risk (i.e., shifts the distribution toward lower risk). This happens primarily because close exposure distances (60 and 200 meters), which correspond to relatively high risks, occur less frequently and thus are less heavily weighted than greater distances. In addition, the effect of pit size weighting tends to shift the weighted distribution toward lower risk because small (i.e., lower risk) pits occur more frequently and are thus more heavily weighted. These factors override the effect of flow field weighting, which would tend to shift the distribution toward higher risk because the high-risk flow fields for arsenic (C and D) are heavily weighted. The national weightings of recharge, depth to ground water, and subsurface permeability probably had little overall impact on the risk distribution (i.e., if weighted only for these three factors, the distribution probably would not differ greatly from unweighted). All weighting factors used are given in Appendix B of the EPA technical support document (USEPA 1987a).

Zone-Weighted Risk Distributions

Overall, differences in risk distributions among zones were relatively small. Cancer risk estimates under best-estimate modeling assumptions were zero for all zones. Under conservative assumptions, the cancer risk distributions for zones 2 (Appalachia), 4 (Gulf), 6 (Plains), and 7 (Texas/Oklahoma) were slightly higher than the distribution for the nation as a whole. The cancer risk distributions for zones 5 (Midwest), 8 (Northern Mountain), 9 (Southern Mountain), 10 (West Coast), and 11B (Alaska, non-North Slope) were lower than the nationally weighted distribution; zones 10 and 11B were much lower. The risk distributions for individual zones generally varied from the national distribution by less than one order of magnitude.

Noncancer risk estimates under best-estimate modeling assumptions were extremely low for all zones. Under conservative assumptions, zones 2, 4, 5, 7, and 8 had a small percentage (1 to 10 percent) of weighted scenarios with threshold exceedances for sodium; other zones had less than 1 percent. There was little variability in the noncancer risk distributions across zones.

The reasons behind the differences in risks across zones are related to the zone-specific relative weightings of reserve pit size, distance to receptor populations, and/or environmental variables. For example, the main reason zone 10 has low risks relative to other zones is that 92 percent of drilling sites were estimated to be in an arid setting above a relatively low-risk ground-water flow field having an aquitard (flow field F). Zone 11B has zero risks because all potential exposure wells were estimated to be more than 2 kilometers away.

In summary, differences in cancer risks among the geographic zones were not great. Cancer risks were only prevalent in the faster aquifers (i.e., flow fields C, D, and E, with C having the highest cancer risks). Zone 4, with the highest cancer risks overall, also was assigned the highest weighting among the zones for flow field C. Noncancer risks caused by sodium were highest in zone 5. Noncancer risks occurred only in the more slow-moving flow fields (i.e., flow fields A, B, and K, with A having the highest noncancer risks); among the zones, zone 5 was assigned the highest weighting for flow field A. EPA considered the possible role of distributions of size and distance to exposure points, but determined that aquifer configuration and velocity probably contributed most strongly to observed zone differences in estimates of human health risks. The consistent lack of risk for zone 11B, however, is entirely because of the large distance to an exposure point. (See the section that follows on estimated population distributions.)

<u>Evaluation of Major Factors Affecting Health Risk</u>

EPA examined the effect of several parameters related to pit design and environmental setting that were expected to influence the release and transport of contaminants leaking from onsite reserve pits. To assess the effect of each of these parameters in isolation, all other parameters were held constant for the comparisons. The results presented in this section are not weighted according to either national or zone-specific frequencies of occurrence. Instead, each model scenario is given equal weight. Thus, the following comparisons are not appropriate for drawing conclusions concerning levels of risk for the national population of onsite reserve pits. They are appropriate for examining the effect of selected parameters on estimates of human health risk.

The presence or absence of a conventional, single synthetic liner underneath an onsite reserve pit had virtually no effect on the 200-year maximum health risk estimates. A liner does affect timing of exposures and risks, however, by reducing the amounts of leachate (and chemicals) released early in the modeling period. EPA's modeling assumed a single synthetic liner with no leak detection or leachate collection. (Note that this is significantly different from the required Subtitle C liner system design for hazardous waste land disposal units.) Furthermore, EPA assumed that such a liner would eventually degrade and fail, resulting in release of the contaminants that had been contained. Thus, over a long modeling period, mobile contaminants that do not degrade or degrade very slowly (such as the ones modeled here) will produce similar maximum risks whether they are disposed of in single-synthetic-lined or unlined pits (unless a significant amount of the contained chemical is removed, such as by dredging). This finding should not be interpreted to discount the benefit of liners in general. Measures of risk over time periods shorter than 200 years would likely be lower for lined pits than for unlined ones. Moreover, by delaying any release of contaminants, liners provide the opportunity for management actions (e.g., removal) to help prevent contaminant seepage and to mitigate seepage should it occur.

Figure V-5 represents unweighted risks associated with unlined reserve pits under the conservative modeling assumptions for three reserve pit sizes and three distances to the exposure point. Each combination of distance and reserve pit size includes the risk results from all environmental settings modeled (total of 63), equally weighted. Figure V-5 shows that the unweighted risk levels decline with increasing distance to the downgradient drinking water well. The decline is generally less than an order of magnitude from 60 to 200 meters, and greater than an order of magnitude from 200 to 1,500 meters. Median cancer risk values exceed 10^{-10} only at the 60-meter distance, and median dose-to-threshold ratios for noncancer effects exceed 1.0 only for large pits at the 60-meter distance. Risks also decrease as reserve pit size decreases at all three distances, although risks for small and large pits are usually within the same order of magnitude.

Figure V-6 compares risks across the seven ground-water flow field types modeled in this analysis. Both cancer and noncancer risks vary substantially across flow fields. The noncancer risks (from sodium) are greatest in the slower moving flow fields that provide less dilution (i.e., flow fields A, B, and K), while the cancer risks (from arsenic) are greatest in the higher velocity/higher flow settings (i.e., flow fields C, D, and E). Sodium is highly mobile in ground water, and it is diluted to below threshold levels more readily in the high-velocity/high-flow aquifers. Arsenic is only moderately mobile in ground water and tends not to reach downgradient exposure points within the 200-year modeling period in the slower flow fields. If the modeling period were extended, cancer risks resulting from arsenic would appear in the more slowly moving flow field scenarios.

As would be expected, both cancer and noncancer risks increased with increasing recharge rate and with increasing subsurface permeability. Risk differences were generally less than an order of magnitude. Depth to ground water had very little effect on the 200-year maximum risk,

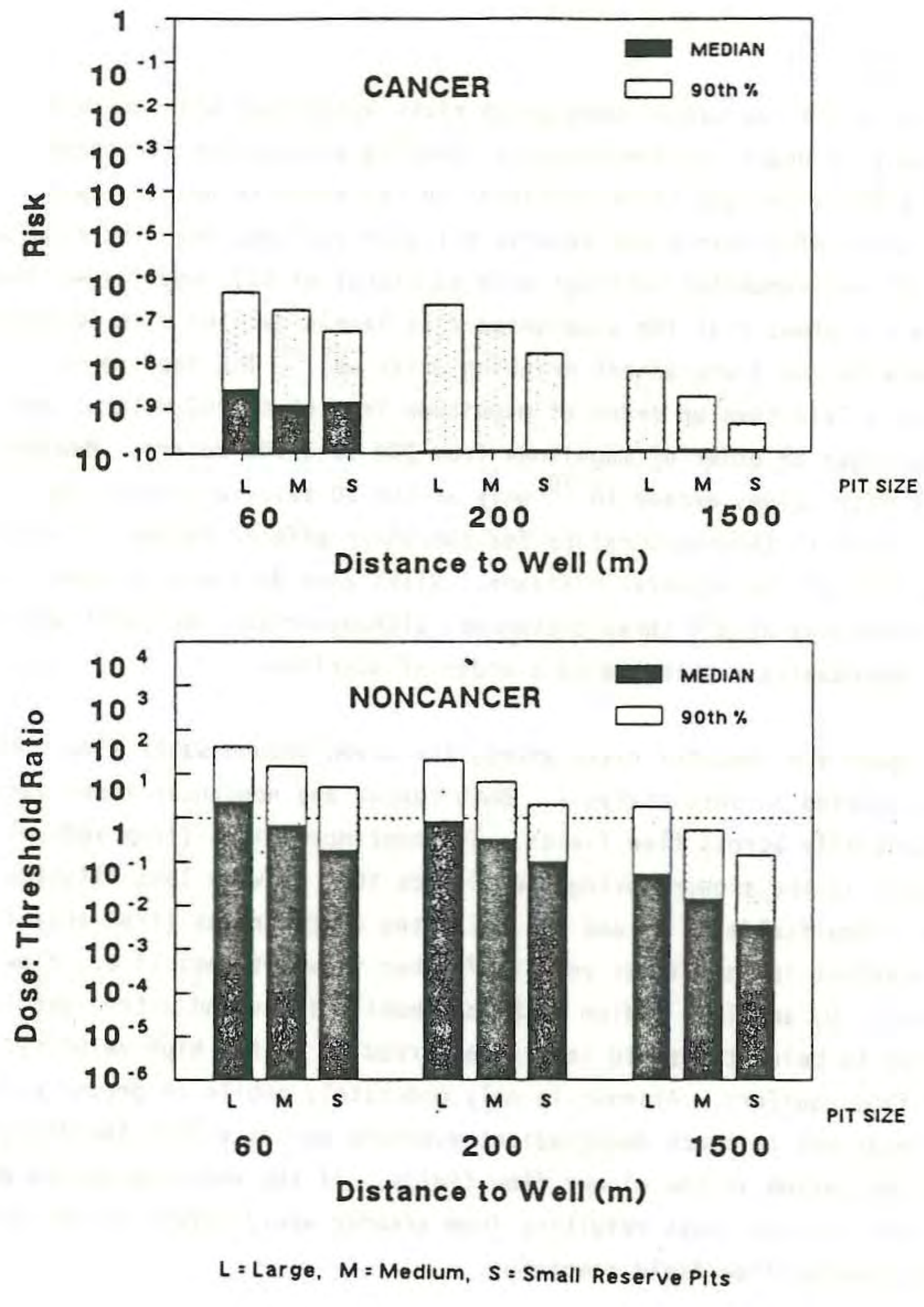

Figure V-5 Health Risk Estimates (Unweighted) as a Function of Size and Distance. Unlined Reserve Pits. Conservative Modeling Assumptions

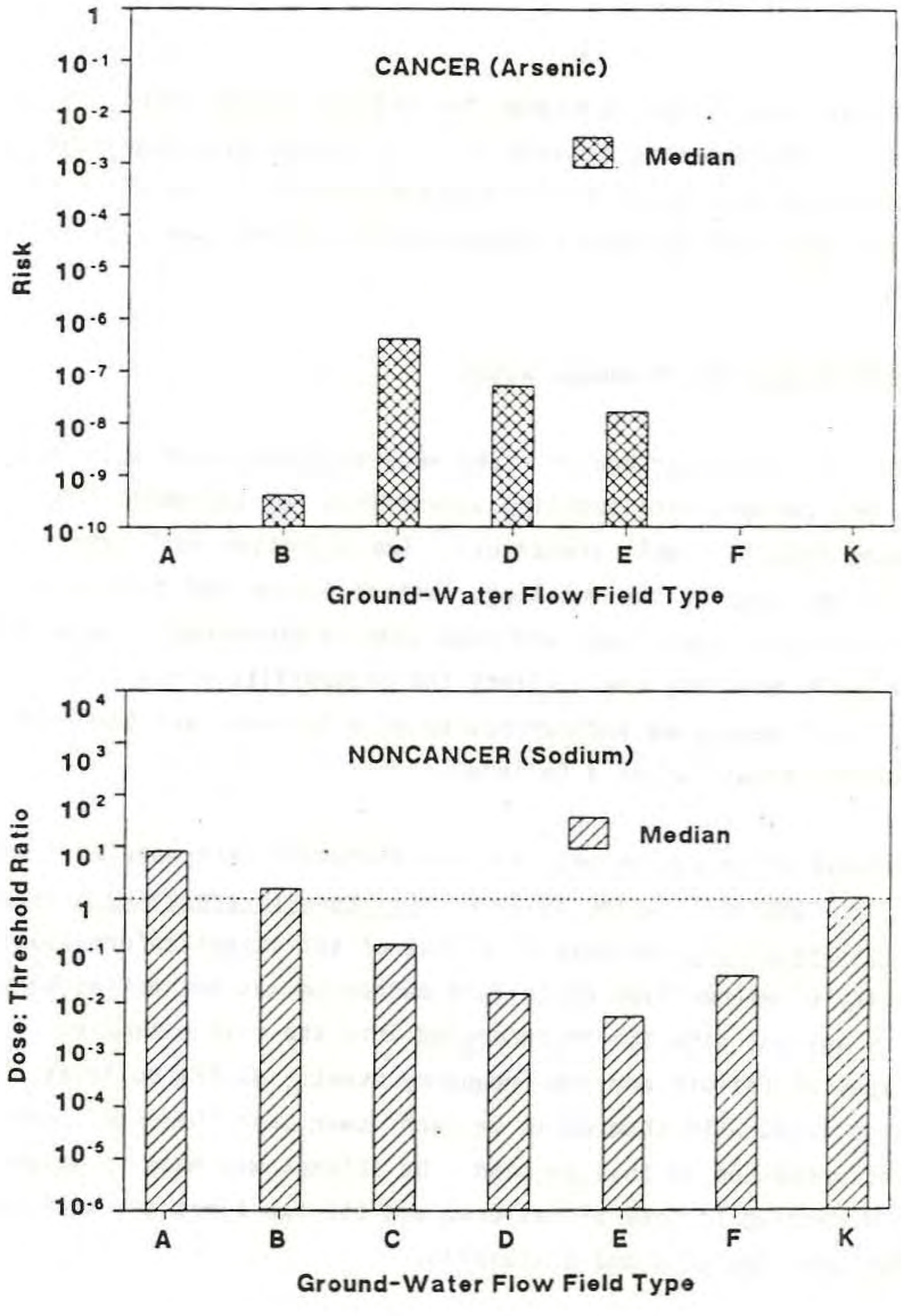

Figure V-6 Health Risk Estimates (Unweighted) as a Function of Ground-Water Type. Unlined Reserve Pits (Large). 60-Meter Exposure Distance. Conservative Modeling Assumptions although risks were slightly higher for shallow ground-water settings. This lack of effect occurs because the risk-producing contaminants are at least moderately mobile and do not degrade rapidly, if at all; thus, the main effect observed for deeper ground-water settings was a delay in exposures.

Underground Injection--Produced Water

Cancer and noncancer health risks were analyzed under both best-estimate and conservative modeling assumptions for 168 model Class II underground injection well scenarios.[9] Two injection well types were differentiated in the modeling: waterflooding and dedicated disposal. Design, operating, and regulatory differences between the two types of wells possibly could affect the probability of failure, the probability of detection and correction of a failure, and the likely magnitude of release given a failure.

Two types of injection well failure mechanism were modeled: grout seal failure and well casing failure. <u>All results presented here assume that a failure occurs</u>; because of a lack of sufficient information, the probability of either type of failure mechanism was not estimated and therefore was not directly incorporated into the risk estimates. If these types of failure are low-frequency events, as EPA believes, actual risks associated with them would be much lower than the conditional risk estimates presented in this section. No attempt was made to weight risk results according to type of failure, and the two types are kept separate throughout the analysis and discussion.

<u>Nationally Weighted Risk Distributions</u>

The risk estimates associated with injection well failures were weighted based on the estimated frequency of occurrence of the following

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9 168 = 7 ground-water flow field types x 3 exposure distances x 2 size categories x 2 well types x 2 failure mechanisms.

variables: injection well type, distance to nearest drinking water well, and ground-water flow field type. In addition, all risk results for grout seal failure were weighted based on injection rate. As for reserve pits, insufficient information was available to account for waste characteristics and other possibly important variables by weighting.

<u>Grout seal failure</u>: Best-estimate cancer risks, given a grout seal failure, were estimated to be zero for more than 85 percent of the model scenarios. The remaining scenarios had slightly higher risks but never did the best-estimate cancer risk exceed 1×10^{-7}. Under conservative assumptions, roughly 65 percent of the scenarios were estimated to have zero cancer risk, while the remaining 35 percent were estimated to have cancer risks ranging up to 4×10^{-4} (less than 1 percent of the scenarios had greater than 1×10^{4} risk). These modeled cancer risks were attributable to exposure to two produced water constituents, benzene and arsenic. Figure V-7 (top portion) provides a nationally weighted frequency distribution of the best-estimate and conservative-estimate cancer risks, given a grout seal failure. Figure V-7 shows the combined distribution for the two well types and two injection rates considered in the analysis, the three exposure distances, and the seven ground-water settings. As with drilling pits, many of the zero risk cases were because the nearest potential exposure well was estimated to be more than 2 kilometers away (roughly 64 percent of all scenarios).

Modeled noncancer risks, given a grout seal failure, are entirely attributable to exposures to sodium. There were no sodium threshold exceedances associated with grout seal failures under best-estimate conditions. Under conservative conditions, roughly 95 percent of the nationally weighted model scenarios also had no noncancer risk. The remaining 5 percent had estimated sodium concentrations at the exposure point that exceeded the effect threshold, with the maximum concentration exceeding the effect threshold by a factor of 70. The nationally

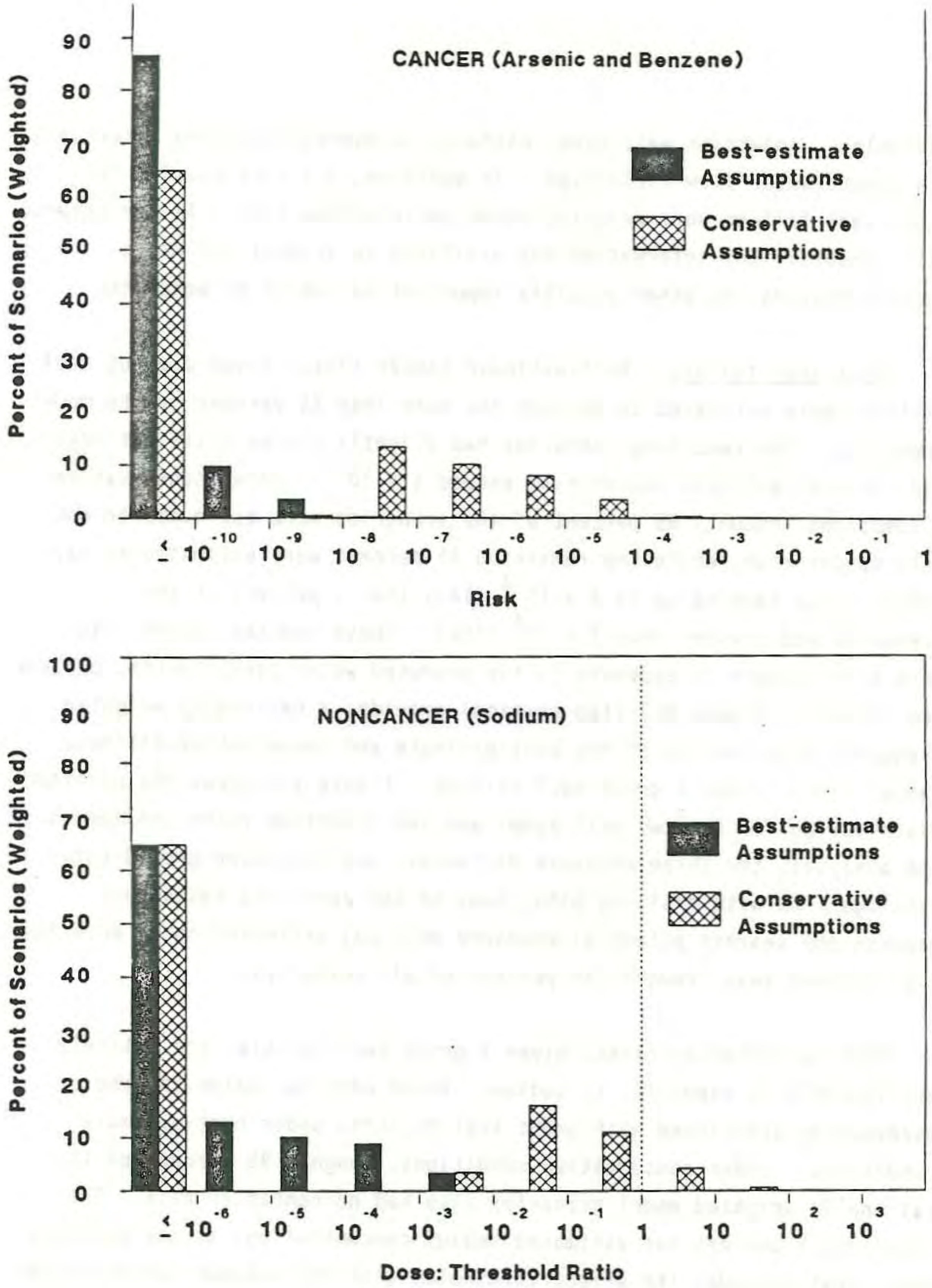

Figure V-7 Nationally Weighted Distribution of Health Risk Estimates. Underground Injection Wells: Grout Seal Failure Assumed weighted frequency distribution of the estimated dose/threshold ratios for sodium is shown in the bottom portion of Figure V-7.

Data are available on the taste and odor thresholds of two produced water model constituents: benzene and chloride. For the maximum cancer risk scenario assuming a grout seal failure, the estimated concentrations of benzene and chloride at the exposure well were below their respective taste and odor thresholds. However, for the maximum noncancer risk scenario assuming a grout seal failure, the estimated chloride concentration did exceed the taste threshold by roughly a factor of three. Therefore, people might be able to taste chloride in the highest noncancer risk scenarios, but it is questionable whether anybody would discontinue drinking water containing such a chloride concentration.

Well casing failure: The nationally weighted distributions of estimated cancer and noncancer risks, given an injection well casing failure, are presented in Figures V-8 and V-9. Figure V-8 gives the risk distributions for scenarios with high injection pressure, and Figure V-9 gives the risk distributions for scenarios with low injection pressure. (Because of a lack of adequate data to estimate the distribution of injection pressures, results for the high and low pressure categories were not weighted and therefore had to be kept separate.)

Best-estimate cancer risks, given a casing failure, were zero for approximately 65 percent of both the high and low pressure scenarios; the remaining scenarios had cancer risk estimates ranging up to 5×10^{-6} for high pressure and 1×10^{-6} for low pressure. The majority (65 percent) of both high and low pressure scenarios also had no cancer risks under the conservative assumptions, although approximately 5 percent of the high pressure scenarios and 1 percent of the low pressure scenarios had conservative-estimate cancer risks greater than 1×10^{-4} (maximum of 9×10^{4}). The rest of the scenarios had conservative-estimate cancer risks greater than zero and less than 1×10^{-4}.

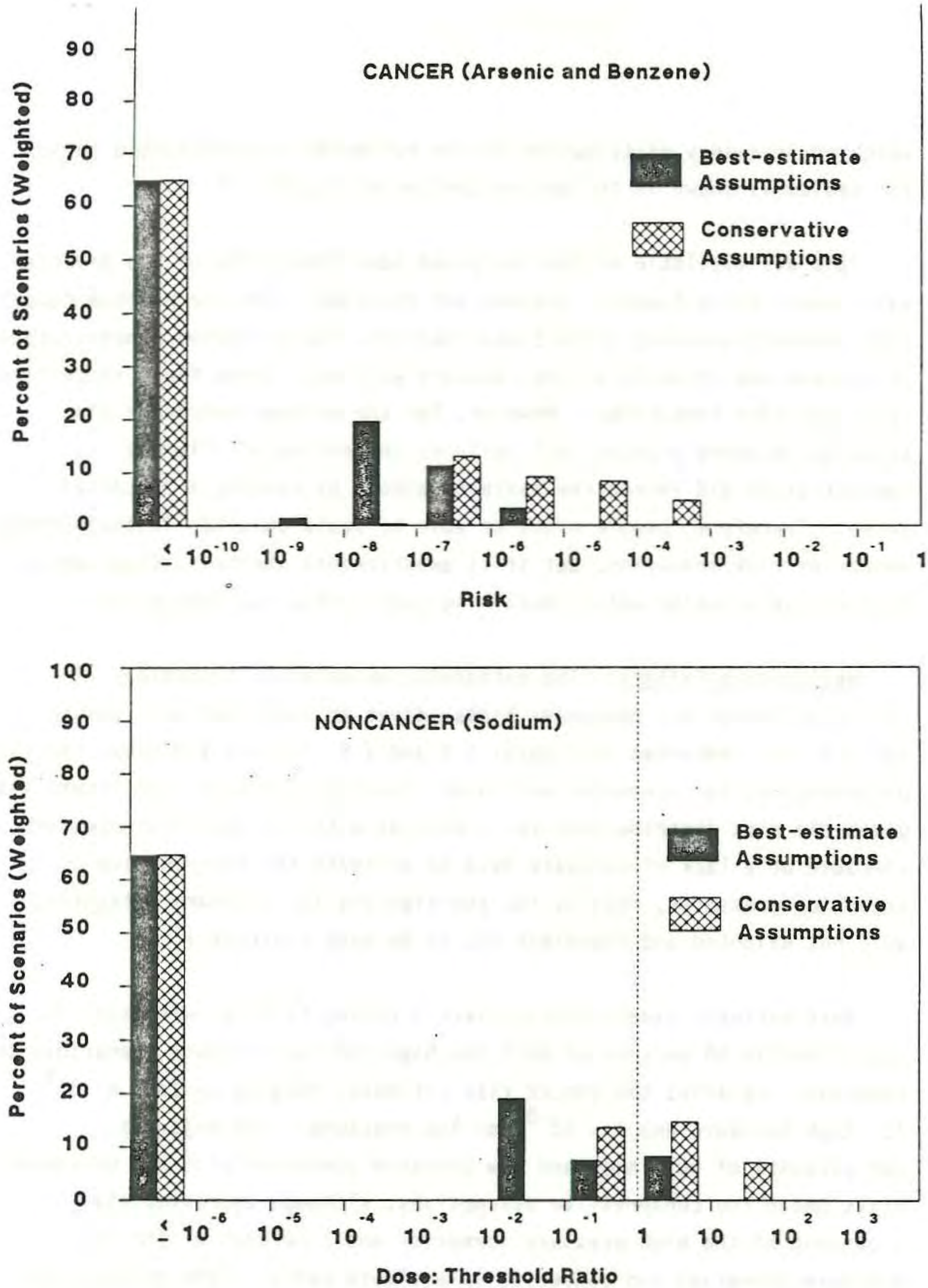

Figure V-8 Nationally Weighted Distribution of Health Risk Estimates. High Pressure Underground Injection Wells: Casing Failure Assumed

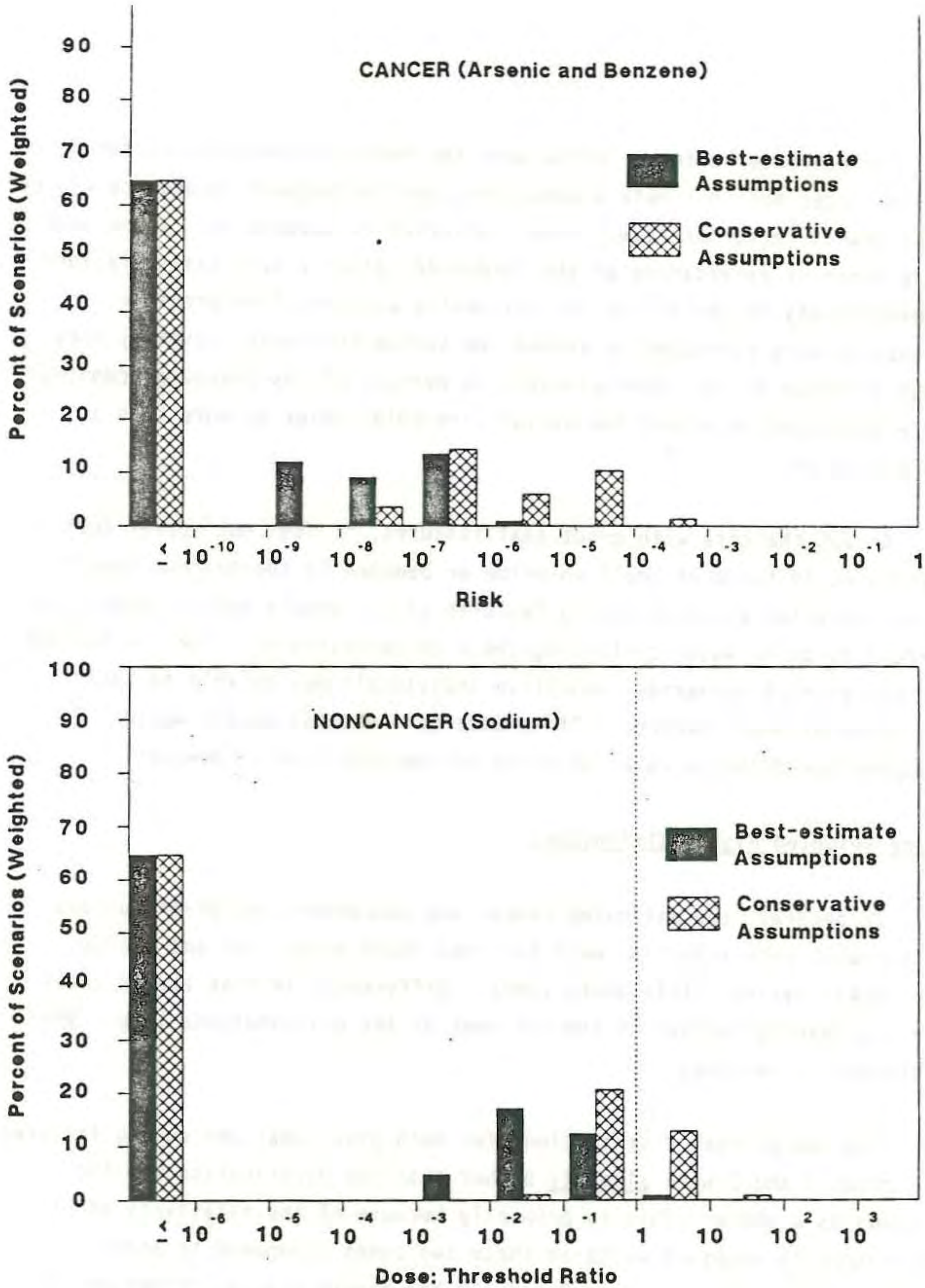

Figure V-9 Nationally Weighted Distribution of Health Risk Estimates. Low Pressure Underground Injection Wells: Casing Failure Assumed

For noncancer effects, there were few threshold exceedances for sodium under best-estimate assumptions, and the highest exceedance was by less than a factor of five. Under conservative assumptions, there were more numerous exceedances of the threshold, given a well casing failure. Approximately 22 percent of the nationally weighted high pressure scenarios were estimated to exceed the sodium threshold, never by more than a factor of 70. Approximately 14 percent of low pressure scenarios were estimated to exceed the sodium threshold, never by more than a factor of 35.

As was the case with grout seal failures, it does not appear that people would taste or smell chloride or benzene in the maximum cancer risk scenarios assuming casing failures (i.e., people would probably not refuse to drink water containing these concentrations). For the maximum noncancer risk scenarios, sensitive individuals may be able to taste chloride or smell benzene. It is uncertain whether people would discontinue drinking water at these contaminant levels, however.

Zone-Weighted Risk Distributions

In general, the estimated cancer and noncancer risk distributions associated with injection well failures (both grout seal and casing failures) varied little among zones. Differences in risk across zones were primarily limited to the extremes of the distributions (e.g., 90th percentile, maximum).

The cancer risk distributions for both grout seal and casing failures in zones 2 and 5 were slightly higher than the distribution for the nation as a whole. This is primarily because of the relatively short distances to exposure wells in these two zones (compared to other zones). In contrast, zones 8 and 11B had cancer risk distributions for injection well failures that were slightly lower than the national distribution. This difference is primarily because of the relatively long distance to exposure wells in these zones. (For almost 80 percent of production sites in both zones, it was estimated that the closest exposure well was more than 2 kilometers away.) A similar pattern of zone differences was observed for the noncancer risk results.

Evaluation of Major Factors Affecting Health Risk

In general, estimated risks associated with well casing failure are from one to two orders of magnitude higher than risks associated with grout seal failure. This is because under most conditions modeled, well casing failures are estimated to release a greater waste volume, and thus a larger mass of contaminants, than grout seal failures.

The risks estimated for disposal and waterflood wells are generally similar in magnitude. For assumed casing failures, waterflood wells are estimated to cause slightly (no more than a factor of 2.5 times) higher risks than disposal wells. This pattern is the net result of two differences in the way waterflood and disposal wells were modeled. The release durations modeled for disposal wells are longer than those for waterflood wells, but the injection pressures modeled for waterflood wells are greater than those modeled for disposal wells. For assumed grout seal failures, disposal wells are estimated to cause slightly (no more than a factor of 3 times) higher risks than waterflood wells. This pattern results because the injection rates modeled for disposal wells are up to 3 times greater than those modeled for waterflood wells.

The distance to a potentially affected exposure well at an injection site is one of the most important indicators of risk potential. If all other parameters remain constant, carcinogenic risks decline slightly less than one order of magnitude between the 60-meter and 200-meter well distances; carcinogenic risks decline between one and two orders of magnitude from the 200-meter to the 1,500-meter well distances. The effect of well distance is a little less pronounced for noncarcinogenic risks. Sodium threshold exceedances drop by less than an order of magnitude between the 60-meter and 200-meter well distances and by approximately one order of magnitude between the 200-meter and 1,500-meter well distances. The reduction in exposure with increased distance from the well is attributable to three-dimensional dispersion of contaminants within the saturated zone. In addition, the 200-year modeling period limits risks resulting from less mobile constituents at greater distances (especially 1,500 meters). Degradation is not a factor because the constituents producing risk degrade very slowly (if at all) in the saturated zone.

Cancer and noncancer risk estimates decrease with decreasing injection rate/pressure. This relationship reflects the dependence of risk upon the total chemical mass released into the aquifer each year, which is proportional to either the assumed injection flow rate (grout seal failure) or pressure (casing failure).

Figure V-10 shows how the unweighted health risk estimates associated with injection well casing failures varied for the different ground-water flow fields. The figure includes only results for the conservative modeling assumptions, the high injection pressure, and the 60-meter modeling distance, because risk estimates under best-estimate assumptions and for other modeling conditions were substantially reduced and less varied. As shown, conservative-estimate carcinogenic risks ranged from roughly 2×10^{-6} (for flow field F) to approximately 6×10^{-4} (for flow field D). The difference in the risk estimates for these two flow fields is due primarily to their different aquifer configurations. Flow field D represents an unconfined aquifer, which is more susceptible to contamination than a confined aquifer setting represented by flow field F.

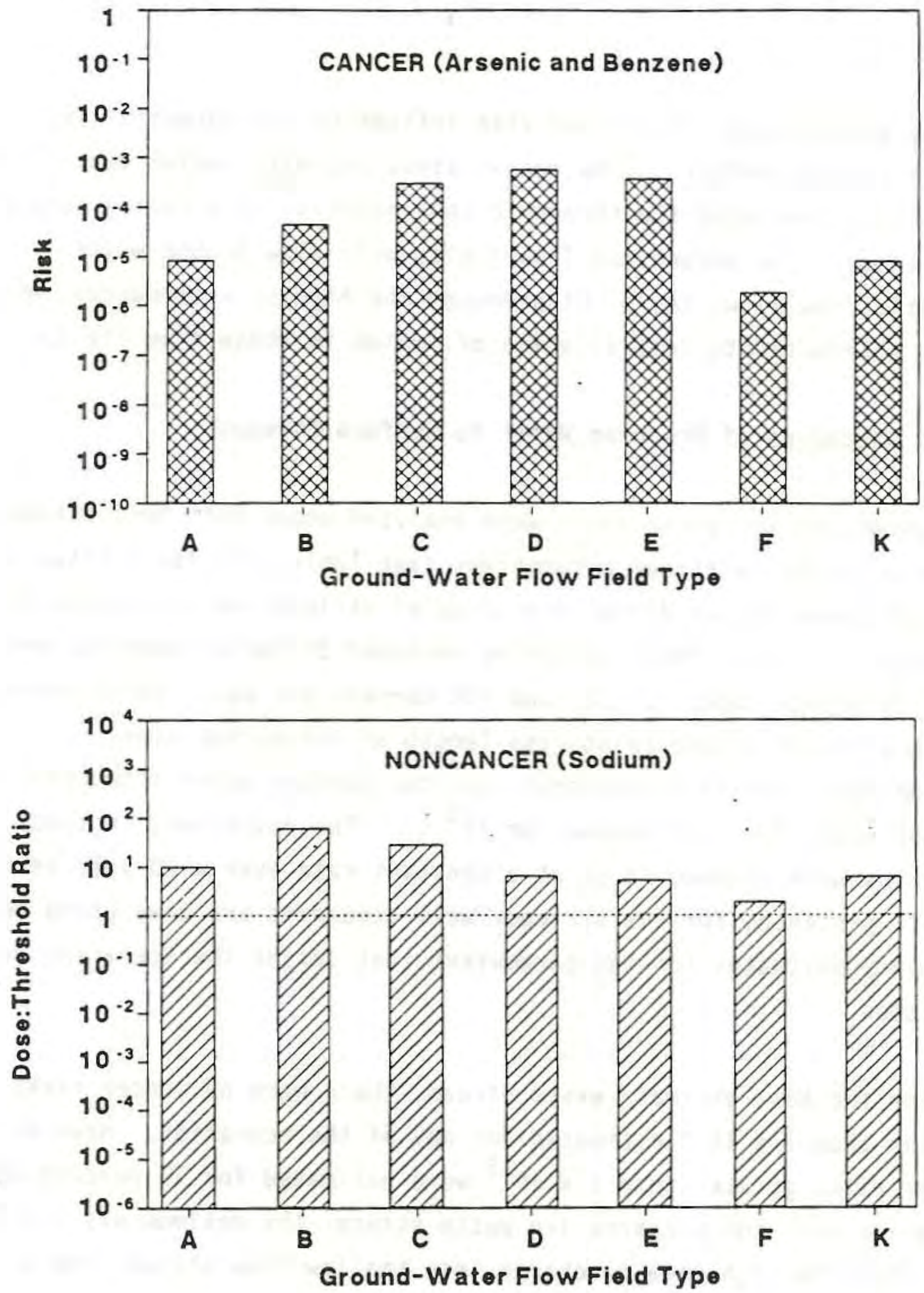

Figure V-10 Health Risk Estimates (Unweighted) as a Function of Ground-Water Type. High Pressure Underground Injection Wells: Casing Failure Assumed. 60-Meter Exposure Distance. Conservative Modeling Assumptions

The ground-water flow field also influenced the potential for noncarcinogenic effects. The conservative-estimate sodium concentrations at 60 meters exceeded the threshold concentration by a factor ranging up to 70 times. The unconfined flow fields with slow ground-water velocities/low flows (A, B, C) produced the highest exceedances, which can be attributed to less dilution of sodium in these flow fields.

Direct Discharge of Produced Water to Surface Streams

Cancer and noncancer risks were analyzed under both best-estimate and conservative waste stream assumptions (see Table V-1) for a total of 18 model scenarios of direct discharge of stripper well-produced fluids to surface waters. These scenarios included different combinations of three discharge rates (1, 10, and 100 barrels per day), three downstream distances to an intake point (the length of the mixing zone, 5 kilometers, and 50 kilometers), and two surface water flow rates (40 and 850 cubic feet per second, or ft^3/s). The discharges in these scenarios were assumed to be at a constant rate over a 20-year period. Results presented for the stripper well scenarios are unweighted because frequency estimates for the parameters that define the scenarios were not developed.

For the best-estimate waste stream, there were no cancer risks greater than 1×10^{-5} estimated for any of the scenarios. However, cancer risks greater than 1×10^{-5} were estimated for 17 percent of the scenarios with the conservative waste stream--the maximum was 3.5×10^{-5} (for the high-rate discharge into the low-flow stream, and a drinking water intake immediately downstream of the discharge point). These cancer risks were due primarily to exposure to arsenic, although benzene also contributed slightly. For noncancer risks, none of the scenarios had a threshold exceedance for sodium, regardless of whether the best-estimate or conservative waste stream was assumed.

EPA recognizes that the model surface water flow rates (40 and 850 ft^3/s) are relatively high and that discharges into streams or rivers with flow rates less than 40 ft^3/s could result in greater risks than are presented here. Therefore, to supplement the risk results for the model scenarios, EPA analyzed what a river or stream flow rate would have to be (given the model waste stream concentrations and discharges rates) in order for the contaminant concentration in the mixing zone (assuming instantaneous and complete mixing but no other removal processes) to be at certain levels.

The results of this analysis, presented in Table V-8, demonstrate that reference concentrations of benzene would be exceeded only in very low-flow streams (i.e., less than 5 ft^3/s) under all of the model conditions analyzed. It is unlikely that streams of this size would be used as drinking water sources for long periods of time. However, concentrations of arsenic and sodium under conservative modeling conditions could exceed reference levels in the mixing zone in relatively large streams, which might be used as drinking water sources. The concentrations would be reduced at downstream distances, although estimates of the surface water flow rates corresponding to reference concentrations at different distances have not been made.

Potentially Exposed Population

Preliminary estimates of the potentially exposed population were developed by estimating the number of individuals using private drinking water wells and public water supplies located downgradient from a sample of oil and gas wells. These estimates were based on data obtained from local water suppliers and 300 USGS topographic maps. One hundred of the maps were selected from areas containing high levels of drilling activity, and 200 were selected from areas containing high levels of production.

Table V-8 Surface Water Flow Rates At Which Concentrations of Waste Stream Constituents in the Mixing Zone Will Exceed Reference Levels[a]

Constituent	Concentration in waste	Waste stream discharge rate: High (100 BPD)	Medium (10 BPD)	Low (1 BPD)
Arsenic	Median	$\leq$ 5 ft^3/s[b]	$\leq$0.5 ft^3/s	$\leq$ .05 ft^3/s
	90th %	$\leq$ 470 ft^3/s	$\leq$ 50 ft^3/s	$\leq$ 5 ft^3/s
Benzene	Median	$\leq$ 1 ft^3/s	$\leq$ 0.1 ft^3/s	$\leq$ 0.01 ft^3/s
	90th %	$\leq$ 3 ft^3/s	$\leq$ 0.3 ft^3/s	$\leq$ 0.03 ft^3/s
Sodium	Median	$\leq$ 3 ft^3/s	$\leq$ 0.3 ft^3/s	$\leq$ 0.03 ft^3/s
	90th %	$\leq$ 20 ft^3/s	$\leq$ 2 ft^3/s	$\leq$ 0.2 ft^3/s

[a]The reference levels referred to are the arsenic and benzene concentrations that correspond to a 1×10^{-5} lifetime cancer risk level (assuming a 70-kg individual ingests 2 L/d) and EPA's suggested guidance level for sodium for the prevention of hypertension in high-risk individuals.

[b]Should be interpreted to mean that the concentration of arsenic in the mixing zone would exceed the 1×10^{-5} lifetime cancer risk level if the receiving stream or river was flowing at a rate of 5 ft^3/s or lower. If the stream or river was flowing at a higher rate, then the maximum concentration of arsenic would not exceed the 1×10^{-5} lifetime cancer risk level.

Table V-9 summarizes the sample results for the population potentially exposed through private drinking water wells. As shown in this table, over 60 percent of the oil and gas wells in both the drilling and production sample did not have private drinking water wells within 2,000 meters downgradient and only 2 percent of the oil and gas wells were estimated to have private drinking water wells within the 60-meter (i.e., higher-risk) distance category. Moreover, the numbers of potentially affected people per oil and gas well in the 60-meter distance category were relatively small. One other interesting finding demonstrated in Table V-9 is that fewer potentially affected individuals were estimated to be in the 1,500-meter distance category than in the 200-meter category. This situation is believed to occur because some residences located farther from oil and gas wells were on the other side of surface waters that appeared to be a point of ground-water discharge.

The sample results for the population potentially exposed through public water supplies are summarized in Table V-10. These results show a pattern similar to those for private drinking water wells; this is, most oil and gas wells do not have public water supply intakes within 2,000 meters and of those that do only a small fraction have public water supply intakes within the 60-meter distance category.

The results in Tables V-9 and V-10 are for the nation as a whole. Recognizing the limitations of the sample and of the analysis methods, EPA's data suggest that zone 2 (Appalachia) and zone 7 (Texas/Oklahoma) have the greatest relative number of potentially affected individuals per oil and gas well (i.e., potentially affected individuals are, on the average, closer to oil and gas wells in these zones relative to other zones). In addition, zone 4 (Gulf) has a relatively large number of individuals potentially affected through public water supplies. Zone 11 (Alaska) and zone 8 (Northern Mountain) appear to have relatively fewer potentially affected individuals per oil and gas well. Further

Table V-9 Population Potentially Exposed Through Private Drinking Water Wells at Sample Drilling and Production Areas

Distance category[a]	Drilling sample results: No. (%) of oil/gas wells with private drinking water wells within distance category	Drilling sample results: Maximum no. of potentially affected individuals per oil and gas well[b]	Production sample results: No. (%) of oil/gas wells with private drinking water wells within distance category	Production sample results: Maximum no. of potentially affected individuals per oil and gas well[b]
60 meters	561(2)	0.11	642(2)	0.17
200 meters	4,765(17)	0.44	5,139(16)	0.58
1,500 meters	5,606(20)	0.32	5,460(17)	0.36
>2,000 meters	17,096(61)	NA[c]	20,879(65)	NA

[a]Drinking water wells were counted as 60 meters downgradient if they were within 0 and 130 meters, were counted as 200 meters downgradient if they were within 130 and 800 meters, and were counted as 1,500 meters downgradient if they were within 800 and 2,000 meters.

[b]These ratios largely overestimate the number of people actually affected per oil and gas well (see text) and should be used to estimate the total number of people affected only with caution. The figures are intended simply to give a preliminary indication of the potentially exposed population and the distribution of that population in different distance categories.

[c]Not available; distances greater than 2,000 meters from oil and gas wells were not modeled.

Table V-10 Population Potentially Exposed Through Public Water Supplies at Sample Drilling and Production Areas

Distance category[a]	Drilling sample results: No. (%) of oil/gas wells with private drinking water wells within distance category		Drilling sample results: Maximum no. of potentially affected individuals per oil and gas well[b]	Production sample results: No. (%) of oil/gas wells with private drinking water wells within distance category		Production sample results: Maximum no. of potentially affected individuals per oil and gas well[b]
60 meters	87	(0.3)	3.6	54	(0.2)	96
200 meters	217	(0.8)	0.76	210	(0.7)	8.1
1,500 meters	232	(0.8)	0.55	617	(2)	3.9
>2,000 meters	27,492	(98)	NA[c]	31,239	(97)	NA[c]

[a]Public water supply intakes were counted as 60 meters downgradient if they were within 0 and 130 meters, were counted as 200 meters downgradient if they were within 130 and 800 meters, and were counted as 1,500 meters downgradient if they were within 800 and 2,000 meters.

[b]These ratios largely overestimate the number of people actually affected per oil and gas well (see text) and should be used to estimate the total number of people affected only with caution. The figures are intended simply to give a preliminary indication of the potentially exposed population and the distribution of that population in different distance categories.

[c]Not available; distances greater than 2,000 meters from oil and gas wells were not modeled.

discussion of the differences in population estimates across zones is provided in the supporting technical report (USEPA 1987a).

The number of potentially affected people per oil and gas well in Tables V-9 and V-10 represents the maximum number of people in the sample that could be affected if all the oil and gas wells in the sample resulted in ground-water contamination out to 2,000 meters. The number of persons actually affected is probably much smaller because ground water may not be contaminated at all (if any) of the sites, some of the individuals may rely on surface water or rainwater rather than on ground water, and some of the individuals and public water supplies may not have drinking water wells that are hydraulically connected to possible release sources. Also, the sample population potentially exposed through public water supplies is probably far less than estimated, because public water is frequently treated prior to consumption (possibly resulting in the removal of oil and gas waste contaminants) and because many supply systems utilize multiple sources of water, with water only at times being drawn from possibly contaminated sources. Therefore, these ratios largely overestimate the number of people actually exposed per oil and gas well and should be used to estimate the total number of people affected only with caution. The figures are intended simply to give a preliminary indication of the potentially exposed population and the distribution of that population in different distance categories.

QUANTITATIVE RISK MODELING RESULTS: RESOURCE DAMAGE

For the purposes of this study, resource damage is defined as the exceedance of pre-set threshold (i.e., "acceptable") concentrations for individual contaminants, based on levels associated with aquatic toxicity, taste and odor, or other adverse impacts. Potential ground-water and surface water damage was measured as the maximum (over the 200-year modeling time period) annual volume of contaminated water flowing past various points downgradient or downstream of the source. Only the volume of water that exceeded a damage threshold concentration was considered to be contaminated. This measure of potential ground-water and surface water damage was computed for each of three distances downgradient or downstream from a source: 60, 200, and 1,500 meters.

These estimates of resource damage supplement, but should be considered separate from, the damage cases described in Chapter IV. The resource damage results summarized here are strictly for the model scenarios considered in this analysis, which represent: (1) seepage of reserve pit wastes; (2) releases of produced water from injection well failures; and (3) direct discharge of produced water from stripper wells to streams and rivers. While these releases may be similar to some of the damage cases described in Chapter IV, no attempt was made to correlate the scenarios to any given damage case(s). In addition, Chapter IV describes damage cases from several types of releases (e.g., land application) that were not modeled as part of this quantitative risk analysis.

Potential Ground-Water Damage--Drilling Wastes

Two contaminants were modeled for ground-water resource damage associated with onsite reserve pits. These contaminants were chloride ions in concentrations above EPA's secondary maximum contaminant level and total mobile ions (TMI) in concentrations exceeding the level of total dissolved salts predicted to be injurious to sensitive and moderately sensitive crops. Chloride is highly mobile in ground water and the other ions were assumed to be equally mobile.

On a national basis, the risks of significant ground-water damage were very low for the model scenarios included in the analysis. Under the best-estimate modeling assumptions, only 2 percent of nationally weighted reserve pit scenarios were estimated to cause measurable ground-water damage at 60 meters resulting from TMI. Under the conservative modeling assumptions, less than 10 percent of reserve pits were associated with ground-water plumes contaminated by chloride and TMI at 60 meters and fewer than 2 percent at 200 meters. On a regional basis, the upper 90th percentile of the distributions for resource damage, under conservative modeling assumptions, were above zero for zones 2, 5, and 8. This zone pattern is similar to the zone pattern of noncancer human health risks from sodium. Flow field A was more heavily weighted for these three zones than for the remaining zones, and this flow field also was responsible for the highest downgradient concentrations of sodium of all the flow fields modeled.

The mobilities of chloride and total mobile salts in ground water were the same as the mobility of sodium, which was responsible for the noncancer human health risks. Thus, the effects of several pit design and environmental parameters on the volume of ground water contaminated above criteria concentrations followed trends very similar to those followed by the noncancer human health risks. These parameters included reserve pit size, net recharge, subsurface permeability, and depth to ground water. In contrast to the trend in noncancer human health risks, however, the magnitude of resource damage sometimes increased with increasing distance from the reserve pit. This is because contaminant concentrations (and thus health risks) decrease with distance traveled; however, the width of a contaminant plume (and thus the volume of contaminated water) increases up to a point with distance traveled. Eventually, however, the center line concentration of the plume falls below threshold, and the estimated volume of contaminated water at that distance falls to zero. Finally, as was the case with noncancer human health risks, only the slower aquifers were associated with significant estimates of resource damage.

Potential Ground-Water Damage--Produced Water

As they were for drilling wastes, chloride and total mobile ions were modeled to estimate ground-water resource damage associated with underground injection of produced water. Under best-estimate conditions, the risk of ground water becoming contaminated above the thresholds if injection well casing failures were to occur was negligible. Furthermore, in all but a few scenarios (approximately 1 percent of the nationally weighted scenarios), the resource damage estimates did not exceed zero under conservative assumptions. Estimated resource damage was almost entirely confined to the 60-meter modeling distance.

Grout seal failures were estimated to pose a slightly smaller risk of contaminating ground water above the chloride or TMI thresholds than injection well casing failures. In roughly 99 percent of the nationally weighted scenarios, grout seal failures never resulted in threshold exceedances, regardless of the set of conditions assumed (best-estimate vs. conservative) or the downgradient distance analyzed. Again, estimated resource damage was almost entirely confined to the 60-meter modeling distance.

In general, injection well failures were estimated to contaminate larger volumes of ground water above the damage criteria under conditions involving higher injection rates/pressures and lower ground-water velocities/flows (i.e., flow fields A, B, C, and K). The estimated TMI concentration exceeded its threshold for the low injection rate very rarely, and only out to a distance of 60 meters. Chloride and TMI threshold exceedances were limited almost exclusively to conditions involving the high injection rate or pressure. The slower velocity/lower flow ground-water settings permit less dilution (i.e., a higher probability of threshold exceedance) of constituents modeled for resource damage effects. In a trend similar to that observed for health risks, waterflood wells were estimated to contaminate larger volumes of ground water than disposal wells under conditions involving casing failures, but disposal wells were estimated to contaminate larger volumes under conditions involving grout seal failures. Finally, the resource damage estimates for injection well failures (and also for reserve pit leachate) indicate that TMI is a greater contributor to ground-water contamination than chloride. The reason for this difference is that the mobile salts concentration in the model produced water waste stream is more than three times the chloride concentration (see Table V-1), while the resource damage thresholds differ by a factor of two (see Table V-2).

Potential Surface Water Damage

EPA examined the potential for surface water damage resulting from the influx of ground water contaminated by reserve pit seepage and injection well failures, as well as surface water damage resulting from direct discharge of stripper well produced water. For all model scenarios, EPA estimated the average annual surface water concentrations of waste constituents to be below their respective thresholds at the point where they enter the surface water; that is, the threshold concentrations for various waste constituents were not exceeded even at the point of maximum concentration in surface waters. This is because the input chemical mass is diluted substantially upon entering the surface water. Surface water usually flows at a much higher rate than ground water and also allows for more complete mixing than ground water. Both of these factor suggest that there will be greater dilution in surface water than in ground water. One would expect, therefore, that the low concentrations in ground water estimated for reserve pit seepage and injection well failures would be diluted even further upon seeping into surface water.

These limited modeling results do not imply that resource damage could not occur from larger releases, either through these or other migration pathways or from releases to lower flow surface waters (i.e., streams with flows below 40 ft^3/s). In addition, surface water damages could occur during short periods (less than a year) of low stream flow or peak waste discharge, which were not modeled in this study.

EPA analyzed what a river or stream flow rate would have to be (given the model produced water concentrations and discharge rates from stripper wells) in order for contaminant concentrations in the mixing zone (assuming instantaneous and complete mixing but not other removal processes) to exceed resource damage criteria. The results of this analysis are summarized in Table V-11. As shown, the maximum concentrations of chloride, boron, sodium, and TMI in streams or rivers caused by the discharge of produced water from stripper wells would (under most modeling conditions) not exceed resource damage criteria unless the receiving stream or river was flowing at a rate below 1 ft^3/s. The exceptions are scenarios with a conservative waste stream concentration and high discharge rate. If produced water was discharged to streams or rivers under these conditions, the maximum concentrations of sodium and TMI could exceed resource damage criteria in surface waters flowing up to 5 ft^3/s. (The maximum concentrations in any surface water flowing at a greater rate would not exceed the criteria.)

The results suggest that, if produced waters from stripper wells are discharged to streams and rivers under conditions that are similar to those modeled, resource damage criteria would be exceeded only in very small streams.

ASSESSMENT OF WASTE DISPOSAL ON ALASKA'S NORTH SLOPE

In accordance with the scope of the study required by RCRA Section 8002(m), this assessment addresses only the potential impacts associated

Table V-11 Surface Water Flow Rates At Which Concentrations of Waste Stream Constituents in the Mixing Zone Will Exceed Aquatic Effects and Resource Damage Thresholds[a]

Constituent	Concentration in waste	Waste stream discharge rate		
		High (100 BPD)	Medium (10 BPD)	Low (1 BPD)
Sodium	Median	$\leq 0.7\ ft^3/s$[b]	$\leq 0.07\ ft^3/s$	$\leq 0.007\ ft^3/s$
	90th %	$\leq 5\ ft^3/s$	$\leq 0.5\ ft^3/s$	$\leq 0.05\ ft^3/s$
Chloride	Median	$\leq 0.2\ ft^3/s$	$\leq 0.02\ ft^3/s$	$\leq 0.002\ ft^3/s$
	90th %	$\leq 0.9\ ft^3/s$	$\leq 0.09\ ft^3/s$	$\leq 0.009\ ft^3/s$
Boron	Median	$\leq 0.06\ ft^3/s$	$\leq 0.006\ ft^3/s$	$\leq 0.0006\ ft^3/s$
	90th %	$\leq 0.8\ ft^3/s$	$\leq 0.08\ ft^3/s$	$\leq 0.008\ ft^3/s$
Total Mobile Ions	Median	$\leq 0.4\ ft^3/s$	$\leq 0.04\ ft^3/s$	$\leq 0.004\ ft^3/s$
	90th %	$\leq 2\ ft^3/s$	$\leq 0.2\ ft^3/s$	$\leq 0.02\ ft^3/s$

[a]The effect thresholds and effects considered in this analysis were as follows: Sodium-83 mg/L, which might result in toxic effects or osmoregulatory problems for freshwater aquatic organisms (note: while this threshold is based on toxicity data reported in the literature, it is dependent on several assumptions and is speculative); chloride--250 mg/L, which is EPA's secondary drinking water standard designed to prevent excess corrosion of pipes in hot water systems and to prevent objectionable tastes; boron--1 mg/L, which is a concentration in irrigation water that could damage sensitive crops (e.g., citrus trees; plum, pear, and apple trees; grapes; and avocados); and total mobile Ions--335 mg/L, which may be a tolerable level for freshwater species but would probably put them at a disadvantage in competing with brackish or marine organisms.

[b]Should be interpreted to mean that the concentration of sodium in the mixing zone would exceed the modeled effect threshold (described in footnote a) if the receiving stream or river was flowing at a rate of 0.7 ft^3/s or lower. If the stream or river was flowing at a higher rate, then the maximum concentration of sodium would not exceed the effect level.

with the management of exempt oil and gas wastes on Alaska's North Slope. It does not analyze risks or impacts from other activities, such as site development or road construction. The North Slope is addressed in a separate, qualitative assessment because readily available release and transport models for possible use in a quantitative assessment are not appropriate for many of the characteristics of the North Slope, such as the freeze-thaw cycle, the presence of permafrost, and the typical reserve pit designs.

Of the various wastes and waste management practices on the North Slope, it appears that the management of drilling waste in above-ground reserve pits has the greatest potential for adverse environmental effects. The potential for drilling wastes to cause adverse human health effects is small because the potential for human exposure is small. Virtually all produced water on the North Slope is reinjected approximately 6,000 to 9,000 feet below the land surface in accordance with discharge permits issued by the State of Alaska. The receiving formation is not an underground source of drinking water and is effectively sealed from the surface by permafrost. Consequently, the potential for environmental or human health impacts associated with produced fluids is very small under routine operating conditions.

During the summer thaw, reserve pit fluids are disposed of in underground injection wells, released directly onto the tundra or applied to roads if they meet quality restrictions specified in Alaska discharge permits, or stored in reserve pits. Underground injection of reserve pit fluids should have minor adverse effects for the same reasons as were noted above for produced waters. If reserve pit fluids are managed through the other approaches, however, there is much greater potential for adverse environmental effects.

Discharges of reserve pit fluids onto the tundra and roads are regulated by permits issued by the Alaska Department of Environmental Conservation (ADEC). In the past, reserve pit discharges have occasionally exceeded permit limitations for certain constituents. New permits, therefore, specify several pre-discharge requirements that must be met to help ensure that the discharge is carried out in an acceptable manner.

Only one U.S. Government study of the potential effects of reserve pit discharges on the North Slope is known to be complete. West and Snyder-Conn (1987), with the U.S. Fish and Wildlife Service, examined how reserve pit discharges in 1983 affected water quality and invertebrate communities in receiving tundra ponds and in hydrologically connected distant ponds. Although the nature of the data and the statistical analysis precluded a definitive determination of cause and effect, several constituents and characteristics (chromium, barium, arsenic, nickel, hardness, alkalinity, and turbidity) were found in elevated concentrations in receiving ponds when compared to control ponds. Also, alkalinity, chromium, and aliphatic hydrocarbons were elevated in hydrologically connected distant ponds when compared to controls. Accompanying these water quality variations was a decrease in invertebrate taxonomic richness, diversity, and abundance from control ponds to receiving ponds.

West and Snyder-Conn, however, cautioned that these results cannot be wholly extrapolated to present-day oil field practices on the North Slope because some industry practices have changed since 1983. For example, they state that "chrome lignosulfonate drill muds have been partly replaced by non-chrome lignosulfonates, and diesel oil has been largely replaced with less toxic mineral oil in drilling operations." Also, State regulations concerning reserve pit discharges have become increasingly stringent since the time the study was conducted. West and

Snyder-Conn additionally concluded that reserve pit discharges should be subject to standards for turbidity, alkalinity, chromium, arsenic, and barium to reduce the likelihood of biological impacts. ADEC's 1987 tundra discharge permit specifies effluent limitations for chromium, arsenic, barium, and several other inorganics, as well as an effluent limitation for settleable solids (which is related to turbidity). The 1987 permit requires monitoring for alkalinity, but does not specify an effluent limit for this parameter.

Reserve pits on the North Slope are frequently constructed above grade out of native soils and gravel. Below-grade structures are also built, generally at exploratory sites, and occasionally at newer production sites. Although the mud solids that settle at the bottom of the pits act as a barrier to fluid flow, fluids from above-ground reserve pits (when thawed) can seep through the pit walls and onto the tundra. No information was obtained on what percentage of the approximately 300 reserve pits on the North Slope are actually leaking; however, it has been documented that "some" pits do in fact seep (ARCO 1985, Standard Oil 1987). While such seepage is expected to be sufficiently concentrated to adversely affect soil, water, vegetation, and dependent fauna in areas surrounding the reserve pits, it is not known how large an area around the pits may be affected. Preliminary studies provided by industry sources indicate that seepage from North Slope reserve pits, designed and managed in accordance with existing State regulations, should not cause damage to vegetation more than 50 feet away from the pit walls (ARCO 1986, Standard Oil 1987). It is important to note that ADEC adopted regulations that should help to reduce the occurrence of reserve pit seepage and any impacts of drilling waste disposal. These regulations became effective in September 1987.

While some of the potentially toxic constituents in reserve pit liquids are known to bioaccumulate (i.e., be taken up by organisms low in the food chain with subsequent accumulation in organisms higher in the food chain), there is no evidence to conclude that bioaccumulation from reserve pit discharge or seepage is occurring. In general, bioaccumulation is expected to be small because each spring thaw brings a large onrush of water that may help flush residual contamination, and higher level consumers are generally migratory and should not be exposed for extended periods. It is recognized, however, that tundra invertebrates constitute the major food source for many bird species on the Arctic coastal plain, particularly during the breeding and rearing seasons, which coincide with the period that tundra and road discharges occur. The Fish and Wildlife Service is in the process of investigating the effects of reserve pit fluids on invertebrates and birds, and these and other studies need to be completed before conclusions can be reached with respect to the occurrence of bioaccumulation on the North Slope.

With regard to the pit solids, the walls of operating pits have slumped on rare occasions, allowing mud and cuttings to spill onto the surrounding tundra. As long as these releases are promptly cleaned up, the adverse effects to vegetation, soil, and wildlife should be temporary (Pollen 1986, McKendrick 1986).

ADEC's new reserve pit closure regulations for the North Slope contain strengthened requirements for reserve pit solids to be dewatered, covered with earth materials, graded, and vegetated. The new regulations also require owners of reserve pits to continue monitoring and to maintain the cover for a minimum of 5 years after closure. If the reserve pit is constructed below grade such that the solids at closure are at least 2 feet below the bottom of the soil layer that thaws each spring, the solids will be kept permanently frozen (a phenomenon referred to as freezeback). The solids in closed above-grade pits will also undergo freezeback if they are covered with a sufficient layer of earth material to provide insulation. In cases where the solids are kept permanently frozen, no leaching or erosion of the solid waste constituents should occur. However, ADEC's regulations do not require reserve pits to be closed in a manner that ensures freezeback. Therefore, some operators may choose to close their pits in a way that permits the solids to thaw during the spring. Even when the solids are not frozen, migration of the waste constituents will be inhibited by the reserve pit cover and the low rate of water infiltration through the solids. Nevertheless, in the long term, the cover could slump and allow increased snow accumulation in depressed areas. Melting of this snow could result in infiltration into the pit and subsequent leaching of the thawed solid waste contaminants. Also, for closed above-grade pits, long-term erosion of the cover could conceivably allow waste solids, if thawed, to migrate to surrounding areas. Periodic monitoring would forestall such possibilities.

LOCATIONS OF OIL AND GAS ACTIVITIES IN RELATION TO ENVIRONMENTS OF SPECIAL INTEREST

EPA analyzed the proximity of oil and gas activities to three categories of environments of special interest to the public: endangered and threatened species habitats, wetlands, and public lands. The results of this analysis are intended only to provide a rough approximation of the degree of and potential for overlap between oil and gas activities and these areas. The results should not be interpreted to mean that areas where oil and gas activities are located are necessarily adversely affected.

All of the 26 States having the highest levels of oil and gas activity are within the historical ranges of numerous endangered and threatened species habitats. However, of 190 counties across the U.S. identified as having high levels of exploration and production, only 13 (or 7 percent) have Federally designated critical habitats[10] within their boundaries. These 13 counties encompass the critical habitats for a total of 10 different species, or about 10 percent of the species for which critical habitats have been designated on the Federal level.

Wetlands create habitats for many forms of wildlife, purify natural waters by removing sediments and other contaminants, provide flood and storm damage protection, and afford a number of other benefits. In general, Alaska and Louisiana are the States with the most wetlands and oil and gas activity. Approximately 50 to 75 percent of the North Slope area consists of wetlands (Bergman et al. 1977). Wetlands are also abundant throughout Florida, but oil and gas activity is considerably less in that State and is concentrated primarily in the panhandle area. In addition, oil and gas activities in Illinois appear to be concentrated in areas with abundant wetlands. Other States with abundant wetlands (North Carolina, South Carolina, Georgia, New Jersey, Maine, and Minnesota) have very little onshore oil and gas activity.

For the purpose of this analysis, public lands are defined as the wide variety of land areas owned by the Federal Government and administered by the Bureau of Land Management (BLM), National Forest Service, or National Park Service. Any development on these lands must first pass through a formal environmental planning and review process. In many cases, these lands are not environmentally sensitive. National Forests, for example, are established for multiple uses, including timber development, mineral extraction, and the protection of environmental values. Public lands are included in this analysis, however, because they are considered "publicly sensitive," in the sense that they are commonly valued more highly by society than comparable areas outside

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10 Critical habitats, which are much smaller and more rigorously defined than historical ranges, are areas containing physical or biological factors essential to the conservation of the species.

their boundaries. The study focuses only on lands within the National Forest and National Park Systems because of recent public interest in oil and gas development in these areas (e.g., see Sierra Club 1986; Wilderness Society 1987).

The National Forest System comprises 282 National Forests, National Grasslands, and other areas and includes a total area of approximately 191 million acres. Federal oil and gas leases, for either exploration or production, have been granted for about 25 million acres (roughly 27 percent) of the system. Actual oil and gas activity is occurring on a much smaller acreage distributed across 11 units in eight States. More than 90 percent of current production on all National Forest System lands takes place in two units: the Little Missouri National Grassland in North Dakota and the Thunder Basin National Grassland in Wyoming.

The National Park System contains almost 80 million acres made up by 337 units and 30 affiliated areas. These units include national parks, preserves, monuments, recreation areas, seashores, and other areas. All units have been closed to future leasing of Federal minerals except for four national recreation areas where mineral leasing has been authorized by Congress and permitted under regulation. If deemed acceptable from an environmental standpoint, however, nonfederally owned minerals within a unit's boundaries can be leased.[11] Ten units (approximately 3 percent of the total) currently have active oil and gas operations within their boundaries. Approximately 23 percent of the land area made up by these ten units is currently under lease (approximately 256,000 acres); however, 83 percent of the area within the ten units (almost one million acres) is leasable. The National Park Service also has identified 32 additional units that do not have active oil and gas operations at present, but do have the potential for such activities in the future.

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[11] Nonfederally owned minerals within National Park System units exist where the Federal Government does not own all the land within a unit's boundaries or does not possess the subsurface mineral rights.

Several of these units also have acres that are under lease for oil and gas exploration, development, and production. In total, approximately 334,700 acres within the National Park System (or roughly 4 percent of the total) are currently under lease for oil and gas.

CONCLUSIONS

EPA's major conclusions, along with a summary of the main findings on which they are based, are listed below. EPA recognizes that the conclusions are limited by the lack of complete data and the necessary risk modeling assumptions. In particular, the limited amount of waste sampling data and the lack of empirical evidence on the probability of injection well failures have made it impossible to estimate precisely the absolute nationwide or regional risks from current waste management practices for oil and gas wastes. Nevertheless, EPA believes that the risk analysis presented here has yielded many useful conclusions relating to the nature of potential risks and the circumstances under which they are likely to occur.

General Conclusions

- For the vast majority of model scenarios evaluated in this study, only very small to negligible risks would be expected to occur even if the toxic chemical(s) of concern were of relatively high concentration in the wastes <u>and</u> there was a release into ground water as was assumed in this analysis. Nonetheless, the model results also show that there are realistic combinations of measured chemical concentrations (at the 90th percentile level) and release scenarios that could be of substantial concern. EPA cautions that there are other release modes not considered in this analysis that could also contribute to risks. In addition, there are almost certainly toxic contaminants in the large unsampled population of reserve pits and produced fluids that could exceed concentration levels measured in the relatively small number of waste samples analyzed by EPA.

- EPA's modeling of resource damages to surface water--both in terms of ecological impact and of resource degradation--generally did not show significant risk. This was true both for ground-water seepage and direct surface water discharge (from stripper wells) pathways for drilling pit and produced water waste streams. This conclusion holds for the range of receiving water flow rates modeled, which included only moderate (40 ft^3/s) to large (850 ft^3/s) streams. It is clear that potential damages to smaller streams would be quite sensitive to relative discharge or ground-water seepage rates.

- Of the hundreds of chemical constituents detected in both reserve pits and produced water, only a few from either source appear to be of primary concern relative to health or environmental damages. Based on an analysis of toxicological data, the frequency and measured concentrations of waste constituents in the relatively small number of sampled waste streams, and the mobility of these constituents in ground water, EPA found a limited number of constituents to be of primary relevance in the assessment of risks via ground water. Based on current data and analysis, these constituents include arsenic, benzene, sodium, chloride, cadmium, chromium, boron, and mobile salts. All of these constituents were included in the quantitative risk modeling in this study. Cadmium, chromium, and boron did not produce risks or resource damages under the conditions modeled. Note: This conclusion is qualified by the small number of sampled sites for which waste composition could be evaluated.

- Both for reserve pit waste and produced water, there is a very wide (six or more orders of magnitude) variation in estimated health risks across scenarios, depending on the different combinations of key variables influencing the individual scenarios. These variables include concentrations of toxic chemicals in the waste, hydrogeologic parameters, waste amounts and management practices, and distance to exposure points.

Drilling Wastes Disposed of in Onsite Reserve Pits

- Most of the 1,134 onsite reserve pit scenarios had very small or no risks to human health via ground-water contamination of drinking water for the conditions modeled. Under the best-estimate assumptions, there were no carcinogenic waste constituents modeled (median concentrations for carcinogens in the EPA samples were zero or below detection), and more than 99 percent of the nationally weighted reserve pit scenarios resulted in exposure to noncarcinogens (sodium, cadmium, chromium) at concentration levels below health effect thresholds. Under more conservative assumptions, including toxic constituents at 90th percentile sample concentrations, no scenarios evaluated yielded lifetime cancer risks as high as 1 in 100,000 (1×10^{-5}),[12] and only 2 percent of the nationally weighted conservative scenarios showed cancer risks greater than 1×10^{-7}. Noncancer risks were estimated by threshold exceedances for only 2 percent of nationally weighted scenarios, even when the 90th percentile concentration of sodium in the waste stream was assumed. The maximum sodium concentration at drinking water wells was estimated to be roughly 32 times the threshold for hypertension. In general, these modeling results suggest that most onsite reserve pits will present very low risks to human health through ground-water exposure pathways.

- It appears that people may be able to taste chloride in the drinking water in those scenarios with the highest cancer and noncancer risks. It is questionable, however, whether people would actually discontinue drinking water containing these elevated chloride concentrations.

- Weighting the risk results to account for different distributions of hydrogeologic variables, pit size, and exposure distance across geographic zones resulted in limited variability in risks across zones. Risk distributions for individual zones generally did not differ from the national distribution by more than one order of magnitude, except for zones 10 (West Coast) and 11B (Alaska, non-North Slope), which usually were extremely low. Note: EPA was unable to develop geographical comparisons of toxic constituent concentrations in drilling pit wastes.

- Several factors were evaluated for their individual effects on risk. Of these factors, ground-water flow field type and exposure distance had the greatest influence (several orders of magnitude); recharge rate, subsurface permeability, and pit size had less, but measurable, influence (approximately one order of magnitude). Typically, the higher risk cases occur in the context of the largest unlined pits, the short (60-meter) exposure distance, and high subsurface permeability and infiltration. Depth to ground water and presence/absence of a single synthetic liner had virtually no measurable influence over the 200-year modeling period; however, risk estimated over shorter time periods, such as 50 years, would likely be lower for lined pits compared to unlined pits, and lower for deep ground water compared to shallow ground water.

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12 A cancer risk estimate of 1×10^{-5} indicates that the chance of an individual contracting cancer over a 70-year average lifetime is approximately 1 in 100,000. The Agency establishes the cutoff between acceptable and unacceptable levels of cancer risk between 1×10^{-7} and 1×10^{-4}.

- Estimated ground-water resource damage (caused by exceedance of water quality thresholds for chloride and total mobile ions) was very limited and essentially confined to the closest modeling distance (60 meters). These resource damage estimates apply only to the pathway modeled (leaching through the bottom of onsite pits) and not to other mechanisms of potential ground-water contamination at drilling sites, such as spills or intentional surface releases.

- No surface water resource damage (caused by exceedance of thresholds for chloride, sodium, cadmium, chromium VI, or total mobile ions) was predicted for the seepage of leachate-contaminated ground water into flowing surface water. This finding, based on limited modeling, does not imply that resource damage could not occur from larger releases, either through this or other pathways of migration, or from releases to lower flow surface waters (below 40 ft^3/s).

Produced Water Disposal in Injection Wells

- All risk results for underground injection presented in this chapter assume that either a grout seal or well casing failure occurs. However, as anticipated under EPA's Underground Injection Control (UIC) regulatory program, these failures are probably low-frequency events, and the actual risks resulting from grout seal and casing failures are expected to be much lower than the conditional risks presented here. The results do not, however, reflect other possible release pathways such as migration through unplugged boreholes or fractures in confining layers, which also could be of concern.

- Only a very small minority of injection well scenarios resulted in meaningful risks to human health, due to either grout seal or casing failure modes of release of produced water to drinking water sources. In terms of carcinogenic risks, none of the best-estimate scenarios (median arsenic and benzene sample concentrations) yielded lifetime risks greater than 5 per 1,000,000 (5×10^{-6}) to the maximally exposed individual. When the 90th percentile benzene and arsenic concentrations were examined, a maximum of 35 percent of EPA's nationally weighted scenarios had risks greater than 1×10^{-7}, with up to 5 percent having cancer risks greater than 1×10^{-4} (the highest risk was 9×10^{-4}). The high cancer risk scenarios corresponded to a very short (60-meter) exposure distance combined with relatively high injection pressure/rates and a few specific ground-water flow fields (fields C and D in Table V-7).

- Noncancer health effects modeled were limited to hypertension in sensitive individuals caused by ingestion of sodium in drinking water. In the best-estimate scenarios, up to 8 percent of EPA's nationally weighted scenarios had threshold exceedances for sodium in ground-water supplies. In the conservative scenarios, where 90th percentile sodium concentrations were assumed in the injection waters, threshold exceedances in drinking water were predicted for a maximum of 22 percent of the nationally weighted scenarios. The highest sodium concentration predicted at exposure wells under conservative assumptions exceeded the threshold for hypertension by a factor of 70. The high noncancer risk scenarios corresponded to a very short (60-meter) exposure distance, high injection pressures/rates, and relatively slow ground-water velocities/low flows.

- It appears that people would not taste or smell chloride or benzene at the concentration levels estimated for the highest cancer risk scenarios, but sensitive individuals would be more likely to detect chloride or benzene tastes or odors in those scenarios with the highest noncancer risks. It is questionable, however, whether the detectable tastes or smells at these levels would generally be sufficient to discourage use of the water supply.

- As with the reserve pit risk modeling results, adjusting (weighting) the injection well results to account for differences among various geographic zones resulted in relatively small differences in risk distributions. Again, this lack of substantial variability in risk across zones may be the result of limitations of the study approach and the fact that geographic comparisons of toxic constituents in produced water was not possible.

- Of several factors evaluated for their effect on risk, exposure distance and ground-water flow field type had the greatest influence (two to three orders of magnitude). Flow rate/pressure had less, but measurable, influence (approximately one order of magnitude). Injection well type (i.e., waterflood vs. disposal) had moderate but contradictory effects on the risk results. For casing failures, high-pressure waterflood wells were estimated to cause health risks that were about 2 times higher than the risks from lower pressure disposal wells under otherwise similar conditions. However, for grout seal failures, the risks associated with disposal wells were estimated to be up to 3 times higher than the risks in similar circumstances associated with waterflood wells, caused by the higher injection rates for disposal.

- Estimated ground-water resource damage (resulting from exceedance of thresholds for chloride, boron, and total mobile ions) was extremely limited and was essentially confined to the 60-meter modeling distance. This conclusion applies only to releases from Class II injection wells, and not to other mechanisms of potential ground-water contamination at oil and gas production sites (e.g., seepage through abandoned boreholes or fractures in confining layers, leaching from brine pits, spills).

- No surface water resource damage (resulting from exceedance of thresholds for chloride, sodium, boron, and total mobile ions) was predicted for seepage into flowing surface water of ground water contaminated by direct releases from injection wells. This finding does not imply that resource damage could not occur via mechanisms and pathways not covered by this limited surface water modeling, or in extremely low flow streams.

Stripper Well Produced Water Discharged Directly into Surface Water

- Under conservative modeling assumptions, 17 percent of scenarios (unweighted) had cancer risks greater than 1×10^{-5} (the maximum cancer risk estimate was roughly 4×10^{-5}).[13] The maximum cancer risk under best-estimate waste stream assumptions was 4×10^{-7}. No exceedances of noncancer effect thresholds or surface water resource damage thresholds were predicted under any of the conditions modeled. The limited surface water modeling performed applies only to scenarios with moderate- to high-flow streams (40 to 850 ft^3/s). Preliminary analyses indicate, however, that resource damage criteria would generally be exceeded in only very small streams (i.e., those flowing at less than 5 ft^3/s), given the sampled waste stream chemical concentrations and discharge rates for stripper wells of up to 100 barrels per day.

Drilling and Production Wastes Managed on Alaska's North Slope

- Adverse effects to human health are expected to be negligible or nonexistent because the potential for human exposure to drilling waste and produced fluid contaminants on the North Slope is very small. The greatest potential for adverse environmental impacts is caused by discharge and seepage of reserve pit fluids containing toxic substances onto the tundra. A field study conducted in 1983 by the U.S. Fish and Wildlife Service indicates that tundra discharges of reserve pit fluids may adversely affect water quality and invertebrates in surrounding areas; however, the

13 These results are unweighted because the frequency of occurrence of the parameters that define the stripper well scenarios was not estimated.

results of this study cannot be wholly extrapolated to present-day practices on the North Slope because some industry practices have changed and State regulations concerning reserve pit discharges have become increasingly more stringent since 1983. Preliminary studies from industry sources indicate that seepage from operating above-ground reserve pits on the North Slope may damage vegetation within a radius of 50 feet. The Fish and Wildlife Service is in the process of studying the effects of reserve pit fluids on tundra organisms, and these studies need to be completed before more definitive conclusions can be made with respect to environmental impacts on the North Slope.

Locations of Oil and Gas Activities in Relation to Environments of Special Interest

- All of the top 26 States that have the highest levels of onshore oil and gas activity are within the historical ranges of numerous endangered and threatened species habitats; however, of 190 counties identified as having high levels of exploration and production, only 13 (or 7 percent) have federally designated critical habitats for endangered species within their boundaries. The greatest potential for overlap between onshore oil and gas activities and wetlands appears to be in Alaska (particularly the North Slope), Louisiana, and Illinois. Other States with abundant wetlands have very little onshore oil and gas activity. Any development on public lands must first pass through a formal environmental review process and some public lands, such as National Forests, are managed for multiple uses including oil and gas development. Federal oil and gas leases have been granted for approximately 25 million acres (roughly 27 percent) of the National Forest System. All units of the National Park System have been closed to future leasing of federally owned minerals except for 4 National Recreation Areas where mineral leasing has been authorized by Congress. If deemed acceptable from an environmental standpoint, however, nonfederally owned minerals within the park boundaries can be leased. In total, approximately 4 percent of the land area in the National Park System is currently under lease for oil and gas activity.

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CHAPTER VI

COSTS AND ECONOMIC IMPACTS OF ALTERNATIVE WASTE MANAGEMENT PRACTICES

OVERVIEW OF THE COST AND ECONOMIC IMPACT ANALYSIS

This chapter provides estimates of the cost and selected economic impacts of implementing alternative waste management practices by the oil and gas industry. The industry's current or "baseline" practices are described in Chapter III. In addition to current practices, a number of alternatives are available. Some of these offer the potential for higher levels of environmental control. Section 8002(m) of RCRA requires an assessment of the cost and impact of these alternatives on oil and gas exploration, development, and production.

This chapter begins by providing cost estimates for baseline and alternative waste management practices. The most prevalent current practices are reserve pit storage and disposal for drilling wastes and Class II deep well injection for produced water. In addition, several other waste management practices are included in the cost evaluation. The cost estimates for the baseline and alternative waste management practices are presented as the cost per unit of waste disposal (e.g., cost per barrel of drilling waste, cost per barrel of produced water). These unit cost estimates allow for a comparison among disposal methods and are used as input information for the economic impact analysis.

After establishing the cost of baseline and alternative practices on a unit-of-waste basis, the chapter expands its focus to assess the impact of higher waste management costs both on individual oil and gas projects and on the industry as a whole. For the purpose of this assessment, three hypothetical regulatory scenarios for waste management are defined. Each scenario specifies a distinct set of alternative environmentally protective waste management practices for oil and gas projects that generate potentially hazardous waste. Projects that do not generate hazardous waste may continue to use baseline practices under this approach.

After the three waste management scenarios have been defined, the remainder of the chapter provides estimates of their cost and economic impact. First, the impact of each scenario on the capital and operating cost and on the rate of return for representative new oil and gas projects is estimated. Using these cost estimates for individual projects as a basis, the chapter then presents regional- and national-level cost estimates for the waste management scenarios.

The chapter then describes the impact of the waste management scenarios on existing projects (i.e., projects that are already in production). It provides estimates of the number of wells and the amount of current production that would be shut down as a result of imposing alternative waste management practices under each scenario. Finally, the chapter provides estimates of the long-term decline in domestic production brought about by the costs of the waste management scenarios and estimates of the impact of that decline on the U.S. balance of payments, State and Federal revenues, and other selected economic aggregates.

The analysis presented in this chapter is based on the information available to EPA in November 1987. Although much new waste generation and waste management data was made available to this study, both by EPA and the American Petroleum Institute, certain data limitations did restrict the level of analysis and results. In particular, data on waste generation, management practices, and other important economic parameters were generally available only in terms of statewide or nationwide averages. Largely because of this, the cost study was conducted using "average regional projects" as the basic production unit of analysis. This lack of desired detail could obscure special attributes of both marginal and above average projects, thus biasing certain impact effects, such as the number of well closures.

The scope of the study was also somewhat limited in other respects. For example, not all potential costs of alternative waste management under the RCRA amendments could be evaluated, most notably the land ban and corrective action regulations currently under development. The Agency recognizes that this could substantially understate potential costs of some of the regulatory scenarios studied. The analysis was able to distinguish separately between underground injection of produced water for disposal purposes and injection for waterflooding as a secondary or enhanced energy recovery method. However, it was not possible during the course of preparing this report to evaluate the costs or impacts of alternative waste management regulations on tertiary (chemical, thermal, and other advanced EOR) recovery, which is becoming an increasingly important feature of future U.S. oil and gas production.

COST OF BASELINE AND ALTERNATIVE WASTE MANAGEMENT PRACTICES

Identification of Waste Management Practices

The predominant waste management practices currently employed by the oil and gas industry are described in Chapter III of this report. For drilling operations, wastes are typically stored in an unlined surface impoundment during drilling. After drilling, the wastes are dewatered, either by evaporation or vacuum truck, and buried onsite. Where vacuum trucks are used for dewatering, the fluids are removed for offsite disposal, typically in a Class II injection well. For production operations, the predominant disposal options are injection into a Class II onsite well or transportation to an offsite Class II disposal facility. Where onsite injection is used, the Class II well may be used for disposal only or it may be used to maintain pressure in the reservoir for enhanced oil recovery.

In addition to the above disposal options, a number of additional practices are considered here. Some of these options are fairly common (Table VI-1). For example, 37 percent of current drill sites use a lined disposal pit; 12 percent of production sites in the lower 48 States (Lower 48) discharge their produced water to the surface. Other disposal options considered here (e.g., incineration) are not employed to any significant extent at present.

For drilling waste disposal, nine alternative practices were reviewed for the purpose of estimating comparative unit costs and evaluating subsequent cost-effectiveness in complying with alternative regulatory options:

1. Onsite unlined surface impoundment;
2. Onsite single-synthetic-liner surface impoundment;
3. Offsite single-synthetic-liner surface impoundment;
4. Offsite synthetic composite liner with leachate collection (SCLC), Subtitle C design;
5. Landfarming consistent with current State oil and gas field regulations;
6. Landfarming consistent with RCRA Subtitle C requirements;
7. Waste solidification;
8. Incineration; and
9. Volume reduction.

Table VI-1 Summary of Baseline Disposal Practices, by Zone, 1985

Zone	Drilling waste disposal (percent of drill sites)		Produced water disposition (percent of produced waters)		
				Class II Injection	
	Unlined facilities	Lined facilities	Surface discharge	EOR	Disposal
Appalachian	23	77	50	25	25
Gulf	89	11	34	11	55
Midwest	47	53	0	91	9
Plains	49	51	0	38	62
Texas/ Oklahoma	60	40	4	69	27
Northern Mountain	65	35	12	45	42
Southern Mountain	50	50	0	84	16
West Coast	99	1	23	54	23
Alaska	67	33	0	71	29
Total U.S.	63	37	11	59	28
Lower 48 States	63	37	12	60	28

Sources: Drilling waste and produced water disposal information from API, 1987a except for produced water disposal percents for the Appalachian zone, which are based on personal communications with regional industry sources.

NOTE: Produced water disposition percents for total U.S. and Lower 48 are based on survey sample weights. Weighting by oil production results in a figure of 9 percent discharge in the Lower 48 (API 1987b).

In addition to these disposal options, costs were also estimated for ground-water monitoring and general site management for waste disposal sites. These latter practices can be necessary adjunct requirements for various final disposal options to enhance environmental protection.

For produced water, two alternative practices were considered in the cost analysis: Class I injection wells and Class II injection wells. Both classes may be used for water disposal or for enhanced energy recovery waterflooding. They may be located either onsite or, in the case of disposal wells, offsite. To depict the variation in use patterns of these wells, cost estimates were developed for a wide range of injection capacities.

Cost of Waste Management Practices

For each waste disposal option, engineering design parameters of representative waste management facilities were established for the purpose of costing (Table VI-2). For the baseline disposal methods, parameters were selected to typify current practices. For waste management practices that achieve a higher level of environmental control than the most common baseline practices, parameters were selected to typify the best (i.e., most environmentally protective) current design practices. For waste management practices that would be acceptable for hazardous waste under Subtitle C of RCRA, parameters were selected to represent compliance with these regulations as they existed in early 1987.

Capital and operating and maintenance (O&M) costs were estimated for each waste management practice based on previous EPA engineering cost documents and tailored computer model runs, original contractor engineering cost estimates, vendor quotations, and other sources.[1] Capital costs were annualized using an 8 percent discount rate, the

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[1] See footnotes to Tables VI-3 and VI-4 and Eastern Research Group 1987 for a detailed source list.

Table VI-2 Summary of Engineering Design Elements for Baseline and Alternative Waste Management Practices

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Unlined pit	• Pit excavation (0.25 acre) • Clearing and grubbing • Contingency • Contractor fee	• Negligible	• Pit burial (earth fill only) • Contingency • Contractor fee	
One-liner pit (waste buried on site)	• Clearing and grubbing • Pit excavation (0.25 acre) • Berm construction (gravel and vegetation) • 30-mil synthetic liner • Liner protection (geotextile subliner) • Engineering, contractor, and inspection fee • Contingency	• Negligible	• Pit burial (earth fill) • Capping - 30-mil PVC synthetic membrane - topsoil • Revegetation • Engineering, contractor, and inspection fee • Contingency	
Offsite one-liner facility	• Pit excavation (15 acres) • Same costs as onsite one-liner pit with addition of: - land cost - utility site work - pumps - spare parts - dredging equipment - inlet/outlet structures - construction and field expense	• Operating labor - clerical staff - foremen • Maintenance labor and supplies • Utilities • Plant overhead • Dredging	• Same costs as onsite one-liner pit • Solidification • Free liquid removal and treatment	

Table VI-2 (continued)

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Offsite SCLC facility	• Pit excavation (15 acres) • Same costs as commercial one-liner pit with the addition of: - additional pit liners - clay liner replaces geotextile subliner	• Same costs as commercial one-liner pit	•Same costs as onsite one-liner pit with addition of synthetic cap • Equipment decontamination	(See ground-water monitoring and site management)
Ground water monitoring and site management	• Ground-water monitoring wells • Leachate collection system - drainage tiles - leachate collection layer (sand or gravel) for single-liner case only - leachate collection liner for single-liner case only • Signs/fencing • RCRA permitting (for RCRA scenario)	• Ground-water monitoring wells sampling and laboratory fees • Leachate treatment	• Soil poisoning (to prevent disruption by long-rooted plants) • Cover drainage tile - collection layer (sand or gravel) - geotextile filter fabric in one-liner pit • Monitoring • Certification, supervision	• Monitoring well sampling • Leachate treatment • Notice to local authorities • Notation on property deed • Facility inspection • Maintenance and repair • Cover replacement • Engineering and inspection fees • Contingency
Offsite, multiple-application landfarming	• Land cost • Land clearing cost • Building cost • Lysimeter cost (RCRA scenario) • Cluster wells (RCRA scenario)	• Labor • Ground-water monitoring • Soil core cost • Maintenance • Utilities • Insurance, taxes, and G & A	• Revegetation • Testing	• Land authority and property deed cost • Ground-water monitoring cost • Soil core cost • Erosion control cost • Vegetative cover cost

Table VI-2 (continued)

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Offsite, multiple-application landfarming (continued)	• Wind dispersal control (RCRA scenario) • Storage tanks • Engineering and inspection • Contingency • Retention pond (RCRA scenario) • Berms (RCRA scenario)			• Engineering and inspection costs • Contingency
Volume reduction	• Equipment rental - mechanical or vacuum separation equipment • Tanks	• Chemicals • Labor		
Injection (Class II)	• Convert existing well to disposal well - completion rig contract - drilling fluids - cementing - logging and perforating - stimulation - liner and tubing • Site work/building • Holding tanks • Skim tanks • Filters and pumps • Pipelines	• Labor • Chemicals • Electricity • Filters • Disposal of filtrates • Pump maintenance • Pressure tests • Liability costs	• Plug and abandon	

Table VI-2 (continued)

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Injection (Class I)	• Drill new well - drilling rig contract - completion rig contract - cementing - logging and perforating - site preparation - casing - liner - tubing • Storage tanks • Annular fluid tank • Filters • Pumps • Pipelines • Site work/buildings • RCRA permit cost (RCRA scenario)	• Same costs as Class II wells with addition of: - tracer survey - cement bond log - pipe evaluation - disposal of filtrate in hazardous waste facility	• Plug and abandon	

approximate after-tax real cost of capital for this industry. Annualized capital costs were then added to O&M costs to compute the total annual costs for typical waste management unit operations. Annual costs were divided by annual waste-handling capacity (in barrels) to provide a cost per barrel of waste disposal. Both produced water disposal costs and drilling waste (i.e., muds and cuttings) disposal costs are expressed on a dollars-per-barrel basis.

The average engineering unit cost estimates for drilling wastes are presented in Table VI-3 for each region and for a composite of the Lower 48. Regional cost variations were estimated based on varying land, construction, and labor costs among regions. The costs for the Lower 48 composite are estimated by weighting regional cost estimates by the proportion of production occurring in each region. (Throughout the discussion that follows, the Lower 48 composite will be referenced to illustrate the costs and impacts in question.)

For the Lower 48 composite, the drilling waste disposal cost estimates presented in Table VI-3 range from $2.04 per barrel for onsite, unlined pit disposal to $157.50 per barrel for incineration. Costs for the disposal options are significantly higher for Alaska because of the extreme weather conditions, long transportation distances from population and material centers to drill sites, high labor costs, and other unique features of this region.

Costs for produced water are presented in Table VI-4. Disposal costs include injection costs, as well as transport, loading, and unloading charges, where appropriate. Injection for EOR purposes occurs onsite in either Class II or Class I wells. Class II disposal occurs onsite in all zones except Appalachia. Class I disposal occurs offsite except for the Northern Mountain and Alaska zones. Well capacities and transport distances vary regionally depending on the volume of water production and the area under production.

Table VI-3 Unit Costs of Drilling Waste Disposal Options, by Zone (Dollars per Barrel of Waste, 1985 Basis)

	Zone								
Disposal option	Appalachian	Gulf	Midwest	Plains	Texas/ Oklahoma	Northern Mountain	Southern Mountain	West Coast	Alaska	Lower 48
Surface impoundment[a]										
Unlined (0.25 acre)	\$ 2.09	\$ 1.98	\$ 2.00	\$ 1.98	\$ 2.10	\$ 2.00	\$ 2.00	\$ 2.04	\$ 2.69	\$ 2.04
Single-liner (0.25 acre)	4.62	4.32	4.35	4.29	4.63	4.35	4.35	4.46	6.16	4.46
SCLC (15 acres)	18.26	12.41	25.61	19.54	11.66	19.73	20.69	27.54	20.27	15.52
Landfarming[b]										
Current	13.21	12.06	12.41	15.91	17.01	16.14	15.99	16.42	N.E.	15.47
Subtitle C	30.23	31.58	28.94	39.14	40.31	36.45	36.38	38.45	N.E.	37.12
Solidification[c]	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	N.E.	8.00
Incineration[d]	157.50	157.50	157.50	157.50	157.50	157.50	157.50	157.50	N.E.	157.50
Volume reduction and offsite single-liner disposal[e]	15.16	3.18	17.24	9.50	5.83	5.40	6.15	21.87	5.67	6.74
Volume reduction and offsite SCLC disposal[e]	19.27	7.94	25.50	15.94	9.91	11.90	12.93	30.71	12.57	11.95

N.E. = Not estimated; disposal method not practical and/or information not available for Alaska.

[a]Source: Pope Reid Associates 1985a, 1985b, 1987a; costs for SCLC disposal include transportation charges.
[b]Source: Pope Reid Associates 1987b.
[c]Source: Erlandson 1986; Webster 1987; Tesar 1986; Camp, Dresser & McKee 1986; Hanson and Jones 1986; Cullinane et al. 1986; North American Environmental Service 1985.
[d]Source: USEPA 1986.
[e]Source: Slaughter 1987; Rafferty 1987. Costs include equipment rental and transport and disposal of reduced volume of waste. All costs are allocated over the original volume of waste so that per-barrel costs of waste disposal are comparable to the other cost estimates in the table.

Table VI-4 Unit Costs of Underground Injection of Produced Water, by Zone (Dollars per Barrel of Water)

Zone	Class II injection		Class I injection[a]	
	Disposal	EOR	Disposal	EOR
Appalachian[b]	$1.26-1.33	$0.75	$2.45	$6.12
Gulf	0.10	0.23	0.84	1.35
Midwest	0.29	0.13	1.14	0.84
Plains	0.14	0.19	0.86	1.21
Texas/Oklahoma	0.11	0.14	0.96	0.76
Northern Mountain	0.01	0.14	0.40	0.58
Southern Mountain	0.07	0.14	1.05	0.67
West Coast	0.04	0.05	0.72	0.25
Alaska	0.05	0.41	1.28	2.15
Lower 48 States	0.10	0.14	0.92	0.78

[a] Disposal costs for Class I injection include transportation and loading/unloading charges except for the Northern Mountain zone and Alaska, where onsite disposal is expected to occur.

[b] Class II disposal costs for Appalachian zone includes transport and loading/unloading charges. Lower estimate is for intermediate scenarios; higher estimate is for baseline practice due to change in transport distances. For all other zones, Class II disposal is assumed to occur onsite.

Sources: Tilden 1987a, 1987b.

NOTE: Base year for costs is 1985.

Produced water disposal costs range from $0.01 to $1.33 per barrel for Class II disposal and EOR injection and from $0.40 to $6.12 per barrel for Class I disposal and EOR injection. Costs for Class I facilities are substantially higher because of the increased drilling completion, monitoring, and surface equipment costs associated with waste management facilities that accept hazardous waste.

The transportation of waste represents an additional waste management cost for some facilities. Transportation of drilling or production waste for offsite centralized or commercial disposal is practiced now by some companies and has been included as a potential disposal option in the waste management scenarios. Drilling waste transport costs range from $0.02 per barrel/mile for nonhazardous waste to $0.06 per barrel/mile for hazardous waste. Produced water transport costs range from $0.01 per barrel/mile (nonhazardous) to $0.04 per barrel/mile (hazardous). Distances to disposal facilities were estimated based on the volume of wastes produced, facility capacities, and the area served by each facility. Waste transportation also involves costs for loading and unloading.

WASTE MANAGEMENT SCENARIOS AND APPLICABLE WASTE MANAGEMENT PRACTICES

In order to determine the potential costs and impacts of changes in oil and gas waste disposal requirements, three waste management scenarios have been defined. The scenarios have been designed to illustrate the cost and impact of two hypothetical additional levels of environmental control in relation to current baseline practices. EPA has not yet identified, defined, or evaluated its regulatory options for the oil and gas industry; therefore, it should be noted that these scenarios <u>do not</u> represent regulatory determinations by EPA. A regulatory determination will be made by EPA following the Report to Congress.

Baseline Scenario

The Baseline Scenario represents the current situation. It encompasses the principal waste management practices now permitted under State and Federal regulations. Several key features of current practice for both drilling waste and produced water were summarized in Table VI-1, and the distribution of disposal practices shown in Table VI-1 is the baseline assumption for this analysis.

Intermediate Scenario

The Intermediate Scenario depicts a higher level of control. Operators generating wastes designated as hazardous are subject to requirements more stringent than those in the Baseline Scenario. An exact definition of "hazardous" has not been formulated for this scenario. Further, even if a definition were posited (e.g., failure of the E.P. toxicity test), available data are insufficient to determine the proportion of the industry's wastes that would fail any given test. Pending an exact regulatory definition of "hazardous" and the development of better analytical data, a range of alternative assumptions has been employed in the analysis. In the Intermediate 10% Scenario, the Agency assumed, for the purpose of costing, that 10 percent of oil and gas projects generate hazardous waste and in the Intermediate 70% Scenario that 70 percent of oil and gas projects generate hazardous waste.

For drilling wastes designated hazardous, operators would be required to use a single-synthetic-liner facility, landfarming with site management (as defined in Table VI-2), solidification, or incineration. Operators would select from these available compliance measures on the basis of lowest cost. Since a substantial number of operators now employ a single synthetic liner in drilling pits, only those sites not using a liner would be potentially affected by the drilling waste requirements of the Intermediate Scenario.

For produced waters, the Intermediate Scenario assumes injection into Class II facilities for any produced water that is designated hazardous. Operators now discharging waste directly to water or land (approximately 9 to 12 percent of all water) would be required to use a Class II facility if their wastes were determined to be hazardous.

"Affected operations" under a given scenario are those oil and gas projects that would have to alter their waste management practices and incur costs to comply with the requirements of the scenario. For example, in the Intermediate 10% Scenario, it is assumed that only 10 percent of oil and gas projects generate hazardous waste. For drilling, an estimated 63 percent of oil and gas projects now use unlined facilities and are therefore potentially affected by the requirements of the scenario. Since 10 percent of these projects are assumed to generate hazardous waste, an estimated 6.3 percent of the projects are affected operations, which are subject to higher disposal costs.

The Subtitle C Scenario

In the Subtitle C Scenario, wastes designated as hazardous are subject to pollution control requirements consistent with Subtitle C of RCRA. For drilling wastes, those wastes that are defined as hazardous must be disposed of in a synthetic composite liner with leachate collection (SCLC) facility employing site management and ground-water monitoring practices consistent with RCRA Subtitle C, a landfarming facility employing Subtitle C site management practices, or a hazardous waste incinerator. In estimating compliance costs EPA estimated that a combination of volume reduction and offsite dedicated SCLC disposal would be the least-cost method for disposal of drilling waste. For production wastes, those defined as hazardous must be injected into Class I disposal or EOR injection wells.

Since virtually no drilling or production operations currently use Subtitle C facilities or Class I injection wells in the baseline, all projects that generate produced water are potentially affected. In the Subtitle C 10% Scenario, 10 percent of these projects are assumed to be affected; in the Subtitle C 70% Scenario, 70 percent of these projects are affected. The Subtitle C Scenario, like the Intermediate Scenario, does not establish a formal definition of "hazardous"; nor does it attempt to estimate the proportion of wastes that would be hazardous under the scenario. As with the Intermediate Scenario, two assumptions (10 percent hazardous, 70 percent hazardous) are employed, and a range of costs and impacts is presented.

This Subtitle C Scenario does not, however, impose all possible technological requirements of the Solid Waste Act Amendments, such as the land ban and corrective action requirements of the Hazardous Solid Waste Amendments (HSWA), for which regulatory proposals are currently under development in the Office of Solid Waste. Although the specific regulatory requirements and their possible applications to oil and gas field practices, especially deep well injection practices, were not sufficiently developed to provide sufficient guidelines for cost evaluation in this report, the Agency recognizes that the full application of these future regulations could substantially increase the costs and impacts estimated for the Subtitle C Scenario.

The Subtitle C-1 Scenario

The Subtitle C-1 Scenario is exactly the same as the Subtitle C Scenario, except that produced water used in waterfloods is considered part of a production process and is therefore exempt from more stringent (i.e., Class I) control requirements, even if the water is hazardous. As shown in Table VI-1, approximately 60 percent of all produced water is used in waterfloods. Thus, only about 40 percent of produced water is potentially affected under the Subtitle C-1 Scenario. The requirements of the Subtitle C-1 Scenario for drilling wastes are exactly the same as those of the Subtitle C Scenario. As with the other scenarios, alternative assumptions of 10 and 70 percent hazardous are employed in the Subtitle C-1 Scenario.

Summary of Waste Management Scenarios

Table VI-5 summarizes the major features of all the waste management scenarios. It identifies acceptable disposal practices under each scenario and the percent of wastes affected under each scenario. The Subtitle C 70% Scenario enforces the highest level of environmental control in waste management practices, and it affects the largest percent of facilities.

COST AND IMPACT OF THE WASTE MANAGEMENT SCENARIOS FOR TYPICAL NEW OIL AND GAS PROJECTS

Economic Models

An economic simulation model, developed by Eastern Research Group (ERG) and detailed in the Technical Background Document (ERG 1987), was employed to analyze the impact of waste management costs on new oil and gas projects. The economic model simulates the performance and measures the profitability of oil and gas exploration and development projects both before and after the implementation of the waste management scenarios. For the purposes of this report, a "project" is defined as a single successful development well and the leasing and exploration activities associated with that well. The costs for the model project include the costs of both the unsuccessful and the successful leasing and exploratory and development drilling required, on average, to achieve one successful producing well.

Table VI-5 Assumed Waste Management Practices for Alternative Waste Management Scenarios

Waste management scenario	Drilling wastes: Disposal method	Drilling wastes: Potentially affected operations	Produced waters: Disposal method	Produced waters: Potentially affected operations
Baseline	Unlined surface impoundment Lined surface impoundment	N.A.	Class II injection Surface discharge	N.A.
Intermediate	Baseline practices for nonhazardous wastes For hazardous wastes: - Lined surface impoundment - Landfarming with site management - Solidification - Incineration	Facilities not now using liners: approximately 63% of total[a]	Baseline practices for nonhazardous wastes Class II injection for hazardous wastes	Facilities not now using Class II injection: approximately 20% of total[d]
Subtitle C	Baseline practices for nonhazardous wastes For hazardous wastes: - SCLC impoundment with Subtitle C site management - Landfarming with Subtitle C site management - Hazardous waste incineration	All facilities[b]	Baseline practices for nonhazardous wastes Class I injection for hazardous wastes	All facilities[e]
Subtitle C-1	Same as Subtitle C scenario	Same as Subtitle C scenario[c]	Baseline practices for nonhazardous wastes For hazardous wastes: - Class I injection for nonwaterfloods - Class II injection for waterfloods	Facilities not now waterflooding: approximately 40% of total[f]

[a] In the Intermediate 10% Scenario, 10% of the 63%, or 6.3%, are assumed to be hazardous; in the Intermediate 70% Scenario, 70% of the 63%, or 44.1%, are assumed to be hazardous.

[b] In the Subtitle C 10% Scenario, 10% of the 100%, or 10.0%, are assumed to be hazardous; in the Subtitle C 70% Scenario, 70% of the 100%, or 70.0%, are assumed to be hazardous.

[c] In the Subtitle C-1 10% Scenario, 10% of the 100%, or 10.0%, are assumed to be hazardous; in the Subtitle C-1 70% Scenario, 70% of the 100%, or 70.0%, are assumed to be hazardous.

[d] In the Intermediate 10% Scenario, 10% of the 20%, or 2.0%, are assumed to be hazardous; in the Intermediate 70% Scenario, 70% of the 20%, or 14.0%, are assumed to be hazardous.

[e] In the Subtitle C 10% Scenario, 10% of the 100%, or 10.0%, are assumed to be hazardous; in the Subtitle C 70% Scenario, 70% of the 100%, or 70.0%, are assumed to be hazardous.

[f] In the Subtitle C-1 10% Scenario, 10% of the 40%, or 4.0%, are hazardous and not exempt because of waterflooding. In the Subtitle C-1 70% Scenario, 70% of the 40%, or 28.0%, are hazardous and not exempt because of waterflooding.

For this study, model projects were defined for oil wells (with associated casinghead gas) in the nine active oil and gas zones and for a Lower 48 composite. Model gas projects were defined for the two most active gas-producing zones (the Gulf and Texas/Oklahoma zones). Thus, 12 model projects have been analyzed. The Technical Background Document for the Report to Congress provides a detailed description of the assumptions and data sources underlying the model projects.

A distinct set of economic parameter values is estimated for each of the model projects, providing a complete economic description of each project. The following categories of parameters are specified for each project:

1. Lease Cost: initial payments to Federal or State governments or to private individuals for the rights to explore for and to produce oil and gas.
2. Geological and Geophysical Cost: cost of analytic work prior to drilling.
3. Drilling Cost per Well.
4. Cost of Production Equipment.
5. Discovery Efficiency: the number of wells drilled for one successful well.
6. Production Rates: initial production rates of oil and gas and production decline rates.
7. Operation and Maintenance Costs.
8. Tax Rates: Rates for Federal and State income taxes, severance taxes, royalty payments, depreciation, and depletion.
9. Price: wellhead selling price of oil and gas (also called the "first purchase price" of the product).
10. Cost of Capital: real after-tax rate of return on equity and borrowed investment capital for the industry.
11. Timing: length of time required for each project phase (i.e., leasing, exploration, development, and production).

The actual parameter values for the 12 model projects are summarized in Table VI-6.

For each of the 12 model projects, the economic performance is estimated before (i.e., baseline) and after each waste management scenario has been implemented. Two measures of economic performance are employed in the impact assessment presented here. One is the after-tax rate of return. The other is the cost of production per barrel of oil (here defined as the cost of the resources used in production, including profit to the owners of capital, excluding transfer payments such as royalties and taxes). A number of other economic output parameters are described in the Technical Background Document.

Quantities of Wastes Generated by the Model Projects

To calculate the waste management costs for each representative project, it was necessary to develop estimates of the quantities of drilling and production wastes generated by these facilities. These estimates, based on a recent API survey, are provided in Table VI-7. Drilling wastes are shown on the basis of barrels of waste per well. Production wastes are provided on the basis of barrels of waste per barrel of oil.

For the Lower 48 composite, an estimated 5,170 barrels of waste are generated for each well drilled. For producing wells, approximately 10 barrels of water are generated for every barrel of oil. This latter statistic includes waterflood projects, some of which operate at very high water-to-oil ratios.

Model Project Waste Management Costs

Model project waste management costs are estimated for the baseline and for each waste management scenario using the cost data presented in

Table VI-6 Economic Parameters of Model Projects for U.S. Producing Zones
(All Costs in Thousands of 1985 Dollars, Other Units as Noted)

Parameter	Appalachian	Gulf	Gulf	Midwest	Plains	Texas/ Oklahoma	Texas/ Oklahoma	Northern Mountain	Southern Mountain	West Coast	Alaska	Lower 48 States
Production	Oil/Gas	Oil/Gas	Gas	Oil/Gas	Oil/Gas	Oil/Gas	Gas	Oil/Gas	Oil/Gas	Oil/Gas	Oil/Gas	Oil/Gas
Yr of first prod.	1	1	1	1	1	1	1	2	1	1	10	1
Lease cost	1.146	19.296	154.368	2.509	2.080	11.200	22.400	4.992	2.251	33.178	161.056	14.877
G & G expense	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%
Well cost	63.911	244.276	640.146	122.138	186.347	246.324	727.636	421.142	492.053	160.995	3,207.388	248.607
Disc. efficiency	85%	59%	59%	51%	52%	71%	71%	55%q	72%	90%	88%	69%
Infrastructure cost	45.000	73.189	35.297	60.788	81.855	86.820	39.824	102.662	109.357	82.560	45,998.400	83.952
O & M costs (per yr)	4.500	13.349	18.486	11.807	14.529	15.114	21.048	17.015	17.781	13.370	690.900	14.463
Initial prod. rates												
Oil (bbl/day)	4	60	0	16	26	37	0	53	32	35	3700	41
Gas (Mcf/day)	16	82	1295	15	34	69	1038	72	69	0	686	57
Prod. decline rates	9%	19%	19%	17%	19%	12%	12%	13%	13%	7%	9%	12%
Federal corp. tax	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%
State corp. tax	0%	8%	8%	4%	6.75%	5%	5%	0%	6%	9.35%	9.40%	6.14%
Royalty rate	18.75%	18.75%	18.75%	12.50%	12.50%	20.00%	20.00%	12.50%	16.00%	18.75%	14.30%	18.24%
Severance tax												
Oil	0.5%	12.5%	12.5%	0%	8%	7%	7%	6%	4%	0.14%	a	6.67%
Gas	1.5%	4.25%	4.25%	4.84%	0%	8%	7%	7%	6%	4%	0.14%	a
Wellhead price												
Oil ($/bbl)	$20.90	$21.65	$21.65	$22.11	$21.14	$22.03	$22.03	$20.74	$21.16	$18.38	$16.37	$20.00
Gas ($/Mcf)	$ 2.00	$ 1.99	$ 1.99	$ 2.03	$ 1.43	$ 1.58	$ 1.58	$ 1.77	$ 1.98	$ 2.21	$ 0.49	$ 1.65

[a] Tax based on formula in tax code, not a flat percentage.

Source: ERG 1987.

Table VI-7 Average Quantities of Waste Generated, by Zone

Model project/ zone	Drilling waste barrels/well	Produced water (barrels/barrel of oil)
Appalachian	2,344	2.41
Gulf	10,987	8.42
Midwest	1,853	23.61
Plains	3,623	9.11
Texas/Oklahoma	5,555	10.62
Northern Mountain	8,569	12.30
Southern Mountain	7,153	7.31
West Coast	1,414	8.05
Alaska	7,504	0.15
Lower 48 States	5,170	9.98
Gulf (gas only)	10,987	17.17[a]
Texas/Oklahoma (gas only)	5,555	17.17[a]

[a] Barrels of water per million cubic feet of natural gas.

Sources: API 1987a; Flannery and Lannan 1987.

Tables VI-3 and VI-4 and the waste quantity data shown in Table VI-7. For each model project, waste management costs are calculated for each waste management scenario.

For each model project and scenario, the available compliance methods were identified (Table VI-5). Cost estimates for all available compliance methods, including transportation costs for offsite methods, were developed based on the unit cost factors (Tables VI-2 and VI-3) and the waste quantity estimates (Table VI-7). Each model facility was assumed to have selected the lowest cost compliance method. Based on compliance cost comparisons, presented in more detail in the Technical Background Document, the following compliance methods are employed by affected facilities under the waste management scenarios:

Intermediate Scenario

1. Drilling wastes - single-liner onsite facility; volume reduction and transport to offsite single-liner facility if cost-effective.

2. Production wastes - Class II onsite facility.

Subtitle C Scenario

1. Drilling wastes - transport to offsite SCLC facility with site management and with volume reduction if cost-effective.

2. Production wastes - for waterfloods, onsite injection in Class I facility; for nonwaterfloods, transport and disposal in offsite Class I facility.

Subtitle C-1 Scenario

1. Drilling wastes - transport to offsite SCLS facility with site management and with volume reduction if cost-effective.

2. Production wastes - waterfloods exempt; for nonwaterfloods, transport and injection in offsite Class I facility.

For each model facility under each scenario, the least-cost compliance method was assumed to represent the cost of affected projects. Costs for unaffected projects were estimated based on the cost of baseline practices. Weighted average costs for each model under each scenario (shown in Tables VI-8 and VI-9) incorporate both affected and unaffected projects. For example, in the Subtitle C 70% Scenario, while 70 percent of projects must dispose of drilling wastes in Subtitle C facilities, the other 30 percent can continue to use baseline practices. The weighted average cost is calculated as follows:

Project category	Percentage of projects	Drilling waste disposal cost	Weighted cost
Affected operations	70%	$61,782	$43,248
Unaffected operations	30%	$15,176	$ 4,552
Weighted average			$47,800

For drilling wastes, the weighted average costs range from $15,176 per well in the Baseline to $47,800 per well in the RCRA Subtitle C 70% case. Thus, the economic analysis assumes that each well incurs an additional $32,624 under the RCRA Subtitle C 70% Scenario. For produced water, costs per barrel of water disposed of range from $0.11 in the Baseline to $0.62 in the RCRA Subtitle C 70% Scenario. Thus, there is an additional cost of $0.51 per barrel of water under this scenario.

Impact of Waste Management Costs on Representative Projects

The new oil and gas projects incur additional costs under the alternative waste management scenarios for both drilling and production waste management. By incorporating these costs into the economic model simulations, the impact of these costs on financial performance of typical new oil and gas projects is assessed. These impacts are presented in Tables VI-10 and VI-11.

As shown in Table VI-10, the internal rate of return can be substantially affected by waste management costs, particularly in the Subtitle C 70% Scenario. From a base case level of 28.9 percent, model