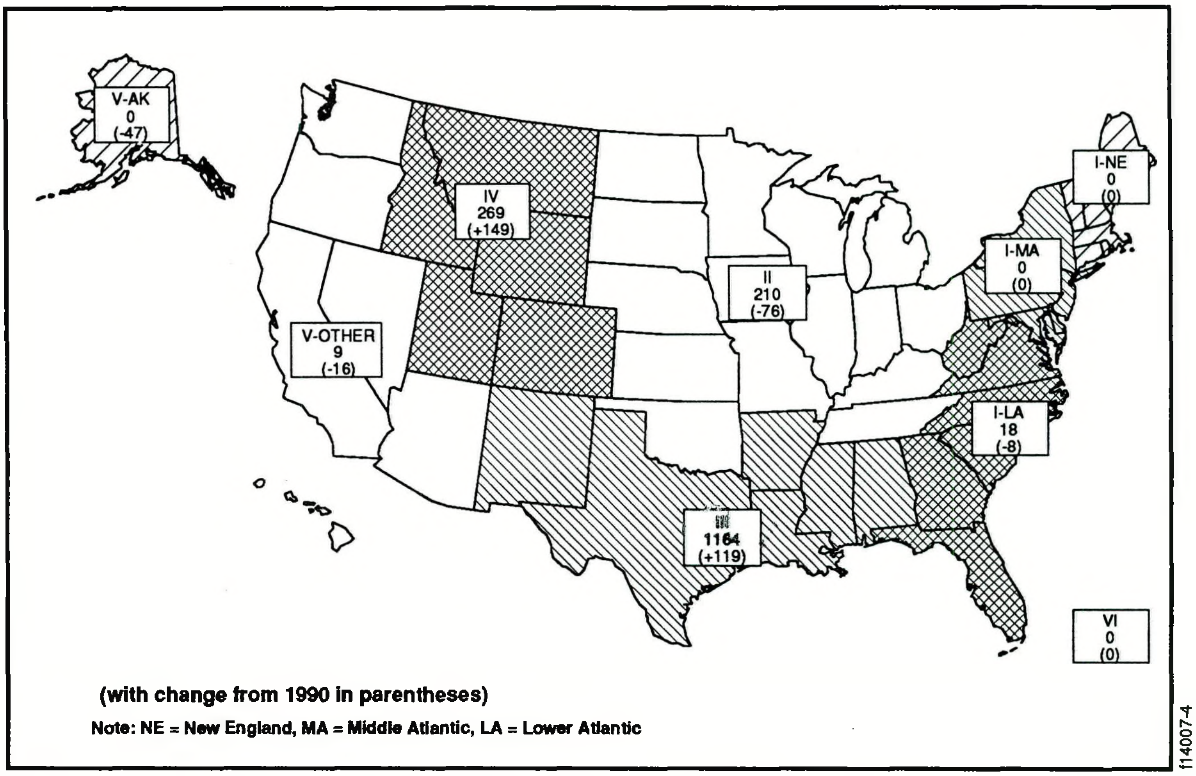


**Figure A-5. UNITED STATES FIELD PRODUCTION OF NGLs BY PADD AND SUB-PADD - 2000 BASE CASE (MBD)**

**TABLE A-2**
**Canadian Crude Oil Production Estimates (MBD)**

| Crude Oil Supply | 1990** | 2000 | Change |
|---|---|---|---|
| Conventional Light* | 996 | 859 | (137) |
| Heavy | 305 | 257 | (48) |
| Synthetic | 206 | 298 | 92 |
| Bitumen | 137 | 305 | 168 |
| Offshore | 0 | 350 | 350 |
| Total | 1,644 | 2,069 | 425 |

* Includes Pentanes
** Estimates provided by the NEB, Canada

**Regional Product Imports**

According to EIA, petroleum product imports to PADDs I through V are projected to be 2.69 million barrels per day in 2000, with product exports of 710,000 barrels per day in that same year. Figure A-6 shows the estimated product imports on a regional basis. Projected product imports from Canada and the rest of the world are identified separately. Product imports grow rapidly in two regions:

- PADD I - The combination of no refineries in New England, few if any in the Lower Atlantic, and environmental constraints on the expansion of refineries in the Mid-Atlantic results in more product imports.

- PADD V: Product imports increase rapidly into the West Coast due to environmental constraints on refineries, particularly in the Los Angeles area.

**Estimated Refinery Capacity Utilization and Crude Consumption**

Capacity utilization for the U.S. refinery industry in 1990 was about 88% on an operable capacity basis. Capacity utilization is projected to rise during the 1990's due to a lack of significant growth in U.S. refinery capacity. The utilization of crude distillation capacity rises to the assumed maximum of 93 percent only in PADD I. All other regions possess spare crude distillation capacity to varying degrees although PADD II, and to a lesser extent PADD III and V, have very little spare

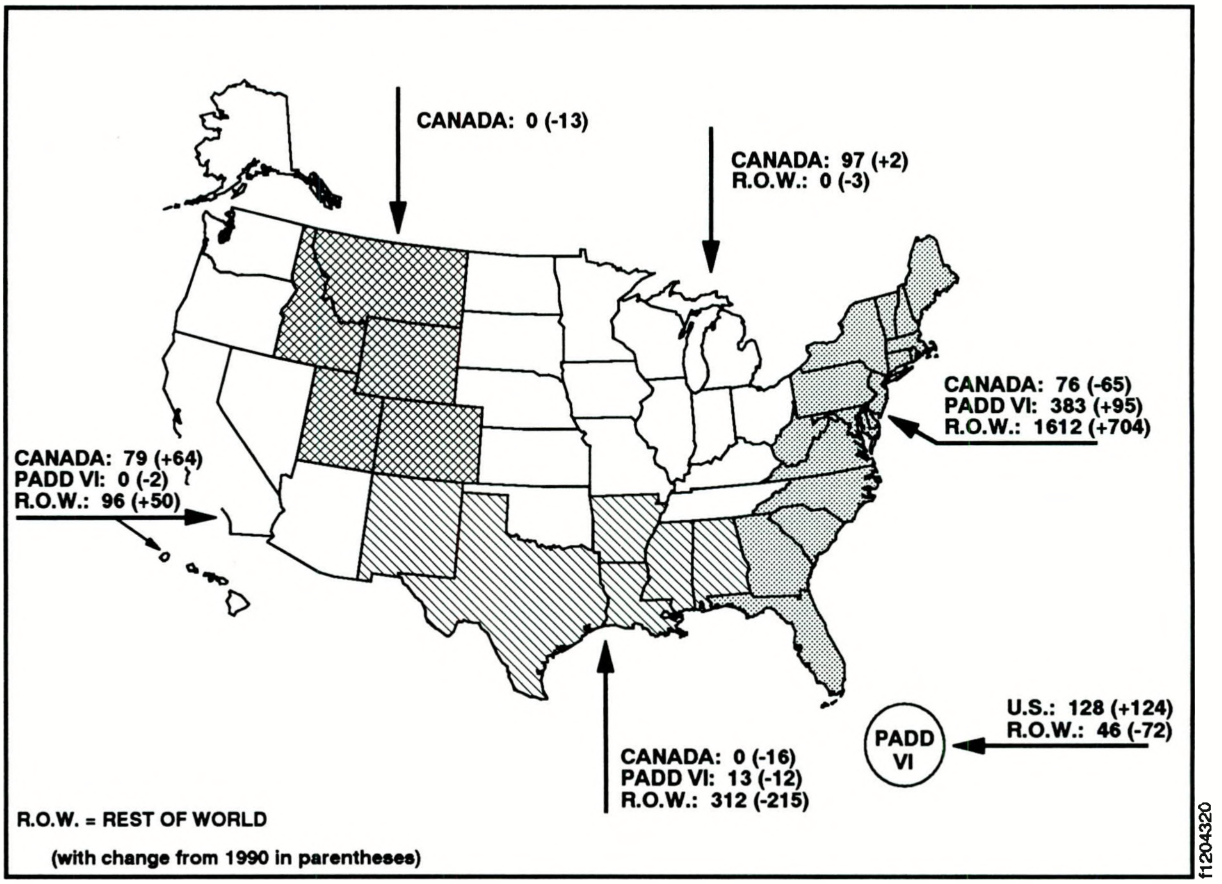


**Figure A-6. PRODUCT IMPORTS BY SOURCE INTO PADDs - 2000 BASE CASE (MBD)**

capacity. PADD V growth is constrained due to environmental concerns, while PADD IV utilization declines due to problems with crude availability. Estimated Year 2000 refinery utilization can be seen in Figure A-7.

Figure A-8 shows projected crude oil consumption by region based on the previously-discussed refinery assumptions and utilization patterns. Crude supplied to domestic refineries rises to 14.5 million barrels per day in 2000. Consumption growth is principally in PADD III (the U.S. Gulf Coast region) as it is here that most of the usable spare capacity currently exists. Refinery consumption of crude oil grows at a lesser rate elsewhere in the country except for PADD IV, where it declines, reflecting the declining availability of local crude oil.

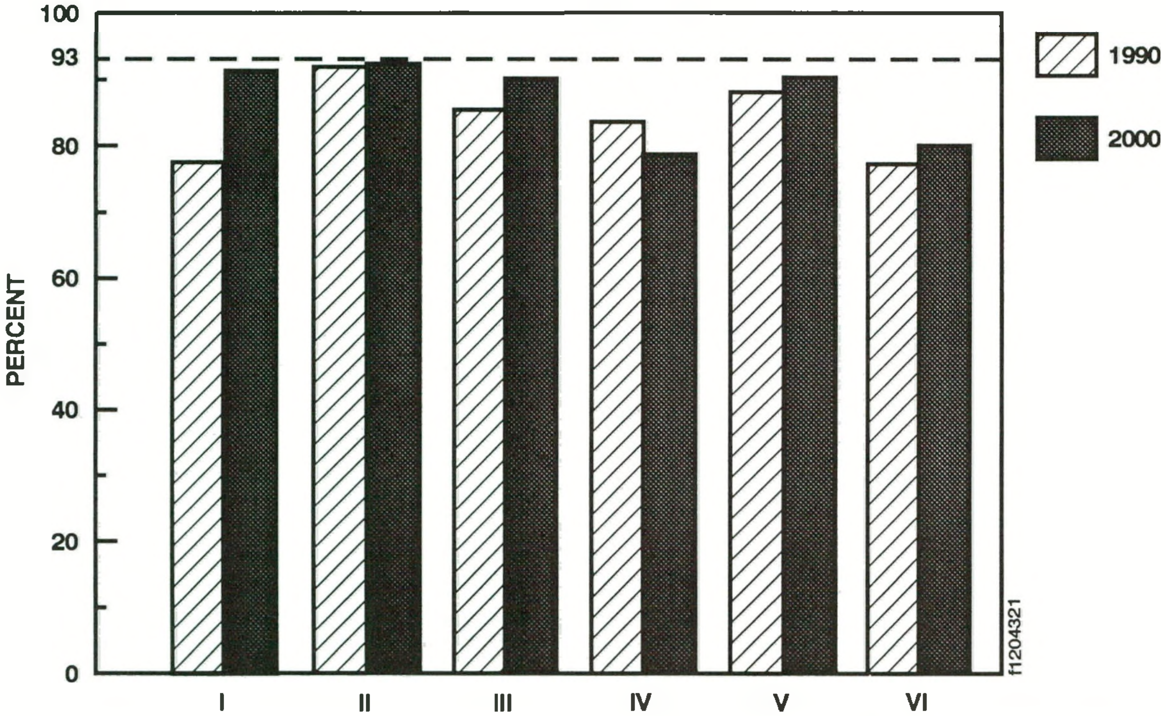


**Figure A-7. REFINERY CRUDE DISTILLATION CAPACITY UTILIZATION BY PADD: 1990 VS 2000 BASE CASE**

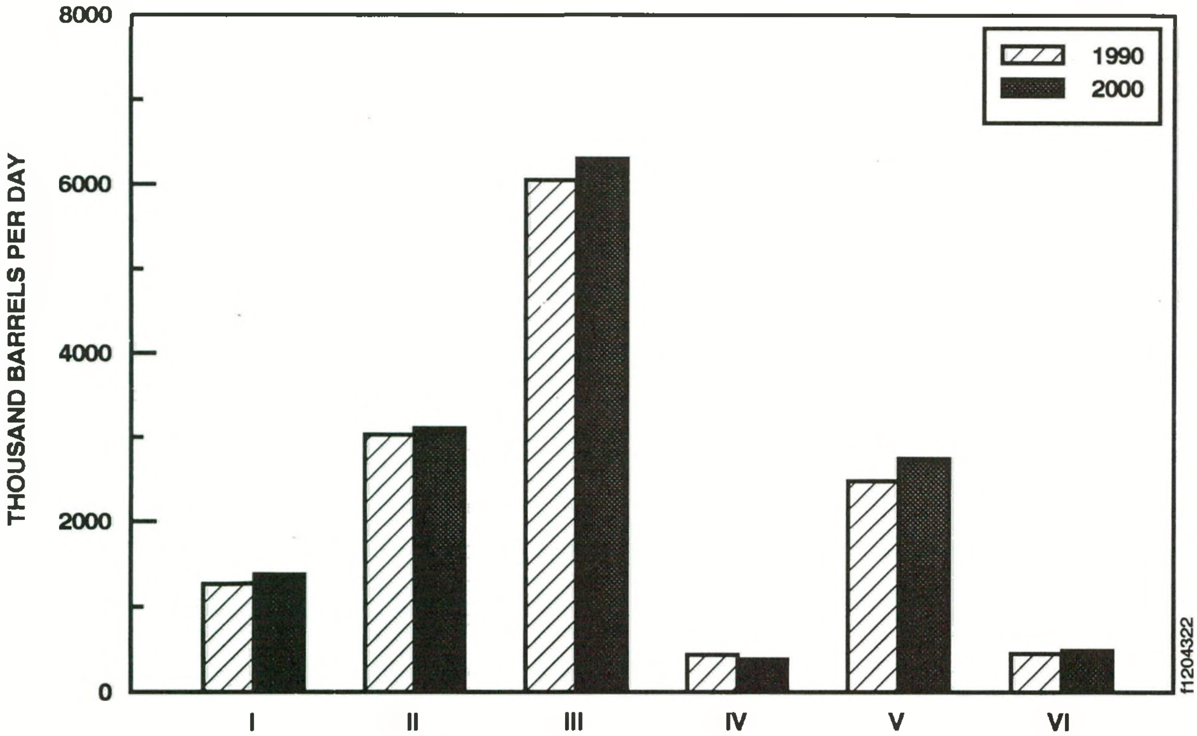


**Figure A-8. U.S. CRUDE OIL CONSUMPTION BY PADD AND SUB-PADD: 1990 VS 2000 BASE CASE**

**Regional Crude Oil Imports**

Total crude oil imports into the U.S. grow steadily out through 2000 to replace the falling supply of domestic crude. Crude continues to be imported from Western Canada but at a lesser rate reflecting Canada's own increasing internal consumption. Overall imports from Canada are 23 percent lower than in 1990. In addition, as Canadian refineries have limited capacity to deal with heavy crude, an ever increasing percentage of imports from Western Canada are heavy crude oil and bitumen. Given that offshore Eastern Canadian production is of crude with a high wax content, it is assumed that much of it will be exported to the more complex refineries in the Mid-Atlantic.

Figure A-9 shows estimated crude oil imports into the PADDs with Canadian imports broken out. Non-Canadian imports into PADDs II and III have more than doubled by 2000. Crude oil imports also increase significantly on the U.S. West Coast due in large part to EIA's projected steep decline of Alaskan crude production.

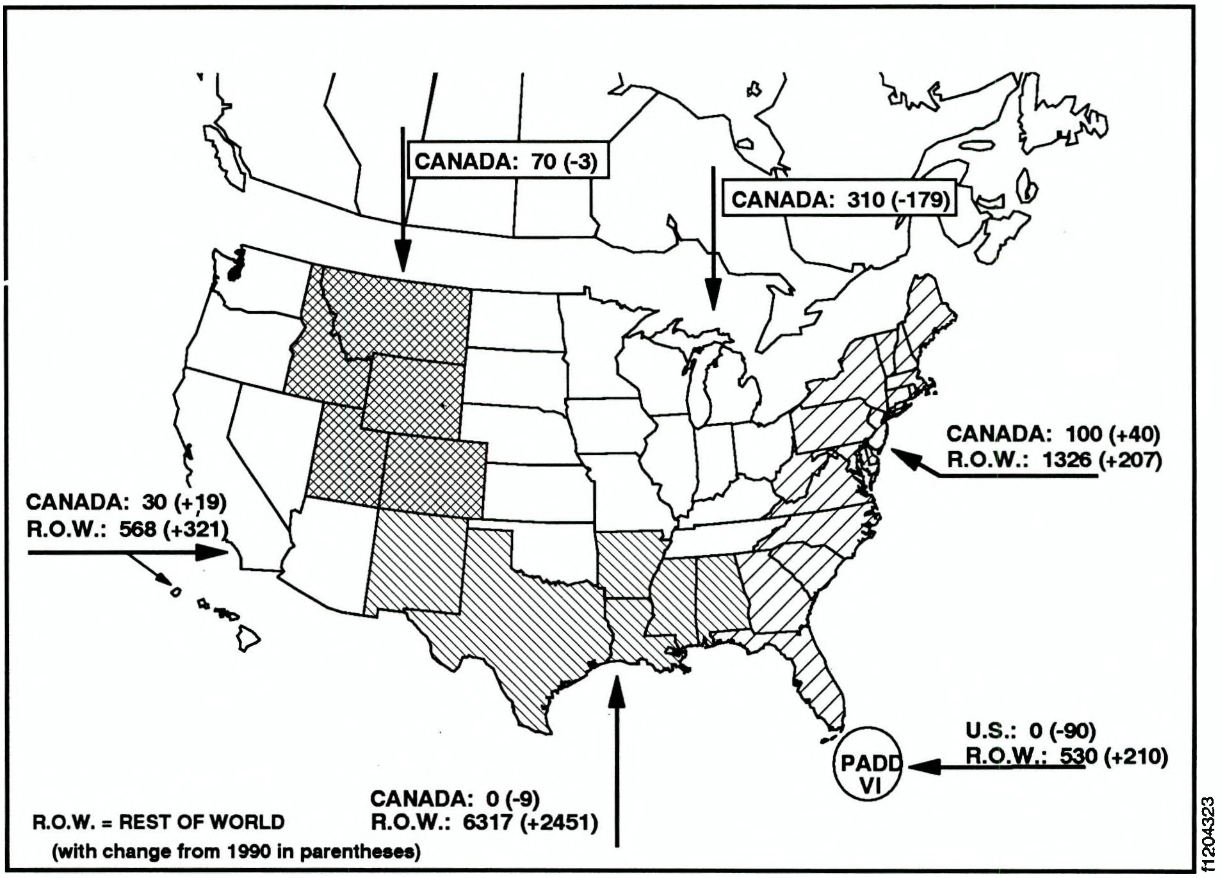


**Figure A-9. UNITED STATES CRUDE OIL IMPORTS - 2000 BASE CASE (MBD)**

Table A-3 presents the projected supply/demand balance for each PADD region in the year 2000, based on NACOD model disaggregation. In total, these PADD balances will sum to the national projections published in EIA's *Annual Energy Outlook 1991.*

**Table A-3**
**Projected Supply/Demand Balance by PADD - 2000 Base Case**
**MBD**

| | PADD | | | | | | VI | Total |
|---|---|---|---|---|---|---|---|---|
| | I | II | III | IV | V | Sub-Total | | |
| **Local Demand** | 5878 | 4271 | 4655 | 621 | 3110 | 18535 | 298 | 18833 |
| | | | | | | | | |
| **Crude Oil Supplies** | | | | | | | | |
| Production | 27 | 470 | 2245 | 374 | 2245 | 5360 | 0 | 5360 |
| Imports[1/] | 1426 | 310 | 6317 | 70 | 598 | 8721 | 530 | 9252 |
| Exports | 0 | -30 | 0 | 0 | -50 | -80 | 0 | -80 |
| Domestic Marine Ship | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Domestic Marine Rec. | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Domestic Pipeline Ship | -84 | -20 | -2341 | -27 | 0 | -2472 | 0 | -2472 |
| Domestic Pipeline Rec | 0 | 2368 | 84 | 20 | 0 | 2472 | 0 | 2472 |
| Other[2/] | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | | | | | | | |
| **Product Supplies** | | | | | | | | |
| Imports | 2072 | 97 | 326 | 0 | 176 | 2670 | 174 | 2844 |
| Exports | -17 | -25 | -504 | 0 | -165 | -710 | -416 | -1126 |
| Domestic Marine Ship | -8 | -61 | -738 | 0 | 0 | -807 | 0 | -807 |
| Domestic Marine Rec | 564 | 238 | 5 | 0 | 0 | 807 | 0 | 807 |
| Domestic Pipeline Ship | -277 | -142 | -2415 | -115 | 0 | -2949 | 0 | -2949 |
| Domestic Pipeline Rec | 2076 | 685 | 61 | 0 | 127 | 2949 | 0 | 2949 |
| Other[3/] | 99 | 381 | 1615 | 300 | 179 | 2574 | 10 | 2584 |
| | | | | | | | | |
| **Total Supplies** | 5878 | 4271 | 4655 | 621 | 3110 | 18535 | 298 | 18833 |
| Crude Oil Runs | 1369 | 3098 | 6305 | 437 | 2793 | 14001 | 530 | 14532 |

1/ Does not include SPR Fill.
2/ Losses and unaccounted for. Stock changes set at 0.
3/ LPG produced and used and refinery gains. Stock changes set at 0.

# *Appendix B*

## *Supplement Analysis for the Programmatic Environmental Impact Statement of the Strategic Petroleum Reserve*

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# *SUPPLEMENT ANALYSIS FOR THE PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT OF THE STRATEGIC PETROLEUM RESERVE*

*Prepared for:*

***UNITED STATES DEPARTMENT OF ENERGY***
***Strategic Petroleum Reserve Office***

*Prepared by:*

***ICF INCORPORATED***
***9300 Lee Highway***
***Fairfax, Virginia 22013-1207***

***March 6, 1991***

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## TABLE OF CONTENTS (CONTINUED)

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# LIST OF EXHIBITS

# LIST OF ACRONYMS

| | |
|---|---|
| **AFFF** | Aqueous Film Forming Foam |
| **bbl** | Barrel |
| **CAA** | Clean Air Act |
| **CERCLA** | Comprehensive Environmental Response, Compensation, and Liability Act |
| **CWA** | Clean Water Act |
| **DOE** | Department of Energy |
| **DWP** | Deepwater Port |
| **DWT** | Dead Weight Tonnage |
| **EA** | Environmental Assessment |
| **EHS** | Extremely Hazardous Substance |
| **EIQ** | Emission Inventory Questionnaire |
| **EIS** | Environmental Impact Statement |
| **EP** | Extraction Procedure |
| **EPA** | Environmental Protection Agency |
| **EPCA** | Energy Policy and Conservation Act |
| **EPCRA** | Emergency Planning and Community Right-to-Know Act |
| **ESR** | Early Storage Reserve |
| **FEA** | Federal Energy Administration |
| **FONSI** | Finding of No Significant Impact |
| **fps** | feet per second |
| **FR** | Federal Register |
| **FWPCA** | Federal Water Pollution Control Act |
| **HSWA** | Hazardous and Solid Waste Amendments |
| **LEPC** | Local Emergency Planning Committee |
| **LOOP** | Louisiana Offshore Oil Port |
| **MARPOL** | International Convention for the Prevention of Pollution From Ships |
| **MMBD** | Million Barrels per Day |

| | |
|---|---|
| **MMB** | Million Barrels |
| **MSDS** | Material Safety Data Sheets |
| **NAAQS** | National Ambient Air Quality Standards |
| **NCP** | National Oil and Hazardous Substances Pollution Contingency Plan |
| **NEPA** | National Environmental Policy Act |
| **NMFS** | National Marine Fisheries Service |
| **NOAA** | National Oceanic and Atmospheric Administration |
| **NPDES** | National Pollutant Discharge Elimination System |
| **NRC** | National Response Center |
| **OPA** | Oil Pollution Act |
| **PEIS** | Programmatic Environmental Impact Statement |
| **PCB** | Polychlorinated Biphenyl |
| **ppm** | parts per million |
| **ppt** | parts per trillion |
| **RCRA** | Resource Conservation and Recovery Act |
| **ROD** | Record of Decision |
| **RPR** | Regional Petroleum Reserve |
| **RQ** | Reportable Quantity |
| **SA** | Supplement Analysis |
| **SARA** | Superfund Amendments and Reauthorization Act |
| **SDWA** | Safe Drinking Water Act |
| **SERC** | State Emergency Response Commission |
| **SPR** | Strategic Petroleum Reserve |
| **TCLP** | Toxicity Characteristic Leaching Procedure |
| **TPQ** | Threshold Planning Quantity |
| **TSCA** | Toxic Substances Control Act |
| **UIC** | Underground Injection Control |
| **UST** | Underground Storage Tank |

**VLCC** Very Large Crude Carrier
**VOCs** Volatile Organic Compounds

**WQA** Water Quality Act

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# 1.0 INTRODUCTION

## 1.1 Purpose

The purpose of this document is to perform a Supplement Analysis (SA) to determine whether it is necessary and prudent, as outlined in the Department of Energy's (DOE) National Environmental Policy Act (NEPA) Compliance Guidelines[1/] and the proposed DOE rule for implementing NEPA [2/], to supplement the 1976 Programmatic Environmental Impact Statement (PEIS) and its 1979 Supplement that address the establishment of a Strategic Petroleum Reserve (SPR) at a 500-million-barrel (500-MMB) level and further expansion to a storage level of one billion barrels (1,000 MMB).

This SA provides a detailed review of the PEIS and Supplement, hereafter referred to simply as the PEIS, and the original conclusions regarding environmental impacts and mitigation measures in the light of subsequent environmental analyses and assessments regarding the operational history of the SPR program, changes in technology or program approach, and regulatory changes that could affect conclusions about potential environmental impacts.

## 1.2 Background

An SA is a formal NEPA document prepared when it is unclear whether or not an EIS supplement is required. It describes any changes in a proposed action that are relevant to environmental concerns, or any significant new circumstances and information relevant to environmental concerns and bearing on the proposed action and its impacts. An SA should contain enough information to determine whether an existing EIS should be supplemented, a new EIS should be prepared, an existing Record of Decision (ROD) should be revised, or no further NEPA documentation is required.

The legislative authority for the establishment of an SPR (with a storage capacity of up to 1,000 MMB) of petroleum was provided by the Energy Policy and Conservation Act (EPCA) of 1975. Since NEPA requires that all Federal agencies prepare detailed environmental impact statements for major Federal actions that could significantly affect the human environment, a PEIS was prepared in 1976 to provide consideration of overall program efforts and alternatives and potential cumulative impacts for a 500-MMB reserve at the national and regional level rather than site-specific level. The authorization to increase the SPR to 1,000 MMB triggered a Supplement to the PEIS in 1979 to

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1/ 52 FR 47662, December 15, 1987.

2/ 55 FR 46444, November 2, 1990.

address this planned expansion at the programmatic level. Subsequently, site-specific EISs were prepared for proposed SPR storage sites which identified and addressed impacts at the local level.

The SPR has over ten years of operating history that can be reviewed and analyzed in terms of actual environmental impacts that can then be compared with those originally projected in the PEIS and Supplement. Further, many dramatic regulatory changes concerning multi-media environmental issues have occurred in the intervening period since 1979. Thus, the DOE determined that it was appropriate to evaluate whether the conclusions made concerning the environmental impacts of the SPR Program in the PEIS remain valid or whether a Supplement or an entirely new PEIS is indicated.

### 1.3 Scope and Organization of Document

This Supplement Analysis details the analytical review and comparison of the PEIS and Supplement with existing environmental data from operational history of the SPR storage sites and also addresses the changed regulatory environment. This document is organized into the following chapters:

**1.0 Introduction**

**2.0 Overview of Major Findings**

**3.0 Comparison of Proposed Action with the Action Considered in the PEIS**

**4.0 Analysis and Update of Applicable Regulations**

**5.0 Re-examination of Environmental Impacts**

Chapter 2.0 presents an overview of the major findings of the analysis and provides a summary of the more detailed analyses found in chapters 3.0, 4.0, and 5.0. There are also technical appendices to the document concerning the feasibility of the inground tank alternative, water quality, and updated threatened and endangered species listings for Texas and Louisiana.

# 2.0 OVERVIEW OF MAJOR FINDINGS

This chapter provides a brief overview of the major findings of the SA on actions covered and not covered by the PEIS, changes in alternatives addressed by these studies, changes caused by technology and regulations, and a recommendation regarding the need for a supplement to the PEIS. The PEIS, as referred to in all subsequent chapters of the SA, is the 1976 Final EIS and its 1979 Supplement.

## 2.1 Applicability of the PEIS to the Proposed Action

This section will provide an overview of the applicability of the PEIS to a proposal to expand the SPR to 1,000 MMB, including any changes in alternatives that have occurred since the original programmatic NEPA documentation was prepared.

### 2.1.1 Overview of Action Covered in the PEIS

The potential programmatic level environmental impacts of the SPR program were investigated and results published in the *Final Environmental Impact Statement, Vols. I and II, Strategic Petroleum Reserve, FES 76-2, December, 1976* and its Supplement in 1979. The PEIS examined the environmental impacts of creating a crude oil petroleum reserve under a schedule to store at least 150 MMB by December 1978, 500 MMB by December 1982, and an eventual expansion to 1,000 MMB.

The PEIS examined the environmental and socioeconomic impacts of storing crude oil in conventional mines, steel tanks, surplus oil tankers, and solution-mined cavities in salt domes, and studied a wide range of environmental issues that included geology, hydrology, water quality, meteorology, climatology, air quality, noise, history, archaeology, land use, demography, and economics. Prototype "worst-case" scenarios for facilities and operations provided a basis for determining potential program impacts and resource requirements. In addition to the environmental impacts associated with a large storage reserve, the PEIS examined several alternative storage methods for an SPR program designed to store crude oil using storage capacity, transport and distribution network accessibility, technical feasibility, site acquisition requirements, and cost as the major selection criteria. Based on the selection criteria, the salt dome storage option was chosen as the preferable alternative, yet the PEIS stated that storage in conventional mines and/or above-ground tankage remained valid though less desirable alternatives for future expansion activities.

DOE initiated a similar environmental review process for candidate storage and expansion sites when the SPR Plan Amendment #2 authorized increasing the reserve from 500 MMB to

1,000 MMB in 1978. A supplement to the PEIS was prepared in 1979 to address environmental parameters affected by the proposed reserve expansion. In particular, the Supplement examined the environmental impacts of proposed inland salt dome areas (using brine disposal by deepwell injection) in the Gulf Coast region using a new model developed by DOE, as well as economic tradeoffs created by inland dome storage. Air emissions data for above-ground tanks also reflected the more standard use of floating roof tanks (which was not documented in the PEIS) and updated emission factor data.

### 2.1.2 Proposed Action Not Covered by the PEIS

The PEIS covered all programmatic and technical areas to develop the reserve to the 1,000-MMB storage level and to implement the SPR's comprehensive strategy to protect the environment. To date, plans have been authorized for implementing a 750-MMB Reserve. No decisions have been made regarding implementation of the final 250 MMB of a 1,000-MMB Reserve. The preferred configuration for the proposed expansion would be 250 MMB of crude oil storage in the Gulf Coast region due to its low development and operating cost. The 1989 Report to Congress[3/] recommended a new 150-MMB site in the lower Mississippi River area (Capline Complex), and an additional 100-MMB site either on the Gulf Coast or in the vicinity of the major East Coast refining complex. The PEIS considered storage alternatives in both of these locations; however, it did not explicitly consider an inground concrete tank facility as a technology for storage of crude oil at an East Coast location.

### 2.1.3 Change in Alternatives Addressed by the PEIS

As part of the proposed SPR expansion to 1,000 MMB, DOE considered the construction of an inground tank storage facility at an East Coast location with a total capacity of 100 MMB. The PEIS did not address the environmental impacts of an inground storage facility, but some elements of the generic discussion of environmental impacts of other storage alternatives may be broadly applicable to inground tanks. For example, the PEIS analysis of land disturbance problems from construction of above-ground tank farms may apply to inground storage tanks. Technical feasibility, cost, and environmental analyses indicate that the new technological approach of inground concrete tank storage would be extremely costly and would involve such serious technical uncertainties and potential environmental problems as to pose a significant and possibly insurmountable risk to the program. Consequently, DOE has concluded that inground concrete tank storage is not a reasonable alternative at this time.

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3/ *Report to the Congress on Expansion of the Strategic Petroleum Reserve to One Billion Barrels*, DOE/FE-0126, Department of Energy, Office of Strategic Petroleum Reserve, April 1989.

## 2.2 Impacts Analysis

The following sections outline the operating impacts that have been experienced at SPR facilities, regulatory changes, and any changes in technology and methodology since the preparation of the PEIS.

### 2.2.1 History of Operational Impacts

The SPR currently consists of six Gulf Coast underground salt dome storage facilities, a marine terminal facility, and an administrative facility. Currently, the facilities store about 580 MMB of crude oil.[4/] The SPR program works to protect all environmental media including water, air, and ground from the major impact producing activities of the program. The initial construction activities included storage site construction, marine-related facility construction, and marine operations involving the transport of oil. The environmental impacts of these initial construction activities are generally short-term, but ongoing facility operations can cause more severe long-term impacts due to brine spills, oil spills, hydrocarbon emissions from transfer activities, dredging, and loss of wetlands and ecosystems associated with subsidence in the Gulf Coast region. To date, the major environmental issues at SPR facilities have involved the accidental release of brine or crude oil spills which have had impacts on groundwater and freshwater wetlands. However, a review of brine and crude oil spills from 1982-1989 indicated a general decline in the number of spills[5/], a significant drop in the volumes of accidental releases, and no long-term adverse environmental impacts.[6/]

The following describe the areas of environmental concern and any documented impacts based on the actual operation of the SPR:

- Oil Spill Impacts and Mitigation - In general, the spill incident and exposure data used to estimate the risk of accidental spills during oil transport in the PEIS are still conservative and therefore remain valid. The conclusions regarding potential impacts of oil spills remain relatively accurate in areas such as the importance of weathering of oil in spill cleanups and the gross effects of spills on land and aquatic ecosystems.

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4/ *1989 Annual Environmental Monitoring Report For The Strategic Petroleum Reserve*, Document Number D506-02502-09, U.S. Department of Energy, June 1990, p. x.

5/ *1988 Annual Environmental Monitoring Report For The Strategic Petroleum Reserve*, Document Number D506-02197-09, U.S. Department of Energy, June 1989, pp. 5-6.

6/ *1989 Annual Environmental Monitoring Report For The Strategic Petroleum Reserve*, Document Number D506-02502-09, U.S. Department of Energy, June 1990, pp. 4-7.

- Water Quality Impacts - An extensive review and analysis showed that the SPR has effective site-specific water quality monitoring programs and permits for brine discharges to the Gulf, stormwater runoff, and sewage treatment plant effluent. In general, the overall water quality record at SPR sites has been excellent. There have been spill events (as anticipated in the Supplement) that have had adverse environmental impacts, the most notable being the 1989 brine spill at the Bryan Mound site. Extensive study of brine disposal into the Gulf has demonstrated that the adverse ecological impacts predicted in the PEIS have not taken place. Although the PEIS model was recognized as having technical limitations and was updated in later site-specific EISs, the overall conclusions of the PEIS regarding the potential impacts of brine disposal into the Gulf were conservative (e.g., overestimated impacts) and, therefore, remain valid.

- Air Quality Impacts: The PEIS focused on evaporative hydrocarbon emissions from transport and transfer operations. The estimated annual emissions for tanker loading and unloading at a typical salt dome as well as from surge and storage tanks, pump seals, and pipeline valves appear to be conservative compared to more recent estimates based on actual experience at the St. James terminal.

- Ecological Impacts (including wetlands): Since there have been no major changes in SPR construction methods, ecological impacts from construction, as well as from waste disposal, dredging operations, excavation, and devegetation are expected to be comparable to those projected in the PEIS. The potential impacts on wetlands are also still relevant, although the degree of damage and extent of recovery at specific sites appear to be more variable than first estimated.

- Geological Impacts: Potential geological impacts from the SPR program identified in the PEIS included halokinesis or cavern "creep" (i.e., the tendency of caverns to close as a consequence of the plastic flow of salt under heat and pressure), subsidence (i.e., subsidence of the surface resulting from cavern contraction), and seismic stability (i.e., local likelihood of earthquakes). The development and filling of salt domes in the Gulf region has progressed much as projected in the PEIS and the analysis of potential impacts conducted at that time is still judged to be sufficient and valid.

### 2.2.2 Regulatory Changes

Since the PEIS was prepared, environmental regulations have become increasingly stringent and have expanded substantially in scope. Specific aspects of SPR operations that are subject to increasingly strict regulation under the Resource Conservation and Recovery Act (RCRA) include standards for underground storage tanks used for on-site storage (e.g., gasoline tanks), and disposal restrictions for wastes generated on-site by operations (e.g., spent solvents). NPDES permits for such discharges as brine to the Gulf, stormwater runoff, and sewage treatment plant effluent are effective regulatory tools for limiting the discharge of any pollutants that could have adverse environmental consequences. Since 1979, regulations for the NPDES permit program, including stormwater discharge permits, have become more comprehensive. NPDES regulating parties (i.e., the States) have been given more authority to mitigate effects of future potential problems through revision of the regulations.

A significant regulatory development affecting future oil spills will result from the landmark Oil Pollution Act of 1990 (OPA). The new law has several provisions directed towards preventing oil spills from vessels, including tanker navigation safety studies, provisions on personnel policies, and tug escort requirements. New oil tankers must have double hulls and certain existing tankers must be retrofitted by the year 2015. Other OPA provisions address mitigating the effects of spills that do occur. Coast Guard regulations governing operational discharges from vessels have also been strengthened. Thus, it is likely that more stringent regulations will contribute to a reduction in both frequency of oil spills and in related environmental impacts, compared to those estimated in the PEIS.

It is likely that additional legislative and regulatory initiatives will result in regulations that provide even more mitigation of impacts. For example, under the Clean Air Act Amendments of 1990, standards are required for the maximum concentration of VOCs (volatile organic compounds) that can be released during tanker loading and unloading; there are also likely to be more restrictive requirements at the State level for hydrocarbon emissions related to tanker loading and unloading activities. In addition, Congressional initiatives providing comprehensive wetland legislation and reauthorizing the RCRA program, if passed, would likely result in regulations that place more stringent requirements on the operations of the SPR.

At this time, the existing Gulf Coast SPR storage sites are in compliance with existing regulations.

### 2.2.3 Changes in Technology and Methodology

The concepts assessed in the PEIS were subsequently elaborated, modified, and improved by the development of engineering design criteria, construction practices and operational procedures to minimize environmental impacts from SPR development and fill operations. Changes have been based in consideration of site-specific potential impacts and operating experience. Engineering design criteria modifications for cavern development virtually eliminated the possibility of cavern collapse, and leaching procedures further enhance and protect the stability of the geologic environment. The brine diffuser system used for disposal of brine into the Gulf was redesigned to maximize mixing and dilution of disposed brine. The brine dispersion model originally used in the PEIS was recognized as being less than adequate and was replaced by a new model to provide a more realistic projection of potential impacts of brine disposal on Gulf ecosystems. Differences between concepts assessed in the PEIS and actual implementation have all been addressed in site-specific and other subsequent SPR NEPA documentation; therefore, no supplement to the PEIS is required to address these changes for the expansion of the reserve to 1,000 MMB.

### 2.3 Recommendations of Supplement Analysis

Overall, only minor technical and legislative issues have been identified as changing since the completion of the PEIS. In general, these changes have only further enhanced or strengthened the environmental safety at SPR facilities and represent no compliance problems for the SPR. In addition, DOE has concluded that the inground concrete tank storage alternative is not reasonable. Therefore, the Supplement Analysis concludes that no supplement to the PEIS is required to support the expansion of the SPR to 1,000 MMB.

# 3.0 COMPARISON OF PROPOSED ACTION WITH THE ACTION CONSIDERED IN THE PEIS

## 3.1 Action Covered by the PEIS

The Energy Policy and Conservation Act of 1975 (EPCA), Title I, Part B provided for the creation of a Strategic Petroleum Reserve for the storage of crude oil. Sections 151 and 154 of EPCA give legislative authority for the storage of up to one billion barrels (1,000 MMB) of petroleum products, including crude oil[7/]. These sections also required the storage of at least 150 MMB by December 22, 1978, and storage of 500 MMB (i.e., the volume of oil equivalent to the highest national imports for three consecutive months) by December 1982.

The potential environmental impacts of establishing a program to create a reserve were investigated and the results published in the *Final Environmental Impact Statement, Vols. I and II, Strategic Petroleum Reserve, FES 76-2, December, 1976* and the *Final Supplement to Final Environmental Impact Statement, FEA-FES-76-2, Strategic Petroleum Reserve, Expansion of Reserve, January, 1979.* In accordance with NEPA requirements, the Federal Energy Administration (FEA) (now the Department of Energy) analyzed the environmental impacts associated with a storage reserve of 500 MMB in the 1976 PEIS. In the 1979 Supplement, the environmental impacts associated with increasing the size of the reserve to 1,000 MMB were examined; expansion of the reserve to that size was planned for in Amendment No. 2 to the SPR Plan for the Expansion of the SPR, June 1978.

In addition to storage of crude oil in a centralized reserve, three alternative reserve systems were considered in the PEIS: an Early Storage Reserve (ESR), an Industrial Petroleum Reserve (IPR), and a Regional Petroleum Reserve (RPR). The Supplement explains that the ESR approach was incorporated into the SPR program. However, FEA concluded that an SPR would provide an adequate reserve for national security purposes and would meet the requirements set forth in EPCA, and, therefore, neither an IPR nor an RPR program was required.

In the PEIS, analytic efforts focused on examining several alternative storage methods for an SPR program designed to store crude oil. Three alternative SPR storage systems were identified: solution-mined cavities in salt (i.e., salt domes), conventional mines, and above-ground tankage. Evaluation of these storage options was based on the following criteria:

7/ *Energy Policy and Conservation Act*. Public Law 94-163, December 22, 1975.

- Existing and potential capacity.
- Accessibility to distribution network.
- Technical desirability.
- Extent of environmental impact.
- Feasibility of acquiring sites.
- Costs.

Based on these criteria, the salt domes storage option was chosen as the preferable alternative, yet the PEIS stated that storage in conventional mines and/or above ground tankage remained valid alternatives.

The East and Gulf Coasts were analyzed in great detail to determine the most desirable location for SPR facilities. After examining numerous environmental parameters, the Gulf Coast region was selected as the preferable option; however, the East Coast maintained its status as a viable but less desirable alternative.

Another programmatic decision was the source of oil for storage. The possible sources included:

- Using Naval Petroleum Reserve oil.
- Using Royalty oil.
- Using "old" oil.
- Purchasing oil in the open market.
- Importing oil.

The choice to acquire oil for the SPR was via the open market from either foreign or domestic sources using established Federal procurement procedures.

In summary, the PEIS provides an overview of the broadly based environmental impacts anticipated from construction and operation of an SPR with capacity of 1,000 MMB, including examination of alternatives for technical storage method, geographical location, and source of oil.

### 3.2 Actual SPR Operations and Proposed Action

The following section summarizes the actual SPR operations to-date and the action proposed for the expansion.

#### 3.2.1 Actual Operations Since the PEIS

The current status of the SPR program shows progress towards achieving the stated goals. The DOE has acquired and developed six underground crude oil storage facilities in salt domes along the Gulf coasts of Texas and Louisiana, and has constructed and operated a marine terminal on the Mississippi River. These six sites are Bayou Choctaw, Big Hill, Bryan Mound, Sulphur Mines, West Hackberry, and Weeks Island and the marine terminal is the Saint James Terminal. The six SPR facilities had a total crude inventory of approximately 580 MMB as of December 1989. All major surface construction at the six SPR facilities is completed, and cavern development is in progress to achieve a storage capacity of 750 MMB.

The current and planned capacities, as well as the current site crude oil inventory, are presented in Exhibit 3-1. The storage capacity development is complete at four storage sites, while capacity development is proceeding at Bayou Choctaw and Big Hill. Current plans provide for the decommissioning of Sulphur Mines, with replacement capacity to be developed by the on-going enlargement of the caverns at Bayou Choctaw and Big Hill.

**Exhibit 3-1: Storage Capacity and Crude Inventory for SPR Facilities (as of December 31, 1989)**

| Storage Facility | Current Storage Capacity | Planned Storage Capacity | Current Site Crude Inventory |
|---|---|---|---|
| Bryan Mound | 226 | 226 | 220.4 |
| West Hackberry | 219 | 219 | 205.8 |
| Weeks Island | 73 | 73 | *72.6 |
| Sulphur Mines | 26 | ** | *25 |
| Bayou Choctaw | 56 | 72 | 52.4 |
| Big Hill | 0 | 160 | .6 |
| **TOTAL** | 600 | 750 | ***576.8 |

* Site on operational standby.
** Site scheduled for decommissioning.
*** Total does not include crude oil in pipelines.

In addition to the PEIS, NEPA requirements for the SPR have been fulfilled by a series of site-specific EISs. Sites were grouped by geographic location and three site-specific EISs were completed by November 1978. The three geographical groups are:

- The Capline Group, located in eastern Louisiana and serviced by the St. James Terminal;

- The Texoma Group, located in western Louisiana and eastern Texas and serviced by the Sun Terminal; and

- The Seaway Group, located in Texas and serviced by Phillips and ARCO Terminals.

These site-specific EISs examined the environmental impacts associated with the construction and operation of the six selected sites, assuming a combined capacity of 538 MMB (slightly above the 500-MMB storage goal for December 1982). A Phase III supplement to the original site-specific EISs evaluated the environmental impacts of increasing the storage capacity to 750 MMB. An Environmental Assessment (EA) evaluated the impacts of closing the Sulphur Mines storage facility and increasing the capacity of the Big Hill facility. This EA was released with a finding of no significant impact (FONSI).

One of the major components that DOE has implemented in their environmental review and planning process is the Environmental Action Report (EAR) or Environmental Plan. The plan translates environmental impacts identified in an EIS into site development and operational requirements. Its purpose is to guide the examination and resolution of site-specific environmental problems and to implement DOE's policy of environmental protection and impact mitigation. The requirements have included modification of design criteria, construction practices and operational procedures to minimize environmental impacts. The EARs have also identified procedures for responding to accidents and natural disasters, and procedures to reduce oil spillage and facilitate cleanup operations.

An equally important function of the EAR is to establish a system of environmental monitoring for those occurrences which could result in very damaging impacts (e.g., accidental spills, pipeline accidents, cavity collapse, and storage tank settling). The monitoring system identifies the environmental parameters to be overseen, location of monitoring points, frequency of data collection, and all required documentation. Annual monitoring reports for the SPR include updates on air quality, surface water quality, ground water, environmental permits, and any other significant environmental activity for each of the facility sites. Particular aspects of the operating experience of the SPR are discussed in Chapter 5.0 of this report, and the impacts from actual operating experience are compared to those predicted in the PEIS.

In addition to being consistent with NEPA, DOE must also comply with the regulatory and permit requirements of other Federal agencies, in particular the U.S. Environmental Protection Agency (EPA), U.S. Army Corps of Engineers, the U.S. Coast Guard, State and local agencies, and other safety, historic, and wildlife preservation agencies. The SPR is primarily regulated under the jurisdiction of the Clean Water Act, EPA's National Pollutant Discharge Elimination System (NPDES) program, and the Clean Air Act. There is significant permit activity because the SPR sites contain a total of 73 wastewater and stormwater discharge monitoring stations.[8] Permits currently in effect (as of June 1990) include seven NPDES permits, six air quality permits, 45 Corps of Engineer wetland permits, and over 100 pit, underground injection, and mining permits.[9] In addition, a number of corresponding state and local permits are in effect. All operating permits are current. The SPR is under no regulatory compliance orders or Notices of Violation, nor are there any lawsuits involving environmental issues at the SPR.

The SPR also operates under the requirements of Part 105 of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA). Site activities also are subject to the Resource Conservation and Recovery Act (RCRA), but the sites are considered Conditionally Exempt Small Quantity Generators and do not require RCRA permits. A more comprehensive discussion of regulatory requirements is contained in Chapter 4.0 of this report. This discussion focuses on the changes in regulations since the PEIS.

### 3.2.2 Description of Proposed Action

The PEIS evaluated the environmental impacts of a 1,000-MMB SPR system; at this time DOE is considering implementing the expansion of the reserve from the current planned storage capacity of 750 MMB to the final storage capacity authorized under EPCA of 1,000 MMB. Storage alternatives under consideration for the final 250 MMB of needed storage capacity include:

- Expansion of capacity at existing salt dome sites.

- Construction of new salt dome sites.

The preferred expansion configuration is 250 MMB of additional storage in the Gulf Coast, involving construction of a 150-MMB Capline storage site plus a 100-MMB Seaway storage site. DOE has identified several salt domes in each geographical group as candidates for SPR expansion; the determinants of the final configuration of the expansion will include development cost, storage technology feasibility, land requirements and availability, and environmental impacts of the proposed alternatives. Site-specific EISs have not yet been completed for these candidate sites.

An option eliminated from consideration would have included construction of a 100-MMB inground concrete tank storage facility on the East Coast. This option was determined to be technically feasible although very costly and to involve serious environmental questions (e.g., siting, construction, public opposition) which would pose significant risks to the program. Conceptual

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8/ *1989 Annual Environmental Monitoring Report For The Strategic Petroleum Reserve*, Document Number D506-02502-09, U.S. Department of Energy, June 1990, p. x.

9/ Ibid., p. xii.

engineering for this facility has been developed and DOE has conducted cost studies and an evaluation of the potential environmental concerns such a facility might face. Significant delays and cost growth were encountered in the early stages of Gulf Coast SPR development due to regulatory requirements in the permitting process. Contributing factors included lack of familiarity of State agencies with SPR systems, activities, and procedures, and public suspicion of large-scale development employing technology that, at the time, was unproven for crude oil storage in this country.

For similar reasons, there is a significant risk to the program of major delays and cost growth associated with implementing an untried concept, large-scale inground concrete storage tanks, in a region, the East Coast, that has no experience with the SPR program. Further, because the East Coast lacks necessary infrastructure (i.e., pipeline and marine terminal) for crude oil transport and distribution, siting and construction of these facilities would involve serious environmental issues. Further details regarding the inground tank alternative and associated concerns are found in Attachment I. Based on the evaluation of technical feasibility, cost, and environmental considerations, DOE has concluded that inground concrete tank storage is not a reasonable alternative at this time and an East Coast facility will not be considered further for expansion of the SPR to the 1,000 MMB.

# 4.0 ANALYSIS AND UPDATE OF APPLICABLE REGULATIONS

This chapter provides an analysis and update of applicable water, air, waste management, sensitive environment, and other legislation and regulations that have been promulgated since the PEIS was completed. Each section discusses major Federal and state legislation and associated regulations passed since 1979 and their potential impacts on the SPR program. Overall, these regulations have served to strengthen the SPR's comprehensive environmental protection strategy and excellent record of maintaining environmental safety. The PEIS generally described the regulatory framework at the time and concluded that these regulations served as mitigating factors for potential adverse environmental impacts. This approach remains valid and the existence of new regulations does not require a Supplement to the PEIS.

## 4.1 Water-related Regulations

Any potential adverse impacts on water quality at SPR sites are mitigated by several regulations. The Federal Water Pollution Control Act Amendments of 1972 (FWPCA) established the basis for controlling toxic discharges. In 1977, the Clean Water Act (CWA) updated the FWPCA and provided for more extensive control of pollutant discharges. The Water Quality Act (WQA) of 1987 further expanded the discharge regulations that had been established. As well, the Safe Drinking Water Act (SDWA) of 1974 established criteria for underground injection control (UIC). The Oil Pollution Act (OPA) of 1990 represents the most recent development in the protection of water quality. In addition to the OPA, there are provisions of the CWA that cover discharges of oil. Since the PEIS was written, there have been numerous statutory and regulatory changes. Though many of these modifications have been administrative, in general, revisions have served to strengthen state and Federal controls over water quality.

**Clean Water Act (CWA).** One program that significantly affects the SPR program is the CWA's National Pollutant Discharge Elimination System (NPDES). The NPDES permit program is the CWA's major vehicle to attain its goals of controlling the types of substances and their concentrations allowed in toxic pollutant discharges. At SPR sites, NPDES permits regulate brine discharge into the Gulf, stormwater runoff, and sewage treatment plant discharge. As a provision of these NPDES permits, SPR sites are required to test and report data for a total of seven conventional and nonconventional pollutants. Sites also are required to test for other priority pollutants based on the indicated likelihood that the pollutant will be present in the discharge from a site. The NPDES program has developed into an effective tool for safeguarding the environment from pollutants that might exist in SPR discharges.

Accidental oil spills, as well as certain operational discharges, are subject to the Environmental Protection Agency's (EPA) oil discharge regulations. Amendments to the regulations that incorporate the 1977, 1978, and 1980 amendments to section 311 of the CWA extend the geographical scope of the rule from the contiguous zone seaward to approximately 200 miles from shore, require reporting of discharges of quantities of oil that "may be harmful" to the public health and welfare, and exempt operational discharges permitted under the International Convention for the Prevention of Pollution from Ships (MARPOL 73/78).[10/] The regulations reaffirmed the "sheen test" as the oil discharge reporting trigger, rejecting an industry suggestion that it be replaced by a less stringent volumetric trigger.

**Water Quality Act.** As previously mentioned, permitting of stormwater discharge is one element of the NPDES program. Additions to the regulation of stormwater discharge represent one of the most significant regulatory developments affecting water quality in the last ten years. The WQA of 1987 made changes in the stormwater discharge permit applicability. Such revisions include giving authority to the EPA Administrator or State Director to designate the need for a stormwater discharge permit on a case-by-case basis. Recently, extensive revisions were made to the stormwater discharge permit requirements.[11/] The rule phases in new permit application requirements, deadlines, and compliance standards. These revisions give permitting authorities the option of establishing permit limitations for toxic pollutants found in stormwater discharges. Although SPR facilities currently have stormwater discharge permits with limitations for conventional pollutants, in the unlikely event that toxic pollutants were detected in SPR stormwater discharges, they could now be controlled.

**Safe Drinking Water Act.** Both Texas and Louisiana, states in which SPR sites are located, were given primacy over the SDWA's UIC programs in 1982. These state-administered programs tend to be more stringent than those under Federal authority. Generally, UIC wells at SPR sites dispose of brine from salt dome excavation and are classified as Class II hydrocarbon storage wells. Compared to Federally-run programs, Texas and Louisiana have the same general requirements for inspections and permitting of Class II wells. However, the testing procedures to establish well integrity used by the States are more sophisticated than those required by Federal programs. As well, the States require the SPR sites to provide more detailed geologic information on the salt domes permit applications than the Federal program. Texas also requires a notice of publication to appear for three days, while the Federal program only requires one day. In short, state programs are as demanding as Federally-administered programs, and in some cases, state requirements are much more stringent. The state UIC programs in Louisiana and Texas have remained essentially unchanged since their creation in 1982.

**Oil Pollution Act of 1990.** Significant regulatory developments affecting future oil spills will result from the landmark OPA, signed into law on August 18, 1990. The new law contains several

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10/ 52 FR 10712, April 2, 1987.

11/ 55 FR 48062, November 16, 1990.

provisions directed toward preventing accidental oil spills from vessels. These include new authorities and studies regarding tanker navigation safety, provisions on vessel personnel policies, and tug escort requirements. New oil tankers are required to have double hulls, and certain existing tankers without double hulls must be retrofitted or retired from service by the year 2015. Other OPA provisions address mitigating the effects of spills that do occur. For example, the law increases the role of the Federal government in oil spill response, requires the formation of Coast Guard district response groups, and requires the preparation of area contingency plans and vessel response plans. Thus, it is likely that the OPA will contribute to a reduction both in the frequency of oil spills and in related environmental impacts, compared to the estimates in the PEIS.

**Port and Tanker Safety Act.** The PEIS considered operational discharges of oil, such as those resulting from the disposal of oily bilge waters, tank washings, and ballast waters, in an analysis separate from accidental spill risks. It was noted that U.S. Coast Guard pollution prevention regulations and international conventions would limit the discharge of oily mixtures from tanker operations. The Coast Guard regulations under the Port and Tanker Safety Act have been amended since 1979.[12/] New vessel requirements include the installation and use of approved cargo monitors on board tank vessels of 150 gross tons, and the installation at each discharge point of stop valves actuated by the system's cargo monitor. These valves prevent oily discharges to the sea in concentrations that exceed those allowed by MARPOL 73/78. In an effort to reduce discharges of oil (primarily during deballasting of cargo tanks and tank cleaning) from existing tankships of 20,000 to 40,000 deadweight tons (DWT), the regulations were amended to require the installation of segregated ballast tanks, dedicated clean ballast tanks, or crude oil washing systems. The effect of these more stringent standards on reducing oil pollution will be greatest during the decade from 1990 to 2000 and will gradually be reduced thereafter as the existing vessels affected by these regulations are retired from service. The PEIS concluded that if the Coast Guard regulations are followed, operational discharges will tend to be widely dispersed over the open ocean. The recent amendments to those regulations will further limit such discharges.

A review of the changes in the regulations that govern water quality reveal that most of the modifications have been minor. However, the general trend in these revisions has been to reinforce state and Federal controls over covered facilities. Compared to the controls that were defined in the 1979, authorities now have a greater capacity to protect the quality of our waters.

### 4.2 Air-Related Regulations

In the PEIS, projected hydrocarbon emissions for SPR activities (particularly tanker loading and unloading) were derived. These emission estimates were then used to predict, for worst case conditions, the area around a tanker or terminal in which the National Ambient Air Quality Standards (NAAQS) for hydrocarbons would be violated. Hydrocarbons were initially included in the NAAQS

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12/ 48 FR 45718, October,6, 1983 and 50 FR 11622, March 22, 1985.

because they contribute to the formation of ozone. Subsequently, EPA reviewed the hydrocarbon criteria and concluded that although hydrocarbons in ambient air are major precursors to ozone and other photochemical oxidants, no consistent quantitative relationship exists nationwide between ambient air ozone concentrations and hydrocarbon air quality levels. Thus, the hydrocarbon NAAQS were revoked.[13/] Hydrocarbon emissions from tanker loading and unloading continues to be regulated by states, however. For example, the Louisiana Environmental Control Commission established limits for the St. James terminal based on an Emission Inventory Questionnaire prepared in 1983.

In 1990, significant amendments to the Clean Air Act were enacted for the first time since 1977. Certain provisions on attainment of NAAQS will affect areas proposed for SPR expansion. Specifically, ozone nonattainment areas are divided into classes that have different deadlines and schedules for compliance. The classes also affect required control measures and the definition of "major" air pollution sources. In addition, the Act contains a specific provision that requires EPA to promulgate standards for emission of volatile organic compounds (VOCs) and other air pollutants from tanker loading and unloading. Thus, it is likely that in the future, both emission of VOCs and ambient concentrations of ozone will be reduced more quickly than anticipated prior to enactment of the new law.

### 4.3 Waste Management-related Regulations

Recent waste management legislation does have some limited consequences for the SPR program. Requirements of the Resource Conservation and Recovery Act of 1976 (RCRA) and the Hazardous and Solid Waste Amendments of 1984 (HSWA) are likely to affect SPR sites only in certain circumstances. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980 and Title III of the Superfund Amendments and Reauthorization Act (SARA) of 1986 requirements represent further advances in environmental legislation, however, they also will have only a limited impact on SPR sites. RCRA and CERCLA have limited applicability to the SPR sites both because of the small quantity of hazardous waste generated and because SPR sites as Federal facilities are exempt from certain requirements. Though the impact of these laws on the SPR program is not extensive, the presence of these laws reflects increasing public concern about protection of the environment from hazardous waste.

**Resource Conservation and Recovery Act (RCRA).** Current RCRA regulations govern hazardous waste treatment, storage, disposal, and transportation, non-hazardous waste management, and underground storage tanks (USTs). Under RCRA Subtitle C, facilities must treat, store, and dispose of hazardous waste in accordance with certain administrative and technical requirements. In both Texas and Louisiana, the state has the authority to administer the RCRA hazardous waste program, and both states have incorporated Federal regulations into their own laws. Because the oil

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13/ 48 FR 626, January 5, 1983.

stored at SPR sites is not a waste, RCRA regulations do not affect the storage of crude oil at SPR sites. In addition, wastes associated with the subsurface storage of oil, such as sludges or tank bottoms generated at SPR sites may be exempt from RCRA hazardous waste regulations.[14/]

SPR sites that do generate RCRA hazardous wastes may have to comply with Subtitle C requirements, depending on the quantity of hazardous waste produced. Most SPR sites generate hazardous waste in the form of spent solvents and contaminated rags and equipment. Sites that generate less than 100 kg/month of hazardous waste are exempt from Subtitle C requirements. (In Louisiana, however, they are subject to Chapter 21 of the Louisiana Hazardous Waste Rules, under which they must notify the state in writing that they are claiming small-quantity generator status.) Sites that generate between 100 kg and 1,000 kg per month are exempt only from the administrative requirements of Subtitle C. Currently, all SPR sites that generate hazardous wastes claim the small-quantity generator exemption. If a site does not qualify for this exemption, it will be subject to hazardous waste regulations including permitting requirements, minimum technology requirements for storage tanks, and disposal restrictions. In addition, whenever any quantity of hazardous waste is stored at a facility, the site must meet container labelling and storage requirements. Shipping control tickets (i.e., manifests) are required when the hazardous waste is sent off site.

Non-hazardous solid wastes must be managed in accordance with RCRA Subtitle D requirements. In Texas and Louisiana, the State has established regulations governing the management of these wastes.

RCRA Subtitle I regulates petroleum products and hazardous substances stored in underground tanks. UST regulations include performance standards for new tanks and regulations for leak detection, prevention, closure, financial responsibility, and corrective action at underground tank sites. SPR sites that have USTs must comply with these requirements.

In summary, RCRA regulations are likely to apply to SPR sites only if they begin to generate large quantities of hazardous waste and/or have underground storage tanks. In any cases where RCRA compliance is required, the requirements will contribute to the mitigation of any potential environmental impacts from hazardous waste generation at the site and leaks from underground tanks.

**Comprehensive Environmental Response, Compensation, and Liability Act.** CERCLA's primary purpose is to provide funding and enforcement authority for cleaning up the thousands of abandoned hazardous waste sites throughout the United States and for responding to hazardous substance releases. Through SARA, Congress enacted significant revisions to CERCLA that

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14/ Telephone conversation with EPA Section Chief for Oil and Gas Wastes Dan Derkics, January 15, 1991; see *Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes*, 53 FR 25454, July 6, 1988.

expanded the scope and coverage of the law. Title III of SARA, also known as the Emergency Planning and Community Right-to-Know Act (EPCRA), is a freestanding provision of SARA. The enactment of Title III was prompted by the catastrophic release of methyl isocyanate from a Union Carbide facility in Bhopal, India. The statute is designed to compel state and local governments to develop plans for responding to unanticipated environmental releases of substances identified as hazardous. Title III also requires businesses that use certain substances to notify state and local emergency planning entities of the presence of those substances in their facilities and to report on the inventories and environmental releases of those substances. In addition, the statute requires that such chemical information be made publicly available.

Section 105 of CERCLA requires EPA to promulgate and revise the National Oil and Hazardous Substances Pollution Contingency Plan (NCP) (40 CFR Part 300). In accordance with the provisions of the NCP, Federal facilities, such as SPR storage sites, must comply with CERCLA. Under CERCLA section 103, facilities or vessels must report to the National Response Center (NRC) a release of a reportable quantity (RQ) or more of any several hundred hazardous substances defined in CERCLA section 101(14). The number of hazardous substances (excluding petroleum) at SPR facilities is limited. Under DOE Order 5480.14, the wastes from selected SPR sites were tested and determined not to require reporting under CERCLA[15/]. In addition, field surveys of SPR sites did not reveal the presence of any abandoned hazardous wastes that could result in a reportable release or necessitate a CERCLA response action. Although CERCLA section 101(14) generally exempts petroleum from the section 103 reporting provisions[16/], as discussed above in Section 4.1, Federal agencies are required by the CWA to report discharges of oil from facilities or vessels into U.S. waters to the NRC.[17/]

SARA Title III expands the emergency reporting requirements of CERCLA to include notification to state and local response authorities for releases of CERCLA hazardous substances,

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15/ Under CERCLA section 101(14), a "hazardous substance" is any substance EPA has designated for special consideration under the Clean Air Act (CAA), Clean Water Act (CWA), or Toxic Substances Control Act (TSCA), and any "hazardous waste" under RCRA. SPR wastes were tested using the EP Toxicity test and were determined not to qualify as RCRA hazardous wastes; therefore, they are not reportable under CERCLA. Because the EP Toxicity test has been replaced by the TCLP test (55 FR 11798, March 29, 1990), it may be appropriate to retest SPR wastes.

16/ The petroleum exclusion applies to crude oil, petroleum feedstocks, and refined petroleum products, even if a designated hazardous substance is a constituent of such products, or is normally mixed with or added to them during refining. Hazardous substances that increase in concentration as a result of contamination of the petroleum during use, however, are not considered part of the petroleum and are not excluded from reporting.

17/ For example, a sizable petroleum release into navigable waters that occurred at the West Hackberry SPR site in 1986 was reported to the NRC.

or releases of any one of 360 extremely hazardous substances (EHSs). Although Federal facilities, such as the SPR sites, are exempt from Title III provisions, they are still encouraged to comply with these provisions. SPR facilities generally have elected to participate in Title III efforts and the following Title III activities when applicable:

- Emergency Planning (Sections 301-303).
- Emergency Release Notification (Section 304).
- Hazardous Chemical Reporting (Sections 311-312).

Under the Title III emergency planning provisions, each state has appointed a state emergency response commission (SERC) to coordinate state-wide chemical emergency planning activities. The SERCs established emergency planning districts and coordinated local emergency planning committees (LEPCs). LEPCs are responsible for developing and updating local emergency response plans. As part of the local planning efforts, facilities that use or store one of the 360 EHSs above threshold planning quantities (TPQs) must notify the LEPC of the presence of these chemicals and participate in emergency planning activities. Under section 304, facilities must notify SERCs and LEPCs of releases of EHSs or CERCLA hazardous substances that equal or exceed the designated RQ. Section 311 requires that facilities submit material safety data sheets (MSDSs) for each on-site chemical to the SERC, LEPC, and fire department. Under section 312, facilities must provide annual inventories of these same hazardous chemicals on a Tier One or Tier Two inventory form.

The environmental staff at SPR facilities have determined that their inventories of hazardous chemicals do not meet or exceed the relevant TPQs. However, SPR facilities have provided MSDSs and Tier II chemical inventory forms for each on-site chemical to the appropriate SERC, LEPC, and fire department located near their sites or pipelines. These reports provide a tool for LEPCs to develop and update emergency plans, and for emergency response organizations, such as fire departments, to plan training exercises and response activities for possible chemical emergencies. In addition, SPR facilities notify the LEPC in case of a petroleum release, and have coordinated their contingency planning efforts for petroleum releases with the LEPC and local fire department. In addition, certain states, such as Louisiana, require notification of petroleum releases under state law.

### 4.4 Other Regulations/Programs

#### 4.4.1 Wetlands and Coastal Zone Considerations

Since 1979, Federal and state programs have been instituted to protect wetlands, floodplains, and coastal zone areas. In general, these requirements would result in additional mitigation of impacts that might be caused by SPR facilities, including identification of candidate sites that would not impact these environments.

**Coastal Zone Management.** A major development in the area of coastal management since 1979 has been the completion of state Coastal Zone Management Programs as mandated by the Coastal Zone Management Act of 1972. The goal of these programs is to preserve, protect, develop, and, where possible, to restore or enhance the resources of the Nation's coastal zone. Louisiana's Coastal Zone Management Program, completed in 1980, is administered by the Coastal Management Division within the Louisiana Department of Natural Resources. Through this program, land use within the coastal zone is regulated by a permit system. The process requires an assessment of individual and cumulative impacts from proposed development and other activities on coastal areas and resources, with the final decision on permit approval made by the Secretary of the Department of Natural Resources. A similar program in Texas has not yet been approved. Activities in the Texas coastal area are subject to review by a number of state agencies including the Texas Parks and Wildlife Division and the General Land Office and by the local communities.

**DOE Compliance With Executive Orders Regarding Wetlands and Floodplains.** As described in the PEIS, Executive Order 11988, Floodplain Management, and Executive Order 11990, Protection of Wetlands, require each Federal agency to issue or amend existing procedures and regulations to ensure consideration of flood risks and wetlands protection in decision making. In compliance with these orders, DOE, in 1979, issued regulations designed to minimize impacts to floodplains and wetlands. The regulations are applicable to all DOE activities and require the Department to identify proposed actions in floodplain/wetland areas, provide the opportunity for public review, prepare floodplain/wetlands assessments, and issue statements of findings for actions in floodplains. If DOE finds that no practicable alternatives to locating in the floodplain/wetland are available, the Department is required to design or modify its action in order to protect facilities located in floodplains and to minimize potential harm to the floodplain or wetland.

**Louisiana Coastal Wetlands Conservation, Restoration, and Management Acts.** A major development in the protection of Louisiana's coastal wetlands since 1979 was the enactment, in 1980, of the Louisiana Coastal Wetlands Conservation, Restoration and Management Act requiring the development of a state plan for protecting and restoring coastal wetlands. Developed by the Wetlands and Conservation Authority within the governor's office, the plan is administered by the office of coastal restoration and management within the Louisiana Department of Natural Resources. Under this plan, the administering agency is required to review and modify coastal permits prior to issuance to assure that such activities will not significantly impact coastal wetlands.

**National Flood Insurance Program.** There have been no substantial changes to the National Flood Insurance Program that affect the expansion of the SPR. The proposed site locations will be subject to the provisions of the 1968 National Flood Insurance Act, as amended. The goals of the technical standards in the Act are to:

- Constrict the development of land which is exposed to flood damage, where appropriate.

- Guide the development of proposed construction away from locations that are threatened by flood hazard.

- Assist in reducing damage caused by floods.

- Otherwise improve the long-range land management and use of flood-prone areas.

Any structure within a flood-prone area must either be flood-proofed or flood-protected to meet the technical requirements applicable to the proposed SPR expansion. To be flood-protected, the facility must be isolated from the flood waters by a stable berm or levee embankment that will not readily erode in a flood. Flood-protective berms or levee embankments can affect the watercourse if a flood occurs. In order to minimize these effects, it must also be shown that any encroachment within the floodway does not increase the water surface elevation of the base flood by more than one foot at any point in the immediate vicinity of the facility (based on a 100-year survey of floodplain water levels and boundaries).

In coastal areas with potentially serious flood water levels, new construction or expansion is restricted to the landward side of mean high tide and at a distance sufficient to create a safety buffer consisting of a natural vegetative or contour strip. The use of fill for structural support in these areas is forbidden. In addition, structures must be designed to withstand flooding without substantial hydraulic consequences.

### 4.4.2 Other Sensitive Environments-Related Regulations

There are several changes to the endangered species list in the States of Texas and Louisiana which are presented in Appendices C and D. No legislative or regulatory changes have occurred, and the listing of additional species does not alter the findings of the PEIS.

No species protected under the Marine Mammals Protection Act are likely to be affected by the operation of the SPR.

In addition, there are no areas protected under the Wild and Scenic Rivers Act within the areas bounded by the SPR sites.

### 4.4.3 Other Considerations

**Land Use Patterns.** It is recognized that the population in the Gulf Region has changed since the PEIS. However, because the SPR sites are on land that is still rural, changes in population patterns do not affect these sites.

**Noise Control Act.** No regulations have been promulgated since 1979 that would have an impact on noise control at SPR sites, either during construction or operations. The analysis of potential noise impacts in the PEIS, however, remains valid.

# 5.0 RE-EXAMINATION OF ENVIRONMENTAL IMPACTS

This chapter discusses the conclusions regarding projected environmental impacts associated with the implementation of the SPR program as detailed in the PEIS, and examines these impacts and their validity in the light of the operating experience of the SPR.

## 5.1 Oil Spill Impacts and Mitigation

This section discusses and compares the projected impacts due to oil spills as detailed in the PEIS with operating experience and updated data with regard to the oil transport scenarios identified, spill frequency data, expected impacts on ecosystems, and the economic impacts associated with oil spill cleanups.

### 5.1.1 Overview of PEIS

As noted in the PEIS, the most publicized and widely reported actions pertaining to petroleum and the environment occur from oil spills, and special emphasis was placed on evaluating the potential for environmental impacts in this area. The PEIS estimated the risk of "worst case" oil spills in five major geographical areas when transporting oil to the SPR using three baseline transportation scenarios and additional alternatives for the time required to fill the reserve, considering various storing configurations and amounts of oil reserved.

The five geographic areas considered when making the estimate, include:

- Open ocean, primarily the North Atlantic, the South Atlantic, and the Western Indian oceans.
- The Gulf of Mexico and the Caribbean Sea (50 miles or more offshore).
- The U.S. coast of the Gulf of Mexico from the Florida Straits to Texas (50 miles or less from shore).
- Harbors and inland waters of the U.S. Gulf Coast, including the channels connecting the harbors with the sea and with the SPR storage sites.
- Gulf Coast wetlands and other lands near the pipelines connecting a storage site with a marine terminal.

The three scenarios all involved transporting the oil from the Middle East using various sizes of tankers. Among the six alternatives for the time required to fill the reserve were storing 1,000 MMB in Gulf Coast salt domes by 1983 and storing 1,000 MMB in Gulf Coast salt domes by 1985.

Worst case estimates of the frequency of a major oil spill during transport of 1,000 MMB are shown in Exhibit 5-1. These estimates were based on historical data including: (1) tank vessel casualties; (2) onloading-offloading accidents at marine terminals; (3) spills during vessel-to-vessel transfers; and (4) pipeline accidents.

**Exhibit 5-1**
**Risk of a Major Oil Spill for Various Geographical Areas**

| Area of Impact | Size of Major Spill | Worst Case Frequency During Transport of 1,000 MMB |
|---|---|---|
| Open Ocean | 100,000 gallons | 1.8 |
| Gulf of Mexico and Caribbean Sea | 100,000 gallons | 0.38 |
| Gulf Coast | 100,000 gallons | 0.018 |
| Harbors and Inland Waters | 10,000 gallons | 1.0 |
| Pipeline Routes | 10,000 gallons | 0.70 |

The PEIS also summarized the biological impacts of oil spills based on information gathered from field and laboratory studies. Large oil spills may produce immediate and widespread death to aquatic communities by smothering and through the toxic effects of some of the oil's components. The most heavily impacted ecosystems are enclosed and/or shallow areas such as wetlands, estuaries, bays, channels, and harbors. Open ocean impacts are assessed as light. Subtidal benthos can suffer heavy initial damage and may be particularly slow to recover. A review of potential environmental impacts from oil spills off the Texas Gulf Coast and the Southeastern coast of Louisiana describes long-term damage as minimal. A survey of the economic impacts of oil spills included in the Supplement cites a wide range of cleanup costs per barrel of oil spilled, depending upon factors such as the size and location of the spill.

## 5.1.2 Oil Transport Scenarios and Spill Frequency Data

A survey of recent literature suggests that the PEIS may have overestimated the oil spill risk. Recent data indicate that frequency of spills has declined over the decade from 1976 to 1986 in the areas for which information was collected to complete the PEIS. Additionally, the three transport scenarios used in the PEIS assumed that the oil would be transported greater distances than SPR oil actually has traveled. Therefore, the impacts in the PEIS are overstated and remain valid.

**Accuracy of Data on the Frequency of Oil Spills.** Although the movement of oil by sea has increased by nearly 10 percent between 1971 and 1989, the total amount of oil spilled has decreased significantly over a comparable period. By 1989, oil spillage from marine transportation sources had decreased by approximately 73 percent from 1973 levels and by over 61 percent from 1981 levels. Nearly all sources of marine oil spillage have shown a decrease in the total quantity of oil spilled over this period.[18/] Other findings reported by the Minerals Management Service indicate that the spill rate for worldwide tanker traffic between 1974 and 1985 was 0.90 spills per 1,000 MMB of oil transported, which is only half the rate for a major open ocean spill assumed in the PEIS.[19/]

The number of reported oil spills from tankers in and around U.S. waters has declined significantly as well. Reported oil spills from tankers averaged approximately 650 spills per year from 1976-1979 and peaked at over 700 spills a year in 1978 and 1979. Since then, tanker spills have steadily declined to a low of 173 incidents reported in 1985 (a yearly high-to-low decrease of 76 percent). For the period from 1980-1986, the average number of tanker spills has been about 310 incidents per year.[20/] During this same period, the volume of crude oil imported into the U.S. has declined, but to a lesser extent. Total crude oil imports peaked in 1977 at 6.6 million barrels per day (MMBD) and dropped to 3.2 MMBD in 1985 (a yearly high-to-low decrease of 52 percent). Since 1985, imports of crude oil and petroleum products have increased steadily to nearly 6.0 MMBD in 1990, while the number of tanker spills has remained roughly constant.[21/]

Spills during onloading and offloading at marine terminals also have declined dramatically over the decade from 1976 through 1986. Reported spills occurring during onshore/offshore bulk cargo transfer at marine terminals averaged 367.5 spills per year from 1976 through 1979 and peaked at

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18/ *Update of Inputs of Petroleum Hydrocarbon Into the Oceans Due to Maritime Transportation Activities*, International Maritime Organization, unpublished paper, September 19, 1990.

19/ Oil Spill Intelligence Report, January 10, 1991, p.4.

20/ *Polluting Incidents In and Around U.S. Waters, 1976-1986*, Washington, D.C., U.S. Coast Guard, U.S. Government Printing Office, 1986.

21/ *Monthly Energy Review, January 1991*, Washington, D.C., U.S. Department of Energy, Energy Information Administration, U.S. Government Printing Office, 1991, p. 37.

450 spills in 1977. Since then, these types of spills have declined to a low of 11 in 1986 (a yearly high-to-low decrease of 98 percent). For the entire period 1980 through 1986, the average number of spills occurring during onshore/offshore bulk cargo transfer at marine facilities has been about 189.[22/]

Additionally, spills from pipelines have declined significantly over the decade from 1976 to 1986, although the total annual quantity of crude oil and petroleum products transported by pipelines over the same period has remained fairly constant at roughly 567 billion ton-miles.[23/] From 1976-1979, the average number of oil spills from pipelines was approximately 550; from 1980-1986, the number of incidents was approximately one-half (275). In addition, the mean quantity spilled declined by two-thirds over the same period.[24/]

The PEIS emphasized spills that might occur during transport to the Gulf Coast. Site-specific EISs address spill potential at the salt domes themselves and at terminals and pipelines associated with the storage sites. The Supplement, however, also provided general estimates of inland spills at harbors and inland waters and at areas near pipelines connecting the terminals to the storage sites. The quantity of oil predicted to be spilled during transport of 500 MMB to Gulf Coast salt domes was about 1,300 to 1,600 bbls for harbors and inland waters and 1,800 bbls for areas near pipelines. Actual inland spill experience during transport to the salt domes appears to be minor. For example, there were 22 oil spills in excess of 1 bbl at SPR sites in the period 1987 through 1989; of these, only one 2-bbl spill was reported at the St. James Terminal and one 4-bbl spill occurred from a pipeline at Bryan Mound.[25/] Both of the spills were cleaned up promptly, and neither affected surface waters.

**Adequacy of Transport Scenarios and Storage Alternatives.** The PEIS assumed that all crude oil destined for the SPR would originate from the Middle East, resulting in the longest possible vessel transport of oil, which is overly conservative given actual program experience. Through 1989, only 13.2 percent of SPR crude oil was received from the Middle East (i.e., Iran, Oman, Qatar, Saudi Arabia, and United Arab Emirates). An additional 10.3 percent originated in Africa (i.e., Algeria,

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22/ *Polluting Incidents In and Around U.S. Waters, 1976-1986*, Washington, D.C., U.S. Coast Guard, U.S. Government Printing Office, 1986.

23/ *Basic Petroleum Data Book, Petroleum Industry Statistics*, American Petroleum Industry, 1989, Volume IX, Number 1.

24/ *Polluting Incidents In and Around U.S. Waters, 1976-1986*, Washington, D.C., U.S. Coast Guard, U.S. Government Printing Office, 1986.

25/ *U.S. DOE 1987 Annual Environmental Monitoring Report for the Strategic Petroleum Reserve*, Boeing Petroleum Services, Inc., New Orleans, Louisiana, April 1988 and *U.S. DOE 1989 Annual Environmental Report for the Strategic Petroleum Reserve*, Boeing Petroleum Services, Inc., New Orleans, Louisiana, June 1990.

Cameroon, Egypt, Gabon, Libya, and Nigeria). More proximal sources, such as Mexico and the United States, have accounted for more than one-half of the crude oil received.[26/] Because the actual transport distances have been considerably shorter than assumed in the analysis, the Supplement, which estimates oil spill rates based on the frequency of incidents per unit of distance travelled, overestimates the expected number of oil spills and, as a result, the total quantity of oil spillage.

Also, oil spillage from barge transport and operations was considered in the PEIS because pipelines between the storage sites and the marine terminal would not have been completed during the interim fill phase. Because the SPR expansion currently under consideration will occur at sites near existing storage facilities, it is assumed that an interim fill phase using barge transport will not be required, and, therefore, consideration of spills from this mode of transportation is not necessary. Consequently, including spills from barges in the PEIS overestimates the expected total quantity of oil spillage.

Additionally, although the scenario of a U.S. deepwater port was considered in the 1976 PEIS, that scenario was not included in the 1979 Supplement because it was thought that such a port would not come into existence until after the initial fill was completed. However, the Louisiana Offshore Oil Port (LOOP), a deepwater port (DWP) that allows large tankers to offload oil directly to a pipeline connected to a terminal facility, has been in operation since the early 1980s. The availability of a U.S. DWP allows transoceanic shipment of crude oil by very large crude carrier (VLCC) while avoiding the need for lightering to smaller vessels for coastal transport or offloading at a Caribbean DWP and transhipment to the U.S. by smaller vessels. In its eight years of operation, the LOOP has not experienced a "significant" oil spill.[27/]

Finally, when estimating worst case risks, the PEIS considered alternatives that involved some offshore storage. For example, the 0.018 estimate for frequency of spills in the Gulf Coast was based on an alternative which included storing 150 MMB offshore. Alternatives that include offshore storage are not being considered as part of the SPR expansion. The risks of spills, therefore, may not be as great as calculated in the PEIS.

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26/ *Strategic Petroleum Reserve Annual/Quarterly Report, February 15, 1990*, Washington, D.C., U.S. Department of Energy, Office of Petroleum Reserves, U.S. Government Printing Office, 1990, p. 20.

27/ *Oil Spill Intelligence Report*, September 27, 1990, p.1.

### 5.1.3 Oil Spill Impacts

The following sections discuss the various impacts associated with oil spills, including impacts on ecosystems in general and the Gulf Coast specifically and the economic impacts associated with cleanups.

**Biological Impacts.** The impacts of major oil spills on aquatic ecosystems described in the PEIS are in general agreement with findings presented in more recent articles. Specifically, the gross effects of major oil spills on aquatic biota noted in the PEIS have not been contradicted by later research. Large oil spills may produce immediate and widespread damage to aquatic communities by smothering and through the toxic effects of some oil components. More recent studies have concentrated on the effects of low-level chronic oil pollution. The gross effects of high concentrations of oil encountered during spills are essentially the same as those reported in the PEIS. The following paragraphs summarize these effects.

The PEIS, as confirmed by more recent reports, rates the impact of oil spills on bird populations as heavy.[28/29/] The feathers of seabirds, if fouled with oil, become water-logged and lose their insulative properties with death resulting from drowning or hypothermia. Birds can ingest oil while preening and may also suffer stress-related effects as they attempt to detoxify the ingested oil, an effect which has only recently been determined. The most vulnerable species of birds, as noted in the PEIS, are those that dive regularly for food such as ducks and other waterfowl.

The PEIS rates the impact of oil spills on fish populations as light to moderate. This is in agreement with findings presented in other reports.[30/31/32/] Although fish are very sensitive to short-term acute exposures to oil, most adult fish can avoid the most heavily contaminated areas or may, in some cases, be protected by the natural mucus covering their bodies. As noted in the PEIS, the early life cycle stages are the most vulnerable, with death resulting from smothering or

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28/ Graham, F., Jr., Audubon, September 1989, pp.102-111.

29/ *Oil in the Sea: Inputs, Fates, and Effects*, Washington, D.C., National Research Council, National Academy of Sciences, 1985.

30/ *Fate and Effects of Oil in the Sea: Exxon Background Series*, New York, Exxon Corporation, 1985.

31/ *Oil in the Sea: Inputs, Fates, and Effects*, Washington, D.C., National Research Council, National Academy of Sciences, 1985.

32/ Teal, J.M., and Howarth, R.W., Environmental Management, 1984, Volume 8, Number 1, p. 27-44.

through the effects of the dissolved toxins. Other potential effects cited by more recent studies include failure of the eggs to hatch and complications arising from larval deformities.[33/]

According to the PEIS, benthic invertebrates are the most vulnerable to the effects of oil spills although, as the Supplement notes, there does exist a wide range of tolerances between genera and species and among various life cycle stages of any one species. Death is primarily by smothering although oil collected in the sediment can continue to release toxins over a long period of time. Benthic invertebrates living in the intertidal zone are the most vulnerable to the effects of oil spills due to the tendency of the oil to concentrate in a narrow band along the shore. These findings have been confirmed by more recent research.[34/]

As noted in the PEIS, oil can adhere to aquatic plants, directly killing the parts exposed to oil and preventing or slowing gas exchange. Plants growing in intertidal areas are the most vulnerable to the effects of oiling although subtidal and submerged flora can also be impacted. The photosynthetic and growth rates of phytoplankton are reduced following exposure to oil although their rapid regeneration rates and wide distribution would most likely prevent any major impacts to the community. This is also true for zooplankton communities, as noted in the PEIS, and confirmed by more recent research, where total biomass and standing crop are not significantly impacted by oil spills. [35/36/]

**Ecological Impacts.** The impacts of oil spills on ecosystem structure and function is a relatively new area of research so that this subject was not covered in detail in the PEIS. Due to the complex and varied nature of the relationships that are involved, the effects are not easily defined or readily apparent. In general, oil spills can alter food web relationships and affect competition for available resources (e.g., space). Species diversity and total abundance may decrease but the populations of resistant and opportunistic species can dramatically increase as these organisms profit from the added available space.[37/38/] Biomass density, and species numbers all declined following

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33/ Ibid.

34/ *Oil in the Sea: Inputs, Fates, and Effects*, Washington, D.C., National Research Council, National Academy of Sciences, 1985.

35/ Ibid.

36/ *Fate and Effects of Oil in the Sea*, New York, Exxon Corporation, Exxon Background Series, 1985.

37/ *Oil in the Sea: Inputs, Fates, and Effects*, Washington, D.C., National Research Council, National Academy of Sciences, 1985.

38/ Teal, J.M., and Howarth, R.W., Environmental Management, Volume 8, Number 1, 1984, p. 27-44.

the Arco Anchorage oil spill in 1985 at Ediz Hook, Washington.[39/40/] The timing of the spill can be of crucial importance as spills occurring during spawning or migration seasons, for example, can wipe out entire populations.[41/] Chemical constituents of oil generally are not concentrated in the food chain.[42/]

According to the PEIS, marshes, lagoons, embayments, estuaries, and tidal flats are among the ecosystems that are most affected by oil spills. These are low-energy environments with shallow waters capable of concentrating and retaining oil over long periods of time. It has recently been hypothesized that sediment grain size controls the rate of penetration of the oil into the sediment.[43/] Oil can sink deeper into sediment, where it can remain unchanged for decades, producing toxic effects. Oil deposited on rocky shores will harden to form a tough, tarry skin which is gradually removed by wave erosion.[44/45/]

In contrast, oil spills in the open ocean potentially have a much smaller impact.[46/] This is in agreement with the findings presented in the PEIS. Currents and diffusion acting in the open ocean will rapidly decrease concentrations making the oil less toxic and more amenable to degradation. Recent studies have identified evaporation as a key weathering process, reducing spill volumes by one-third to one-half while removing the more toxic low molecular weight

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39/ Blaylock, W.M., and Houghton, J.P., In *Proceedings of the 1989 Oil Spill Conference*, Washington, D.C., American Petroleum Institute, 1989, pp. 421-426.

40/ Mancini, E.R., Lindstedt-Siva, J., and Chamberlain, D.W., In *Proceedings of the 1989 Oil Spill Conference*, Washington, D.C., American Petroleum Institute, 1989, pp 459-462.

41/ *Oil in the Sea: Inputs, Fates, and Effects*, Washington, D.C., National Research Council, National Academy of Sciences, 1985.

42/ Abelson, P.H., Science, 1989, Volume 244, Number 4905, p. 629.

43/ *Oil in the Sea: Inputs, Fates, and Effects*, Washington, D.C., National Research Council, National Academy of Sciences, 1985.

44/ Ibid.

45/ Teal, J.M., and Howarth, R.W., Environmental Management, 1984, Volume 8, Number 1, pp. 27-44.

46/ *Oil in the Sea: Inputs, Fates, and Effects*, Washington, D.C., National Research Council, National Academy of Sciences, 1985.

components.[47/48/49] Other important weathering processes include dissolution, emulsification, sedimentation, biodegradation, and photo-oxidation. The importance of microbial decomposition in removing petroleum pollutants from low-energy depositional areas has only recently been recognized.[50/51] According to the PEIS, weathering of crude oil will generally produce less toxic products although photo-oxidation may increase the toxicity of certain petroleum and petroleum products. Recent studies have concluded that the weathering processes are essential to spill cleanup, reducing the crude to small, inert tar balls which eventually sink to the sea floor or wash up on shore before being broken down.[52] However, emulsification and photo-oxidation of certain compounds may produce more toxic and soluble products.[53/54]

**Major Gulf Coast Spill Impacts.** The PEIS described potential environmental impacts from oil spills in the Texas Gulf Coast and the southeastern coastal area of Louisiana. Information on large oil spills in the Gulf Region indicates that effects can vary considerably, but no major irreversible environmental damage has been reported.

The environmental impacts of the IXTOC I oil spill on the Texas coast are documented more extensively than those of any other major Gulf spill. The incident began on June 3, 1979, when an exploratory well, IXTOC I, blew out in the Bay of Campeche, about 80 km northwest of Ciudad del Carmen, Mexico. By the time the spill was brought under control in late March, 1980, IXTOC I had released an estimated half million tons of oil, the largest spill in history prior to the Persian Gulf release during the war with Iraq.[55] A wide variety of environmental resources were at risk in the south Texas area during the IXTOC I incident, including sensitive marshlands, waterfowl and

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47/ Ibid.

48/ Hall, S.K., Pollut. Eng., 1989, Volume 21, Number 13, pp. 59-63.

49/ Oil and Gas Journal, 1989, Volume 87, Number 15, p.17.

50/ *Oil in the Sea: Inputs, Fates, and Effects*, Washington, D.C., National Research Council, National Academy of Sciences, 1985.

51/ Page, D.S., Foster, J.C., Fickett, P.M., and Gilfillan, E.S. In *Proceedings of the 1989 Oil Spill Conference*, Washington, D.C., American Petroleum Institute, 1989, pp. 401-405.

52/ Oil and Gas Journal, 1989, Volume 87, Number 15, p.17.

53/ Ibid.

54/ Graham, F., Audubon, September 1989, pp. 102-111.

55/ Atwood, D.K. *Proceedings, Symposium on Preliminary Scientific Results from the Researcher/Pierce Cruise to the IXTOC I Blowout*, Boulder, Colorado, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, 1980.

shorebird wintering areas, and the habitats of eighteen species of marine mammals and five species of marine turtles. Numerous biological studies conducted during the IXTOC I spill to monitor changes in dominant, important, or indicative species indicated that, in general, the oil had only a minimal impact on local biota. This result was no doubt influenced by the presence of coastal barrier islands which, as predicted by the Supplement, largely prevented the oil from entering the more biologically sensitive lagoons and wetland areas.[56/]

For two spills that did occur in sensitive Texas coastal regions, the 645,000-gallon Corpus Christi Harbor spill of 1988 and the 250,000-gallon Galveston Bay spill of 1989, favorable weather conditions enabled cleanup operations to be executed effectively, preventing any significant environmental damage.[57/58/] When the oil tanker Alvenus spilled approximately 2.8 MMB of Venezuelan crude 10 miles from the Louisiana coast, recovery efforts were hampered by inclement weather.[59/] The spill never reached the coast, however, thus seeming to support the Supplement's conclusion that offshore spills in the Gulf of Mexico are not likely to impinge upon the Louisiana coast.

**Economic Impacts.** The Supplement used actual data from oil spills to obtain cleanup cost estimates. Cost estimates for a large spill were provided on a per barrel basis along with estimates for a spill from a 400,000 DWT tanker. These estimates range from a minimum of $1.34 to $67 per barrel of oil spilled, with cleanup costs from a 400,000 DWT tanker estimated at $3.7 million to $187 million.[60/] A survey of recent literature indicates that these figures have, in some instances, dramatically increased. Cleanup costs now range from approximately $0.75 per barrel[61/] to the

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56/ Ibid.

57/ Alejandro, A.C., and Crickard, A.M., In *Proceedings of the 1989 Oil Spill Conference*, Washington, D.C., American Petroleum Institute, 1989, pp. 71-76.

58/ Environment Reporter, 1989, Volume 20, Number 9, pp. 487-488.

59/ Alejandro, A.C., and Buri, J.M., In *Proceedings of the 1989 Oil Spill Conference*, Washington, D.C., American Petroleum Institute, 1989, pp. 27-32.

60/ All costs are expressed as 1990 dollars.

61/ White, I.C., and Nichols, J.A., In *Proceedings of the 1983 Oil Spill Conference*, Washington, D.C., American Petroleum Institute, 1985, pp. 541-545.

$7,560 per barrel reported for the Exxon Valdez spill.[62/] Liability may be limited to approximately $240 million for oil spilled from a 400,000 DWT tanker.[63/]

Two factors noted in the Supplement that can affect per barrel cleanup costs are spill size and spill location with costs of up to $1,300 per barrel for small spills in waterways and harbors. Recent studies confirm these relationships. A 1986 study places the average cleanup cost at $354 per barrel for spills of 1,000 gallons as compared to the $133 per barrel estimated for spills of 10,000 gallons.[64/] A 1979 spill in the open ocean, with no onshore contamination, resulted in cleanup costs of less than one dollar per barrel while the cleanup cost of a similar size spill in a highly sensitive area was $5,200 per barrel.[65/]

One subject not mentioned in the PEIS is the growing importance of liability costs as a factor in the total cleanup costs. In some cases, liability costs have greatly exceeded the actual cleanup costs. Total costs resulting from a 1979 spill of 150 tons of crude oil in the Far East were $9.1 million of which only $1.0 million represented the actual cleanup costs. The remaining $8.1 million was awarded to seaweed farmers whose equipment and crop were contaminated by the spill.[66/] A total of $75.26 million was awarded as compensation to parties affected by the 1978 Amoco Cadiz spill which contaminated several hundred miles of coastline and nearshore waters.[67/] Actual cleanup costs for the spill were estimated at $119 million to $132 million.[68/]

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62/ The Exxon Valdez figure represents an extreme case and includes not only the direct cost of oil removal but also compensation to fishermen for lost income and to native Americans for lost livelihood. It does not, however, include civil damages from pending lawsuits or penalties for violations of administrative or civil law.

63/ In calculating the upper bound for oil spilled from a 400,000 DWT tanker, the liability limit of $1,200 per gross ton of oil spilled from a vessel set by the Oil Pollution Act of 1990 was used to represent potential costs.

64/ Cohen, M.A., J. Env. Econ. and Mgmt., 1986, Volume 13, pp. 167-188.

65/ White, I.C., and Nichols, J.A., In *Proceedings of the 1983 Oil Spill Conference*, Washington, D.C., American Petroleum Institute, 1983, pp. 541-544.

66/ Ibid.

67/ Gundlach, E., In *Proceedings of the 1989 Oil Spill Conference*, Washington, D.C., American Petroleum Institute, 1989, pp. 503-508.

68/ Bower, B., Ed., *Assessing the Social Cost of Oil Spills: the Amoco Cadiz Case Study*, Washington, D.C., National Oceanic and Atmospheric Administration, 1983.

## 5.2 Water Quality Impacts

This section evaluates the continued applicability of the water quality impact analysis in the PEIS. It starts by providing an overview of the PEIS analysis and conclusions in Section 5.2.1. Section 5.2.2 then evaluates how well that analysis applies to construction, spill, and underground injection impacts associated with the proposed action. Section 5.2.3 evaluates the continued applicability of the PEIS to anticipated impacts associated with brine discharges in the Gulf of Mexico.

In general, records of incidents at SPR facilities resulted in water quality impacts that are within the scope of impacts considered in the PEIS; the PEIS, therefore, is sufficient to address the proposed expansion to 1,000 MMB. Those impacts that were not addressed in the PEIS (e.g., brine spills from settling ponds, possible releases from Aqueous Film Forming Foam (AFFF) fire suppression systems) are considered to have minor, short-term effects, and would be best addressed in a site-specific EIS rather than in a supplement to the PEIS. In addition, available monitoring data indicate that the actual areas of brine plumes into the Gulf of Mexico caused by SPR discharges have been larger than predicted in the site-specific EISs for Bryan Mound and West Hackberry. However, the overall impacts of these plumes have been insignificant, as was also indicated in the site-specific EISs. Given the overall small impacts caused by existing operations, it is likely that additional brine discharges associated with an expansion of the SPR system would cause similarly small impacts. Therefore, no supplement to the PEIS is needed with respect to the Gulf discharges associated with the proposed expansion.

### 5.2.1 Overview of the PEIS

Threats to water quality posed by SPR activities can be divided into four major groups, depending on the type of site activity that poses the threat: construction, spills of brine and other materials during site operations, deep-well injection of brine, and discharge of brine to the Gulf of Mexico. As summarized below, the PEIS discusses the events that are most likely to affect water quality as a result of these activities.

- Construction: Due to the added water traffic that SPR sites will create, increased dredging is predicted to be necessary throughout the affected region. Dredging could result in the temporary siltation of surface waters, causing decreased photosynthesis, and the release of contaminants that are often contained within these sediments (e.g., pesticides, PCBs). In addition, construction activities will disturb soil and strip sites of vegetation, increasing the probability of the siltation of surface waters. The PEIS also cites the flushing of contaminants from pits and drilling sites by storm water as a possible threat to surface water quality.

- Site Operation (Spills of Brine, Oil, and Other Substances): Potential impacts caused by spills of crude oil by transport vessels or at handling facilities are mentioned in the PEIS. In addition, the PEIS mentions that a cavern roof could collapse, but this was not considered likely. The effects of such an event would include the almost certain contamination of ground water. The Supplement to the PEIS mentions the possibility of brine discharges from the solution cavities, brine spills resulting from pipeline accidents, and brine contamination of freshwater aquifers from abandoned cavern wellheads.

- Deep-Well Brine Injection: During cavern construction a tremendous volume of brine will be produced (up to 41,000 gallons per minute continuously over a 36-month period in solution mining a 200-MMB storage facility), much of which will be disposed via deep-well injection. Possible impacts of injection on water quality considered in the PEIS include: contamination of the barriers between fresh and saline aquifers, fracturing of geological formations due to the high injection pressures, and ground-water contamination caused by the migration of brine through new or existing fractures, well casings that have lost their integrity, or unplugged or poorly plugged abandoned wells. Because brine injection has been a common practice in the Gulf Coast region for some time, many old wells exist and the location of all of these wells is not recorded. As a result, the possibility of breaching one of these abandoned wells during construction, thus providing a pathway for ground-water contamination, is noted as a significant concern in the PEIS. Furthermore, the deep-well injection of brine results in a resource loss, as it permanently precludes the receiving aquifer from future use as a brine source or liquid waste disposal site.

- Discharge of Brine to the Gulf of Mexico: The Gulf impact modeling performed for the PEIS has been superseded by more extensive modeling in the site-specific EISs for the Bryan Mound and West Hackberry sites. As discussed in these site-specific EISs, the primary concern associated with this method of brine disposal is the elevated salinity that will occur in the vicinity of the diffuser (the point of release). Additional potential impacts to water quality include other chemical and thermal disturbances and the accumulation of excess solids on the Gulf bottom.

### 5.2.2 Continued Applicability of the PEIS to Construction, Spill, and Deep-Well Injection

The SPR has been in existence for slightly more than ten years, and during that time a significant quantity of monitoring data and system evaluation information has been accumulated. Various reports covering the years 1982 through 1990 were reviewed to determine the types of water quality impacts that have actually occurred at the SPR sites, and to evaluate how well those impacts are covered by the PEIS. Attachment II presents a list of documented impacts and possible threats that is by no means complete, but illustrates the major type and severity of events that have occurred in the past and that may occur again in the future.

One example of documented impacts in Attachment II that was not addressed within the PEIS is leakage from brine ponds. Brine ponds at SPR sites vary in their construction and uses. In general, the ponds are earthen reservoirs lined with a synthetic material (e.g., hypalon). All of the ponds are built over naturally occurring high density clay, which limits the further migration of any brine that leaks through the synthetic liner. Some of the ponds also have other design features to help control brine migration. For example, some of the ponds are equipped with bentonite clay slurry walls, many are equipped with underdrains for the detection of leaks, and the majority have a protective layer of concrete over the synthetic liner material. The ponds range in capacity from 100,000 barrels to approximately 200,000 barrels. The ponds are used during solution mining of new capacity, oil fill and refill, and brine displacement to reduce pressure in caverns in standby status. As brine is stored in the ponds prior to its ultimate disposition, solids settle to the bottom and any suspended oil floats to the top, where it is collected for reinjection into a salt dome. Originally, oil/water separators were used to recover this oil from the brine ponds, but they frequently became clogged with solids and were much less successful than the present method. Occasionally, fresh water used to remove oil from the salt domes is also stored in the ponds.

Although brine ponds were not specifically discussed at the programmatic level, they are an integral part of the brine disposal systems detailed in the PEIS. The impacts identified in Attachment II associated with the operation of brine ponds are within the scope of projected impacts predicted by the PEIS and have been specifically dealt with at the site-specific level. No supplement is required at the programmatic level, therefore, to address the impacts of brine pond leakage.

In view of the documented impacts and threats to water quality that have been observed at the SPR sites since the PEIS, the conclusions in these prior documents still are basically timely with respect to construction, site spill, and underground injection impacts. A further supplement to address these impacts, therefore, does not appear to be warranted for the proposed expansion of the system to 1,000 MMB. This conclusion is based on three primary findings.

First, the PEIS provides reasonably good coverage of the types of impacts and threats that have actually occurred over the past ten years of operation. In many cases, certain impacts addressed in the initial NEPA documents have occurred, just as predicted. Despite years of thorough site study and evaluation, no significant information (e.g., geologic, meteorologic, or oceanographic data) has been discovered that would invalidate the initial PEIS. Overall, the environmental impacts at the SPR sites have been minor and compliance has been good, with only a few percent of releases in non-compliance annually.

Second, there have been impacts that, although not addressed in the PEIS, do not appear to warrant an additional supplement. Most of the omissions involve relatively small leaks and minor short-term impacts. Brine spills from settling ponds and releases from Aqueous Film Forming Foam (AFFF) fire suppression systems are the only situations identified on a programmatic level that may result in potentially significant water quality impacts. With respect to spills from brine ponds, much has already been learned through remediation activities and through investigations of the causes of these events (e.g., the Bryan Mound brine spill), so little new insight would be gained from an additional supplement to the PEIS. With respect to releases of AFFF, no such releases actually have occurred and, while steps should be taken to prevent water quality impacts through this pathway, this omission does not appear significant enough to warrant further evaluation on a programmatic level.

Third, all of the impacts that have occurred were site-specific and are thus best addressed in required site-specific EISs. For example, the construction of the Bryan Mound pump pads on fill material and the existence of collapsed wells at Bayou-Choctaw described in Attachment II, do not warrant consideration in a programmatic discussion, but should be considered in terms of the particular conditions at each site. They would be much more effectively covered, therefore, in a site-specific assessment.

### 5.2.3 Continued Applicability of Existing NEPA Documentation to Gulf Discharges

Following the publication of the PEIS, DOE recognized certain technical limitations in the approach used to model impacts caused by the discharge of brine in the Gulf of Mexico. As a result, the Department developed and used a more rigorous modeling approach in the analysis of site-specific impacts of Gulf discharges at the Bryan Mound and West Hackberry sites. The modeling approach and conclusions documented in the site-specific EISs for these two sites[69/70/] thus supersede the modeling documented in the PEIS.

This section evaluates the continued applicability of the site-specific EISs from two standpoints. First, it evaluates the applicability of the approach used to model Gulf impacts by comparing the modeling assumptions and input values used in the site-specific EISs to actual site

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69/ *Final Environmental Impact Statement for the Strategic Petroleum Reserve, Texoma Group Salt Domes*, 5 Vols., Washington, D.C., U.S. Department of Energy, November 1978.

70/ *Final Environmental Impact Statement for the Strategic Petroleum Reserve, Seaway Salt Domes*, 3 Vols., Washington, D.C., U.S. Department of Energy, June 1978.

operating practices. It then evaluates the applicability of the modeling conclusions by comparing the predicted impacts to actual observed impacts.

**Applicability of the Modeling Approach.** Exhibit 5-2 summarizes the input values used for key modeling parameters considered in the site-specific EISs for Bryan Mound and West Hackberry. For comparison, the exhibit also presents the actual values observed at each site since brine discharges to the Gulf were initiated.

As shown, the diffuser design and operating parameters modeled in the site-specific EISs for Bryan Mound and West Hackberry are generally reflective of actual conditions at the two sites. In both EISs, all model values except for the brine flow rate are very close to or are more conservative (i.e., tending to overestimate impacts) than actual values. In general, the West Hackberry modeling values mirror the actual values more closely than those of Bryan Mound. The actual brine discharge rate at Bryan Mound has been at least 1.5 times larger than the discharge rate assumed in the Bryan Mound EIS. This difference could contribute to an underestimation of brine disposal impacts at Bryan Mound. Conversely, the West Hackberry modeling assumed a brine discharge rate that is around 1.25 times the average discharge rate since disposal began, thereby possibly overstating impacts at that site.

With respect to water currents in the Gulf, the model input values appear to approximate actual current velocities. The approach used to model both sites attempts to account for wind-driven cycles of the Gulf of Mexico by simulating a periodic rotation between stagnant conditions and two different currents of opposite direction. Both EISs analyze the effects of these cycles twice using different sources of values for water current velocities: once using estimates and once using field-measured values. As shown in Exhibit 5-2, the modeled current velocities obtained from these two sources bracket the actual currents that have been observed since the start of site operations.

Based on this comparison, the modeling approach and assumptions used in the two site-specific EISs remain generally valid and representative of actual conditions. While it is necessary to evaluate the net interactive effect of all parameters on the modeling results, rather than the isolated effects of individual parameters, many of the modeled values by themselves would tend to result in predictions that overestimate actual impacts. Therefore, assuming additional brine discharges associated with the SPR expansion would be conducted in the same basic way, the modeling approach in the two site-specific EISs would be equally valid for the proposed expansion.

**Applicability of the Modeling Conclusions: Model Predictions.** Both EISs address potential impacts associated with increases in salinity as well as thermal, physical, and chemical disruptions resulting from brine discharge. The modeling predictions in the site-specific EISs with respect to salinity increases are summarized in Exhibit 5-3.

The site-specific EISs predict that the most severely impacted region would be the area nearest to the diffuser port where the highest salinity concentration, most severe physical disturbance due to "jetting," and the highest temperature exist. The EISs state that significant mortality of aquatic organisms could occur, especially among the benthic community, within the area of +3 ppt increases in salinity. Ecological impacts beyond the +3 ppt contour, however, are predicted to be minimal. Therefore, the site-specific EISs predict that significant impacts due to salinity increases would be confined within a 70-acre area at the Bryan Mound diffuser, and within an area of more than 207 acres at the West Hackberry diffuser. With regard to the effect of diffuser jetting and temperature increases, only organisms very close to the diffuser were predicted to be affected.

**Exhibit 5-2**
**Comparison of Model Parameters and Actual Values**
**for Bryan Mound and West Hackberry[1/]**

| Modeling Parameter | Bryan Mound | | West Hackberry | |
|---|---|---|---|---|
| | Model Value | Actual Value | Model Value | Actual Value |
| Offshore Distance of Diffuser | 5 miles | 12.4 miles | 6 & 3 miles | 7 miles |
| Water Depth | 50 feet | 65 feet | 30 & 20 feet | 30 feet |
| Diffuser Length | 2000 feet | 3061 feet | 3070 feet | 3240 feet |
| # of Ports | 34 | 52 | 52 | 55 |
| Port Interval | 60 feet | 59 feet | 59 feet | 59 feet |
| Port Diameter | 3 inches | 3 inches | 3 inches | 3 inches |
| Port Orientation | Upward | Upward | Upward | Upward |
| Brine Exit Velocity | 25 fps | 29 fps | 25 fps | 25 fps |
| Excess Brine Salinity | 230 ppt | 220 ppt | 230 ppt | 207 ppt |
| Brine Flow Rate (bpd) | 534,000 | >800,000 | 1,000,000 | >800,000 |
| Current Velocity (fps) | 0, 0.5, 1.0 | 0.33 | 0, 0.25, 0.75 | 0.45 |

1/ "Actual values" presented for the brine exit velocity, excess brine salinity, and brine flow rates represent averages of operating data collected at Bryan Mound and West Hackberry. The excess brine salinity at the two sites were calculated assuming that ambient water salinity is 30 ppt.

The EISs also predict that brine discharges would not cause significant adverse changes in the chemical composition of affected seawater. In particular, the EISs predict that there would be minimal impacts caused by changes in the concentration and speciation of heavy metals. The change in the Ca/Mg and K/Na ratios in seawater is also of special interest because the proportions of these ions in ambient waters have been shown to have an adverse effect on several aquatic organisms. The EISs predict that the Ca/Mg ratio would change insignificantly, but the resulting imbalance of the K/Na ratio could affect organisms within the entire +1 ppt contour. Additionally, the EISs predict that the concentrations of most precipitates would increase with increasing excess salinity, possibly resulting in the formation and settling of particulates on the Gulf floor.

**Exhibit 5-3**

**Predicted Areas Experiencing Excess Salinity Concentrations at Bryan Mound and West Hackberry**

| Site/EIS | Scenario/Current[1/] | Mean Areal Extent (Acres) | | |
|---|---|---|---|---|
| | | 1.0 ppt | 3.0 ppt | 5.0 ppt |
| Bryan Mound | 16-day cycle, estimated current | 2,800 | 70 | 25 |
| Bryan Mound | 16-day cycle, field-measured current | NA | NA | 25 |
| West Hackberry | 16-day cycle, estimated current | 3,700 | 140 | 30 |
| West Hackberry | 4-day cycle, field-measured current | 1,860 | 207 | NA |

1/ These scenarios represent different combinations of wind-driven current cycles and different sources of current velocities (either estimated values or field-measured values). With one exception, all the scenarios presented here represent worst-case conditions, as they involve the longest expected periods of stagnation. Results for the West Hackberry analysis using field-measured data for current velocities represent less severe conditions.

**Applicability of the Modeling Conclusions: Actual Impacts of Brine Disposal.** Exhibit 5-4 summarizes the average plume sizes for three salinity level increases at the Bryan Mound and West Hackberry sites.[71/72/] Bryan Mound data were collected during the first 42 months of brine

71/ Hann, R.W. et al., *Offshore Oceanographic and Environmental Monitoring Services for the Strategic Petroleum Reserve: Annual Report for the Bryan Mound Site from September 1982 through August 1983*, Final Report to Department of Energy, 3 Vols. Texas A&M University, College Station, Texas, 1984a.

disposal until August 1983. West Hackberry data were collected during the first 30 months of brine disposal until August 1983. The averages presented in this exhibit are lower than the present plume areas since the brine discharge rates and brine salinity levels during the first year of operation were significantly lower than present conditions. For example, at Bryan Mound, the mean areal extent of the +1 ppt and +3 ppt contours during the last 33 months of the study period are more than twice as large as the mean areal extent of the same contours generated during the first 9 months of brine disposal. Similarly, at West Hackberry, the mean areal extent of the +1 ppt and +3 ppt contours during the last 23 months of the study period were, respectively, three and two times the size of the same contours generated during the first 7 months of brine disposal. Nevertheless, the figures in Exhibit 5-4 illustrate the actual areas of brine plumes that can be compared to the model predictions.

**Exhibit 5-4**
**Mean Areal Extent Affected by a Given Salinity Concentration at Bryan Mound and West Hackberry**

| Facility | Average Current Velocity | Mean Areal Extent (Acres): | | |
|---|---|---|---|---|
| | | 1.0 ppt | 3.0 ppt | 5.0 ppt |
| Bryan Mound | 0.45 fps | 3,158 | 385 | 110 |
| West Hackberry | 0.33 fps | 4,010 | 875 | 274 |

Under the worst-case modeling assumptions (i.e., a 16-day current cycle) of the site-specific EISs, the actual +1 ppt brine plumes at Bryan Mound and West Hackberry cover areas similar to those predicted by the model. However, the actual mean areal extents of the +3 and +5 ppt contours are larger than predicted. The mean areal extent of the +3 ppt contours at the two sites are at least five times greater than predicted. Also, the mean areal extent of the +5 ppt contour at the Bryan Mound site is more than four times the predicted area. At the West Hackberry site, the mean areal extent for the +5 ppt contour is nine times greater than the predicted area.

72/ (...continued)

72/ Hann, R.W. et al., *Offshore Oceanographic and Environmental Monitoring Services for the Strategic Petroleum Reserve: Eighteen-Month Report for the West Hackberry Site from May 1982 through November 1983*, Final Report to Department of Energy, 2 Vols. Texas A&M University, College Station, Texas, 1984b.

Water and sediment quality parameters have also been monitored in the vicinity of the Bryan Mound diffuser (from September 1983 to August 1984)[73/] and West Hackberry diffuser (from May 1982 to October 1983).[74/] Although some water and sediment quality monitoring was conducted before these periods, only the most recently available data were used for the purpose of this analysis. Parameters measured at both facilities included salinity, temperature, pH, oil and grease, dissolved bulk ions ($Ca^{++}$, $Mg^{++}$, $Na^{+}$, $K^{+}$, $Cl^{-}$, $SO_4^{--}$), and high molecular weight hydrocarbons. Monitoring at Bryan Mound also included analyses of dissolved heavy metals (Cd, Cr, Cu, Hg, Zn, Pb, Al, Fe, Ni), and other bulk ions ($I^{-}$, $Br^{-}$). At West Hackberry, monitoring also included measurements of dissolved oxygen, turbidity, total phosphorus, phosphate, silicate, nitrate, nitrite, and ammonia. As summarized below, this monitoring indicates that slight increases in the concentrations of some constituents are observable in areas near the diffuser, but as predicted in the site-specific EIS, the levels of contamination are low and are not likely to cause significant impacts.

- Bottom Waters. At both facilities, slight increases in salinity and ion concentrations ($Na^{+}$, $Cl^{+}$ at both sites; $K^{+}$, $Ca^{++}$, $SO_4^{--}$ at West Hackberry) were observed in bottom waters. Similar patterns were observed in major ion ratios in bottom waters at West Hackberry (Na/K, Ca/Mg, and $Cl/SO_4$). Levels of heavy metals in bottom waters in the Bryan Mound diffuser area were similar to those measured at control stations and, if not lower, they were similar to previously observed levels in the vicinity of the diffuser before discharges were started. Furthermore, the levels of metals in the Bryan Mound diffuser area never exceeded EPA criteria for marine aquatic life. The monitoring also determined that heavy molecular weight hydrocarbons previously detected in bottom and surface waters at the Bryan Mound diffuser were of natural origin.

- Sediment Pore Water. At Bryan Mound, brine discharge has resulted in statistically significant increases (6-9%) in salinity, and in sodium

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73/ Hann, R.W. et al., *Offshore Oceanographic and Environmental Monitoring Services for the Strategic Petroleum Reserve: Annual Report for the Bryan Mound Site from September 1983 through August 1984*, Draft Final Report to Department of Energy. Texas A&M University, College Station, Texas, 1985. DOE Report No. DOE/P010850-4, p. 3-1. (Although the final Hann et al., 1984a report cited previously provides water and sediment quality data for an earlier period, the data in this draft report were for the purpose of this analysis because they are more current.)

74/ Hann, R.W. et al., *Offshore Oceanographic and Environmental Monitoring Services for the Strategic Petroleum Reserve: Eighteen-Month Report for the West Hackberry Site from May 1982 through November 1983*, Final Report to Department of Energy, 2 Vols. Texas A&M University, College Station, Texas, 1984b.

and chloride ion concentrations in sediment pore waters near the diffuser, relative to those far away. These increases in sodium and chloride ions at Bryan Mound have led to an insignificant increase in the Na/K ratio and a decrease in the $SO_4$/Cl ratio in pore waters at the diffusers. Increases in the Na/K ion ratios and decreases in Ca/Mg ratios in West Hackberry pore waters indicate a natural variation rather than diffuser effects. An analysis of soluble metals in Bryan Mound sediment pore waters indicates that nickel and chromium exceeded EPA criteria for aquatic organisms during the summer when redox potentials were lowest. However, additional data are needed to develop a model of metal solubility versus redox potential in order to predict the solubilization and potential impacts of the metals.[75/] Just like the bottom water results, the monitoring data show that sediment hydrocarbons at the Bryan Mound diffuser were of natural origin.

Assessments of the ecological impacts of brine discharge in the Gulf of Mexico were also conducted at the Bryan Mound and West Hackberry sites by NOAA.[76/77/] These studies draw upon pre-disposal and post-disposal monitoring data, numerical models of brine diffusion characteristics, and other pertinent NOAA and DOE marine environmental studies conducted to address concerns about offshore disposal of brine. Despite the underestimation of brine plume size and dispersion in the site-specific EISs, the conclusions of the NOAA studies reinforce the expectations of the EISs. The two studies conclude that:

- Neither of the two sites are situated at or near a unique or sensitive environment (e.g., estuarine areas, coastal wetlands, inshore bays, and areas of reproduction).

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75/ Hann, R.W. et al., *Offshore Oceanographic and Environmental Monitoring Services for the Strategic Petroleum Reserve: Annual Report for the Bryan Mound Site from September 1983 through August 1984*, Draft Final Report to Department of Energy. Texas A&M University, College Station, Texas, 1985, p. 3-1. DOE Report No. DOE/P010850-4.

76/ *Brine Disposal in the Gulf of Mexico: Assessment and Analysis for Bryan Mound*, Washington, D.C., U.S. Department of Commerce, National Oceanic and Atmospheric Administration, November 1984.

77/ *Brine Disposal in the Gulf of Mexico: Assessment and Analysis for West Hackberry,* Washington, D.C., U.S. Department of Commerce, National Oceanic and Atmospheric Administration, November 1985.

- There is no substantiated evidence that the first 18 months of brine disposal at Bryan Mound, or the first 48 months of brine disposal at West Hackberry, have detrimentally impacted biota.

- The only direct impact of brine disposal is elevated salinities in the lower water column and sediment pore water in the immediate vicinity of the brine diffuser. Ionic imbalances, halite precipitation, and pesticide, heavy metal, and petrogenic hydrocarbon accumulations in the benthic sediments have not occurred.

- Measurable ecosystem variability in the vicinity of the brine diffusers is a result of natural environmental factors, not brine disposal.

- Hypoxia (i.e., a condition in which the dissolved oxygen concentration approaches 0 ppm) occurs naturally at the sites with measurable impact, but is not related to brine disposal operations.

In conclusion, available monitoring data indicate that the actual areas of brine plumes caused by SPR discharges have been larger than predicted in the site-specific EISs for Bryan Mound and West Hackberry. However, the overall impacts of these plumes have been insignificant. As a result, the scope of the discussion and basic conclusions in the EISs concerning water quality impacts caused by Gulf discharges appear to adequately represent existing operations. In addition, given the overall small impacts caused by existing operations, it appears likely that additional brine discharges associated with an expansion of the SPR system to 1,000 MMB would cause similarly low impacts. The conclusions regarding water quality impacts in the PEIS also remain valid even though the model used to make them had technical limitations and was replaced. Therefore, no supplement to the PEIS appears to be needed with respect to the Gulf discharges associated with the proposed expansion.

### 5.3 Ecological Impacts

This section evaluates the PEIS for environmental impacts on ecology and wetlands. This update reviews each of these topics to determine if the analyses from PEIS are still valid, and if any significant new information can be used to update these analyses. In general, no significant changes are found, because many of the studies based on scientific and academic case studies are still accurate and valid assessments of potential environmental impacts from the SPR program. Even after reviewing the case study on the Bryan Mound brine spill leak, there is no indication that the major findings of the PEIS have changed.

### 5.3.1 Impacts on Ecology

Potential adverse ecological impacts from the SPR program result from facility construction and accidental releases into the ecosystem. Assuming no major changes from the proposed construction methods, ecological impacts from construction, waste disposal, dredging operations, excavation, and devegetation have not changed significantly to change the status of the PEIS. Also, as discussed in detail in Section 5.1.3, there have been no major changes in the conclusions from scientific and academic literature on ecological impacts from large oil spills. Further, the conclusions regarding vulnerability of marine organisms to oil spills and biological recovery from oil spills, are still valid and provide accurate assessments of potential ecological impacts from accidental spills.

Site-specific studies investigated the impact of brine disposal at the Bryan Mound, West Hackberry, and Big Hill sites for brown and white shrimp, and redfish (or red drum) populations from 1981 to 1984. The National Marine Fisheries Service (NMFS) under the direction of NOAA conducted the analysis with a forecasting model using catch and effort of shrimp as dependent variables.[78/] The model evaluated the potential effects of brine disposal on the growth, migration, mortality, and spawning of shrimp populations. This model and additional studies examining shrimp growth, mortality[79/], migration, spawning, and maturation[80/] indicated no significant negative impacts of brine disposal from SPR sites. Bioassay results for redfish populations also indicated no significant impacts.[81/]

There are several changes to the endangered species list in the States of Texas and Louisiana which are presented in Attachments III and IV. The listing of additional species, however, does not alter the findings of the PEIS.

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78/ *Shrimp Population Studies; Bryan Mound Brine Disposal Site Off Freeport, Texas, 1981-1982, Volume II*, NOAA/NMFS Final Report to DOE, U.S. Department of Commerce, December 1982, pp. 3-5.

79/ Gazey, W.J et al., *Shrimp Mark-Release and Port Interview Sampling of Shrimp Catch and Effort With Recovery of Recaptured Tagged Shrimp*, in *Shrimp Population Studies; West Hackberry and Big Hill Brine Disposal Sites Off Southwest Louisiana and Upper Texas Coasts, 1980-1982, Volume I*, NOAA/NMFS Final Report to DOE, U.S. Department of Commerce, November 1982, p. 306.

80/ Gallaway, B.J., and L.A. Reitsema, *Shrimp Spawning Site Survey, Volume III, Shrimp and Redfish Studies; Bryan Mound Brine Disposal Site Off Freeport, Texas*, NOAA Technical Memorandum NMFS-SEFC-67, 1979-1981, p. 84.

81/ Perret, S.W. et al., *Fishery Profile of Red Drum and Spotted Sea Trout*, Gulf States Mar. Fish. Comm., Ocean Springs, Mississippi, p. 60.

### 5.3.2 Impacts on Wetlands

Estimates of the potential impacts of the SPR program on wetlands cited in the PEIS[82/],[83/] are still timely and relevant. The PEIS concluded that the initial impact of oil on a wetland could be a potentially serious threat as a result of vulnerability to spills and significance of ecological functions (e.g., nursery and breeding grounds, high productivity, basis of detritus food chain). Wetlands were estimated as having one of the slowest recovery rates. The impact and subsequent recovery of an area following a petroleum oil spill will depend upon a complex variety of factors such as type of material spilled, time of year, energy characteristics of the impacted area (e.g., tidal exchange, wave action), vulnerability of biological community, and dynamics of the affected populations (e.g., turnover rates, fecundity).

An accidental brine disposal leak at the Bryan Mound brine disposal pipeline in 1989 provides a relevant case study of the SPR's effects on wetlands.[84/] At this site, about 825,000 barrels of brine were accidentally discharged from pipeline leaks that severely impacted the vegetation of approximately 8.3 acres of coastal marsh. Recovery of the vegetation has been variable, although a marsh recovery study in 1990 indicated that the measurable surface water and soil impacts were relatively short-term because frequent and severe tidal circulation and precipitation events provided excellent natural flushing to the marsh. However, the area closest to the spill, which has poor tidal circulation, experienced deep root damage and a prolonged soil impact causing complete plant death, chlorosis or apical necrosis of plant leaves and stems, and deterioration of woody stem and root tissue. Except for the most severely impacted area which will be extremely slow to recover naturally, annual spring growth produced significant recovery and some redistribution of species.[85/] This evidence correlates with PEIS analyses that concluded that accidental spills would be toxic to any plant and animal which comes into direct contact with the substance. The Bryan Mound study, however, does offer a scientific assessment of how variability within the wetlands ecosystem can affect the degree of ecological damage and recovery within the system.

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82/ Hyland, J.L., and E.D. Schneider, *Petroleum Hydrocarbons and Their Effects on Marine Organisms, Populations, Communities and Ecosystems*, in Sources, Effects and Links of Hydrocarbons in the Aquatic Environment, American Institute of Biological Sciences Symposium, August 9-11, 1976, Washington, D.C., pp. 463-506.

83/ Hershner, C., and K. Moore, *Effects of the Chesapeake Bay Oil Spill on Salt Marshes of the Lower Bay*, Proceedings: 1977 Oil Spill Conference, March 8-10, 1977, New Orleans, American Petroleum Institute, Washington, D.C., pp. 529-533.

84/ *Final Bryan Mound Environmental Monitoring Status Report, Brine Disposal Pipeline Leak Incident*, Boeing Petroleum Services, Inc., October 12, 1990, pp. 1-4.

85/ Wilkinson, Dan L., *Nine Month Review of the State of the Marsh at the Bryan Mound Strategic Petroleum Reserve Brine Disposal Pipeline Leak - Brazoria County, Texas*, Boeing Petroleum Services, May 12, 1990, pp. 3-5.

## 5.4 Air Quality Impacts

The PEIS assessed the air quality impact of salt dome storage in the Gulf region and evaporative hydrocarbon emissions from tanker unloading and loading operations at terminal areas. The assessment of salt dome storage for both the construction and the operational phases was based on cumulative impacts, assuming worst case scenarios in critical areas. In addition, a comparison of evaporative hydrocarbon emissions from two sizes of salt dome facilities was conducted. Two hypothetical salt dome facilities (one with 200-MMB capacity; another with a 60-MMB capacity) were selected for the emissions analysis. These represented the largest proposed facility and a typical small-size storage facility in the Gulf Coast storage region.

The PEIS considered evaporative hydrocarbon emissions from tanker transfer and transport operations at terminal areas, and the estimated maximum emissions at the St. James terminal were 1856 lbs/hr for tanker unloading operations and 2434 lbs/hr for tanker loading operations. Subsequent estimates of emissions based on then current equations and emissions factors published by EPA, as well as actual site performance data at St. James for the periods 1980, 1981, and 1982 were presented in a 1983 Emission Inventory Questionnaire (EIQ) for the State of Louisiana.[86/] These estimates showed approximately 1326 lbs/hr for unloading and 577 lbs/hr for loading. This suggests that the estimates in the PEIS were conservative in that they overestimated the maximum emissions.

Estimated annual emissions for tanker loading and unloading associated with a hypothetical 60-MMB salt dome facility (693 tons/year for loading operations and 529 tons/year for unloading) also appear to be conservative when compared to more recent estimates from the St. James terminal. The St. James terminal serves two salt dome storage site areas: Weeks Island (approximately 72 MMB of oil in storage in 1990) and Bayou Choctaw (approximately 56 MMB of oil in storage in 1990). In the EIQ, hydrocarbon emissions for St. James were estimated at 866 metric tons/year (954 tons/year) for loading operations and 541 metric tons/year (596 tons/year) for unloading operations.[87/] Since St. James serves two salt dome storage areas, the hypothetical 60-MMB salt dome estimates can be doubled for comparison of emissions. The resulting estimates are 1,386 tons/year for loading and 1,058 tons/year for unloading. Thus, the more recent EIQ estimates for St. James terminal are below the levels associated with the hypothetical salt dome facilities in the PEIS.

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86/ *Environmental Survey Preliminary Report for the Strategic Petroleum Reserve*, U.S. Department of Energy, 1989.

87/ *U.S. DOE Strategic Petroleum Reserve, 1987 Annual Environmental Monitoring Report*, Boeing Petroleum Services, U.S. Department of Energy, 1988. Document Number D506-01728-09.

In addition, actual emissions from tanker loading and unloading operations at St. James are lower than the 1983 EIQ estimates. In each year since the EIQ was submitted, hydrocarbon emissions were well below the levels projected in the EIQ.[88/]

Using EPA dispersion models for worst-case conditions, the PEIS concluded that emissions during tanker loading and unloading may result in limited violation of the National Ambient Air Quality Standards (NAAQS) for hydrocarbons. The NAAQS for hydrocarbons was revoked in 1983, so such a comparison no longer has regulatory significance. Further, with hydrocarbon emissions lower than predicted in the PEIS, it can be assumed that downwind concentrations will also be lower than predicted.

In addition to emissions associated with tanker loading and unloading, estimated annual emissions from surge and storage tanks, pump seals, and pipeline valves appear to be conservative compared to recent estimates from the salt dome sites. The Supplement estimated hydrocarbon emissions from surge and storage tanks to be 59 tons/year (based on three 200,000 bbl tanks and one 1,000 bbl tank) or 65 tons/year (based on two 400,000 bbl tanks and one 5,000 bbl tank). The maximum allowable emission rate for the surge tanks at the Bryan Mound site (four 200,000 bbl tanks) under permits issued by the Texas Air Control Board is 6.1 tons/year, and calculated emissions, based on monthly throughput, are routinely below this limit.[89/] The Supplement estimated hydrocarbon emissions for pump seals and pipeline valves from the 60-MMB hypothetical facility to be 19 tons/year. Emissions from valves and pumps estimated in the 1987 EIQ for the Bayou Choctaw site were less than 1 ton/year.[90/]

Hydrocarbons in the atmosphere affect ambient concentrations of ozone (a NAAQS pollutant), and most SPR facilities are in nonattainment areas for ozone. Although hydrocarbon emissions have occurred at SPR facilities, these emissions are not likely to have been major contributors to regional ozone levels. In fact, ozone in the Houston-Galveston-Brazoria, Texas area decreased by 24 percent for the period 1979 to 1988.[91/]

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88/ *U.S. DOE Strategic Petroleum Reserve, 1984-1988 Annual Environmental Monitoring Report*, Boeing Petroleum Services, 1985-1989 and *U.S. DOE Strategic Petroleum Reserve, 1989 Annual Environmental Report*, Boeing Petroleum Services, 1990.

89/ *Environmental Survey Preliminary Report for the Strategic Petroleum Reserve*, U.S. Department of Energy, 1989.

90/ Ibid.

91/ *National Air Quality and Emissions Trends Report, 1989*, U.S. Environmental Protection Agency, 1990.

Although the PEIS focused on hydrocarbon emissions, other short-term effects such as fugitive dust emissions were also mentioned. The Environmental Survey Preliminary Report demonstrated that such dust impacts were localized and short-term, and have been minimized with adequate dust control methods. For example, at several salt dome sites, roads were graded to level, as necessary, and applications of calcium chloride were used at 90-day intervals to minimize fugitive dust emissions.[92/]

One environmental issue not considered in the PEIS is the effect of certain air pollutants on long-term changes to the global atmosphere. SPR facilities, however, are not thought to be significant sources of carbon dioxide, which contributes to global warming through the greenhouse effect, or chlorofluorocarbons and halons, which break down the stratospheric ozone layer. Emissions of hydrocarbons, the primary air pollutant associated with SPR activities, are not expected to affect global climate. Overall, no supplement to the PEIS appears warranted based on air quality impacts.

### 5.5 Other Environmental Impacts

The other environmental impacts discussed in the following sections address geology and land use patterns.

#### 5.5.1 Geologic Impacts

Potential geological impacts from the SPR program identified in the PEIS included halokinesis or cavern "creep" (i.e., the tendency of caverns to close as a consequence of the plastic flow of salt under heat and pressure), subsidence (i.e., subsidence of the surface resulting from cavern contraction), seismic stability (i.e., local likelihood of earthquakes), and impacts to soil. The development and filling of salt domes in the Gulf region has progressed much as projected in the PEIS, and the analysis of potential geologic impacts remains valid.

**Subsidence.** Significant rates of subsidence have been reported in the Gulf Coast region. The following is an overview of this issue and an evaluation of the impact of SPR activities on subsidence in this region.

Local subsidence in the Gulf Coast region is primarily attributable to human activity.[93/],[94/],[95/] Subsidence rates of 7.0 mm per year have been recorded for New Orleans

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92/ *Environmental Survey Preliminary Report for the Strategic Petroleum Reserve*, U.S. Department of Energy, 1989.

93/ Holdahl, S.R. and Morrison, N.L., *Regional Investigations of Vertical Crustal Movements in the U.S., Using Precise Relevelings and Mareograph Data*, Tectonophysics, Volume 23, 1974, pp. 373-390.

and several decimeters per year for Galveston.[96/] Overpumping of groundwater has been cited as a major contributor to land surface subsidence in the Galveston region.[97/98/] Subsidence in coastal Louisiana has been attributed to impacts from oil and gas extraction, groundwater withdrawal, and sediment compaction.[99/,100/] Over the longer term, subsidence results from isostatic correction to sediment loading, principally from the Mississippi River, which is causing the gradual oceanward tilt of the Gulf Coast Syncline.[101/]

Subsidence has been cited as a factor in the loss of Louisiana's coastal wetlands. Thirty-two thousand acres, of a total of approximately three million acres of wetlands in Louisiana, are lost every year.[102/] Land use practices, such as construction of levees and navigation channels, have prevented sediment and fresh water from reaching wetlands. The gradual submergence of wetlands

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94/(...continued)

94/ Brown, L.D. and Oliver, J.D., *Vertical Crustal Movements from Leveling Data and their Relation to Geologic Structure in the Eastern United States*, Reviews of Geophysics and Space Physics, Volume 14, 1976, pp. 35.

95/ Leatherman, S.P., *Coastal Geomorphic Responses to Sea Level Rise: Galveston Bay, Texas,* in Greenhouse Effect and Seal Level Rise, M.G. Barth and J.G. Titus (eds), Van Nostrand Reinhold, NY, NY, 1984, pp. 151-178.

96/ Holdahl, S.R. and Morrison, N.N., *Regional Investigations of Vertical Crustal Movements in the U.S., Using Precise Relevelings and Mareograph Data*, Tectonophysics, Volume 23, 1974, pp. 373-390.

97/ Leatherman, S.P., *Coastal Geomorphic Responses to Sea Level Rise: Galveston Bay, Texas*, in Greenhouse Effect and Sea Level Rise, M.G. Barth and J.G. Titus (eds), Van Nostrand Reinhold, NY, NY, 1984, pp. 151-178.

98/ Brown, L.D. and Oliver, J.E., *Vertical Crustal Movements from Leveling Data and Their Relation to Geologic Structure in the Eastern United States*, Reviews of Geophysics and Space Physics, Volume 14, 1976, pp. 13-35.

99/ Ibid.

100/ Chi, S.C. and R.E. Reilinger, *Geodetic Evidence for Subsidence Due to Groundwater Withdrawal in Many Parts of the United States of America*, Journal of Hydrology, Volume 67, 1984, pp. 155-182.

101/ Brown, L.D. and Oliver, J.E., *Vertical Crustal Movements from Leveling Data and Their Relation to Geologic Structure in the Eastern United States*, Reviews of Geophysics and Space Physics, Volume 14, 1976, pp. 13-35.

102/ Koppleman, L., *Independent Reviews*, in Greenhouse Effect and Sea Level Rise, M.G. Barth and J.G. Titus (eds), Van Nostrand Reinhold, NY, NY, 1984, pp. 313-316.

has allowed intrusion of saltwater further inland which has killed some cypress swamps while converting freshwater wetlands to brackish and saltwater marshes.[103/]

Subsidence at SPR sites could occur following cavern creep closure. In creep closure, lithostatic and hydrostatic stress differentials exert pressures which close certain areas of the cavern. The SPR Capline Group EIS concludes, however, that only an insignificant fraction of the total cavern area would be affected by this process.

Extreme creep can result in cavern collapse. The SPR Capline Group EIS assesses ' ˬ probability of any type of salt dome collapse as "extremely unlikely" based upon past experience with the storage of petroleum hydrocarbons in salt domes in the U.S., Germany, and France.[104/] Over the last 25 years, there have been no recorded collapses of salt caverns. Evidence of creep can be readily detected and appropriate measures taken to prevent further degradation. Preventative measures include ensuring adequate wall and roof thickness, with a minimum separation distance of 480 ft. between the walls of adjacent caverns and 300 feet between the cavity ceiling and the caprock.

Even assuming a worst-case scenario, subsidence bowls from a general cavern collapse would not exceed tens of feet for the shallowest mines, and even less for solution mined caverns. Oil would probably reach the caprock in small seeps, forming a small surface depression equal in volume to the original cavern. As a result, the impacts would be localized and are not likely contribute to subsidence on a regional scale.[105/] In addition, SPR facilities are working closely with state and local authorities to analyze the causes and contributions to regional subsidence.

**Seismic Stability.** Ground motion resulting from an earthquake could, depending on magnitude, result in damage to oil storage tanks and pipelines. This in turn could result in oil spills. However, the overall risk of seismic damage to facilities in the Gulf Coast region is very low and the risk of damage to a salt dome cavity is even lower, because resonance generally does not take place between the cavity and the vibrating medium that contains it, and any differential movements within the rock mass are not amplified. Furthermore, as concluded in the PEIS, the impacts associated with a given seismic event are probably less for salt dome storage than for any other geologic (or man-made) structure, because salt's viscoplastic properties minimize the likelihood of fracture development and also "heal" any fractures that might result from earthquake activity and seismic loading.

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103/ Titus, J.G. (ed), *Greenhouse Effect, Sea Level Rise and Coastal Wetlands*, U.S. EPA: Office of Policy, Planning and Evaluation, 1988. EPA Report Number: EPA-230-05-86-013.

104/ *Strategic Petroleum Reserve: Capline Group Salt Domes Final Environmental Impact Statement, Volume IV*, U.S. Department of Energy, July 1978.

105/ Ibid.

**Impacts to Soils.** The greatest concern in terms of impacts to soil is that of prolonged seepage of brine into the ground from an undetected leak in the brine handling equipment, according to the PEIS. If such an accident did occur, the soil would become less able to support vegetation. The length of time this effect would last would depend upon the extent of seepage and local conditions that would wash away the salt deposit; but generally, brine seepage from an undetected leak would have adverse impacts, as identified in the PEIS.

### 5.5.2 Impacts on Land Use Patterns

The PEIS included a description of the major effects on land use that would result from the construction, noise, traffic and visual impacts. The PEIS stated that depending on the particular location, the surrounding land may be pasture, crop land, forest, marsh, or swamp. Candidate storage sites may also be located in floodplains. In accordance with DOE policy (see section 4.4.1), precautions to reduce the risk of flood and minimize the impacts of floods are considered in site selection and design plans.

Significant changes in land use patterns probably have not occurred since the PEIS's original assessment; minor adjustments in the breakdown of urban/rural population centers in the Gulf Coast storage area have probably occurred. Considerations identified in the PEIS such as pipeline right-of-way and power transmission corridors would need to be evaluated in a site-specific assessment. Portions of the rights-of-way would have to be maintained in accordance with any federal, state, local or municipal regulations, as applicable.

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ATTACHMENT I

EAST COAST INGROUND TANK
FACILITY FEASIBILITY

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# ATTACHMENT I

DOE considered the feasibility of the construction of an inground tank storage facility at an East Coast location. Total storage capacity was estimated to be 100 MMB. In addition to construction of an inground tank, supporting infrastructure (i.e., marine terminal and connecting bi-directional pipeline) was considered. As a result of this assessment, DOE has determined that the costs and potential environmental impacts that would be associated with such a facility make this not a reasonable alternative for the proposed expansion of the SPR.

The U.S. Army Corps of Engineers performed a survey overview of potential sites for an East Coast expansion of the SPR. A total of 20 sites were considered and evaluated for the location of an inground tank facility based on certain locational and geographic criteria. These areas included:

- New Jersey counties of Gloucester, Salem, and Cumberland.
- Maryland county of Cecil.

Since the development of an East Coast storage facility would likely require construction of a new government-owned marine terminal connected to the storage facility via a bi-directional pipeline, further siting constraints were imposed on the consideration of potential sites, leading to consideration of the following for the marine terminal:

- New Jersey Shore between Gibbstown and Pennsville.
- Delaware Shore between New Castle and the Chesapeake and Delaware Canal.

The PEIS did not address the specific environmental impacts of an inground storage facility. However, some elements of the generic discussion of environmental impacts of other storage alternatives may be broadly applicable to inground tanks. For example, the PEIS analysis of land disturbance problems from construction of tank farms may apply to inground storage tanks. The issue of groundwater contamination was not addressed for tank farms, but would have to be evaluated if the option of inground tanks is pursued. Inground concrete tank storage would be significantly different from the alternatives considered in the PEIS, and as such, would require further description and analysis in site-specific NEPA documentation. The applicability of the PEIS is discussed in more detail in Section A.1.

Based on the environmental considerations discussed in Section A.2 below, pursuit of an East Coast inground concrete storage facility would present significant risk to the SPR program, and therefore, DOE has determined that the alternative is not reasonable for the proposed expansion.

### A.1 Inground Storage Tanks: Design Description and Applicability of PEIS

A conceptual plan for a 100-MMB inground tank storage facility has been developed and DOE has conducted preliminary cost studies. Inground oil storage tanks similar to the one contemplated by DOE have been constructed in Africa and have been operational for over ten years with no reported environmental problems.

The proposed facility would be composed of a series of near-surface buried tanks built primarily of cast-in-place concrete. Each tank would have a capacity of 4.8 million $ft^3$ and hold approximately 850,000 barrels. The tanks would be built in clusters of four, with each cluster forming a module. A total of 30 modules, each containing up to 3.4 million barrels would be required to reach the total planned capacity of 100 million barrels.[1/]

The exterior walls of each module would be constructed of reinforced concrete placed upon concrete footings. Each tank would have a series of parallel interior walls spaced approximately 40 feet apart to support the roof sections. Openings would be made in each of the walls to allow oil to flow readily between the tank sections. The roof of each tank would be constructed of precast, prestressed double-tee concrete slabs approximately 40 feet long that span the spaces between the interior walls. A flexible membrane liner would cover the floor, the roof, and the interior walls of each tank to prevent leakage to the surrounding area. The membrane is proposed to be made of high density polyethylene, a material that has been used successfully in similar types of construction activities.

The inground storage tank would be designed to hold oil under pressure so that vapor losses are eliminated during the period of storage. Vapor control equipment would be necessary during the filling and drawdown periods. Petroleum would enter the tank from a pipeline that connects the facility to the distribution system. When the petroleum is removed from the tanks during drawdown, an inert gas would be pumped in to eliminate explosion hazards.

In addition to the tanks, the storage facility would require support facilities including control, administration, and maintenance buildings, collection tanks, electrical substation, and pumping and oil heating systems. Offsite construction would include a pipeline, pumping station, and power station for an offsite pumping system.

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1/ U.S. Department of Energy, *Expansion of the Strategic Petroleum Reserve to One-Billion Barrels: Site Identification, Screening, and Selection*, Volume 1, February 10, 1989. pp. 301-304.

The primary advantages of an inground tank facility are that it requires less land area than tank farms on the land, air emissions are reduced, and it may be less prone to damage from air accidents and sabotage. The major environmental threat posed by such a facility is the potential contamination to groundwater from leakage or structural failure. For example, leaks in the membrane lining could be caused by welding errors or cracks in floors or walls due to the improper laying of cement. These types of problems are quite common in construction projects of this magnitude and need to be taken into account in assessing environmental risks, especially since the large volumes of oil held in these tanks could result in severe groundwater contamination if a failure were to occur. Additional environmental damage could result from disturbances in drainage patterns due to excavation, contamination from stormwater runoff, and leaks in pipelines.

The most significant environmental risk associated with an inground tank is the potential contamination of groundwater in the event of structural failure or undetected leaks. Because of the large volume of oil that would be held in these tanks, the extent of contamination could be quite large before the problem is fixed, especially if the unit is poorly sited hydrologically. Groundwater contamination from these types of units or failures was not addressed in the PEIS because inground storage was not considered as an alternative in the original SPR planning.

Another potential source of environmental contamination is stormwater runoff from the storage unit area, which could potentially become contaminated with spilled oil and suspended solids. If the runoff is not properly contained, contamination of adjacent surface or groundwater systems is possible.

In addition, the construction of inground storage units would require significant excavation and disturbance of existing soils. Degradation of adjacent water systems might occur as a result of potential changes in drainage patterns during construction. The vulnerability to erosion is of particular concern at East Coast locations, where intensive land use has already resulted in severe disturbances of natural drainage patterns. These issues were addressed generally in the PEIS, but in conjunction with construction of above-ground tanks. The type of excavation required for an inground tank facility may result in more severe impacts on the environment. For example, although the inground tank facility would likely need less acreage than an above-ground tank facility, more actual excavation may occur.

### A.2 Environmental Issues

Significant delays and cost growth were encountered in the early stages of Gulf Coast SPR development due to regulatory requirements in the permitting process. Contributing factors included lack of familiarity of state agencies with SPR systems, activities, and procedures, and public suspicion of large-scale development employing technology that, at the time, was unproven for crude oil storage in this country. For similar reasons, there is a significant risk to the program of major delays and cost growth associated with implementing an untried concept, large-scale inground concrete storage tanks, in a region, the East Coast, that has no experience with the SPR program. Further, a major consideration associated with an East Coast storage site is the lack of relevant infrastructure for crude oil transport and distribution. Siting and constructing these associated facilities (i.e., pipeline and marine terminal) would encounter serious problems because of environmental concerns.

### A.2.1 General Considerations

Development of a 100-MMB inground tank storage facility would result in the extreme disturbance of a 640-acre site; this represents an irreversible and irretrievable loss of resources. The facility could pose serious environmental risks during operations through the potential for large crude oil leaks to groundwater and releases to land and surface water. These risks, however, would be mitigated in accordance with existing Departmental orders through an extensive groundwater monitoring program and spill prevention and control designs, procedures, and countermeasures. Although the inground approach necessarily requires siting the storage facility to avoid wetlands (and to be above the water table), wetland involvement may be unavoidable in siting a marine terminal or in routing a pipeline between the docks and the storage facility.

Aside from the public concern that would be anticipated with such a project, there is heightened public sensitivity to siting industrial facilities throughout the Delaware River basin. Accordingly, the affected States have imposed stringent regulations including prohibition of undesired facilities. For example, Delaware prohibits siting of any new heavy industrial facilities or new offshore liquid transfer facilities in the coastal zone; consequently, siting a marine terminal may be unrealistic. The States of New Jersey, Delaware, and Maryland all have extensive regulations covering construction on or disturbance of the areas' wetlands and coastal zones. Because the pipeline and marine terminal would likely impact these areas, requirements for permits, mitigation measures (e.g., replacement of wetlands), and determinations that no alternative sites exist would pose additional requirements.

The stretches of the Delaware River under consideration for a marine terminal are located in a nonattainment area for the ozone National Ambient Air Quality Standard (NAAQS). Releases of hydrocarbons, such as those anticipated during loading and unloading of crude oil, increase the formation of atmospheric ozone. Therefore, siting a marine terminal in an ozone nonattainment area would be difficult, if not impossible. Such siting could only be accomplished in accordance with the Clean Air Act's offset policy. Under the offset policy, before a permit can be issued for a new source in a nonattainment area, legally enforceable emission reductions are required for all existing sources. Extensive negotiations with all existing sources would be necessary to achieve this requirement; financial compensation also likely would be required. In addition, as a new source, the marine terminal would be required to install state-of-the-art control technology, which would be very expensive. The risk of cost growth and schedule delay that could result from the offset policy is unknown at this time, but it is deemed to be significant, and possibly insurmountable.

An additional concern is the increased risk of oil spills on the Delaware River given typical oil-handling operations. The replacement of 100 MMB of lost imports from a local storage facility could effectively triple the petroleum handling operations on the waterway: the transfer from tanker to terminal during fill of the storage facility; the transfer from terminal to tanker during a drawdown; and the transfer from the tanker to local refinery docks. This is particularly important given public concern over recent oil spills and resulting adverse impacts on the Delaware River.

### A.2.2. Specific State Considerations

The specific considerations for a New Jersey site, and for a Delaware/Maryland site are discussed in the sections that follow.

**New Jersey.** All three counties considered for the inground tank facility in New Jersey border the Delaware River and, thus, both the pipeline from the Marine Transfer Terminal (if located on the New Jersey shore) to the tank facility and the inground tank will be subject to New Jersey state laws and regulations.

- Coastal Zones and Wetlands

The state of New Jersey has a significant amount of coastal and inland wetlands. Coastal wetlands are distributed along the regions of Gloucester, Salem, and Cumberland counties that border the Delaware River. Several Federal and state laws regulate certain uses of many of the New Jersey wetlands. While the sites in New Jersey being considered for the inground tank facility will most likely not fall within regions in the jurisdiction of the state's coastal zones and wetlands regulations, the pipeline certainly will. This would impose requirements primarily during the construction phase (as opposed to the operational) of any project.

> **The New Jersey Coastal Area Facility Review Act** requires that facilities involved with bulk storage, handling, and transfer facilities for crude oil apply for a permit before construction can take place in the coastal area (as defined in the Act). The permit application must include an environmental impact statement (EIS). This Act might impose permit and EIS requirements during the construction of the MTT and the pipeline.
>
> **The New Jersey Wetlands Act** requires that a permit be obtained prior to conducting a regulated activity upon a wetland, whether or not that activity would change the tidal ebb and flow. Regulated activities include the erection of structures, driving of pilings, and the placing of obstructions.

**New Jersey Freshwater Wetlands Protection Act/New Jersey Freshwater Wetlands Regulations** apply to the alteration or disturbance in and around freshwater wetland areas in New Jersey. These regulations also require a permit for certain regulated activities that may be conducted in wetlands, including activities leading to the destruction of plant life that would alter the character of a freshwater wetland (e.g., cutting trees). One of the requirements for receiving a permit is performance of mitigating actions, which may impose requirements such as restoration, creation, and enhancement of wetlands.

- Water Quality

A number of water pollution control and hazardous discharges laws in New Jersey can be expected to impose additional requirements during both the construction and operational phases of a project.

**The Water Pollution Control Act** can apply to the storage of any liquid pollutant, and requires that a permit be obtained before any discharge to the waters of the state can occur.

**The Spill Compensation and Control Act** specifically covers the storage and transfer of petroleum products between vessels and facilities and imposes a requirement for submission of information, including contingency cleanup and removal plans.

**The New Jersey Hazardous Discharges Law and the New Jersey Rules on Discharge of Petroleum and other Hazardous Substances** set forth certain design and maintenance requirements for major facilities that handle petroleum. These regulations also establish reporting and notice requirements and procedures concerning discharges.

In addition, depending on the state's interpretation of certain provisions, the inground tank facility could be subject to **New Jersey Underground Storage Tank Rules** that would impose registration and certification requirements for the operation of the facility.

- Oil Spills

New Jersey water pollution control laws also establish a **Spill Compensation Fund** that sets liability limits and penalties, and levies taxes to ensure compensation for cleanup costs and damages. Under New Jersey regulations, major facilities (those storing 400,000 gallons or more) must provide evidence of financial responsibility and prepare prevention and cleanup plans (including requirements for bulk storage tanks and marine transfer facilities). Oil spill prevention measures require: detailed discharge prevention plans; fees and taxes on regulated companies; illumination and booms during oil transfer operations; civil penalties of up to $10 million for spills of 100,000 gallons or more, in addition to cleanup costs; and registration and stricter regulation of intrastate pipeline facilities.

- Air Quality

Under the Federal **Clean Air Act**, many areas in New Jersey are listed as nonattainment areas for ozone, that may be formed by VOCs emitted during the operational, and, possibly, the construction phases of a project. This may present an impediment to siting the inground tank facility in these areas. Furthermore, there are state laws (i.e., **New Jersey Emission Offset Rules**) that also identify nonattainment areas and restrict activities that will cause a threshold increase, in a nonattainment area, of a criteria pollutant. These rules impose a requirement for an air quality impact review including air quality simulation modeling to determine if such a threshold increase would occur.

> Particularly applicable to the construction of the inground tank and pipeline are the **New Jersey Regulations on Permits and Certificates**. These regulations require that a permit and operating certificate be obtained for equipment such as storage tanks that are used for storage of liquids (in excess of 10,000 gallons), except water or distillates of air, and for storage of volatile organic substances (in excess of 2,000 gallons). The construction of such equipment requires a permit, and the State may request applicants to perform air quality simulation modeling to show that ambient air quality standards will not be violated.
>
> Finally, the construction and operation of the pipeline and the inground tank may be subject to the **New Jersey Regulations on Emergencies**, which require the preparation of standby plans designed to reduce and eliminate emissions of air contaminants into the atmosphere during periods of an air pollution alert.

**Delaware/Maryland.** Due to the geography of the area, if the MTT was located in Delaware, an inground tank facility could be located in Maryland with a pipeline in both states. Such a configuration would come under the jurisdiction of the regulations of both states, and, therefore, the applicable state laws and regulations for Delaware and Maryland are considered together in this section.

- Coastal Zones and Wetlands

Both Delaware and Maryland have extensive state regulations covering construction on or disturbance of the areas' wetlands and coastal zones. Sites in Cecil County, Maryland and New Castle County, Delaware may fall within these regions. Maryland sites also could fall under the requirements of the **Maryland Chesapeake Bay Critical Area Act**, which would impose additional requirements; in selecting potential locations for an inground tank facility, fewer environmental considerations would exist if sites in Chesapeake Bay critical areas were eliminated as candidates.

**The Delaware Coastal Zone Act** prohibits any (as of June 1971) heavy industry facilities and offshore liquid transfer facilities from operating in the state's coastal zones. While it is unknown whether an MTT would be classified in one of these two categories, the tone of the law indicates that the state is willing to impose stringent regulations, including prohibition of undesired facilities. For allowed facilities, the law requires issuance of a permit prior to construction. In evaluating permit requests, factors analyzed include environmental impacts (particularly air and water pollution, destruction of wetlands, and water quality impacts), aesthetic effects, and effects on neighboring land uses.

**The Delaware Beach Preservation Act** requires permits and/or letters of approval for various construction activities in the area defined as "beach." Because the beach by definition terminates at a point south of the proposed MTT location (i.e., "the Old Marina Canal immediately north of Pickering Beach"), this act is not likely to affect any probable SPR locations.

**The Maryland Coastal Facilities Review Act/Rules** require a permit for (1) any pipeline carrying crude oil ashore from offshore sources and (2) any crude oil storage facility whose total design capacity is at least 100,000 barrels, or which occupies at least fifty acres, if such a facility is located in the "coastal area." The coastal area includes Cecil County and all other counties that border Delaware. For permit approval, a facility must comply with all applicable air, water, noise, and solid waste laws of the state, and local land use laws; have no material adverse impact on the natural environment; and have no material adverse impact on public health, safety or welfare.

**The Delaware Wetlands Act/Regulations, The Delaware Underwater Lands Act, The Maryland Wetlands Act/Regulations and The Maryland Non-Tidal Wetlands Protection Act** prohibit or regulate various construction activities in the wetland or underwater areas they cover. In several cases permits are required; conditions of permits include: (1) no alternative site exists and (2) mitigation measures be performed, for example by replacing the impacted wetlands or by monetary compensation.

- <u>Air Quality</u>

Most areas in Delaware and Maryland currently are listed as nonattainment areas with respect to the federal National Ambient Air Quality Standard (NAAQS) for ozone. Thus, this would present an issue in these areas. State air pollution laws may be an additional concern in that most require permits for construction and operation of facilities which may contaminate the air.

**The Maryland Air Pollution Regulations** specify that sources and installations that are subject to requirements for construction approvals and permits, including petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels and volatile organic liquid storage vessels (e.g., petroleum liquid storage vessels) having a capacity in excess of 10,570 gallons. In addition, the state determines if such installations require a separate operating permit. Furthermore, Cecil County falls in a specific area designated by the regulations (i.e., Area VI), and, therefore, more stringent requirements (e.g., need for control equipment) may apply to the construction and operation of an inground tank facility.

**The Maryland Air Quality Control Act** has broad jurisdiction in that its definition of a "source" is any person or property that contributes to air pollution. This Act may impact a project primarily by imposing permit and registration requirements for the construction and operation of the inground tank, if the state determines that the facility is a source.

**The Delaware Environmental Protection Laws** require that a permit be obtained before any activity is undertaken that may cause or contribute to the discharge of an air contaminant. More specifically, these laws identify that the construction, maintenance, and operation of a pipeline system including any appurtenances such as a storage tank or pump station, constitute such activity.

**Delaware Regulations Governing the Control of Air Pollution** apply mainly to the petroleum storage vessel rather than the pipeline itself, and, therefore, may not be applicable to a project (because the inground tank would more likely be sited in Maryland). The MTT, however, may be covered under these regulations.

- <u>Water Quality</u>

A number of water pollution control laws in Maryland and Delaware can be expected to impose additional requirements during both the construction and operational phases of a project.

**The Maryland Water Pollution Control Regulations** set forth guidelines for the reporting and cleanup of oil spills and discharges. The regulations also require that a license be obtained in order to transfer oil in the state and that facilities storing oil in quantities greater than 10,000 gallons obtain a permit.

**The Delaware Water Pollution Control Laws/Regulations** can apply to facilities which store any liquid pollutant, including petroleum, and prohibits the discharge of any pollutant into groundwater or surface water without a permit. The Act sets forth cleanup requirements for oil discharges and proscribes penalties for violators.

**The Delaware River Basin Commission Water Quality Regulations** set limits for oil and grease in stormwater runoff from oil storage facilities.

In addition, the inground tank facility could be subject to **Delaware Underground Storage Tank Rules** that would impose registration and certification requirements for the operation of the facility.

- Oil Spills

**The Delaware Oil Pollution Liability Act** establishes penalties for dischargers, requires dischargers to pay for damages and cleanup costs, sets liability limits, and mandates that vessels and facilities meet financial responsibility requirements.

**The Maryland Oil Pollution Control Act/Regulations** establishes a program for licensing storage and transfer of oil and penalties for oil spillage.

ATTACHMENT II

WATER QUALITY IMPACTS
FROM SPR OPERATIONS

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# ATTACHMENT II

**Documented Impacts to Water Quality from SPR Operations**

The following list represents a sampling of those incidents at SPR facilities that have had an impact on water quality from 1982 through 1990. In general, these incidents fall within the scope of impacts considered in the PEIS, have resulted in minor water quality impacts, and would be best addressed in site-specific EISs. The water quality impacts identified in the PEIS, therefore, are generally comparable to those experienced during SPR operations to-date.

- On June 22, 1989, 825,000 barrels of waste brine (salinity 0-274 ppt) were released into a coastal salt marsh just south of the Bryan Mound site. Vegetation was killed throughout the impacted area. Natural flushing allowed for the rapid dispersion of brine to the Intercoastal Waterway, and vegetation recovered quickly in all but the most severely affected areas. A site-specific report[1/] prepared after the spill concluded that such events should cause only temporary damage.

- In 1985, an earlier brine spill at Bryan Mound drained into nearby Blue Lake, raising salinities as high as 35 ppt.[2/]

- Groundwater monitoring at well PB-1 at the West Hackberry site has shown that the aquifer at a depth of 40 to 50 feet was contaminated with brine, while a more shallow aquifer was not. Because only the deeper aquifer shows contamination, the source is thought to be an abandoned cavern wellhead plugged in the 1950's. However, a brine pond is also in the vicinity and may be a contributing factor or possibly the sole source of the excess salinity.[3/] Annual environmental monitoring reports have also noted the increasing salinity in this well.

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1/ *Final Bryan Mound Environmental Monitoring Report, Brine Disposal Pipeline Leak Incident*, Boeing Petroleum Services, Inc., October 12, 1990 .

2/ *U.S. DOE Strategic Petroleum Reserve, 1985 Annual Environmental Monitoring Report*, Boeing Petroleum Services, Inc, 1986. Document Number D506-01105-09.

3/ *Strategic Petroleum Reserve Environmental Survey Plan Phase I, November 30 - December 11, 1987*, U.S. Department of Energy, Environment, Safety, and Health: Office of Environmental Audit, 1987.

The salinity ranges were 7.8-17.0 ppt in 1985,[4/] and 0.8-113.5 ppt in 1987.[5/] Unusually low pHs, ranging from 3.2 to 6.1, were also observed in this monitoring well in 1987.[6/]

- Brine pond leakage may be occurring at Bryan Mound, West Hackberry, Bayou Choctaw, and Sulfur Mines sites. At Bryan Mound, the concrete basin is cracked, liner damage is suspected, and monitoring wells show brine contamination of shallow and deep aquifers. The West Hackberry and Bayou Choctaw sites have no leakage detection systems (i.e., underdrains and sumps), and the concrete pond at West Hackberry is cracked and the liner torn.[7/] Finally, liquid collected from the underdrain beneath the Sulfur Mines brine pond was reported to range in salinity from 39-210 ppt.[8/]

- For three years, groundwater samples from monitoring wells at Bryan Mound have contained elevated salinities: 8-118 ppt in 1984[9/], 88-112 ppt in 1985[10/], and 97-270 ppt in 1986.[11/] The probable causes are cited as interconnections between freshwater and saltwater aquifers and the proximity of wells to salt domes.

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4/ Ibid.

5/ *U.S. DOE Strategic Petroleum Reserve, 1987 Annual Environmental Monitoring Report*, Boeing Petroleum Services, Inc., 1988. Document Number D506-01728-09.

6/ Ibid.

7/ *Environmental Survey Preliminary Report, Strategic Petroleum Reserve: Texas and Louisiana Gulf Coast*, U.S. DOE, Environment, Safety, and Health: Office of Environmental Audit, January 1989, pp. 3-24, 6-25,26, 8-24,25. DOE/EH/OEV-34-P.

8/ *U.S. DOE Strategic Petroleum Reserve, 1985 Annual Environmental Monitoring Report*, Boeing Petroleum Services, Inc, 1985. Document Number D506-01105-09.

9/ *U.S. DOE Strategic Petroleum Reserve, 1984 Annual Environmental Monitoring Report*, Boeing Petroleum Services, Inc, 1985. Document Number 124-84-AS-001.

10/ Op cit.

11/ *U.S. DOE Strategic Petroleum Reserve, 1986 Annual Environmental Monitoring Report*, Boeing Petroleum Services, 1987. Document Number D506-01439-09.

- A seal leak on the high pressure pump pad at Sulfur Mines caused the release of brine into surface waters, resulting in salinity concentrations of up to 18 ppt, well above background levels. At West Hackberry, a similar mechanical malfunction on the high pressure pump pad increased the salinity in surface water samples as high as 64.6 ppt in 1982[12/] and 43.2 ppt in 1983.[13/]

- Wells to be used in cavern formation at Big Hill were sampled, because it was suspected that the contractor who drilled them added substances other than just clean brine. Investigation revealed high viscosity liquids at various locations in the wells. Upon further testing, these liquids were found to be long-chain hydrocarbons.[14/]

- Groundwater monitoring wells at Big Hill were found to contain high levels of inorganic contaminants of unknown origin including: lead, cadmium, copper, mercury, zinc, cyanide, nickel, antimony, and thallium. In most cases, these concentrations exceeded 1 ppm. Discharge of the contents of the wells to the Gulf of Mexico was authorized for those wells with "low" levels of contamination. The contents of the remaining wells were flushed into storage tanks and disposed of "appropriately" depending upon the contaminants present.[15/]

- Some of the radioactive tracer pellets used in drilling brine disposal wells at Sulfur Mines were lost in the process, and may have posed a threat to water quality. The materials used typically have short half lives (e.g., 8 days for iodine-131), and have probably long since decayed.[16/] This type of release, therefore, does not appear to pose a long-term threat.

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12/ *U.S. DOE Strategic Petroleum Reserve, 1982 Annual Environmental Monitoring Report*, Boeing Petroleum Services, 1983, p. 3-25. Doc. No. 124-83-A5-001.

13/ *U.S. DOE Strategic Petroleum Reserve, 1983 Annual Environmental Monitoring Report*, Boeing Petroleum Services, 1984. Doc. No. 124-84-AS-001.

14/ *Strategic Petroleum Reserve Environmental Survey Plan Phase I, November 30 - December 11, 1987*, U.S. Department of Energy, Environment, Safety, and Health: Office of Environmental Audit, 1987, Section 5.1.

15/ Ibid. Section 5.1.

16/ U.S. DOE, Health, Safety, and Environment: Office of Environmental Audit, 1989, p. 5-23.

- An unpermitted release from an oxidation pond, in which grease, oil, and surfactants biodegrade, occurred at West Hackberry. The effluent was discharged to a drainage ditch and eventually flowed off-site.[17/] Furthermore, steps have since been taken to permit this release to assure that it is adequately controlled in the future.

- The potable water treatment unit at Sulfur Mines produces a salt solution that is discharged to a ditch that eventually flows off-site. This discharge was not included in this site's permit at the time,[18/] but steps have been taken to get the release permitted. The impacts associated with these releases in the past appear to have been minor and will be further mitigated in the future by new permit controls.

**Situations with Potential for Water Quality Impacts**

Site-specific analyses of the SPR facilities have identified several treatment processes, abandoned wells, and potential leaks that may result in adverse water quality impacts if left unattended. These potential impacts currently are being mitigated by engineering practices, controls, and repairs.

- Aqueous Film Forming Foam (AFFF) is utilized at all SPR sites for fire suppression because it is effective on hydrocarbon liquid-based fires. These products can cause oxygen depletion if released into surface waters, and contain fluorocarbons that are non-biodegradable. Treatment of these products in on-site water treatment facilities would reduce the threat to surface waters, but existing facilities only have enough capacity to treat a small fraction of the effluent that is produced by the bi-annual testing of the fire suppression system, let alone that produced by a major fire.[19/]

- At Big Hill, brackish water is used in the fire suppression system and could possibly result in the contamination of freshwater marshes or groundwater.[20/]

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17/ Ibid. p. 6-21.

18/ Ibid. p. 5-20.

19/ Ibid. p. 3-19,20.

20/ Ibid. p. 4-12,20.

25/

- Unplugged abandoned wells at Bayou Choctaw and Sulfur Mines could act as vertical conduits between the caprock, overlying aquifers, and the surface, potentially allowing the contamination of shallow aquifers or even surface waters. Upward migration of brine through these abandoned wells has not occurred, but DOE's Office of Environment, Safety and Health has recommended that the wells be plugged to make sure it does not happen. Unfortunately, some of the casings have been pulled and the holes have been allowed to collapse, making identification and proper plugging of these wells impossible.[21/] In 1984, groundwater samples from Bayou Choctaw exhibited salinities from 9.0-40.0 ppt, but these elevated levels were thought to be the result of past oil and gas production activities not associated with the SPR.[22/]

- The cavern pad dike at the Bryan Mound site is built on fill material, and the pad has been shown, via dye tests, to leak into nearby Mud Lake. Another pad at this site was built on an old landfill and is also suspected to leak, possibly leaching hazardous substances from the buried materials. After investigation, a DOE survey team concluded that these pads could leak brine, oil, or hazardous materials into nearby surface waters.[23/]

- A leak in a section of a cavern pad containment dike at Sulfur Mines could result in the release of crude oil or brine to surface waters in the event of a spill.[24/]

- Cavern pad drain valves at Big Hill have been found to leak. Following a precipitation event, a small quantity of contaminants could be released to surface waters as the stormwater is drained from these containment areas.[25/]

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21/ Ibid. p. 5-24, 8-26,27.

22/ *U.S. DOE Strategic Petroleum Reserve, 1984 Annual Environmental Monitoring Report*, Boeing Petroleum Services, Services, Inc., 1985. Document Number 124-84-AS-001.

23/ U.S. DOE, Environment, Safety, and Health: Office of Environmental Audit, January 1989, pp. 3-23,24,28,29.

24/ Ibid. p. 5-20.

25/ Ibid. p. 5-20.

- Acid is frequently used to remove precipitated salts from injection wells at the Sulfur Mines site. The pad area, however, is not diked to prevent brine or acid spills from entering surface waters. A DOE survey team also reported that careful attention must be given to pipelines and valves during this procedure to avoid shallow groundwater contamination.[26/]

26/ Ibid. p. 5-24.

## ATTACHMENT III

## CHANGES TO TEXAS' THREATENED AND ENDANGERED SPECIES LISTS

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# ATTACHMENT III

Of the five sea turtles cited as endangered or threatened in the original Environmental Assessment: Strategic Petroleum Reserve Sulphur Mines Decommissioning and Big Hill Expansion, four are still considered endangered: Kemp's Ridley (*Lepidocelys kempi*), Hawksbill (*Eretmochelys i. imbricata*), Leatherback (*Dermochelys coriacea*), and Loggerhead (*Caretta caretta*). The Atlantic green sea turtle (*Chelonia m. mydas*) is still considered threatened. Note that in the 1979 Environmental Assessment the Loggerhead sea turtle was incorrectly classified as *Macroclemys temmincki*.

The following species have been added to the Texas endangered species list since 1979:

| COMMON NAME | SCIENTIFIC NAME | EFFECTIVE DATE |
|---|---|---|
| **Mammals:** | | |
| Bear, black | *Ursus americanus* | March 1, 1987 |
| Coati | *Nasua nasua* | March 1, 1987 |
| Bat, longnose | *Leptonycteris nivalis* | December 30, 1988 |
| **Birds** | | |
| Falcon, Aplomado[1/] | *Falco femoralis* | March 1, 1987 |
| Vireo, black-capped | *Vireo atricapillus* | December 28, 1987 |
| Warbler, Golden-cheeked | *Dendroica chrysoparia* | Dec. 21, 1990 |
| **Reptiles** | | |
| Snake, Louisiana pine[1/] | *Pituophis melanoleucus ruthveni* | March 1, 1987 |
| Snake, western smooth green | *Opheodrys vernalis blanchardi* | March 1, 1987 |
| Snake, northern cat-eyed[1/] | *Leptodeira s. septentrionalis* | March 1, 1987 |
| Turtle, Big Bend mud[1/] | *Kinosternon hirtipes murrayi* | March 1, 1987 |
| Loggerhead[1/] | *Caretta caretta* | March 1, 1987 |
| **Amphibians** | | |
| Newt, black-spotted[1/] | *Notophthalmus meridionalis* | March 1, 1987 |
| Salamander, Blanco blind | *Typhlomolge robusta* | March 1, 1987 |
| Siren, Rio Grande lesser[1/] | *Siren intermedia texana* | March 1, 1987 |

| | | |
|---|---|---|
| Frog, white-lipped[1/] | *Leptodactylus fragilis* | March 1, 1987 |
| **Fish** | | |
| Gambusia, blotched[1/] | *Gambusia senilis* | March 1, 1987 |
| Shiner, phantom | *Notropis orca* | March 1, 1987 |
| Goby, blackfin | *Gobionellus atripinnis* | March 1, 1987 |
| **Plants** | | |
| <u>Cactus</u> | | |
| Tobusch fishhook cactus | *Ancistrocactus tobuschii* | April 29, 1983 |
| Nellie cory cactus | *Coryphantha minima* | April 29, 1983 |
| Sneed pincushion cactus | *Cory phthantha sneedii* | April 29, 1983 |
| | var. *sneedii* | April 29, 1983 |
| Lloyd's hedgehog cactus | *Echinocereus lloydii* | April 29, 1983 |
| black lace cactus | *Echinocereus reichenbachii* | April 29, 1983 |
| | var. *albertii* | April 29, 1983 |
| Davis' green pitaya | *Echinocereus viridiflorus* | April 29, 1983 |
| | var. *davisii* | April 29, 1983 |
| <u>Shrubs</u> | | |
| Johnston's frankenia | *Frankenia johnstonii* | January 9, 1987 |
| Texas snowbells | *Styrax texana* | January 9, 1987 |
| <u>Wildflowers</u> | | |
| Texas poppy-mallow | *Callirhoe scabriuscula* | April 29, 1983 |
| ashy dogweed | *Dyssodia tephroleuca* | January 9, 1987 |
| slender rush-pea | *Hoffmannseggia tenella* | January 9, 1987 |
| Texas bitterweed | *Hymenoxys texana* | January 9, 1987 |
| white bladderpod | *Lesquerella pallida* | May 18, 1987 |
| large-fruited sand verbena | *Abronia macrocarpa* | November 1, 1988 |
| <u>Grasses and Grass-like plants</u> | | |
| Texs wild-rice | *Zizania texana* | April 29,1983 |
| <u>Orchids</u> | | |
| Navasota ladies'-tresses | *Spiranthes parksii* | April 29,1983 |

The following species have been added to the Texas threatened species list since 1979:

| COMMON NAME | SCIENTIFIC NAME | EFFECTIVE DATE |
|---|---|---|
| **Mammals** | | |
| Rat, Coues Rice | *Oryzomys couesi* | March 1, 1987 |
| **Birds** | | |
| Becard, rose-throated | *Pachyramphus aglaiae* | March 1, 1987 |
| Falcon, Arctic peregrine[2/] | *Falco peregrinus tundrius* | March 1, 1987 |
| Parula, tropical | *Parula pityayumi* | March 1, 1987 |
| Plover, piping | *Charadrius melodus* | March 1, 1987 |
| Sparrow, Bachman's | *Aimophila aestivalis* | March 1, 1987 |
| Sparrow, Botteri's | *Aimophila boterii* | March 1, 1987 |
| Tern, sooty | *Sterna fuscata* | March 1, 1987 |
| Tyrannulet, northern beardless | *Camptostoma imberbe* | March 1, 1987 |
| **Reptiles** | | |
| Turtle, alligator snapping | *Macroclemys temminckii* | March 1, 1987 |
| Rattlesnake, timber | *Crotalus horridus* | March 1, 1987 |
| Snake, Big Bend blackhead | *Tantilla rubra* | March 1, 1987 |
| Snake, northern scarlet | *Cemophora coccinea copei* | March 1, 1987 |
| Snake, Brazos water[2/] | *Nerodia h. harteri* | March 1, 1987 |
| **Amphibians** | | |
| Salamander, Cascade Cavers[2/] | *Eurycea latitans* | March 1, 1987 |
| **Fishes** | | |
| Chubsucker, creek | *Erimyzon oblongus* | March 1, 1987 |
| Darter, blackside | *Percina maculata* | March 1, 1987 |
| Goby, river | *Awaous tajasica* | March 1, 1987 |
| Pipefish, opossum | *Oostethus brachyurus* | March 1, 1987 |
| Pupfish, Pecos | *Cyprinodon pecosensis* | March 1, 1987 |
| Shiner, bluehead | *Notropis hubbsi* | March 1, 1987 |

**Plants**

| | | |
|---|---|---|
| Cacti | | |
| bunched cory cactus | *Coryphantha ramilosa* | April 29, 1983 |
| Lloyd's Mariposa cactus | *Neolloydia mariposensis* | April 29, 1983 |
| Chisos hedgehog cactus | *Echinocereus reichenbachii* var. *chisoensis* | November 1, 1988 |
| Wildflowers | | |
| McKittrick pennyroyal | *Hedeoma apiculatum* | April 29, 1983 |
| Trees, Shrubs, and Sub-shrubs | | |
| Hinckley's oak | *Quercus hinckleyi* | November 1, 1988 |

FOOTNOTES

1/ This species was on the threatened species list in 1979, but moved to the endangered list on the effective date.

2/ This species was on the endangered species list in 1979, but moved to the threatened list on the effective date.

## ATTACHMENT IV

## CHANGES TO LOUISIANA'S THREATENED AND ENDANGERED SPECIES LISTS

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# ATTACHMENT IV

The following animals and plants have been listed as endangered or threatened in the State of Louisiana since 1979.

| COMMON NAME | SCIENTIFIC NAME | EFFECTIVE DATE |
|---|---|---|
| **Mammals:** | | |
| No changes | *N/A* | N/A |
| **Birds:** | | |
| Peregrine Falcon | *Falco perigrinus(E)*[1/] | March 20, 1984 |
| Interior Least Tern | *Sterna antillarum athalassos(E)* | May 28, 1985 |
| Piping Plover | *Charadrius melodus(E)* | December 8, 1985 |
| **Reptiles:** | | |
| Ringed Sawback Turtle | *Graptemvs oculifera(T)*[2/] | December 23, 1986 |
| Gopher Tortoise | *Gopherus polyphemus(T)* | July 7, 1987 |
| **Invertebrates:** | | |
| *Louisiana Pearlshell* | Margaritifera hembeli(E) | February 5, 1988 |

FOOTNOTES

1/ Denotes an endangered species.

2/ Denotes a threatened species.

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# *Appendix C*

# *Site Identification and Screening Procedure*

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# APPENDIX C
## SITE IDENTIFICATION AND SCREENING PROCEDURE

This appendix summarizes the original procedure used by the Department of Energy to identify and screen candidate storage sites for expansion of the Reserve to one billion barrels. Specifically described are the three-phase site screening procedure and the major criteria used to identify specific candidate sites for future environmental assessment under the National Environm -tal Policy Act (NEPA).

The site selection procedure used by the Government identified candidate sites which best met its stringent criteria for long-term strategic storage of crude oil. While numerous other sites are not included in the short list of candidates, many exhibit characteristics that might have application to different storage objectives and criteria such as commercial hydrocarbon storage and transfer operations.

### A. Major Site Selection Approach

The Department employed a three-phase site selection procedure to evaluate and reduce approximately 550 salt domes in the Gulf Coast to seven candidate sites. The salt domes were divided into three groups identified by the primary refinery distribution area they would serve, i.e., Capline, Seaway/Texoma, and Corpus Christi. Within each refinery distribution area, the site selection procedure and evaluation criteria, illustrated in Figure C-1, was used to screen and select the "best" candidates taking into consideration the SPR's expansion configuration and distribution objectives.

The site selection process was performed under the direction of the Department's Strategic Petroleum Reserve Office, with the assistance of Sandia National Laboratories in Albuquerque, NM, Boeing Petroleum Services, Inc., and Systematic Management Services, Inc. Members of these organizations, with expertise in geology, engineering, construction, cavern leaching, cost estimating, and project scheduling, formed a team to perform the site selection procedure. The results of this site selection process are preliminary and could change during the formal NEPA review process, which would provide a more comprehensive screening and evaluation of specific sites.

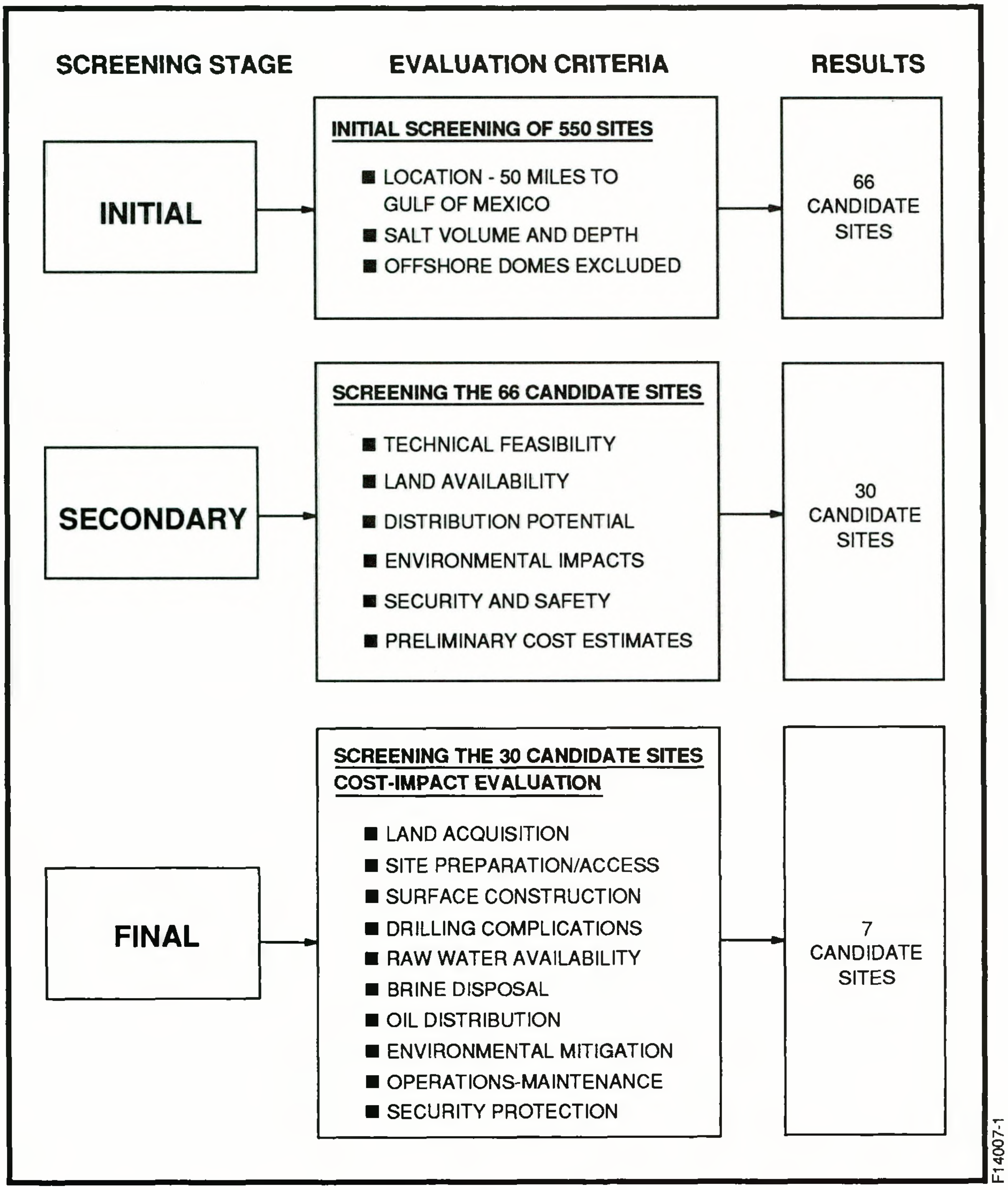


**Figure C-1. SITE IDENTIFICATION AND SCREENING PROCEDURE FOR ADDITIONAL STRATEGIC PETROLEUM RESERVE STORAGE**

## B. Identification of Potential Gulf Coast Sites

### Initial Screening

The site screening process started with a list of approximately 550 known onshore and offshore salt domes within the Gulf Coast. Three crude oil storage and logistics criteria were applied to reduce the initial list of salt domes to 66 SPR candidate salt dome sites. These criteria were:

- Distance to Gulf of Mexico — 50 miles or less.
- Depth to top of salt — not to exceed approximately 2800 feet.
- Location — onshore.

A map showing the location of the sixty-six salt dome candidates is shown in Figure C-2.

### Secondary Screening

The 66 candidate salt dome sites identified in the initial screening stage were then subjected to further evaluation and reduced to 30 candidates (Table C-1) based on the following six development criteria:

- **Technical Feasibility** — The major technical feasibility elements considered were: sufficient salt volume above 5,000 feet depth; geological features such as subsidence over the dome, faulting and fractures in the overlying caprock; availability of water for leaching and drawdown; availability of utilities (power); and storage capacity potential.
- **Land Availability** — Land availability elements evaluated were: sufficient surface area for support systems; site access; appropriateness of terrain for development; and current land usage.
- **Distribution Potential** — Distribution elements considered were: proximity to existing major commercial pipelines, marine terminals (or sites on which to construct them), and oil refineries.
- **Environmental** — Environmental elements considered were: potential environmental problems, such as wetland destruction, and likely required mitigation, and frequency of flooding.

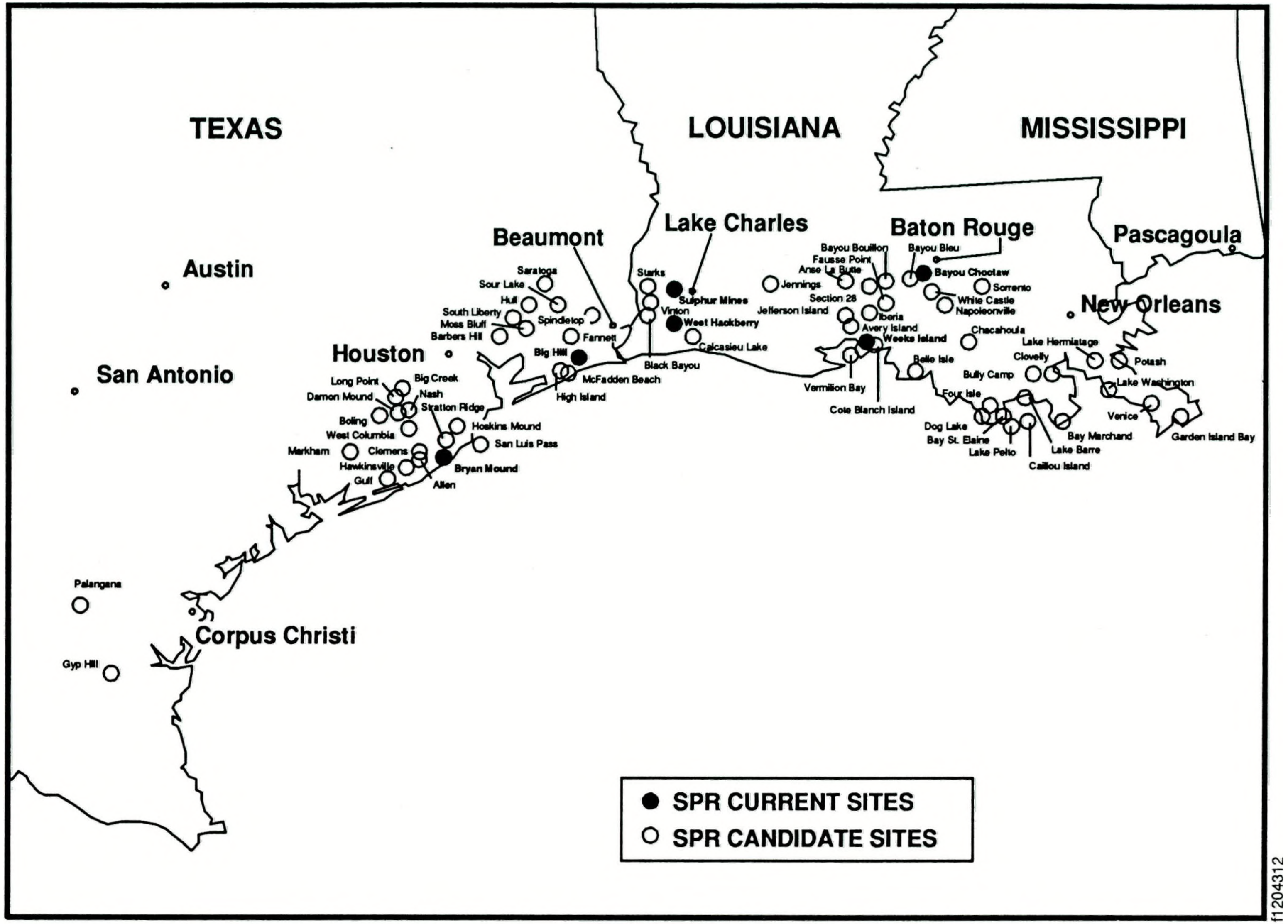


Figure C-2. CANDIDATE GULF COAST SPR STORAGE SITES

**TABLE C-1**
**Secondary Screening: Candidate Sites**

| Capline Complex (15) | Seaway/Texoma Complex (13) | Corpus Christi Complex (2) |
|---|---|---|
| Bayou Choctaw | Big Hill | Gyp Hill |
| Bay St. Elaine | Boling Mound | Palangana |
| Bully Camp | Bryan Mound | |
| Chacahoula | Clemens Dome | |
| Clovelly | Damon Mound | |
| Cote Blanche | Hawkinsville | |
| Dog Lake | High Island | |
| Fausse Pointe | Hoskins Mound | |
| Four Isle | Long Point | |
| Lake Barre | Nash | |
| Lake Washington | South Liberty | |
| Napoleonville | Stratton Ridge | |
| Venice | West Columbia | |
| Vermilion Bay | | |
| Weeks Island | | |

- **Security and Safety** — The major consideration in this criterion is the difficulty of protecting the site.

- **Preliminary Cost** — Gross preliminary costs were limited to site acquisition, probable pipelines required, environmental impact mitigation, and area-unique obstacles.

**Final Screening**

The thirty (30) salt domes sites identified in the secondary screening stage were further evaluated and reduced to seven candidates (Table C-2) based on a major cost impact sensitivity evaluation. Sites were given a relative numerical rating on ten cost/impact criteria. A site with the lower numerical score is relatively more desirable to develop than one with a high score. The numerical scoring system assumes equal weight for each of the cost/impact criteria and was applied uniformly across all the sites. The ten criteria evaluated and scored were:

- **Land Acquisition** — Scores in this category ranged from low scores for Department-owned property, dry land, and proximity to usable major roads to high scores for isolated, marsh (wet) property.

**TABLE C-2**
**Final Gulf Coast Candidate Sites**

| Storage Complex | Candidate Storage Site |
|---|---|
| Capline | Chacahoula<br>Napoleonville<br>Weeks Island<br>Cote Blanche (Mine Conversion) |
| Seaway/Texoma | Big Hill (Expansion Site)<br>Clemens (Satellite Site) |
| Corpus Christi | Gyp Hill |

- **Site Preparation** — Uneven terrain requiring levelling, poor soils requiring filling, and lack of roads and access all contributed to higher scores.

- **Surface Construction** — Wetlands and water bodies and other obstacles such as existing adjacent industrial facilities, and additional well pad foundation engineering would increase costs, and thus lead to higher scores.

- **Drilling** — Greater depth to the salt, thickness and the adverse nature of caprock, including previous sulphur mining, fracturing and faulting, all would increase the cost of completing wells.

- **Raw Water Availability** — Distance to water supply, volume sufficiency, and salinity of the water supply to be used for leaching and drawing down the oil would significantly affect cavern construction costs and drawdown operations.

- **Brine Disposal** — As brine from cavern leaching would be discharged into the Gulf of Mexico, the pipeline length, nature of terrain crossed, power requirements, rights-of-way, and size of storage site are significant cost impact items.

- **Oil Distribution** — Distance to commercial pipeline connections and marine terminals, type of terrain crossed, rights-of-way, and power sources are significant cost factors.

- **Operations and Maintenance** — Storage volume of site, accessibility to existing roads, and local or distant manpower and supply sources are significant cost factors. Expansion of an existing site or development of a satellite site that used existing O&M systems would, of course, result in lower costs than a completely new site.

- **Environment** — Overall development costs rise rapidly with construction and maintenance of sites in wetlands; e.g., for each acre removed from wetlands classification by site development, two acres of wetlands, as a rule, must be created. Additionally, increased monitoring of operations and more backup protection systems are required in these instances.

- **Security** — A wetlands-bound site would require special provisions on the security perimeter with a resulting higher cost and higher score.

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