APPENDIX A

DERIVATION OF WEIGHTED AVERAGE COST OF COMPLIANCE PER WELL TYPE

EPA presented the number of wells and incremental cost of compliance or cost saving by well type, water depth, and drilling fluid used in Section 5 (Table 5-1). These well counts and costs/cost savings are derived from the Development Document (EPA, 2000), which provides well counts, the baseline cost of drill cuttings disposed, the two discharge option costs and zero discharge option costs by region, assumed baseline and post-compliance choice of drilling fluid, water depth, well type, and the assumed discharge or disposal mode chosen by the operator (hauling to shore or injecting the waste). This appendix explains the derivation of well counts and individual well costs found in Table 5-1 from data provided in the Development Document.

A.1 DERIVATION OF WELL COUNTS

Tables A-1 and A-2 reproduce the summary tables of the well counts and compliance costs for the Gulf of Mexico and Alaska, respectively, provided in the Development Document. Well counts and costs for California are not included because the regulation is estimated to have no impact on drilling in that region. Well counts and costs in Table A-1 and Table A-2 are broken down according to drilling fluid, water depth, well type, and discharge/disposal mode.

The number of wells switching the type of drilling fluid used from a baseline to a post-compliance scenario and the discharge/disposal mode under the various regulatory options are calculated from Tables A-1 and A-2. The well counts under the various options are estimated for water depth (deep or shallow), well type (developmental or exploratory), and disposal mode (discharge, haul, or inject). For discharge options 1 and 2, the difference between the number of wells using OBFs and WBFs and the number of wells drilled using OBFs and WBFs in the baseline is the number of wells switching from OBF or WBF to SBF for each group of wells. For the zero discharge option, the difference between the number of wells drilled using SBF under zero discharge and the number of wells using SBFs in the baseline is the number of wells switching from SBF to OBF or WBF for each group of wells. Further, the number of SBF wells

Table A-1

Summary Table of Well Counts and Compliance Costs, By Water Depth, Well Type, and Discharge/Disposal Mode : Gulf of Mexico Region

		Baseline				BAT 1				BAT 2				BAT 3			
Water Depth	**Well Type**	**No. wells / well type(a)**	**Disposal mode**	**Number wells(b)**	**Cost / ZD well(c)**	**No. wells / well type**	**Disposal mode**	**Number ZD wells**	**Cost / ZD well(d)**	**No. wells / well type**	**Disposal mode**	**Number ZD wells**	**Cost / ZD well(e)**	**No. wells / well type**	**Disposal mode**	**Number ZD wells**	**Cost / ZD well**
SYNTHETIC BASED DRILLING FLUIDS																	
			discharge	16	$117,572		discharge	17	$114,787		discharge	17	$111,043		discharge	0	-
	develop	16	100% haul	0	-	17	100% haul	0	-	17	100% haul	17	$4,125	3	100% haul	3	$236,963
deep			0% inject	0	-		0% inject	0	-		0% inject	0	-		0% inject	0	-
			discharge	48	$261,664		discharge	49	$231,038		discharge	49	$223,116		discharge	0	-
	explor	48	100 % haul	0	-	49	100 % haul	0	-	49	100 % haul	49	$10,541	8	100 % haul	8	$575,921
			0% inject	0	-		0% inject	0	-		0% inject	0	-		0% inject	0	-
			discharge	86	$77,792		discharge	124	$85,306		discharge	124	$82,346		discharge	0	-
	develop	86	80% haul	0	-	124	80% haul	0	-	124	100 % haul	124	$2,712	0	100 % haul	0	-
			20% inject	0	-		20% inject	0	-		0% inject	0	-		0% inject	0	-
shallow			discharge	51	$162,877		discharge	74	$158,367		discharge	74	$152,947		discharge	0	-
	explor	51	80% haul	0	-	74	80% haul	0	-	74	100% haul	74	$6,449	0	100% haul	0	-
			20% inject	0	-		20% inject	0	-		0% inject	0			0% inject	0	-
OIL BASED DRILLING FLUIDS																	
			discharge	0	-		discharge	-	-		discharge	0	-		discharge	0	-
	develop	0	100% haul	0	-	0	100% haul	-	-	0	100% haul	0	-	8	100% haul	8	$161,419
			0% inject	0	-		0% inject	-	-		0% inject	0	-		0% inject	0	-
deep			discharge	0	-		discharge	-	-		discharge	0			discharge	0	-
	explor	0	100 % haul	0	-	0	100 % haul	-	-	0	100 % haul	0	-	25	100 % haul	25	$407,793
			0% inject	0	-		0% inject	-	-		0% inject	0	-		0% inject	0	-
			discharge	0	-		discharge	0	-		discharge	0	-		discharge	0	-
	develop	42	80% haul	34	$110,715	25	80% haul	20	$110,715	25	80% haul	20	$110,715	128	80% haul	102	$110,715
			20% inject	8	$83,448		20% inject	5	$83,448		20% inject	5	$83,448		20% inject	26	$83,448
shallow			discharge	0	-		discharge	0	-		discharge	0	-		discharge	0	-
	explor	25	80% haul	20	$236,406	15	80% haul	12	$236,406	15	80% haul	12	$236,406	76	80% haul	61	$236,406
			20% inject	5	$174,853		20% inject	3	$174,853		20% inject	3	$174,853		20% inject	15	$174,853
WATER BASED DRILLING FLUIDS																	
			discharge	12	NA		discharge	11	NA		discharge	11	NA		discharge	17	NA
	develop	12	100% haul	0	-	11	100% haul	0	-	11	100% haul	0	-	17	100% haul	0	-
			0% inject	0	-		0% inject	0	-		0% inject	0	-		0% inject	0	-
deep			discharge	36	NA		discharge	34	NA		discharge	34	NA		discharge	51	NA
	explor	36	100 % haul	0	-	34	100 % haul	0	-	34	100 % haul	0	-	51	100 % haul	0	-
			0% inject	0	-		0% inject	0	-		0% inject	0	-		0% inject	0	-
			discharge	511	NA		discharge	479	NA		discharge	479	NA		discharge	511	NA
	develop	511	80% haul	0	-	479	80% haul	0	-	479	80% haul	0	-	511	80% haul	0	-
			20% inject	0	-		20% inject	0	-		20% inject	0	-		20% inject	0	-
shallow			discharge	298	NA		discharge	279	NA		discharge	279	NA		discharge	298	NA
	explor	298	80% haul	0	-	279	80% haul	0	-	279	80% haul	0	-	298	80% haul	0	-
			20% inject	0	-		20% inject	0	-		20% inject	0	-		20% inject	0	-

Source: Development Document (EPA, 2000).

(a) Represents the total number of wells being drilled in each region for each well type.
(b) Represents the number of wells subject to discharge/zero discharge conditions.
(c) The cost shown in this column represent the compliance costs associated with current treatment technology as the baseline level of technology and cost.
(d) The costs listed under BAT Option 1 represent the cost of improved treatment technology with the discharge of wastes from both cuttings dryers and fines removal units (FRUs); it is the multiple well per structure-adjusted cost .
(e) The "discharge" costs shown under BAT Option 2 represent costs related to cuttings dryer treatment and costs; the "haul" costs shown are Zero Discharge costs applied to FRU wastes; these costs are also multiple well per structure adjusted costs.

Table A-2

Summary Table of Well Counts and Compliance Costs, By Water Depth, Well Type, and Discharge/Disposal Mode : Alaska Region

		Baseline				BAT 1				BAT 2				BAT 3			
Water Depth	**Well Type**	**No. wells / well type(a)**	**Disposal mode**	**Number wells(b)**	**Cost / ZD well(c)**	**No. wells / well type**	**Disposal mode**	**Number ZD wells**	**Cost / ZD well(d)**	**No. wells / well type**	**Disposal mode**	**Number ZD wells**	**Cost / ZD well(e)**	**No. wells / well type**	**Disposal mode**	**Number ZD wells**	**Cost / ZD well**
SYNTHETIC BASED DRILLING FLUIDS																	
			discharge	-	-		discharge	-	-		discharge	-	-		discharge	-	-
	develop	0	0% haul	-	-	0	0% haul	-	-	0	0% haul	-	-	0	0% haul	-	-
deep			0% inject	-	-		0% inject	-	-		0% inject	-	-		0% inject	-	-
			discharge	-	-		discharge	-	-		discharge	-	-		discharge	-	-
	explor	0	0 % haul	-	-	0	0 % haul	-	-	0	0 % haul	-	-	0	0 % haul	-	-
			0% inject	-	-		0% inject	-	-		0% inject	-	-		0% inject	-	-
			discharge	-	-		discharge	0	-		discharge	0	-		discharge	-	-
	develop	0	0% haul	-	-	1	0% haul	0	-	1	0 % haul	0	-	0	0 % haul	-	-
			0% inject	-	-		100% inject	1	$266,864		100% inject	1	$266,864		0% inject	-	-
shallow			discharge	-	-		discharge	-	-		discharge	-	-		discharge	-	-
	explor	0	0% haul	-	-	0	0% haul	-	-	0	0% haul	-	-	0	0% haul	-	-
			0% inject	-	-		100% inject	-	-		100% inject	-	-		0% inject	-	-
OIL BASED DRILLING FLUIDS																	
			discharge	-	-		discharge	-	-		discharge	-	-		discharge	-	-
	develop	0	0% haul	-	-	0	0% haul	-	-	0	0% haul	-	-	0	0% haul	-	-
			0% inject	-	-		0% inject	-	-		0% inject	-	-		0% inject	-	-
deep			discharge	-	-		discharge	-	-		discharge	-			discharge	-	-
	explor	0	0 % haul	-	-	0	0 % haul	-	-	0	0 % haul	-	-	0	0 % haul	-	-
			0% inject	-	-		0% inject	-	-		0% inject	-	-		0% inject	-	-
			discharge	0	-		discharge	-	-		discharge	0	-		discharge	0	-
	develop	1	0% haul	0	-	0	0% haul	-	-	0	0% haul	0	-	1	0% haul	0	-
			100% inject	1	$166,896		100% inject	-	-		100% inject	0	-		100% inject	1	$166,896
shallow			discharge	0	-		discharge	0	-		discharge	0	-		discharge	0	-
	explor	1	0% haul	0	-	1	0% haul	0	-	1	0% haul	0	-	1	0% haul	0	-
			100% inject	1	$349,706		100% inject	1	$349,706		100% inject	1	$349,706		100% inject	1	$349,706
WATER BASED DRILLING FLUIDS																	
			discharge	-	-		discharge	-	-		discharge	-	-		discharge	-	-
	develop	0	0% haul	-	-	0	0% haul	-	-	0	0% haul	-	-	0	0% haul	-	-
			0% inject	-	-		0% inject	-	-		0% inject	-	-		0% inject	-	-
deep			discharge	-	-		discharge	-	-		discharge	-	-		discharge	-	-
	explor	0	0 % haul	-	-	0	0 % haul	-	-	0	0 % haul	-	-	0	0 % haul	-	-
			0% inject	-	-		0% inject	-	-		0% inject	-	-		0% inject	-	-
			discharge	3	-		discharge	3	-		discharge	3	-		discharge	3	-
	develop	3	0% haul	0	-	3	0% haul	0	-	3	0% haul	0	-	3	0% haul	0	-
			100% inject	0	-		100% inject	0	-		100% inject	0	-		100% inject	0	-
shallow			discharge	1	-		discharge	1	-		discharge	1	-		discharge	1	-
	explor	1	0% haul	0	-	1	0% haul	0	-	1	0% haul	0	-	1	0% haul	0	-
			100% inject	0	-		100% inject	0	-		100% inject	0	-		100% inject	0	-

Source: Development Document (EPA, 2000).

(a) Represents the total number of wells being drilled in each region for each well type.

(b) Represents the number of wells subject to discharge/zero discharge conditions.

(c) The cost shown in this column represent the compliance costs associated with current treatment technology as the baseline level of technology and cost.

(d) The costs listed under BAT Option 1 represent the cost of improved treatment technology with the discharge of wastes from both cuttings dryers and fines removal units (FRUs); it is the multiple well per structure-adjusted cost .

(e) The "discharge" costs shown under BAT Option 2 represent costs related to cuttings dryer treatment and costs; the "haul" costs shown are Zero Discharge costs applied to FRU wastes; these costs are also multiple well per structure adjusted costs.

changing discharge/disposal modes under the zero discharge option is also calculated. Table A-3 shows the well count for each well group under the two discharge options and the zero discharge option for the Gulf of Mexico and Alaska.

Table A-3

Number of Wells Switching Drilling Fluids and Disposal Modes in Each Well Group

Well Group	Number of Wells
GULF OF MEXICO - DISCHARGE OPTIONS 1 AND 2	
Development Wells - Deep Water	
WBF discharge to SBF discharge	1
Development Wells - Shallow Water	
OBF 80% haul to SBF discharge	14
OBF 20% inject to SBF discharge	3
WBF discharge to SBF discharge	21
Exploratory Wells - Deep Water	
WBF discharge to SBF discharge	1
Exploratory Wells - Shallow Water	
OBF 80% haul to SBF discharge	8
OBF 20% inject to SBF discharge	2
WBF discharge to SBF discharge	13
TOTAL	**63**
GULF OF MEXICO - ZERO DISCHARGE OPTION	
Development Wells - Deep Water	
SBF discharge to SBF 100% haul	3
SBF discharge to OBF 100% haul	8
SBF discharge to WBF discharge	5
Development Wells - Shallow Water	
SBF discharge to OBF 80% haul	68
SBF discharge to OBF 20% inject	18
Exploratory Wells - Deep Water	
SBF discharge to SBF 100% haul	8
SBF discharge to OBF 100% haul	25
SBF discharge to WBF discharge	15
Exploratory Wells - Shallow Water	
SBF discharge to OBF 80% haul	41
SBF discharge to OBF 20% inject	10
TOTAL	**201**
ALASKA - DISCHARGE OPTIONS 1 AND 2	
Development Well - Shallow Water	
OBF 100% inject to SBF 100% inject	1

Source: Development Document (EPA, 2000).

As mentioned in Section 3, EPA worked with industry to estimate the percentage of wells drilled with each type of fluid (WBF, OBF, or SBF) prior to the regulation, as well as the percentage of WBF or OBF wells that would switch to SBF after the regulation. EPA estimates that almost 18 percent—or 201 wells—are drilled currently with SBFs and 6 percent—or 67 wells—are drilled with OBFs. The remaining 857 wells that are estimated to be drilled annually in the Gulf of Mexico are assumed to be drilled exclusively using WBFs.

Under the discharge options, 27 OBF wells and 54 WBF wells would switch to using SBFs. However, due to the increased drilling efficiency of SBF wells, a fewer number of SBF wells are needed to replace WBF wells. This ratio of WBF to SBF efficiency is 3:2. In other words, 54 WBF wells convert to 36 SBF wells under the discharge options (i.e., 54:36 = 3:2 WBF:SBF efficiency). Under the zero discharge option, the number of wells that switch from SBF to OBF and WBF is 190. The remaining 11 wells continue to use SBFs but change the discharge/disposal mode. (See Development Document for more details.)

A.2 DERIVATION OF INCREMENTAL COSTS OR COST SAVINGS

Table A-4 shows incremental compliance costs per well according to the well groupings, i.e. based on drilling fluid, water depth, well type, and discharge/disposal mode. These costs are also derived from Table A-1 and Table A-2. The incremental cost is calculated by subtracting the baseline cost per well from the cost per well under the options BAT 1 through BAT 3 (zero discharge option) for each group of wells according to the switch in use of drilling fluid and disposal mode. For WBF wells, per-well discharge costs are calculated from aggregated WBF discharge costs. Table A-5 shows the derivation of WBF per-well discharge costs. For each type of well, according to water depth, the sum of total rig time costs and total costs of the discharged WBFs are divided by the total number of WBF wells affected by the regulation to get per-well WBF discharge costs.

Table A-4

Incremental Compliance Costs or Cost Savings According to Well Groups

Well Group	Number of Wells	Option 1	Option 2
GULF OF MEXICO - DISCHARGE OPTIONS 1 AND 2			
Development Wells - Deep Water			
SBF discharge to SBF discharge	16	($2,785)	($2,404)
WBF discharge to SBF discharge	1	($820,278)	($819,897)
Development Wells - Shallow Water			
SBF discharge to SBF discharge	86	$7,514	$7,266
OBF 80% haul to SBF discharge	14	($25,409)	($25,657)
OBF 20% inject to SBF discharge	3	$1,858	$1,610
WBF discharge to SBF discharge	21	($523,914)	($524,162)
Exploratory Wells - Deep Water			
SBF discharge to SBF discharge	48	($30,626)	($28,007)
WBF discharge to SBF discharge	1	($1,822,587)	($1,819,968)
Exploratory Wells - Shallow Water			
SBF discharge to SBF discharge	51	($4,510)	($3,481)
OBF 80% haul to SBF discharge	8	($78,039)	($77,010)
OBF 20% inject to SBF discharge	2	($16,486)	($15,457)
WBF discharge to SBF discharge	13	($1,120,327)	($1,119,298)
GULF OF MEXICO - ZERO DISCHARGE OPTION			
Development Wells - Deep Water		**Zero Discharge Option**	
SBF discharge to SBF 100% haul	3	$119,391	
SBF discharge to OBF 100% haul	8	$48,847	
SBF discharge to WBF discharge	5	$817,493	
Development Wells - Shallow Water			
SBF discharge to OBF 80% haul	68	$32,923	
SBF discharge to OBF 20% inject	18	$5,656	
Exploratory Wells - Deep Water			
SBF discharge to SBF 100% haul	8	$314,257	
SBF discharge to OBF 100% haul	25	$146,129	
SBF discharge to WBF discharge	15	$1,791,961	
Exploratory Wells - Shallow Water			
SBF discharge to OBF 80% haul	41	$73,529	
SBF discharge to OBF 20% inject	10	$11,976	
ALASKA - DISCHARGE OPTIONS 1 AND 2			
Development Well - Shallow Water		**Option 1**	**Option 2**
OBF 100% inject to SBF 100% inject	1	$99,968	$99,968

Source: Development Document (EPA, 2000)

Table A-5

Per Well Discharge Costs for WBF Wells

Well Type	Number*	Total Rig Time costs	Total Cost of Discharged WBF	Per Well Discharge Cost
Deep Water Development	1	$640,000	$295,065	$935,065
Shallow Water Development	2	$13,280,000	$6,215,040	$609,220
Deep Water Exploratory	32	$2,800,000	$1,307,250	$2,053,625
Shallow Water Exploratory	19	$16,560,000	$7,735,185	$1,278,694

Source: Development Document (EPA, 2000).

* The number of wells refers to the number of WBF wells projected to switch to SBF under the two discharge options. However, the actual number of wells that switch is lower because of the increased drilling efficiency of SBF wells, as reflected in Table A-3.

In order to get total per-well costs per well type and fluid used, the discharge/disposal mode categories are combined by totaling all costs for a region, type of well, baseline type of fluid, and water depth. For example, to determine costs to development wells currently using OBF in shallow water under Option 2, the 14 wells that are currently estimated to haul OBF and that would switch to SBF discharge are assigned the Option 2 cost savings of $25,657, and the three wells that currently inject OBF that would switch to SBF discharge are assigned a cost of $1,610 in Table A- 4. The weighted average cost per well in this group is then calculated by dividing the total cost for the group by the total number of wells in the group (17). In the example, the weighted average cost to switch a shallow water development well from OBF to SBF is [(14 x -25,657 + 3 x 1,610) ÷ 17], or -20,845. The results of these calculations are reflected in Table 5-1, where incremental compliance costs for the Gulf of Mexico and Alaska are provided according to well type, water depth, and fluid used.

APPENDIX B

ECONOMIC MODEL FOR OIL AND GAS PRODUCTION IN THE DEEPWATER GULF OF MEXICO

B.1 DESCRIPTION OF THE ECONOMIC MODEL

The Deepwater Gulf Model simulates the costs and petroleum production dynamics expected at the platform or project level in the development and operation of a deepwater Gulf oil and gas project. Data to define a project and its petroleum reservoir are entered into the model. Then, through a series of internal algorithms, the model calculates the economic and engineering characteristics of the project.

The model is structured to be flexible. It is capable of modeling projects that are dynamic, with development occurring over a multiyear drilling period, under a specific, assumed, drilling plan. Furthermore, inputs for a wide variety of variables that define the development and production project can be user-specified. These inputs include, in addition to drilling schedule, operating costs, initial petroleum production, production decline rates, tax rate schedules, and wellhead prices.

The model calculates cost and production performance for each year of the projects' estimated lifetimes. Additional outputs from the model include total production volume, project revenues, and both present value and nondiscounted summary statistics. Annual values and summary statistics are used to evaluate both the project and the effects of pollution control options.

B.1.1 Model Phases

The project life of a deepwater Gulf operation producing oil and/or gas is divided into five phases: 1) from lease bid to the start of exploration, 2) from the start of exploration to the start of delineation, 3) from the start of delineation to the start of development, 4) from the start of development to the start of production, and 5) production.

For NSPS options, EPA evaluates operations at the beginning of phase 1–lease bid through all 5 phases. For BAT options, EPA evaluates operations that have completed the first four phases and are in the fifth phase. In some cases in the BAT option analysis, there may be some overlap between development (the fourth phase) and production (i.e., some wells may be drilled while production continues at other wells associated with the operation). The model is able to add wells to a project, consistent with drilling plan assumptions.

The projects modeled are assumed to operate as long as they generate positive operating cash flow for up to 30 years (further projections add little additional to present value calculations). Algorithms within the model evaluate project economics annually, and the project is shut down when operating cash flow goes negative.

B.1.2 Economic Overview of the Model

The economic characteristics of the model phases are quite different. Phases one through four generate cash outflows; no revenues are earned during those periods. Since all the projects in the BAT analysis are already operating, costs incurred during the first four phases are treated as sunk costs, except in the case of costs for ongoing development (i.e., drilling of new wells while production from other wells continues). Sunk costs are not incorporated into the project evaluation for the BAT model. The fifth phase, production, typically generates net cash inflows. During this phase, the project continues to operate as long as operating cash inflows exceed nondiscretionary cash expenses.

The model deals with a number of basic cash flows (or resource transfers) in the development and production phases. The basic cash flows are as follows:

Leasing Phase:	Lease bid–cost of acquiring rights to explore and develop a tract of land
Exploration Phase	G&G costs–geological and geophysical expenses incurred prior to drilling
	Exploration well costs–cost of drilling an exploration well

	Incremental drilling costs–additional cost of drilling due to new regulations concerning drilling waste
Delineation Phase	Delineation well costs–costs of drilling a delineation well
	Incremental drilling costs–additional costs of drilling due to regulations concerning drilling waste
Development Phase:	Development well costs–cost of drilling a development well
	Cost of building and installing a petroleum production platform
	Infrastructure costs–costs of production equipment installed on the platform
	Incremental drilling costs–additional costs of drilling due to regulatory requirements concerning drilling wastes
Production Phase:	Revenues from oil and gas production--production levels multiplied by assumed wellhead price.
	O&M costs--costs of operating and maintaining the well.

The inputs for these items are provided in Summary of Data to be Used in Economic Modeling (Section III.G of the Rulemaking Record) hereafter called the Summary of Data report, with the exception of incremental costs, which are shown in Table 5-1 for deep water development and exploratory wells currently using SBFs, and the assumed drilling schedule presented in Table B-1.

B.2 STEP BY STEP DESCRIPTION OF THE BAT/NSPS MODELS

This section presents a sequential overview of how the model operates. Due to the way the model was constructed (the BAT phases are presented first, then the NSPS phases), the first part of the model starts with the production phase and ends with the shut down of the project either after 30 years of production or when the project becomes unprofitable. Figure B-1 presented at the end of this appendix presents the inputs, calculations, and outputs for a sample oil and gas platform to illustrate the model's algorithms.

Table B-1

Assumed Drilling Schedules

Platform	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
Small Projects											
SHASTA	0	0	0	0	0	0	0	0	0	0	0
VK862	0	0	0	0	0	0	0	0	0	0	0
ROCKY	0	0	0	0	0	0	0	0	0	1	1
Total	0	0	0	0	0	0	0	0	0	1	1
Medium Projects											
ZINC	0	0	1	0	0	1	0	0	0	0	2
NEPTUNE	2	1	1	1	1	0	0	0	0	0	6
POPEYE	0	0	0	0	0	0	0	0	0	1	1
LENA	0	0	0	0	0	0	0	0	0	0	0
JOLLIET	0	0	0	0	0	0	0	0	0	0	0
ALABASTER	6	4	4	3	2	2	2	2	2	1	28
AMBERJACK	0	0	0	0	0	0	0	0	0	0	0
Total	8	5	6	4	3	3	2	2	2	2	37
Large Projects											
MARS	1	1	0	0	0	0	1	0	0	0	3
COGNAC	0	0	0	0	0	0	0	0	0	0	0
TAHOE	2	2	2	2	2	2	0	0	0	0	12
MENSA	0	1	1	1	1	1	0	0	1	0	6
AUGER	0	0	1	0	1	0	0	1	0	1	4
BULLWINKLE	1	1	2	3	2	2	2	2	2	2	19
RAM-POWELL	1	0	0	0	0	2	0	0	2	0	5
POMPANO	2	4	3	4	3	0	0	0	0	0	16
Total	23	19	21	18	15	13	7	7	9	9	65

The following discussion is based on the computer printout in Figure B-1. Identification numbers for specific lines are given in the left-hand margin. Table B-2 provides a list of user-specified inputs. The values for these inputs are provided primarily in the Summary of Data report. All dollar values (e.g., costs and revenues are expressed in thousands of 1999 dollars).

Line 1 identifies the operation and the pollution control option being analyzed.

Line 2 is the real discount rate, i.e., the cost of capital. This value is used throughout the model to discount future cash inflows, cash outflows, and production so that they can be summarized in present value terms. The rate used is 7 percent, as OMB guidance suggests (OMB, 1992).

Line 3 is the inflation rate. This parameter is used to reduce the value of the deductions for depreciation and cost-basis depletion in future years. The rate used is 3 percent.

Lines 4 and 5 contain information relevant to the calculation of project taxes. The flag in ***Line 4*** indicates whether the operation modeled is an integrated (major) or independent company. Majors must calculate depletion on a cost basis, while independents may choose to do so on either a cost or a percentage basis.

Major and independent operators also differ with respect to the treatment of capital investments in calculating taxable income. Independents may expense 100 percent of their "intangible drilling costs (IDCs), while majors may expense only 70 percent. The expensing of these costs reduces taxable income in the year in which they are expensed and may provide a significant tax shelter.

It is assumed that the taxpayer (oil company) elects to expense IDCs in the year in which they are incurred. IDCs are estimated, on average, to represent 60 percent of the costs of production wells and their infrastructure [citation]. Hence, independents may expense 60 percent of total production well drilling costs (1.00 x 0.60), and majors may expense 42 percent (0.70 x 0.60). The percentage of drilling costs that are eligible for expensing is given in ***Line 5.***

Table B-2

Exogenous Variables Provided to EPA Economic Model

Parameter
Lease cost
Geological and geophysical expense
Real discount rate
Inflation rate
Years between lease sale and exploration
Percent of cost considered expensible intangible drilling costs
Drilling mud cost increment
Federal corporate tax rate
Drilling cost per exploratory well
Platforms per successful exploratory well
Years between start of exploration and delineation
Number of delineation wells drilled
Cost per delineation well
Total platform cost
Years between delineation and development
Number of development wells drilled
Number of development wells drilled per year
Drilling cost per development well
Annual pollution control capital costs
Oil and gas production decline rate
Cost escalator
Royalty rate
Depreciation schedule
Years between development and production
Years at peak production
Oil - peak production rate (bbl/day)
Gas - peak production rate (MMCF/day)
Number of producing wells
Drilling schedule
Wellhead price per barrel - oil
Wellhead price per Mcf - gas
Total operating costs (other than produced water)
Annual pollution control equipment operating cost (produced water)

Lines 6-32 relate to the production phase in both the BAT and NSPS models. In the production phase of the project, a variety of financial and engineering variables interact to form the project's economic history. Oil , gas, and water production figures from 1998 are given in ***Lines 6, 7,*** and ***8. Line 9*** provides the production decline rate for oil and gas. The model uses this rate to create an exponential function for production decline so that a constant proportion of the remaining reserves is produced each year. For every barrel produced in the initial year of operation in this sample project, 0.92 barrel is produced in the second year, $(0.92)^2$ or 0.846 barrel in the third year, etc. See Coastal EIA (USEPA, 1996) for more information on the assumption.

The model is capable of handling cost escalation (see ***Line 10***). In this analysis, EPA is considering costs in real terms, and thus no escalation is assumed.

The royalty rates paid to the lessor of the land (in this case the federal government) are provided in ***Lines 11 and 12.*** Federal and state corporate tax rates are listed in ***Lines 13 and 14. Lines 15 and 16*** provide the number of years over which depreciation occurs and the depreciation schedule for capitalized oil and gas equipment. State severance taxes are not applicable so ***Lines 17 and 18*** are zero.

Basic information describing the production phase of the project is listed in lines ***19 through 32. Line 19*** is not used in this model. ***Line 20*** is not used here, but this information is input later in the NSPS portion of the model. The number of years that a well produces at its peak rate is given in ***Line 21.*** The per well peak production rates for oil and gas are given in ***Lines 22 and 23,*** respectively. These rates apply to wells drilled and brought on line in the model years. Once these wells cease producing at peak rates, production volumes decline annually according to the decline rate in Line 9. The assumed future drilling plans are summarized in ***Line 24. Line 25*** is not used (a drilling schedule, shown in Table B-2 is used; information on how many wells drilled in which years are picked up by the model later in the spreadsheet).

The wellhead prices for oil and gas are entered on ***Lines 26 and 27.*** These values are in 1999 dollars.

Line 28 indicates the number of days per year that a platform or project produces. EPA assumes all projects in the model operate continuously.

Annual operating costs are entered on ***Line 29, Line 30*** is not used, since the regulatory options for the SBF rule do not affect operating costs, these lines are zero both in baseline and postregulatory scenarios. ***Line 31*** is the regulatory option costs per well drilled in any year. ***Line 32*** is not used.

B.2.2.1 Production Volume Calculations

The next several lines in the model calculate the annual production volumes for oil and gas, based on the initial production rates given in ***Lines 6 and 7,*** the decline rate in ***Line 9***, and the assumed future drilling plans. ***Line 33*** contains the number of producing wells brought into service each year. ***Line 34,*** the total barrels of oil produced per day, is the sum of current production (from 1998, declined at the appropriate rate and production from new wells brought into service each year). MMcf of gas per day, ***Line 40***, is calculated in the same manner. The annual oil and gas production numbers in ***Lines 36 and 41*** are the estimated daily production numbers multiplied by the number of days of production per year (***Line 35***).

In general production from a group of wells going into service in the same year is calculated as follows:

Annual Production = Number of Wells x Barrels per Day per Well x Decline Rate(a) x Number of Days

Where a = year of production - number of years at peak production.

For projects with new wells going into production in different years, the equation is expanded in the following manner:

Daily Production Year 2 = 3 wells x (for example) 1,000 bopd = 3,000 bopd
Daily Production Year 3 = (3 x 1,000 x 0.92)

If additional wells were drilled in Year 4,

Year 4 = (3 x 1,000 x0.92^2) + (3 x 1,000) = [run calc.]

and so forth.

The price per barrel is repeated in ***Line 37*** for convenience in cross-checking the gross revenues from oil production (***Line 43***). ***Lines 42 and 44*** list the wellhead price per Mcf of gas and gross revenues from gas production.

B.2.2.2 Income Statement

Lines 43 through 75 comprise an income and cash flow statement that is repeated annually for a 30-year project lifetime (these lines are repeated for years 11-20 and years 21-30, which are not reproduced. Since most projects become uneconomical during this 30-year time-frame, ***line 66*** checks for negative net cash flow. When cash flow is negative, EPA assumes the project shuts down and actual production, revenues, and cash flows are reset to zero in ***lines 67 through 73***. ***Lines 43 and 44*** list revenues from oil and gas productions. Total gross revenues for the year are given in ***line 45***. Royalty payments (***lines 46 and 47***; see lines 11 and 12 for royalty rates) are calculated on the basis of gross revenues. ***Lines 48 and 49*** are not used, since no severance is paid in the deepwater Gulf.

Net revenues, ***line 50***, are calculated as:

Net Revenues = Total Gross Revenues - Royalty Payments

Thus, for year 1 of production in the example in Figure B-1 (year 13 of the project):

Net Revenues = \$121,102 - \$3,241 - \$11,897
= \$105,965

Operating costs are given in ***lines 51 and 52***. ***Line 51*** lists the operating costs estimated for the platform or facility itself. Incremental operating costs for compliance with pollution control regulations appear in ***line 52***. The latter figure reflects incremental costs due to drilling waste requirements.

Operating earnings (***line 53***) are defined as net revenues (line 50) minus operating costs (line 51) minus pollution control operating costs (line 52). For year 2 for the project:

Operating Earnings = Net Revenues - Operating Costs - Pollution Control Operating Costs
= $105,965 - $19,599 - 0 = $86,406

Lines 54 and 55 divide capital costs into two categories for use in calculating the project's taxable income. ***Line 54*** contains the capital costs that can be expensed (in this case, IDCs, or costs for drilling new and recompleted wells multiplied by the percentage in line 5). EPA assumes that oil and gas companies expense the maximum allowable portion of their capital costs. ***Line 55*** contains the capital costs that must be capitalized, including pollution control capital costs and nonexpensible development drilling costs.

The adjusted depreciation allowance in ***line 58*** is calculated on the basis of the capitalized costs in ***line 55*** and the accelerated depreciation schedule in line 16. Because the model's values are given in constant dollars, this figure must then be adjusted for inflation, using the rate in line 3. This adjusted value is taken as a deduction against the taxable income associated with the project.

In the following year, the adjusted depreciation allowance contains the second-year effects from the capital costs for the previous year and any first-year effects from the capital costs for the second year of the well's life.

Line 57, earnings before interest, taxes and oil depletion allowance (ODA), is derived by subtracting expensed capital costs and depreciation and amortization from operating earnings

The adjusted depletion allowance (***line 58***) is a means of treating annual oil and gas production as a wasting asset for tax purposes. For major producers, the depletion allowance is calculated on a cost basis, while for independents, it is calculated on a percentage basis.

Earnings before interest and taxes (EBIT, ***line 57***) is defined as earnings before interest and ODA (line 76) minus the adjusted oil depletion allowance (line 58). The figure on line 57 forms the basis for calculating federal and state income taxes in ***lines 60 and 61***. Taxes are based on the rates given in lines 13 and 14. Earnings before interest and after taxes are given in ***line 62***.

Project cash flows from operations, ***line 63***, are determined by adding costs expensed for tax purposes, depreciation, and depletion back into earnings after taxes.

Whether or not the project continues to operate is determined on the basis of operating earnings (***line 53***). If (net revenues - total operating costs - pollution control operating costs) is less than 0, the project is assumed to shut down. Under such circumstances, net cash flow from operations (line 63) will also be 0. The model prints a "1" in ***line 66*** for years in which the project operates and a "0" for years in which the project does not operate.

In the event that the project is shut down, certain variables must be recalculated to reflect that oil an gas are no longer being produced and sold. ***Lines 67 through 75*** restate production volumes, revenues, and cash flow in the event of a shutdown (i.e., production and revenues are set to zero after the project shuts down). The model allows a negative tax to be calculated in the shutdown year and continues to calculate depreciation after shutdown because it is assumed that the project is part of a larger, ongoing company and that such deductions can be used to adjust taxable income from the company's other operations.

Additional lines, not marked with line numbers repeat lines 33 to 75 are used to take production cash flows out to 30 years of production. This completes the BAT portion of the model.

B.2.3 Earlier Phases (NSPS Model Only)

The next numbered lines apply only to the NSPS model. ***Lines 76 through 84*** are inputs to the NSPS model. The least cost, ***Line 76,*** is a user-specified input, the value of which is based on the lease bid of the relevant platform used in the model (see summary)

Line 77 represents the costs of geological and geophysical (G&G) investigation of the site as a percentage of lease cost. The value shown in line 77 is based on information from the Summary of Data report. The total leasehold cost, ***Line 78,*** is the sum of the lease bid and G&G expenses. The total leasehold costs is a cash outflow in Year 0 of the project; the value on line 3 is therefore the present value of the leasehold cost. The leasehold cost forms the basis for the depletion allowance as calculated on a cost basis for major integrated producers.

Lines 79 through 81 present data calculated by the model using the drilling schedule in Table B-2, but are not used for any calculations. ***Line 82*** takes timing assumption inputs and places the time between lease sale and start of production here. This value is taken from data presented in the Summary of Data report. ***Lines 83 and 84*** are not used in this model.

Lines 85 through 94 calculate the exploration costs for the project. The exploratory well costs for the project. ***Line 85*** presents the numbers of years between lease sale and start of exploration. This timing assumption was derived in the Summary of Data report. ***Line 86*** is the baseline cost of drilling an exploratory well, which was provided as discussed in the Summary of Data report. ***Line 87*** is the option cost of the rule estimated for an exploratory well. ***Line 88*** is not used (set to one). ***Line 89*** is the number of exploratory wells drilled. One exploratory well per find is assumed. All other exploratory wells as determined in the Summary of Data report are assumed delineation wells. Delineation wells are assumed to incur the same costs (baseline and option) as exploratory wells. ***Line 90*** adds lines 86 and 87 for a total exploratory well cost. ***Line 91*** assumes in this model that all exploration wells at this project are successful (alternative assumptions are not used in this model). ***Line 92*** is not used. ***Lines 93 and 94*** split the expensed and capitalized portions on the basis of line 5 (percent costs expensed), which varies depending on whether the project is owned by a major or an independent.

Once the various exploration costs and cash flows have been calculated, they are put in present value terms as of the lease year. For all Gulf of Mexico deepwater projects, exploration costs are incurred in Year 0 plus number of years between lease sale and start of exploration. In this case, exploration expenses start in Year 1.

If an exploration well discovers petroleum, delineation wells may be drilled to confirm the size and extent of the reservoir. In this project, one year is assumed to pass between the start of exploration and the start of delineation (***Line 95***; Summary of Data report provides timing assumptions). In this model four delineation wells (based on data obtained as presented in the Summary of Data report) are drilled, ***Line 96,*** each costing the same as an exploratory well (***Line 97***). ***Line 98*** is the regulatory option cost for exploratory wells. One platform is assumed per project (for simplicity) in ***Line 99***, although costs of additional subsea wells or platforms are included, if applicable.

The delineation costs ***(Line 100)*** assume the number of delineation wells are evenly divided over the number of years between delineation and development; in this case 4 wells have been divided over 4 years. ***Lines 101 and 102*** split out the expensed and capitalized portion of these costs in each year.

Once the various delineation costs and cash flows have been calculated, they are put in present value terms of the half year.

During the development phase, the infrastructure required to extract oil reserves from a site is constructed. Development drilling is also conducted to increase production or to replace nonproducing wells on existing sites. ***Line 103*** shows the number of years between delineation and construction (based on data presented in the Summary of Data report). The costs of constructing platforms, including the costs of production equipment, are entered on ***Line 104***. ***Line 105,*** pollution control capital costs, are entered to account for regulatory option costs for any wells drilled during the construction phase (pollution control costs are pulled in on line 52 for any wells drilled during the production phase). EPA assumes these incremental costs are incurred in year one, which could slightly overstate the present value of these costs. Note that in the baseline, this line will be zero.

Since the development phase of an oil and gas project may overlap with the production phase, the model is designed to incorporate the annual costs of development and increases in production from new wells into estimates of total annual expenses and revenues. These costs and revenues are accounted for in the production portion of the model described earlier. The drilling cost for a development well depends on the type of well (subsea or platform-based or sidetrack) (see the Summary of Data report). The number of wells drilled during the construction phase is shown in ***Line 106.*** ***Line 107*** presents the number of sidetracks drilled, since these are associated with lower costs (see Summary of Data report). ***Line 108*** is not used in this model. Drilling costs per development well or sidetrack are shown in ***Lines 109 and 110.***

Lines 111 through 122 calculate the costs incurred each year from the drilling of production wells and the construction of production equipment. The number of years over which construction occurs is provided by the timing assumption in Line 20. In this case the timing assumption is 2 years (with the costs incurred beginning in the second year), thus the costs are spread over one year, as shown. [***Lines 111 and 112*** repeat the information from lines 109 and 110.] ***Line 113*** adds in the option cost for any wells drilled after completion of the construction phase. ***Line 114*** starts the clock for when production begins, after the construction phase ends. ***Line 115*** brings in the numbers of wells drilled in any year after construction, given the drilling schedule. ***Line 116*** is not used. The total drilling costs in each are given in ***line 117.*** ***Line 118*** splits the capital costs of the platform (line 106) over the total years of construction. ***Line 119*** splits the regulatory option costs in line 105 over three years (any additional regulatory option costs associated with wells drilled after construction are accounted for in the year in which they occur in the production phases in lines 54 and 55). ***Line 120*** totals all capital expenditure. ***Lines 121 and 122*** split these expenditures into those which can be expensed and those which must be capitalized on the basis of line 5.

Expensed development costs, ***Line 120,*** are the product of total drilling costs (***Line 117***) and the percent of drilling costs eligible for expensing (***Line 5***). All costs not eligible for expensing are capitalized and are treated as depreciable assets for tax purposes. Note, in particular, that any capital costs of pollution control are not eligible for expensing as per tax code requirements. Capitalized development costs appear in ***Line 122.***

All costs prior to production are written to an annual cash flow table, which is used in the calculation of net present value. This table also takes in to account depreciation and depletion allowances and calculates a tax shield. Capital expenditures that occur after the beginning of production are visible in the production phase cash flow in lines 54-65.

Figure B-1. Example Model (NSPS)

RESULTS OF MODEL - COPIED FROM END OF SHEET		
PV BOE	**26,218,854**	*Present Value - BOE*
TOTAL BOE	**91,337,071**	*Total Non-Discounted - BOE*
NPV	**($82,695)**	*Net Present Value - Production*
YRS. PROD	**16**	*Producing Years before Closure*
PVRYLT	**$35,876**	*Present Value - Royalties*
PVSEVTAX	**$0**	*Present Value - State & Severance Taxes*
PVINCTAX	**$46,233**	*Present Value -Fed Income Tax*
0.062	IRR	

DEEPWATER GULF OIL & GAS PRODUCTION LOSS MODEL-- PLATFORM/FACILITY LEVEL ANALYSIS

GENERAL MODEL DATA

MANUALLY ENTER C9 AND D9 AND RECALCULATE

	Platform	Option: (BASE, BAT1, BAT2, ZD)
(1) Project Type:	EXAMPLE	ZD
(2) Real Discount Rate:	7%	
(3) Inflation Rate Leashold/Construction Materials:	3%	
(4) Corp. Structure (1-major/2-indep.):	1	
(5) Percent Costs Expensed:	42.00%	

-

FINANCIAL DATA

(6) 1998 Oil Production (BPD) - Platform/Facility	4735							
(7) 1998 Gas Production (MMCF per day) - Platform/Facility	144.9							
(8) 1998 Water Production (kbbl/yr)	20							
(9) Oil/Gas Prod. Decline Rate/Year (%):	85%							
(10) Cost Escalator (%):	0%							
(11) Oil Royalty Rate (%):	12.5%							
(12) Gas Royalty Rate (%):	12.5%							
(13) Federal Tax Rate (%):	34%							
(14) State Corporate Tax Rate (%):	0%							
(15) Average Depreciation Life (years):	7							
(16) Deprec. rate (subsequent years):	14.29%	24.49%	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%
(17) State Severance Tax Rate-Oil:								
(18) State Severance Tax Rate-Gas:								

PRODUCTION DATA

(19) MMS Designated Gas Field? (1=yes; 0=no)	1	Not used
(20) Yrs Btwn Strt Dev & Strt Prod (=<5):	2	
(21) Number of Years at Peak Prod (=>1):	1	
(22) Oil Peak Prod. Rate/Well(bb):	1747	new well info
(23) Gas Peak Prod. Rate/Well(MMCF/D):	69.875	new well info
(24) Total Number of New Producing Wells Planned:	1.00	
(25) Number of Wells Put in Service/Year:	1.00	Not used
(26) Price of Oil Per Barrel:	$15.00	
(27) Price of Gas Per MCF:	$1.80	
(28) Days of Production Per Year:	365	
(29) Total Operating Costs ($000):	$19,548	
(30) Produced Water Pollution Control Operating Costs ($1,000):		not used
(31) Drilling Waste Operating Cost -- New Well ($000):	$333	This is the reg option costs per well
(32) Drilling Waste Operating Cost -- Recompleted Well ($000):	$0	Not currently used.

	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	**SUMS**
OIL, WATER, AND GAS PRODUCTION											
(33) Wells Put Into Production:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	
Barrels of Oil Per Day (New Wells):	0	0	0	0	0	0	0	0	0	1747	1747
Barrels of Oil Per Day (1998 Wells):	4735	4025	3421	2908	2472	2101	1786	1518	1290	1097	25351.99797

(34) Barrels of Oil Per Day (All Wells):	4735	4025	3421	2908	2472	2101	1786	1518	1290	2844	27098.99797
(35) Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365	
(36) Barrels of Oil Per Year:	1728275	1469034	1248679	1061377	902170	766845	651818	554045	470939	1037953	9891134.259
(37) Price/Barrel of Oil:	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	
Barrels of Water Per Day (New Wells)	0	0	0	0	0	0	0	0	0	(1,747)	
Barrels of Water Per Day (Old Wells)	56	766	1,370	1,883	2,319	2,690	3,005	3,273	3,500	3,694	
(38) Barrels of Water per Day (All Wells)	56	766	1,370	1,883	2,319	2,690	3,005	3,273	3,500	1,947	
Total Fluid Per Day (New Wells)	0	0	0	0	0	0	0	0	0	0	
Total Fluid Per Day (Old Wells)	4,791	4,791	4,791	4,791	4,791	4,791	4,791	4,791	4,791	4,791	
(39) Total Fluid Per Day:	4,791	4,791	4,791	4,791	4,791	4,791	4,791	4,791	4,791	4,791	
MMCF of Gas Per Day (New Wells):	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	69.9	69.875
MMCF of Gas Per Day (1998 Wells):	144.9	123.1	104.7	89.0	75.6	64.3	54.6	46.4	39.5	33.6	775.6479919
(40) MMCF of Gas Per Day (All Wells):	144.9	123.1	104.7	89.0	75.6	64.3	54.6	46.4	39.5	103.4	845.5229919
(41) MMCF of Gas Per Year:	52877	44945	38204	32473	27602	23462	19942	16951	14408	37752	308615.8921
(42) Price/MCF of Gas:	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	

INCOME AND PARTIAL CASH FLOW STATEMENT FOR PRODUCTION YEARS 1-10

(43) Annual Oil Revenues ($000):	$25,924	$22,036	$18,730	$15,921	$13,533	$11,503	$9,777	$8,311	$7,064	$15,569	148367.0139
(44) Annual Gas Revenues ($000):	$95,178	$80,902	$68,766	$58,451	$49,684	$42,231	$35,896	$30,512	$25,935	$67,953	555508.6057
(45) Total Revenues ($000):	$121,102	$102,937	$87,496	$74,372	$63,216	$53,734	$45,674	$38,823	$32,999	$83,522	703875.6196
(46) Royalty Payments-Oil ($000):	$3,241	$2,754	$2,341	$1,990	$1,692	$1,438	$1,222	$1,039	$883	$1,946	18545.87674
(47) Royalty Payments-Gas ($000):	$11,897	$10,113	$8,596	$7,306	$6,210	$5,279	$4,487	$3,814	$3,242	$8,494	69438.57571
(48) Severance Taxes-Oil ($000):											
(49) Severance Taxes-Gas ($000):											
(50) Net Revenues ($000):	$105,965	$90,070	$76,559	$65,076	$55,314	$47,017	$39,964	$33,970	$28,874	$73,082	615891.1671
Fixed Operating Costs ($000):	$19,548	$19,548	$19,548	$19,548	$19,548	$19,548	$19,548	$19,548	$19,548	$27,407	203341.7698
Produced Water Operating Costs ($000)	$10.17	$139.79	$249.97	$343.62	$423.22	$490.89	$548.40	$597.28	$638.84	$355.33	3797.507871
(51) Total Operating Costs ($000):	$19,559	$19,688	$19,798	$19,892	$19,972	$20,039	$20,097	$20,146	$20,187	$27,762	207139.2776
(52) Poll.Con.Operating Costs ($000):	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$332.76	332.758
(53) Operating Earnings ($000):	$86,406	$70,382	$56,761	$45,184	$35,343	$26,978	$19,868	$13,824	$8,687	$44,987	408419.1315
(54) Expensed Cap.Costs (Drilling & Poll. Cont.) ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
(55) Capitalized Costs ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
(56) Adjstd Depreciation & Amort ($000):	$8,231	$5,707	$3,962	$3,842	$3,734	$1,811	$0	$0	$0	$0	27286.70688
(57) Earnings Before Interest, Taxes, and ODA ($000):	$78,175	$64,675	$52,800	$41,342	$31,608	$25,167	$19,868	$13,824	$8,687	$44,987	381132.4246
(58) Adjusted Depletion Allowance ($000):	$4,775	$3,941	$3,252	$2,684	$2,215	$1,828	$1,508	$1,245	$1,027	$2,613	25086.39404
(59) Earnings Before Interest and Taxes ($000):	$73,400	$60,734	$49,548	$38,658	$29,394	$23,340	$18,360	$12,580	$7,660	$42,374	356046.0306
(60) Federal Tax (Earnings-State Taxes) ($000):	$24,956	$20,650	$16,846	$13,144	$9,994	$7,935	$6,242	$4,277	$2,604	$14,407	121055.6504
(61) State Income Tax ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
(62) Earnings Before Interest After Tax ($000):	$48,444	$40,085	$32,701	$25,514	$19,400	$15,404	$12,117	$8,302	$5,056	$27,967	234990.3802
(63) Net Cash Flow from Operations ($000):	$61,450	$49,732	$39,915	$32,040	$25,349	$19,042	$13,626	$9,547	$6,083	$30,580	287363.4811
(64) Capital Expenditures on Fixed Assets ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$30,333	30332.758
(65) Net Cash Flow from Operations and Investments ($000):	$61,450	$49,732	$39,915	$32,040	$25,349	$19,042	$13,626	$9,547	$6,083	$247	257030.7231
(66) Shutoff?	1	1	1	1	1	1	1	1	1	1	
(67) Actual Oil Prod./Year (Barrels):	1728275	1469034	1248679	1061377	902170	766845	651818	554045	470939	1037953	9891134.259
(68) Actual Gas Prod./Year (MMCF):	52877	44945	38204	32473	27602	23462	19942	16951	14408	37752	308615.8921
(69) Actual Gross Revenues ($000):	$121,102	$102,937	$87,496	$74,372	$63,216	$53,734	$45,674	$38,823	$32,999	$83,522	703875.6196
(70) Actual Net Revenues ($000):	$105,965	$90,070	$76,559	$65,076	$55,314	$47,017	$39,964	$33,970	$28,874	$73,082	615891.1671
(71) Actual Net Cash Flow from Operations ($000):	$61,450	$49,732	$39,915	$32,040	$25,349	$19,042	$13,626	$9,547	$6,083	$30,580	287363.4811
(72) Actual Capital Expenditures on Fixed Assets ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$30,333	30332.758
(73) Actual Net CF from Operations and Investments ($000):	$61,450	$49,732	$39,915	$32,040	$25,349	$19,042	$13,626	$9,547	$6,083	$247	257030.7231
(74) Actual Federal Taxes Paid ($000):	$24,956	$20,650	$16,846	$13,144	$9,994	$7,935	$6,242	$4,277	$2,604	$14,407	121055.6504
(75) Actual State Income Taxes Paid ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0

	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30	Year 31	Year 32	**SUMS**
OIL, WATER, AND GAS PRODUCTION											
Wells Put Into Production:											
Barrels of Oil Per Day (New Wells):	0	0	0	0	0	0	0	0	0	0	
Barrels of Oil Per Day (1998 Wells):	2417	2055	1746	1484	1262	1073	912	775	659	560	
Barrels of Oil Per Day (All Wells):	2417	2055	1746	1484	1262	1073	912	775	659	560	12941.83519
Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365	3650
Barrels of Oil Per Year:	882260	749921	637433	541818	460545	391463	332744	282832	240407	204346	4723769.843
Price/Barrel of Oil:	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	
Barrels of Water Per Day:	2374	2736	3044	3306	3529	3718	3879	4016	4132	4231	
Total Fluid Per Day:											
MMCF of Gas Per Day (All Wells):	87.9	74.7	63.5	54.0	45.9	39.0	33.2	28.2	24.0	20.4	470.7095087
MMCF of Gas Per Year:	32089	27275	23184	19707	16751	14238	12102	10287	8744	7432	171808.9707
Price/MCF of Gas:	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	
INCOME AND PARTIAL CASH FLOW STATEMENT FOR PRODUCTION YEARS 11-20											
Annual Oil Revenues ($000):	$13,234	$11,249	$9,561	$8,127	$6,908	$5,872	$4,991	$4,242	$3,606	$3,065	70856.54765
Annual Gas Revenues ($000):	$57,760	$49,096	$41,731	$35,472	$30,151	$25,628	$21,784	$18,516	$15,739	$13,378	309256.1472
Total Revenues ($000):	$70,994	$60,345	$51,293	$43,599	$37,059	$31,500	$26,775	$22,759	$19,345	$16,443	380112.6949
Royalty Payments-Oil ($000):	$1,654	$1,406	$1,195	$1,016	$864	$734	$624	$530	$451	$383	8857.068457
Royalty Payments-Gas ($000):	$7,220	$6,137	$5,216	$4,434	$3,769	$3,204	$2,723	$2,315	$1,967	$1,672	38657.0184
Severance Taxes-Oil ($000):											
Severance Taxes-Gas ($000):											
Net Revenues ($000):	$62,120	$52,802	$44,881	$38,149	$32,427	$27,563	$23,428	$19,914	$16,927	$14,388	332598.608
Fixed Operating Costs ($000):	$27,407	$27,407	$27,407	$27,407	$27,407	$27,407	$27,407	$27,407	$27,407	$27,407	274067.4125
Produced Water Operation Costs ($000)	$433.18	$499.35	$555.59	$603.40	$644.03	$678.58	$707.94	$732.89	$754.10	$772.13	6381.190078
Total Operating Costs ($000):	$27,840	$27,906	$27,962	$28,010	$28,051	$28,085	$28,115	$28,140	$28,161	$28,179	280448.6026
Poll.Con.Operating Costs ($000):	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	0
Operating Earnings ($000):	$34,713	$25,395	$17,475	$10,742	$5,020	$156	($3,978)	($7,493)	($10,480)	($13,019)	58531.19551
Expensed Cap.Costs (Drilling & Poll. Cont.) ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Capitalized Costs ($000) (*0 if no new drilling):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Adjstd Depreciation & Amort ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Earnings Before Interest, Taxes, and ODA ($000):	$34,713	$25,395	$17,475	$10,742	$5,020	$156	($3,978)	($7,493)	($10,480)	($13,019)	58531.19551
Adjusted Depletion Allowance ($000):	$4,256	$3,617	$3,075	$2,613	$2,221	$1,888	$1,605	$1,364	$1,160	$986	22784.70807
Earnings Before Interest and Taxes ($000):	$30,457	$21,778	$14,400	$8,129	$2,799	($1,732)	($5,583)	($8,857)	($11,639)	($14,004)	35746.48745
Federal Tax (Earnings-State Taxes) ($000):	$10,355	$7,404	$4,896	$2,764	$952	($589)	($1,898)	($3,011)	($3,957)	($4,762)	12153.80573
State Income Tax ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Earnings Before Interest After Tax ($000):	$20,102	$14,373	$9,504	$5,365	$1,847	($1,143)	($3,685)	($5,846)	($7,682)	($9,243)	23592.68172
Net Cash Flow from Operations ($000):	$24,357	$17,990	$12,579	$7,979	$4,069	$745	($2,080)	($4,481)	($6,522)	($8,257)	46377.38978
Capital Expenditures on Fixed Assets ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cash Flow from Operations and Investments ($000):	$24,357	$17,990	$12,579	$7,979	$4,069	$745	($2,080)	($4,481)	($6,522)	($8,257)	46377.38978
Shutoff?	1	1	1	1	1	1	0	0	0	0	
Actual Oil Prod./Year (Barrels):	882260	749921	637433	541818	460545	391463	0	0	0	0	3663439.879
Actual Gas Prod./Year (MMCF):	32089	27275	23184	19707	16751	14238	0	0	0	0	133243.544
Actual Gross Revenues ($000):	$70,994	$60,345	$51,293	$43,599	$37,059	$31,500	$0	$0	$0	$0	294789.9773
Actual Net Revenues ($000):	$62,120	$52,802	$44,881	$38,149	$32,427	$27,563	$0	$0	$0	$0	257941.2301
Actual Net Cash Flow from Operations ($000):	$24,357	$17,990	$12,579	$7,979	$4,069	$745	$0	$0	$0	$0	67718.41695

Actual Capital Expenditures on Fixed Assets ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Actual Net CF from Operations and Investments ($000):	$24,357	$17,990	$12,579	$7,979	$4,069	$745	$0	$0	$0	$0	67718.41695
Actual Federal Taxes Paid ($000):	$10,355	$7,404	$4,896	$2,764	$952	($589)	$0	$0	$0	$0	25782.36569
Actual State Income Taxes Paid ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0

	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40	Year 41	Year 42	**SUMS**
OIL, WATER, AND GAS PRODUCTION											
Wells Put Into Production:											
Barrels of Oil Per Day (New Wells):											
Barrels of Oil Per Day (All Wells):	476	404	344	292	248	211	179	153	130	110	2547.916094
Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365	3650
Barrels of Oil Per Year:	173694	147640	125494	106670	90670	77069	65509	55682	47330	40231	929989.3742
Price/Barrel of Oil:	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	
Barrels of Water Per Day:	3755	3826	3887	3939	3982	4020	4051	4078	4101	4121	
Total Fluid Per Day:											
MMCF of Gas Per Day:	17	15	13	11	9	8	7	6	5	4	92.67065414
MMCF of Gas Per Year:	6317	5370	4564	3880	3298	2803	2383	2025	1721	1463	33824.78876
Price/MCF of Gas:	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	
INCOME AND PARTIAL CASH FLOW STATEMENT FOR PRODUCTION YEARS 21-30											
Annual Oil Revenues ($000):	$2,605	$2,215	$1,882	$1,600	$1,360	$1,156	$983	$835	$710	$603	13949.84061
Annual Gas Revenues ($000):	$11,371	$9,666	$8,216	$6,983	$5,936	$5,046	$4,289	$3,645	$3,099	$2,634	60884.61977
Total Revenues ($000):	$13,977	$11,880	$10,098	$8,584	$7,296	$6,202	$5,271	$4,481	$3,809	$3,237	74834.46039
Royalty Payments-Oil ($000):	$326	$277	$235	$200	$170	$145	$123	$104	$89	$75	1743.730077
Royalty Payments-Gas ($000):	$1,421	$1,208	$1,027	$873	$742	$631	$536	$456	$387	$329	7610.577472
Severance Taxes-Oil ($000):											
Severance Taxes-Gas ($000):											
Net Revenues ($000):	$12,230	$10,395	$8,836	$7,511	$6,384	$5,426	$4,612	$3,921	$3,332	$2,833	65480.15284
Fixed Operating Costs ($000):	$27,407	$27,407	$27,407	$27,407	$27,407	$27,407	$27,407	$27,407	$27,407	$27,407	274067.4125
Produced Water Operation Costs ($000)	$685.29	$698.31	$709.39	$718.80	$726.80	$733.60	$739.38	$744.29	$748.47	$752.02	
Total Operating Costs ($000):	$28,092	$28,105	$28,116	$28,126	$28,134	$28,140	$28,146	$28,151	$28,155	$28,159	
Poll.Con.Operating Costs ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Operating Earnings ($000):	($15,862)	($17,710)	($19,280)	($20,615)	($21,750)	($22,714)	($23,534)	($24,230)	($24,823)	($25,326)	-215843.608
Expensed Cap.Costs (Drilling & Poll. Cont.) ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Capitalized Costs ($000) (*0 if no new drilling):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Adjstd Depreciation & Amort ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Earnings Before Interest and ODA ($000):	($15,862)	($17,710)	($19,280)	($20,615)	($21,750)	($22,714)	($23,534)	($24,230)	($24,823)	($25,326)	-215843.608
Adjusted Depletion Allowance ($000):	$838	$712	$605	$515	$437	$372	$316	$269	$228	$194	4485.725828
Earnings Before Interest and Taxes ($000):	($16,700)	($18,422)	($19,885)	($21,129)	($22,187)	($23,086)	($23,850)	($24,499)	($25,051)	($25,520)	-220329.334
Federal Tax (Earnings-State Taxes) ($000):	($5,678)	($6,263)	($6,761)	($7,184)	($7,544)	($7,849)	($8,109)	($8,330)	($8,517)	($8,677)	-74911.9736
State Income Tax ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Earnings Before Interest After Tax ($000):	($11,022)	($12,158)	($13,124)	($13,945)	($14,643)	($15,237)	($15,741)	($16,169)	($16,534)	($16,843)	-145417.361
Net Cash Flow from Operations ($000):	($10,184)	($11,446)	($12,519)	($13,431)	($14,206)	($14,865)	($15,425)	($15,901)	($16,305)	($16,649)	-140931.635
Capital Expenditures on Fixed Assets ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cash Flow from Operations and Investments ($000):	($10,184)	($11,446)	($12,519)	($13,431)	($14,206)	($14,865)	($15,425)	($15,901)	($16,305)	($16,649)	-140931.635
Shutoff?	0	0	0	0	0	0	0	0	0	0	
Actual Oil Prod./Year (Barrels):	0	0	0	0	0	0	0	0	0	0	0
Actual Gas Prod./Year (MMCF):	0	0	0	0	0	0	0	0	0	0	0

Actual Gross Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Actual Net Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Actual Net Cash Flow from Operations ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Actual Capital Expenditures on Fixed Assets ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Actual Net CF from Operations and Investments ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Actual Federal Taxes Paid ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Actual State Income Taxes Paid ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0

	MISCELLANEOUS		
(76)	Lease Bid ($000):	$66,198	
(77)	G&G Expense:	2,000	
(78)	Leasehold Cost ($000):	$68,198	
(79)	Number of Producing Wells (1998):	3	
(80)	Total Number of Additional Wells Put Into Service:	1.00	
(81)	Number of Wells Put in Service/Year:	1.00	
(82)	No. Years Between Lease Sale and Start of Production:	13	
(83)	Discount Factor For Prod. PV's:	2.252	
(84)	(Regulation drilling cost for recompletion)	$0	not used

EXPLORATION COSTS

(85)	Yrs Btwn Lease Sale & Strt of Exp:	2			
(86)	Cost Per Exploratory Well ($000):	$25,000			
(87)	Drilling Mud Cost Increment ($000):	$721	For exploratory wells		
(88)	Discovery Efficiency:	1			
(89)	Number of Exploratory Wells Drilled per Project	1			
		Year	Year	Year	Year
	Years of Exploration:	2	3	4	5
(90)	Exploration Costs Per Project:	$25,721	$0	$0	$0
(91)	Cost of Successful Exploration Efforts:	$25,721	$0	$0	$0
(92)	Cost of Unsuccessful Exploration Efforts:	$0	$0	$0	$0
(93)	Expensed Exploration Costs:	$10,803	$0	$0	$0
(94)	Capitalized Exploration Costs:	$14,918	$0	$0	$0
	Total Exploration Costs ($000):		$25,721		

*note that the expensed and capitalized calculations above are based on successful efforts accounting, which permits the company to expense dry holes
*expensed and capitalized costs are broken-out for tax purposes
*row labels are used in an @vlookup command; do not change

DELINEATION COSTS

(95)	Years Between Start of Exploration and Delineation:	0	
(96)	Number of Delineation Wells Drilled:	4	
(97)	Cost per Delineation Well ($000):	$25,000	
(98)	Drilling Mud Cost Increment ($000):	$721	for exploratory wells
(99)	Platforms Per Find:	1	for 2-platform projects, for simplicity just combining costs as if one platform

		Year 2	Year 3	Year 4	Year 5
	Years of Delineation:	2	3	4	5
(100)	Delineation Costs:	$25,721	$25,721	$25,721	$25,721
(101)	Expensed Delineation Costs:	$10,803	$10,803	$10,803	$10,803
(102)	Capitalized Delineation Costs:	$14,918	$14,918	$14,918	$14,918
	Total Delineation Costs ($000):		$102,883		

*expensed and capitalized costs are broken-out for tax purposes only
*row labels are used in an @vlookup command; do not change

CONSTRUCTION COSTS

(103)	Years Between Start of Delineation & Construction:	9	
(104)	Total Platform Cost ($000):	$114,000	
(105)	Pollution Control Capital Costs ($000):	$2,995	Used to pull in pollution control costs for wells assumed drilled during construction phase.
(106)	Number of Additional Wells Drilled:	1.00	Assumed to start in first year of production
(107)	Number of Sidetracks Drilled:	6.00	At completion of initial construction phase (subsequent drilling assumed to be full borehole)
(108)	Number of Recomp. Wells Drilled per Year:		not used
(109)	Drilling Cost Per Sidetrack Well ($000):	$15,000	Used for sidetracks--1/2 total well cost
(110)	Drilling Cost Per New Well ($000):	$30,000	changes depending on whether subsea

	Years of Construction:	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21
(111)	Drilling Cost Per Sidetrack Well:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(112)	Drilling Cost Per New Well:	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000
(113)	Drilling Mud Cost Increment:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(114)	Well Start:	0	0	1	2	3	4	5	6	7	8	9
(115)	Number of New Wells Drilled:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(116)	Number of Recompletion Wells Drilled:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(117)	Total Drilling Costs for Year:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(118)	Annual Platform Cost:	$114,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(119)	Pollution Control Capital Costs:	$2,995	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(120)	Total Annual Capital Costs:	$116,995	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(121)	Expensed Capital Costs:	$47,880	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(122)	Capitalized Capital Costs:	$69,115	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

*expensed and capitalized costs are broken-out for tax purposes only; all pollution control costs are capitalized

APPENDIX C

ENVIRONMENTAL JUSTICE ANALYSIS

Appendix C investigates whether the zero discharge option, BAT 3, may have a potential environmental justice effect on minority and low-income populations surrounding onshore injection wells and landfarming facilities. Since the early 1970s, there has been concern that minority and low-income populations experience higher-than-average exposure to environmental contaminants (Bryant, 1992; Bullard, 1992). These populations may bear disproportionate environmental and human health impacts because disposal facilities tend to be in areas with minority and economically disadvantaged populations.

C.1 WHAT IS ENVIRONMENTAL JUSTICE?

Environmental justice (EJ) ensures that no population will be subjected to disproportionate environmental threats to public health. The U.S. EPA defines environmental justice as:

> "The fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. Fair treatment means that no group of people, including racial, ethnic, or socioeconomic group should bear a disproportionate share of the negative environmental consequences resulting from industrial, municipal, and commercial operations or the execution of federal, state, local, and tribal programs and policies." (http://es.epa.gov/oeca/main/ej/index.html)

Under federal mandate, no stages of policy, guidance, activity, and regulation development should cause minority and low-income populations to experience significantly higher-than-average exposure rates to toxic and hazardous contaminants. On February 11, 1994, the White House issued Executive Order 12898 on Federal Actions to address environmental justice in minority and low-income populations (Clinton, 1994). The order, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, is designed to focus federal agencies attention on environmental and human health conditions in minority and low-income communities. The order directs each federal agency "to make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations" (Clinton, 1994).

C.2 OVERVIEW OF THE ENVIRONMENTAL JUSTICE SCREENING ANALYSIS

The objective of this environmental justice screening analysis is to determine whether the zero discharge option of the effluent guidelines may disproportionately affect minority and/or low-income populations. The analysis will identify those disposal facilities that accept SBFs and are surrounded by significantly higher-than-average minority and/or low-income populations.

The Gulf of Mexico is associated with the only known current use of SBFs and discharge of SBF cuttings (U.S. EPA, 2000). Disposal facilities that accept SBFs are within U.S. EPA Region 6, in Texas and Louisiana (Veil, 1999). To meet the general directive of Executive Order 12898, Region 6 developed an environmental justice methodology tailored to the states within its region (Johnston, 2000). This methodology provides for a tier one screening analysis to evaluate whether sociodemographic data indicate that a disposal facility should be identified as a potential environmental justice case. If the percentage of minority and low-income people living within specified distances of a disposal facility are significantly higher than the state average, the site would be considered a potential environmental justice case. A tier one screening was performed for all disposal facilities accepting SBFs. Disposal facilities are described in Section C.3, methodology in Section C.4, and results in Section C.5.

A tier one screening is limited in that it does not include a site-specific analysis of the populations risk of exposure to contaminants. In a tier two analysis, potential environmental justice cases would undergo further analysis to consider the fate and transport mechanism of the involved facilities' contaminants and to determine if the populations would be subject to high and adverse environmental and public health effects resulting from contaminants. Additionally, locations of other facilities near the populations would be assessed to determine possible cumulative exposure to contaminants. The objective of this environmental justice screening analysis is to identify potential environmental justice cases. However, because the zero discharge option is not the option selected for promulgation, a tier two analysis has not been conducted.

C.3 STUDY AREA: FACILITIES, LOCATIONS, AND DISPOSAL OF SBFs

Under the zero discharge option, SBFs arriving onshore would be disposed of by Newpark Environmental Services and U.S. Liquids. The disposal facilities owned by these two companies are described by Argonne National Laboratory, via communication with the Louisiana Department of Natural Resources, in the document *Update on Onshore Disposal of Offshore Drilling Wastes* (Veil, 1999).

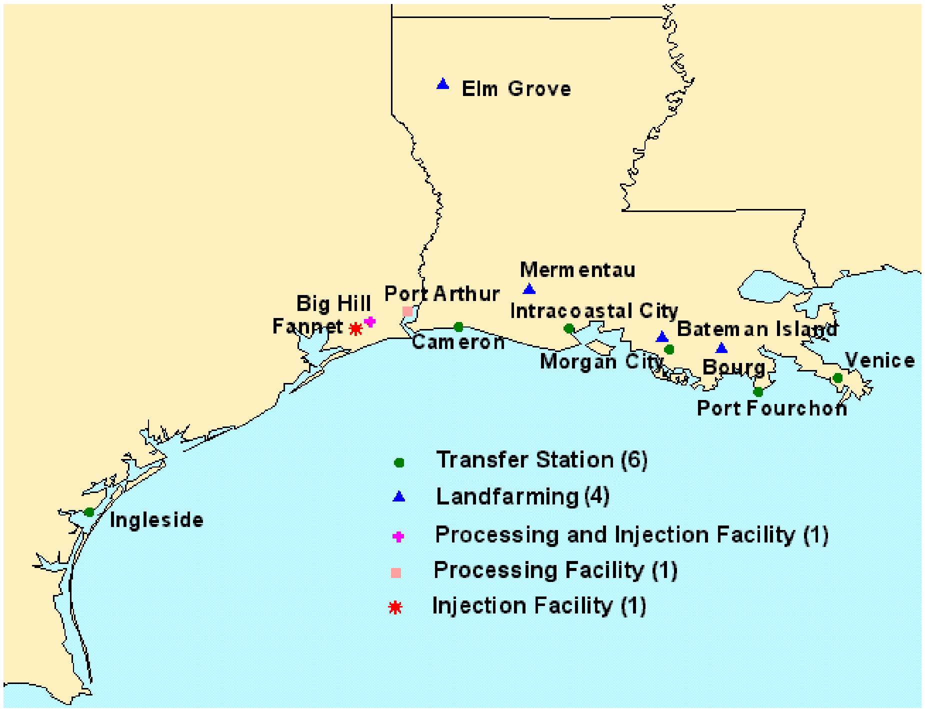
Wastes disposed of by Newpark Environmental Services would be transported by boat to one of the company's marine transfer facilities in Louisiana at Venice, Port Fourchon, Morgan City, Intracoastal City, Ingleside, and Cameron. The wastes would then be loaded into barges and hauled to Port Arthur, Texas where they would be processed and loaded into tank trucks. The trucks would then transfer the wastes to an underground injection disposal site in Fannet, Texas, or nearby at its Big Hill facility. The Big Hill facility also serves as a process station. According to Newpark officials, the Fannet site has up to one billion barrels of waste reserve disposal capacity (Veil, 1999).

U.S. Liquids operates landfarming facilities in Louisiana at Mermentau, Elm Grove, Bourg, and Bateman Island. U.S. Liquids treats the waste by land spreading and land treatment. U.S. Liquids receives almost none of the offshore wastes brought to shore because it only receives waste that Newpark Environmental Services elects not to take. U.S. Liquids no longer owns the marine transfer stations now operated by Newpark Environmental Services. Figure C-1 and Table C-1 show the locations of the marine transfer facilities, process facilities, injection sites, and landfarming facilities. With the exception of the landfarming facilities, all the facilities are owned by Newpark Environmental Services.

Under the zero discharge option using Best Available Treatment Economically Achievable (BAT) for existing sources and New Source Performance Standards (NSPS) for new sources, SBFs would be brought to shore and disposed of in injection wells and landfarming facilities (U.S. EPA, 2000). For shallow water wells, 80 percent of SBFs would be disposed of onshore and 20 percent through offshore onsite injection. For deep water wells, all SBFs would be disposed of onshore (Johnston, 2000).

Figure C-1

SBF Waste Disposal Facilities



Source: Map prepared by Eastern Research Group, Inc., July 2000, using 1990 Census TIGER/Line files to accurately locate facilities. Locational information to create the map obtained from: (1) Newpark Environmental Services, July 2000; (2) Cameron Chamber of Commerce, July 2000; (3) Greater LaFourche Port Commission (http://www.geocities.com/BourbonStreet/Delta/1287/portmap.html), July 2000; and (4) U.S. Liquids (http://www.usliquids.com/now_division.html), July 2000.

Table C-1

**SBF Waste Disposal Facilities Owned by
Newpark Environmental Services and U.S. Liquids**

Newpark Environmental Services	**Address**	**Type of Facility**
Big Hill	26400 Wilber Road, Winnie, TX, 77665	injection
	26462 Wilber Road, Winnie, TX, 77665	processing and injection
Cameron	434 Davis Road, Cameron, LA, 70631	transfer
Fannet	15173 Wilber Road, Hampshire, TX, 77622	injection
Ingleside	2725 Garrett Road, Ingleside, TX, 78362	transfer
Intracoastal City	12334 Offshore Road, Abbeville, LA, 70510	transfer
Morgan City	101 Second Street, Morgan City, LA, 70381	transfer
Port Arthur	8300 Pleasure Islet Road, Port Arthur, TX, 77641	processing
Port Fourchon	145 17th Street, Port Fourchon, LA, 70357	transfer
	181 Anselmi, Port Fourchon, LA, 70357	transfer
Venice	213 Coast Guard Road, Venice, LA 70091	transfer
U.S. Liquids	**Address**	**Type of Facility**
Bateman Island	on Intracoastal Waterway, Morgan City, LA,	land waste disposal
Bourg	771 Bourg-Larose Highway, Bourg, LA, 70343	land waste disposal
Elm Grove	2714 Atkins Clark Road, Elm Grove, LA, 71051	land waste disposal
Mermentau	11031 Campbell Wells Road, Jennings, LA,	land waste disposal

Source: Addresses obtained from (1) Newpark Environmental Services, July 2000; (2) U.S. Liquids (http://www.usliquids.com/now_division.html), July 2000; and (3) Louisiana Office of Conservation, list of permitted commercial treatment and disposal facilities (http://www.dnr.state.la.us/cons/conserin/commfac.ssi), July 2000.

Table C-2 below outlines the amount of SBFs that would be disposed of onshore for shallow water development wells (SWDs), shallow water exploratory wells (SWEs), deep water development wells (DWDs), and deep water exploratory wells (DWEs). Shallow wells are in water less than 1,000 feet deep, while deep wells are in water more than 1,000 feet deep.

Table C-2

Total Amount of SBF Waste Land-Disposed (in Pounds)*

Source	SWD	SWE	DWD	DWE	Total
Existing Sources**	----------	----------	2,852,661	16,913,557	19,766,218
New Sources***	----------	----------	2,852,661	----------	2,852,661
Total	----------	----------	5,705,322	16,913,557	22,618,879

Source: U.S. EPA,2000.
*For Option BAT 3 (zero discharge option), no waste is disposed of by on-site injection.
**Pounds per year based on 3 DWD wells, and 8 DWE wells.
***Pounds per year based on 3 DWD wells.

As shown in Table C-2, the total amount of SBFs disposed of onshore for all existing sources is 19,766,218 pounds per year. The total amount of SBFs disposed of onshore for all new sources is 2,852,661 pounds per year. The total amount disposed of onshore for both new and existing sources is 22,618,879 pounds per year. No SBFs would be disposed of through subsurface on-site water injection.

The environmental justice screening analysis assumes that 80 percent of SBFs would be disposed of by Newpark and 20 percent would be disposed of by U.S. Liquids (Newman, 2000a). Therefore, for both new and existing sources, approximately 18,095,103 pounds of SBFs would be disposed of onshore by Newpark and 4,523,776 pounds of SBFs would be disposed of onshore by U.S. Liquids.

Assuming the SBFs would be distributed proportionally among the Newpark facilities, 3,231,268 pounds of SBFs would pass through each transfer facility. The waste would then be distributed among its process facilities; Big Hill and Port Arthur would each receive 11,309,439 pounds of SBFs. The waste would then be injected into wells, with Big Hill and Fannet each receiving 11,309,439 pounds of SBFs. Assuming that the remaining SBFs would be distributed proportionally among each U.S. Liquid landfarming facility, each facility would receive 2,827,359 pounds of SBFs.

C.4 DESCRIPTION OF REGION 6 ENVIRONMENTAL JUSTICE METHODOLOGY

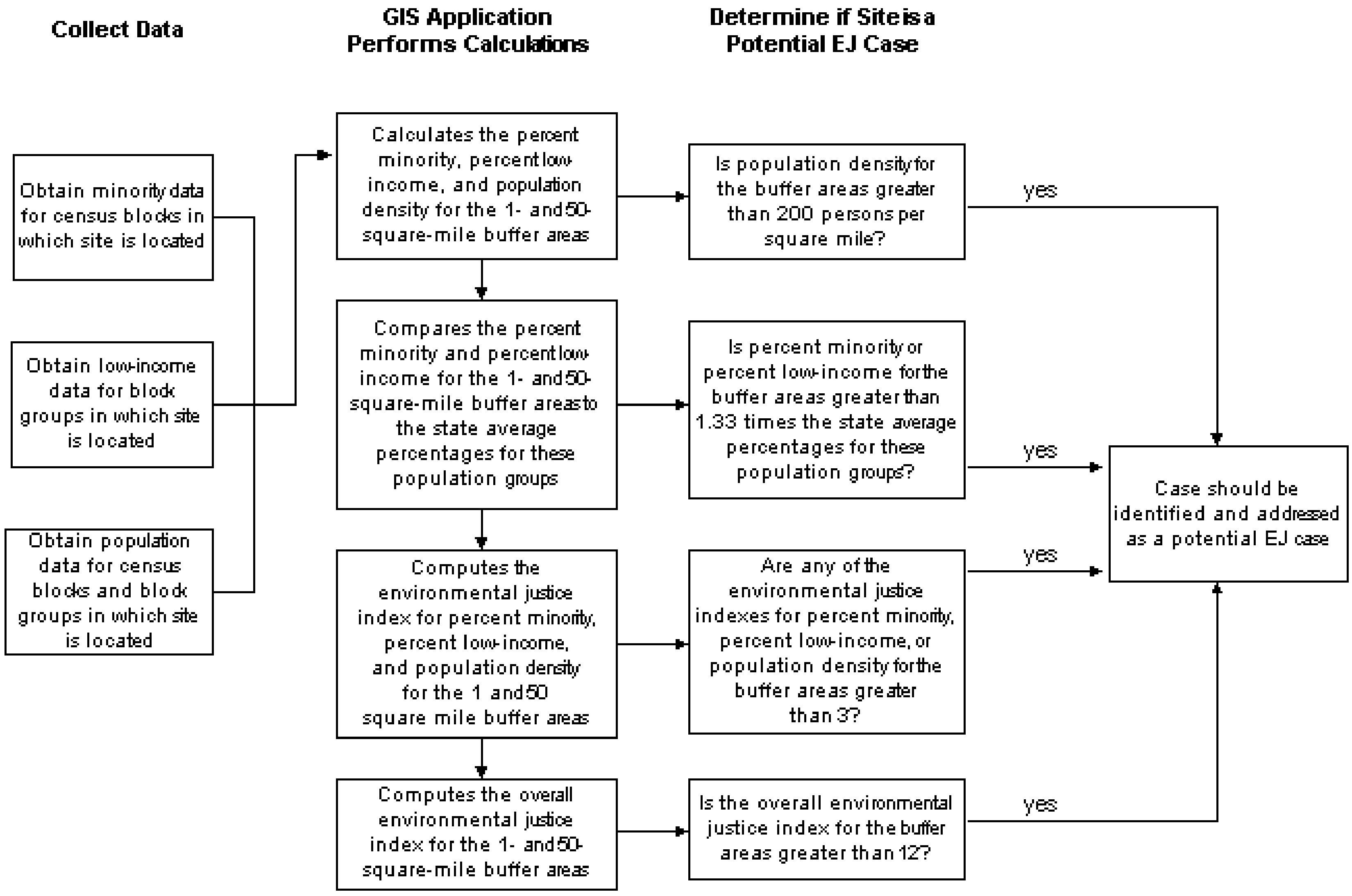
Region 6 developed a screening tool that can evaluate facility locations for potential environmental justice issues. The region developed the tool according to the requirements as laid out in Executive Order 12898. The methodology assesses the characteristics of neighborhoods located within 1- and 50- square-mile buffers around toxic or hazardous waste or facilities that emit toxic or hazardous waste. A site is identified as a potential environmental justice case if a buffer area has significantly higher minority and/or low-income populations than the state average. The methodology is detailed in the Region 6 *Environmental Justice Index Methodology* (U.S. EPA, 1996). Figure C-2 outlines the screening methodology.

Region 6 created an automated Geographic Information Systems (GIS) application that analyzes the sociodemographic make-up of 1- and 50- square-mile buffer areas surrounding a facility, and then compares the characteristics of the area to those of the state as a whole. Buffer areas are used because residences closer to the source are likely to have a higher risk of exposure. More specifically, the GIS application is used to visualize the spatial distribution of sociodemographic indicators, to produce tables summarizing sociodemographic parameters in the vicinity of the facility, and to rank a site for its potential as an environmental justice case.

C.4.1 What Data Are Used?

Before the environmental justice screening analysis can be performed, sociodemographic information for the potentially affected must be obtained. 1990 U.S. Census data for population, minority,

Figure C-2
Environmental Justice Screening Methodology



Source: Based on Region 6 screening methodology (U.S. EPA, 1996) and household income are read from the Census Summary Tape File (STF) 3-A and joined with census geographic boundaries in the GIS application.

The minority data are obtained at the census block level and are the total of the non-White population and the White Hispanic-Origin population. Data on low-income or economically stressed households are obtained at the block group level for households with incomes of less than $15,000 per year. Each of these categories of data are obtained for census blocks and block groups within both the 1- square mile and 50- square-mile buffer areas around the facility.

C.4.2 How are Sites Evaluated?

The GIS application combines the minority population in each census block and the economically stressed households population in each block group for the 1- and 50- square-mile buffer areas. The total minority percentage would be calculated by taking the total minority population in the buffer area and dividing by the total population in that area, and then multiplying by 100.

The GIS application uses an EJ Index formula developed by Region 6 to mathematically compare the percentage of the population groups within a buffer area to the state average percentages. The index determines the potential *degree of vulnerability* for the populations exposed to the facility. The index for this tier one screening analysis does not consider the *degree of impact* from potential chemical exposure and toxicity. A tier two risk screening analysis for those sites identified as potential environmental justice cases could be used to determine the degree of impact. Detailed information on the EJ Index and its relation to the region's Human Health Risk Index (HRI) formula can be found in the document *Environmental Justice Index Methodology* (U.S. EPA, 1996).

The GIS application calculates EJ Indexes by finding the percentage for each population group within the buffer areas, ranking the percentage based on scaling criteria, and then multiplying the rankings. The EJ formulas listed below assume that the *total* population of a buffer area is affected by environmental justice factors.

EJ Index (population)	= [Population Ranking (ranges from 0 to 4)]
EJ Index (minority)	= [Minority Ranking (ranges from 1 to 5)]
EJ Index (economic)	= [Economic Ranking (ranges from 1 to 5)]
EJ Index (overall)	= Population Ranking x (Minority Ranking x Economic Ranking)

According to the formulas above, population density, percent of minority population, and percent of economically stressed households are first ranked individually and then as a whole to determine whether there may be a disproportionate environmental burden. Individually, the percent of minority population and percent of economically stressed household factors can receive a rank of 1 to 5. Population density can receive a rank of 0 to 4. To calculate the overall EJ score, the application multiplies the individual scores together. A site thus receives an overall ranking between 0 and 100.

Generally, a subfactor ranking $\geq$ 3 or an overall EJ index $\geq$ 12 may warrant identification as a potential EJ case (Newman, 2000b). When the factors are evaluated independently, they often provide greater insight into potential environmental justice concerns. For example, the 1- mile buffer area may rank percent of minority population as 1 and percent of economically stressed households as 3. This site may warrant a potential environmental justice case based solely on the area's percentage of economically stressed households.

C.4.3 What Are the Specific Ranking Criteria?

To calculate a buffer area's population ranking, the GIS application calculates the area's population density, then compares that value to an average population density. Table C-3a shows how population rank is derived. The population density ranges were determined by examining natural breaks in the 1992 census population data for cities in the states located within Region 6.

The scaling criteria for percent of minority population and percent of economically stressed households are state-specific. To calculate these rankings, the application calculates the percent of minority population and percent of economically stressed households for the buffer areas and then compares these values to the state average percentages. The state average percentages for these population groups, based on state 1990 census data, are shown in Table C-3b.

Table C-3a

Ranges of Population Density Ranges

Population Density (per square mile)	Scaling score
0	0
> 0 and ≤ 200	1
> 200 and ≤ 1,000	2
> 1,000 and ≤ 5,000	3
> 5,000	4

Table C-3b

State Averages

State	Percent Minority	Percent Economically Stressed
Louisiana	34.2	36.3
Texas	39.4	27.6

Table C-3c shows the relationship between minority and economic stressed household percentages, the state average percentage, and the ranking criteria. For example, if the number of minority members within the 1- square-mile buffer area in Texas is 65 and the total population within the 1- square-mile area is 100, the percent of minority population would be 65. The percent of minority population for the area would receive a ranking of 3 because the relationship percentage is between 1.33 and 1.66 times the Texas state minority average of 39.4 percent.

Table C-3c

Ranking of Environmental Justice Indicators

Criterion	Ranking
Percentage of residents in the risk group is less than or equal to the state average percentage.	1
Percentage of residents in the risk group is greater than the state average percentage, but less than or equal to 1.33 times the state average percentage.	2
Percentage of residents in the risk group is greater than 1.33 times the state average percentage, but less than or equal to 1.66 times the state average percentage.	3
Percentage of residents in the risk group is greater than 1.66 times the state average percentage, but less than or equal to 1.99 times the state average percentage.	4
Percentage of residents in the risk group is greater than or equal to 2 times the state average percentage.	5

C.4.4 What are the Final Outputs?

For each site, the EJ screening analysis produces three final map outputs: “Minority Status,” “Economic Status,” and “Potential Environmental Justice Index.” The “Minority Status” and “Economic Status” maps display the spatial distribution of sociodemographic indicators. The census blocks or census block groups within the 1- and 50- square-mile buffer areas are color-coded according to ranges that depict different levels of *degree of vulnerability*. As such, census blocks and block groups that have minority or low-income populations between > 1.33 and ≤ 1.66 times the state percentage are colored orange and have a ranking of 3. A table summarizes sociodemographic parameters in the vicinity of the facility location including the percent of minority population, percent of economically stressed households, and population density for both buffer areas. The table also shows a rank for each variable and an overall EJ index.

The “Potential Environmental Justice Index” map displays the spatial distribution of the criteria ranked by census block. Each census block within the 1- and 50- square-mile buffer areas is color-coded according to the overall EJ Index for that census block. A census block that receives a minority ranking of 3, economic ranking of 4, and a population ranking of 2 would have an overall ranking of 24. A census block with an overall ranking of 24 would be color-coded yellow. A table summarizes the same information found on the table for the “Minority Status” and “Economic Status” maps.

C.4.5 What Assumptions Are Made in the Screening Analysis?

The Region 6 environmental justice screening analysis relies on the following assumptions: area proportion analysis technique, buffer distance, geographical scale, EJ Index rankings, and the EJ formula. Each of these assumptions are discussed below.

The area-proportion technique assumes that a population is evenly distributed throughout a census block or block group. However, because population is rarely evenly distributed across an area, using the area-proportion technique results in some amount of error. For example, suppose the boundary of a 1-square-mile buffer area crosses through a census block and cuts it in half. Using the area-proportion technique, the environmental justice screening analysis assumes that 50 percent of the population lives outside the buffer area and 50 percent lives inside the buffer area. If a block with 2,000 residents is cut in half, a population of 1,000 is used in the analysis. If all of the population in a census block resides outside the buffer area, then the area-proportion estimate is high and populations would be erroneously included. Conversely, if all of the population in a census block lives inside the buffer polygon, the area-proportion estimate is low. In general, the size of the error generated by the area-proportion technique depends on the number and size of the census blocks and block groups.

The choice of buffer distance is an important variable for determining whether potential inequities exist. The appropriate interval distance to use (e.g., 0.5 miles, 1 mile, 2 miles, 4 miles, etc.) and the basis for that selection influences the analysis. Inequities may not exist at a 0.5-mile distance but may exist at a 4-mile distance. Region 6 uses a 1- square-mile buffer area (0.56-mile radius) and 50- square-mile buffer area (4- mile radius).

Geographic or spatial scales (e.g., census blocks, block groups) are important to consider in the analysis because inequities may exist at one scale but disappear at another. In less densely populated areas where census tracts and block groups are large, the data may not provide meaningful information.

Additionally, block groups or census blocks adjacent to the buffer areas may contain potentially affected populations that are not captured in the screening analysis.

Rankings are influenced by the population size. Higher population areas require higher rankings. If the minority and economic status rankings are both 5 but the site has low population density (a ranking of 1), the highest possible EJ Index is only 25 (on a scale of 0 to 100.) Additionally, an unpopulated area will rank as zero but may be owned by minority and/or low-income groups. Statistically, most overall EJ Indexes will fall between 0 and 50. Cases in which the overall ranking can be greater than 50 are summarized in Table C-4.

The EJ formula assumes that the *total* population of the buffer areas is affected by EJ factors. In other words, potential source impacts are assumed to be equally distributed and all residents are assumed to be potentially affected.

Table C-4

Environmental Justice (EJ) Indexes Greater than Fifty

Population Ranking	Minority Ranking	Economic Ranking	Overall Ranking
3	4	5	60
4	4	4	64
3	5	5	75
4	4	5	80
4	5	5	100

C.5 RESULTS

EPA conducted thirteen Region 6 environmental justice screening analyses to determine whether the facilities are potential EJ cases. The GIS application used minority, population, and low-income data to rank each facility and produce mapping and tabular outputs. Section C.7 of this Appendix contains three maps titled “Minority Status,” “Economic Status,” and “Potential Environmental Justice Index” for each facility. Each map displays a color-coded vulnerability map as well as information on the population ranking, minority ranking, economic ranking, and overall EJ index for each facility. Section C.4 of this appendix explains in more detail how to interpret these outputs.

Tables C-5a and C-5b provide information on whether a facility is a potential environmental justice case. The ranking and index information presented are taken from the mapping outputs provided in Section C.7. According to Tables C-5a and C-5b, five out of thirteen disposal site are potential environmental justice sites. Morgan City, Venice, Bateman Island, and Mermentau facilities are potential environmental justice cases within the 1- square mile area. Port Fourchon and Venice facilities are potential environmental justice cases within the 50- square mile area.

Table C-5a

EJ Status Within 1- Square Mile Radius of Facility

Company	Facility Name	Population Ranking	Minority Status	Economic Status	Environmental Justice Index	Potential EJ Case
Newpark Environmental Services	Big Hill	1	1	1	1	no
	Cameron	1	1	1	1	no
	Fannet	1	1	1	1	no
	Ingleside	1	1	1	1	no
	Intracoastal City	1	1	1	1	no
	Morgan City	3	3	3	27	yes
	Port Arthur	0	1	1	0	no
	Port Fourchon	1	1	1	1	no
	Venice	1	1	5	5	yes
U.S. Liquids	Bateman Island	2	5	4	40	yes
	Bourg	1	1	1	1	no
	Elm Grove	1	1	1	1	no
	Mermentau	1	4	2	8	yes

Table C-5b

EJ Status Within 50- Square Mile Radius of Facility

Company	Facility Name	Population Ranking	Minority Status	Economic Status	Environmental Justice Index	Potential EJ Case
Newpark Environmental Services	Big Hill	1	1	1	1	no
	Cameron	1	1	1	1	no
	Fannet	1	1	1	1	no
	Ingleside	1	1	2	2	no
	Intracoastal City	1	1	1	1	no
	Morgan City	2	1	1	2	no
	Port Arthur	2	1	2	4	no
	Port Fourchon	1	1	3	3	yes
	Venice	1	1	3	3	yes
U.S. Liquids	Bateman Island	2	1	1	2	no
	Bourg	1	1	1	1	no
	Elm Grove	1	1	1	1	no
	Mermentau	1	2	2	4	no

C.6 REFERENCES

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C.7 SUPPLEMENTAL MAPS