SWIFT ENERGY CO
Form 10-K
March 01, 2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

Annual Report Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

For the Fiscal Year Ended December 31, 2006

Commission File Number 1-8754

SWIFT ENERGY COMPANY
(Exact Name of Registrant as Specified in Its Charter)

Texas	20-3940661
(State of Incorporation)	(I.R.S. Employer Identification No.)

16825 Northchase Dr., Suite 400
Houston, Texas 77060
(281) 874-2700
(Address and telephone number of principal executive offices)
Securities registered pursuant to Section 12(b) of the Act:

Title of Class:	Exchanges on Which Registered:
Common Stock, par value $.01 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934. Yes No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days. Yes x No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act).

Large accelerated filer x Accelerated filer ____ Non-accelerated filer ____

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes _____ No X

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of June 2006 was approximately $1,233,453,469.

The number of shares of common stock outstanding as of January 31, 2007 was 29,803,934.

Documents Incorporated by Reference

Document	Incorporated as to
Proxy Statement for the Annual Meeting of Shareholders to be held May 8, 2007	Part II, Item 5 Part III, Items 10, 11, 12, 13 and 14

Form 10-K
Swift Energy Company and Subsidiaries

10-K Part and Item No.

(1) Incorporated by reference from Proxy Statement for the Annual Meeting. of Shareholders to be held May 8, 2007.

PART I

Item 1. Business

See pages 25 and 26 for explanations of abbreviations and terms used herein.

General

Swift Energy Company is engaged in developing, exploring, acquiring, and operating oil and gas properties, with a focus on oil and natural gas reserves onshore and in the inland waters of Louisiana and Texas and onshore in New Zealand. Swift Energy was founded in 1979 and is headquartered in Houston, Texas. At year-end 2006, we had estimated proved reserves of 816.8 Bcfe with a PV-10 Value of $2.7 billion (PV-10 is a non-GAAP measure, see the section titled "Oil and Natural Gas Reserves" in our Property section for a reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure). Our proved reserves at year-end 2006 were comprised of approximately 50% crude oil, 40% natural gas, and 10% NGLs; and 44% of our total proved reserves were proved developed. Our proved reserves are concentrated 64% in Louisiana, 22% in Texas, 13% in New Zealand, and 1% in other states.

We currently focus primarily on development and exploration of fields in three domestic regions and in New Zealand:

- South Louisiana Region
  - Bay de Chene Area
  - Bayou Penchant Area
  - Bayou Sale Area
  - Cote Blanche Island Area
  - High Island Area
  - Horseshoe Bayou Area
  - Jeanerette Area
  - Lake Washington Area

- South Texas Region
  - AWP Olmos Area

- Toledo Bend Region
  - Brookeland Area
  - Masters Creek Area
  - South Bearhead Creek Area

- New Zealand Region
  - Rimu/Kauri Area
  - TAWN Area

Competitive Strengths and Business Strategy

Our competitive strengths, together with a balanced and comprehensive business strategy, provide us with the flexibility and capability to achieve our goals. Our primary goals for the next five years are to increase proved oil and natural gas reserves at an average rate of 5% to 10% per year and to increase production at an average rate of 7% to 12% per year.

Demonstrated Ability to Grow Reserves and Production

We have grown our proved reserves from 645.8 Bcfe to 816.8 Bcfe over the five-year period ended December 31, 2006. Over the same period, our annual production has grown from 44.8 Bcfe to 70.2 Bcfe and our annual net cash provided by operations has increased from $139.9 million to $424.9 million. Our

growth in reserves and production over this five-year period has resulted primarily from drilling activities and acquisitions in our four core regions. More recently, we increased our production by 18% during 2006 as compared to our hurricane affected 2005 production. During 2006, our total proved reserves increased by 7%, primarily due to acquisitions of properties in our South Louisiana region. Based on our long-term historical performance and our business strategy going forward, we believe that we have the opportunities, experience, and knowledge to grow both our reserves and production.

Balanced Approach to Growth

Our strategy is to increase our reserves and production through both drilling and acquisitions, shifting the balance between the two activities in response to market conditions and strategic opportunities. In general, we focus on drilling in our anchor assets and diversity properties in each of our four regions when oil and natural gas prices are strong. When prices weaken and the per unit cost of acquisitions becomes more attractive, or a strategic opportunity exists, we also focus on acquisitions. We believe this balanced approach has resulted in our ability to grow in a strategically cost effective manner. Over the five-year period ended December 31, 2006, we replaced 159% of our production at an average cost of $2.76 per Mcfe. More recently, we replaced 178% of our 2006 production at an average cost of $4.29 per Mcfe. For 2007, we are targeting total production to increase 7% to 10% and proved reserves to increase 4% to 6% over 2006 levels.

Our 2007 capital expenditures are currently budgeted at $350 million to $400 million, net of minor non-core dispositions and excluding any property acquisitions.

Reserves Replacement Ratio and Reserves Replacement Cost

Historically we have added proved reserves through both our drilling and acquisition activities. We believe that this strategy will continue to add reserves for us over the long-term; however, external factors beyond our control, such as adverse weather conditions, commodity market factors, and governmental regulations, could limit our ability to drill wells and acquire proved properties in the future. We calculate and analyze reserves replacement ratios and costs to use as benchmarks against certain of our competitors. These ratios and costs are limited in use by the inherent uncertainties in the reserves estimation process, and other factors discussed below. We have included below a listing of the vintages of our proved undeveloped reserves in the table titled "Proved Undeveloped Reserves" and believe this table will provide an understanding of the time horizon required to convert proved undeveloped reserves to oil and gas production. Our reserves additions for each year are estimates. Reserve volumes can change over time and therefore cannot be absolutely known or verified until all volumes have been produced and a cumulative production total for a well or field can be calculated. Many factors will impact our ability to access these reserves, such as availability of capital, commodity prices, new and existing government regulations, adverse weather conditions, competition within our industry, the requirement of new or upgraded infrastructure at the production site, and technological advances.

The reserves replacement ratio is calculated using reserves replacement volumes divided by production volumes during a specific period. The reserves replacement volumes used in this calculation are listed in the "Supplemental Information (Unaudited)" section of this report, specifically in a table titled "Supplemental Reserves Information." Within this table there are categories titled "Revisions of previous estimates," "Purchases of minerals in place" and "Extensions, discoveries, and other additions" which when added, total the reserves replacement volumes. Production volumes are also listed in the same table, and these production volumes are also used in the reserves replacement ratio calculation.

The reserves replacement cost is calculated using reserves replacement volumes divided into acquisition, exploration, and development costs incurred during a specific period. Our acquisition, exploration, and development costs are listed in the "Supplemental Information (Unaudited)" section of this report, specifically in a table titled "Costs Incurred." Development costs as defined by Securities and Exchange Commission rules include costs incurred to obtain access to proved reserves and provide facilities for extracting, treating, gathering and storing the oil and gas. Development costs thus include well drilling costs for our development wells and facility costs, such as those facility and platform costs we have incurred in our Lake Washington area over the past several years. Costs incurred to explore and develop reserves may extend over several years. We believe a reserves replacement cost estimate is more meaningful when calculated over several periods. Future development costs from prior years are included in this calculation to the extent that they have been included in our actual costs incurred.

Concentrated Focus on Regions with Operational Control

The concentration of our operations in four regions allows us to leverage our drilling unit and workforce synergies while minimizing the continued escalation of drilling and completion costs. Our average lease operating costs, excluding taxes, were $0.89, $0.79, and $0.71 per Mcfe in 2006, 2005, and 2004, respectively. Each of our four regions includes at least one anchor asset, previously termed a core area, and several diversity properties that are targeted for future growth. This concentration allows us to utilize the experience and knowledge we gain in these areas to continually improve our operations and guide us in developing our future activities and in operating similar type assets. For example, in our South Louisiana region, we will apply the experience we have gained in Lake Washington to our Bay de Chene and Cote Blanche Island properties acquired at the end of 2004, which are also situated around salt domes. The value of this concentration is enhanced by our operational control of 94% of our proved oil and natural gas reserves base as of December 31, 2006. Retaining operational control allows us to more effectively manage production, control operating costs, allocate capital, and time field development.

Develop Under-Exploited Properties

We are focused on applying advanced technologies and recovery methods to areas with known hydrocarbon resources to optimize our exploration and exploitation of such properties as illustrated in our four regions. For instance, the Lake Washington field was discovered in the 1930s. We acquired our properties in this area for $30.5 million in 2001. Since that time, we have increased our average daily net production from less than 700 BOE to 18,700 BOE for the quarter ended December 31, 2006. We have also increased our proved reserves in the area from 7.7 million BOE, or 46.2 Bcfe, to approximately 40.3 million BOE or 241.9 Bcfe, as of December 31, 2006. Additionally, on our original 100,000 acre New Zealand permit, only two wells had been drilled at the time that we acquired our interest in 1999 and since that time we have drilled 50 wells in New Zealand. When we first acquired our interests in AWP Olmos, Brookeland, and Masters Creek, these areas also had significant additional development potential. Our properties in the Bay de Chene and Cote Blanche Island fields hold mainly proved undeveloped reserves and we began our initial development activities of these properties in 2006. We intend to continue acquiring large acreage positions where we can grow production by applying advanced technologies and recovery methods using our experience and knowledge developed in our four regions.

Maintain Financial Flexibility and Disciplined Capital Structure

We practice a disciplined approach to financial management and have historically maintained a disciplined capital structure to provide us with the ability to execute our business plan. As of December 31, 2006, our debt to capitalization was approximately 32%, while our debt to proved reserves ratio was $0.47 per Mcfe, and our debt to PV-10 ratio was 14%. We plan to maintain a capital structure that provides financial flexibility through the prudent use of capital, aligning our capital expenditures to our cash flows, and maintaining a strategic hedging program. The combination of hedging with collars, floors, forward sales, and the sale of our New Zealand natural gas production under long-term, fixed-price contracts will provide for a more stable cash flow for the periods covered as described in the "Commodity Risk" section of this report.

Experienced Technical Team

We employ 61 oil and gas professionals, including geophysicists, petrophysicists, geologists, petroleum engineers, and production and reservoir engineers, who have an average of approximately 24 years of experience in their technical fields and have been employed by us for an average of over five years. In addition, we engage experienced and qualified consultants to perform various comprehensive seismic acquisitions, processing, reprocessing, interpretation, and other related services. We continually apply our extensive in-house experience and current technologies to benefit our drilling and production operations.

We increasingly use seismic technology to enhance the results of our drilling and production efforts, including two and three-dimensional seismic acquisition, pre-stack image enhancement reprocessing, amplitude versus offset datasets, coherency cubes, and detailed field reservoir depletion planning. In 2004, we completed our 3-D seismic survey covering our Lake Washington area. In 2006 we utilized this seismic data to drill all of our exploratory and development wells. In 2005, we began a seismic program that encompasses 77 square miles in our Cote Blanche Island area, which was completed in 2006 and analysis of this data will continue into 2007. We now have seismic data covering 4,000 square miles in South Louisiana that has been merged into two data sets, inclusive of data covering five newly acquired fields that will form the base dataset for our regional exploration and development program. This data will be analyzed over the next several years feeding our acquisition and organic growth led strategies. In New Zealand, we also acquired seismic on our offshore Kaheru exploration permit in 2006.

We use various recovery techniques, including gas lift, water flooding, and acid treatments to enhance crude oil and natural gas production. We also fracture reservoir rock through the injection of high-pressure fluid, install gravel packs, and insert coiled-tubing velocity strings to enhance and maintain production. We believe that the application of fracturing and coiled-tubing technology has resulted in significant increases in production and decreases in completion and operating costs, particularly in our AWP Olmos area.

We also employ measurement-while-drilling techniques extensively in our South Louisiana region, which allows us to guide the drill bit during the drilling process. This technology allows the well bore path to be steered parallel to the salt face and to intersect multiple targeted sands in a single well bore.

Item 2. Properties

Operating Areas

The following table sets forth information regarding our 2006 year-end proved reserves of 816.8 Bcfe and production of 70.2 Bcfe by field:

Area	% of Year-End 2006 Proved Reserves	% of 2006 Production
New Zealand.................	13%	19%
South Louisiana.............	53%	61%
South Texas.................	18%	12%
Toledo Bend.................	14%	6%
% of Total...........	98%	98%

Domestic Regional Focus Areas

Our domestic regions consist of three main regions located in South Louisiana, South Texas and Toledo Bend, which straddles the Texas and Louisiana border. South Texas is the oldest of our core regions, with our operations being established in the AWP Olmos area in 1989. In mid-1998, we acquired the Masters Creek and Brookeland areas in the Toledo Bend region, with South Bearhead Creek being our most recent acquisition in this region during late 2005. In South Louisiana, we established our operations when we acquired majority interests in producing properties in the Lake Washington field in early 2001, adding Bay de Chene and Cote Blanche Island in December 2004, and adding five fields in 2006: Bayou Sale, Bayou Penchant, High Island, Horseshoe Bayou, and Jeanerette.

South Louisiana

Lake Washington Area. As of December 31, 2006, we owned drilling and production rights in 21,690 net acres in the Lake Washington area located in Plaquemines Parish in South Louisiana. Approximately 93% of our proved reserves of 40.3 million BOE in this area at December 31, 2006, were oil and NGLs. To date, we have primarily produced from multiple Miocene sands ranging in depth from greater than 2,000 feet to 13,000 feet. The field is located on a salt dome and has produced over 300 million BOE since its discovery in the 1930s. The area around the dome is heavily faulted, thereby creating a large number of potential traps. Oil and gas from approximately 146 producing wells is gathered to three platforms located in water depths from two to 12 feet, with drilling and workover operations performed with rigs on barges.

In 2006, we drilled 21 development wells, of which 18 wells were completed. At year-end 2006, we had 109 proved undeveloped locations in this field. Our planned 2007 capital expenditures in this area will focus on drilling from 24 to 26 wells, along with the construction of a facility on the west side of the field to further improve the deliverability and efficiency in this area.

Bay de Chene and Cote Blanche Island Areas. Bay de Chene is located in Jefferson Parish and Lafourche Parish, while Cote Blanche Island is located in St. Mary Parish, both of which are in South Louisiana in close proximity to Lake

Washington. These fields hold predominantly undeveloped reserves. As of December 31, 2006, we owned drilling and production rights in 16,138 net acres in the Bay de Chene field and 7,030 net acres in the Cote Blanche Island field, along with options covering another 16,650 acres in the Cote Blanche Island field. At year-end 2006, we had five proved undeveloped locations in the Bay de Chene field and 26 in the Cote Blanche Island field. We drilled six development wells in Bay de Chene in 2006, of which three were completed, and we drilled three successful development wells in Cote Blanche Island. During 2007, we plan to drill six to eight wells in Bay de Chene and up to two wells in Cote Blanche Island, along with processing the 3-D seismic data that was shot in Cote Blanche Island in 2006.

Newly Acquired South Louisiana Areas. In October 2006, we acquired interests in five fields located in five primarily onshore South Louisiana fields: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), High Island Field in Cameron Parish and Bayou Penchant Field in Terrebonne Parish. Bayou Sale and Horseshoe Bayou fields are adjacent to each other and located 13 miles southeast of our Cote Blanche Island field. Production in these fields is from formations at depths ranging from 10,000 to 14,000 feet. The Bayou Penchant field was discovered in the 1930s and produces from a number of Middle Miocene sands at depths of 7,000 to 10,000 feet. Bayou Penchant is located approximately 44 miles southeast of Cote Blanche Island and is a non-operated field with Swift holding a 50% working interest. The High Island field is located 65 miles west of Cote Blanche Island and was discovered in 1983. The Jeanerette field is positioned on the flank of a large salt dome and approximately 12 miles north of Cote Blanche Island. Jeanerette Field produces from the Planulina sands in the 10,000 feet to 15,000 feet depth range. We plan to initiate an exploration and development program in 2007 to drill proved undeveloped and probable locations, recomplete several wells, enhance facilities and improve per unit operating costs in these five fields.

South Texas

AWP Olmos Area. As of December 31, 2006, we owned drilling and production rights in 29,278 net acres in the AWP Olmos Area in South Texas. We have extensive experience with low-permeability, tight-sand formations typical of this area, having acquired our first acreage there in 1988. These reserves are approximately 70% natural gas. At year-end 2006, we owned interests in and operated 540 wells in this area producing oil and natural gas from the Olmos sand formation at depths of approximately 9,000 to 11,500 feet. We own nearly 100% of the working interests in all these operated wells.

In 2006, we completed 14 development wells in this area, performed 26 fracture enhancements, but were unsuccessful on five very shallow exploration wells which cost $0.5 million in the aggregate. At year-end 2006, we had 110 proved undeveloped locations. Our planned 2007 capital expenditures will focus on drilling 10 to 12 wells in this area.

Toledo Bend

Brookeland Area. As of December 31, 2006, we owned drilling and production rights in 79,593 net acres and 3,500 fee mineral acres in the Brookeland area. This area is located in East Texas near the border of Louisiana in Jasper and Newton counties. We primarily drill horizontal wells and produce from the Austin Chalk formation in this area. The reserves are approximately 57% oil and natural gas liquids. During 2006, we drilled one development well, which was successful. At year-end 2006, we had ten proved undeveloped locations. Our planned 2007 capital expenditures in the Brookeland area include drilling one to two development wells.

Masters Creek Area. As of December 31, 2006, we owned drilling and production rights in 41,988 net acres and 91,594 fee mineral acres in the Masters Creek area. This area is located in Central Louisiana near the Texas-Louisiana border in the two parishes of Vernon and Rapides. It contains horizontal wells producing both oil and gas from the Austin Chalk formation. The reserves are approximately 69% oil and NGLs. At year-end 2006, we had nine proved undeveloped locations. We do not plan on drilling any wells in this area in 2007.

South Bearhead Creek Area. In November and December 2005, and then in December 2006, we acquired interests in the South Bearhead Creek field, which is located in the Toledo Bend region approximately 50 miles south of our Masters Creek field and 30 miles north of Lake Charles, Louisiana. Oil and gas are produced in this area predominantly from the upper and lower Wilcox sands at depths ranging from approximately 10,600 to 14,100 feet. The field also has production in the Cockfield sands at approximately 8,000 to 8,500 feet. South Bearhead Creek field was discovered in 1958 by a major oil company. It is a large east-west trending anticlinal closure and has had cumulative production of over 4 million BOE.

In 2006, we drilled three development wells in the area, all of which were successful. As of December 31, 2006, we owned drilling and production rights in 6,258 net acres in the South Bearhead Creek area. At year-end 2006, we had 19 proved undeveloped locations in this field. Our 2007 plans for this area include two to four development wells and several recompletions.

Dispositions. In April 2006, we sold our minority interest in the natural gas processing plant and related infrastructure that serves the Brookeland and the Masters Creek areas within our Toledo Bend region. In December 2006, we sold our interest in wells in the Garcia Ranch area within the South Texas region.

New Zealand Regional Focus Areas

Our New Zealand region contains two anchor assets, the Rimu/Kauri area and the TAWN area. Our activity in New Zealand began in 1995. As of December 31, 2006, our exploration and production permits, all of which we operate, total 314,360 acres (182,381 net acres). Our 2007 planned activity in New Zealand includes conducting a major 3-D seismic survey and possibly drilling two development wells. Our infrastructure in New Zealand includes two hydrocarbon-processing plants with significant excess capacity. We also own the pipelines connecting the fields and facilities to export terminals and interior markets.

Rimu/Kauri Area. Since 2002, we have held a 100% working interest in petroleum mining permit 38151 covering approximately 4,552 acres in the Rimu area for a primary term of 30 years. We were awarded a 30-year primary term mining permit (PMP 38155) covering approximately 8,708 acres in the Kauri area in April 2005. During 2006, we completed two out of three development wells in the Kauri area and were unsuccessful with one exploratory well. One of the development wells successfully targeted the Kauri and Tariki sands, and the other was completed in the Manutahi sand. Our natural gas production from this area is sold to Genesis Power Ltd. under a long-term contract for use at its Huntly Power Station, New Zealand's largest thermal power station.

TAWN Area. Our interest in TAWN consists of a 100% working interest in four petroleum mining permits, 38138 through 38141, covering producing oil and gas fields and extensive associated hydrocarbon-processing facilities and pipelines. The properties are collectively identified as the TAWN properties, an acronym derived from the first letters of the field names - the Tariki field, the Ahuroa field, the Waihapa field, and the Ngaere field. The four fields include 18 wells where the purchaser of gas is Contact Energy. In 2006, we completed the Waihapa H-1 development well in the Tikorangi sand in this area and were unsuccessful with two exploratory wells, the Trapper and Goss. The TAWN assets are located approximately 17 miles north of the Rimu/Kauri area.

Diversity Areas. A 152 square kilometer (59 square miles) marine 3-D seismic survey was recorded in production exploration permit 38495 over the Kaheru prospect, which is situated on the southern, offshore extension of the productive Rimu-Kauri structural trend, as a precursor to the possible drilling of an exploratory well on this prospect in 2008. We own 50% of this prospect.

In December 2004, we entered into a farm-in agreement with Ballance Agri-Nutrients Limited of New Zealand for their exploration permit 38742. The approximately 16,800 gross acre permit is located onshore in the north-central Taranaki Basin. Under the terms of the contract, we became the operator of the permit, and now have an 80% working interest. The Kowhai A-1 exploratory well was drilled in this area in the second half of 2006 but was unsuccessful.

Summary of New Zealand Government Licenses and Permits

Our acreage in New Zealand is licensed from the New Zealand government under production exploration permits (PEP), production mining licenses (PML), and production mining permits (PMP). These licenses and permits as of December 31, 2006 are summarized in the following table:

Permit	Date of Initial Interest Acquired	Swift's Interest
PEP 38495	2005	50%
PEP 38742	2004	80%
PML 38138	2002	100%
PML 38139	2002	100%
PML 38140	2002	100%
PML 38141	2002	100%
PMP 38151	2002	100%
PMP 38155	2005	100%

Details of these licenses can be found on the New Zealand government's Crown Minerals website at http://crownminerals.med.govt.nz/index.asp.

Oil and Natural Gas Reserves

The following tables present information regarding proved reserves of oil and natural gas attributable to our interests in producing properties as of December 31, 2006, 2005, and 2004. The information set forth in the tables regarding reserves is based on proved reserves reports prepared by us and audited by H. J. Gruy and Associates, Inc., Houston, Texas, independent petroleum engineers. Gruy has audited 100% of our proved reserves. Gruy's audit was conducted according to standards approved by the Board of Directors of the Society of Petroleum Engineers, Inc. and included examination, on a test basis, of the evidence supporting our reserves. Gruy's audit was based upon review of all available production histories and other geological, economic, and engineering data, all of which were provided by us.

Estimates of future net revenues from our proved reserves and their PV-10 Value are made using oil and gas sales prices in effect as of the dates of such estimates adjusted for the effects of hedging and are held constant, for that year's reserves calculation, throughout the life of the properties, except where such guidelines permit alternate treatment, including, in the case of gas contracts, the use of fixed and determinable contractual price escalations. We

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have interests in certain tracts that are estimated to have additional hydrocarbon reserves that cannot be classified as proved and are not reflected in the following tables. Our hedges at year-end 2006 consisted of natural gas price floors with strike prices higher than the period-end price but did not materially affect prices used in these calculations. The weighted averages of such year-end 2006 prices domestically were $5.84 per Mcf of natural gas, $60.07 per barrel of oil, and $31.54 per barrel of NGL, compared to $10.36, $60.00, and $33.28 at year-end 2005 and $5.87, $42.21, and $26.49 at year-end 2004, respectively. The weighted averages of such year-end 2006 prices for New Zealand were $3.59 per Mcf of natural gas, $63.51 per barrel of oil, and $26.84 per barrel of NGL, compared to $3.79, $60.98, and $19.20 in 2005 and $3.07, $33.60, and $20.48 in 2004, respectively. The weighted averages of such year-end 2006 prices for all our reserves, both domestically and in New Zealand, were $5.46 per Mcf of natural gas, $60.41 per barrel of oil, and $30.93 per barrel of NGL, compared to $8.94, $60.12, and $31.40 in 2005 and $5.16, $41.07, and $25.48 in 2004, respectively.

The following tables set forth estimates of future net revenues presented on the basis of unescalated prices and costs in accordance with criteria prescribed by the Securities and Exchange Commission and their PV-10 Value as of December 31, 2006, 2005, and 2004. Operating costs, development costs, asset retirement obligation costs, and certain production-related taxes were deducted in arriving at the estimated future net revenues. No provision was made for income taxes. The estimates of future net revenues and their present value differ in this respect from the standardized measure of discounted future net cash flows set forth in supplemental information to our consolidated financial statements, which is calculated after provision for future income taxes. We combine NGLs with oil for reserves reporting purposes. PV-10 is a non-GAAP measure; see the reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure, in the section below this table.

	As of
	Total
Estimated Proved Oil and Natural Gas Reserves	
Natural gas reserves (MMcf):	
Proved developed	151,276
Proved undeveloped	172,855
Total	324,131
Oil reserves (MBbl):	
Proved developed	34,956

Proved undeveloped		47,163
Total		82,119
Total Estimated Reserves (Bcfe)		817
Estimated Discounted Present Value of Proved Reserves (In millions)		
Proved developed	$	1,382
Proved undeveloped		1,326
PV-10 Value	$	2,708

	As of	
	Total	
Estimated Proved Oil and Natural Gas Reserves		
Natural gas reserves (MMcf):		
Proved developed		152,001
Proved undeveloped		135,472
Total		287,473
Oil reserves (MBbl):		
Proved developed		37,990
Proved undeveloped		41,063
Total		79,053
Total Estimated Reserves (Bcfe)		762
Estimated Discounted Present Value of Proved Reserves (In millions)		
Proved developed	$	1,721
Proved undeveloped		1,450
PV-10 Value	$	3,171

	As of
	Total
Estimated Proved Oil and Natural Gas Reserves	
Natural gas reserves (MMcf):	
Proved developed	193,311
Proved undeveloped	124,935
Total	318,246

Oil reserves (MBbl):		
Proved developed		42,038
Proved undeveloped		38,229
Total		80,267
Total Estimated Reserves (Bcfe)		800
Estimated Discounted Present Value of Proved Reserves (In millions)		
Proved developed	$	1,182	$
Proved undeveloped		839
PV-10 Value	$	2,021	$

Proved reserves are estimates of hydrocarbons to be recovered in the future. Reservoir engineering is a subjective process of estimating the sizes of underground accumulations of oil and gas that cannot be measured in an exact way. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Reserves reports of other engineers might differ from the reports contained herein. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Future prices received for the sale of oil and gas may be different from those used in preparing these reports. The amounts and timing of future operating and development costs may also differ from those used. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered. There can be no assurance that these estimates are accurate predictions of the present value of future net cash flows from oil and gas reserves.

No other reports on our reserves have been required to be filed, nor have any been filed with any federal agency.

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The closest GAAP measure to PV-10, a non-GAAP measure, is the standardized measure of discounted future net cash flows. We believe PV-10 is a helpful measure in evaluating the value of our oil and gas reserves and many securities analysts and investors use PV-10. We use PV-10 in our ceiling test computations, and we also compare PV-10 against our debt balances. The following table is a reconciliation between PV-10 and the standardized measure of discounted future net cash flows:

	A
	Total
(In millions)	
PV-10 Value	$ 2,

Future income taxes (discounted at 10%)..	(
Asset retirement obligations (discounted at 10%)....................................	
Standardized Measure of Discounted Future Net Cash Flows relating to oil and gas reserves	$ 1,

	Total
(In millions)	
PV-10 Value	$ 3,
Future income taxes (discounted at 10%)..	(
Asset retirement obligations (discounted at 10%)....................................	
Standardized Measure of Discounted Future Net Cash Flows relating to oil and gas reserves	$ 2,

	Total
(In millions)	
PV-10 Value	$ 2,
Future income taxes (discounted at 10%)..	(
Asset retirement obligations (discounted at 10%)....................................	
Standardized Measure of Discounted Future Net Cash Flows relating to oil and gas reserves	$ 1,

Proved Undeveloped Reserves

The following table sets forth the aging and PV-10 value of our proved undeveloped reserves as of December 31, 2006:

Year Added	Volume (Bcfe)	% of PUD Volumes	PV-10 Value (in millions)	% o PV-10
2006	111.9	25%	$ 315.9	
2005	110.6	24%	406.5	
2004	58.4	13%	189.9	
2003	51.4	11%	171.4	
2002	40.3	9%	91.6	
Prior to 2002	83.2	18%	151.2	
Total	455.8	100%	$ 1,326.5	

Sensitivity of Reserves to Pricing

As of December 31, 2006, a 5% increase in crude oil and NGL pricing would increase our total estimated proved reserves of 816.8 Bcfe by approximately 0.6 Bcfe, and increase the total PV-10 Value of $2.7 billion by approximately $139 million. Similarly, a 5% decrease in crude oil and NGL pricing would decrease our total estimated proved reserves by approximately 0.6 Bcfe and decrease the total PV-10 Value by approximately $138 million.

As of December 31, 2006 a 5% increase in natural gas pricing (exclusive of fixed contract volumes) would increase our total estimated proved reserves by approximately 0.7 Bcfe and increase the total PV-10 Value by approximately $42 million. Similarly, a 5% decrease in natural gas pricing (exclusive of fixed contract volumes) would decrease our total estimated proved reserves by approximately 0.6 Bcfe and decrease the total PV-10 Value by approximately $42 million.

Oil and Gas Wells

The following table sets forth the gross and net wells in which we owned an interest at the following dates:

	Oil Wells	Gas Wells	Total Wells(1)
December 31, 2006:			
Gross...............................	423	662	1,085
Net.................................	353.4	562.4	915.8
December 31, 2005:			
Gross...............................	402	565	967
Net.................................	324.8	497.5	822.3
December 31, 2004:			
Gross...............................	358	574	932
Net.................................	308.8	525.9	834.7

(1) Excludes 51 service wells in 2006, 49 service wells in 2005, and 40 service wells in 2004.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2006:

	Developed(1)		Undeveloped
	Gross	Net	Gross
Alabama....................................	9,045	2,588	124
Alaska.....................................	---	---	45,301
Louisiana..................................	126,472	106,133	48,376

Texas	129,997	90,165	18,271
SWyoming	640	151	35,771
All other states	320	266	400
Offshore Louisiana	4,609	277	5,000
Total Domestic	271,083	199,580	153,243
New Zealand	9,960	9,912	304,400
Total	281,043	209,492	457,643

(1) Fee mineral acres acquired in the Brookeland and Masters Creek areas acquisition are not included in the above leasehold acreage table. We have 26,345 developed fee mineral acres and 68,689 undeveloped fee mineral acres for a total of 95,034 fee mineral acres.

Drilling Activities

The following table sets forth the results of our drilling activities during the three years ended December 31, 2006:

for a total of 95,034 fee mineral areas

		Gross Wells			Net Wells	
Year	Type of Well	Total	Producing	Dry	Total	Producing
2006	Exploratory -- Domestic	6	--	6	5.5	--
	Development -- Domestic	49	42	7	47.6	40.6
	Exploratory -- New Zealand	4	--	4	4.0	--
	Development -- New Zealand	4	3	1	4.0	3.0
2005	Exploratory -- Domestic	9	5	4	9.0	5.0
	Development -- Domestic	45	37	8	44.3	36.3
	Exploratory -- New Zealand	5	1	4	3.7	1.0
	Development -- New Zealand	5	2	3	5.0	2.0
2004	Exploratory -- Domestic	10	4	6	7.5	2.3
	Development -- Domestic	44	37	7	41.7	35.0
	Exploratory -- New Zealand	1	--	1	1.0	--
	Development -- New Zealand	11	10	1	11.0	10.0

Operations

We generally seek to be the operator of the wells in which we have a significant economic interest. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. We do not own drilling rigs or other oil field services equipment used for drilling or maintaining wells on properties we operate. Independent contractors supervised by us provide this equipment and personnel. We employ drilling, production, and reservoir engineers, geologists, and other specialists who work to improve production rates, increase reserves, and lower the cost of operating our oil and gas properties.

Oil and gas properties are customarily operated under the terms of a joint operating agreement. These agreements usually provide for reimbursement of the operator's direct expenses and for payment of monthly per-well supervision fees. Supervision fees vary widely depending on the geographic location and depth of the well and whether the well produces oil or natural gas. The fees for these activities in 2006 totaled $8.8 million and ranged from $529 to $2,345 per well per month.

Marketing of Production

Domestically, we typically sell our oil and natural gas production at market prices near the wellhead or at a central point after gathering and/or processing. We usually sell our natural gas in the spot market on a monthly basis, while we sell our oil at prevailing market prices. We do not refine any oil we produce. In 2005 and 2006, several companies accounted for 10% or more of our total revenues. Shell Oil Company and its affiliates, both domestically and in New Zealand, accounted for approximately 30% and 42% of our total oil and gas sales in 2006 and 2005, respectively. In 2006, Chevron and its domestic affiliates accounted for 32% of our total oil and gas sales. However, due to the demand for oil and gas and availability of other purchasers, we do not believe that the loss of any single oil or gas purchaser or contract would materially affect our revenues.

Our oil production from the Lake Washington area is delivered into ExxonMobil's crude oil pipeline system or transported on barges for sales to various purchasers at prevailing market prices or at fixed prices tied to the then current NYMEX crude oil contract for the applicable month(s). Our natural gas production from this area is either consumed on the lease or is delivered into El Paso's Tennessee Gas Pipeline system and then sold in the spot market at prevailing prices.

In 1998, we entered into gas processing and gas transportation agreements for our natural gas production in the AWP Olmos area with PG&E Energy Trading Corporation, which was assumed in December 2000 by El Paso Hydrocarbon, LP, and El Paso Industrial, LP, and then assumed by Enterprise Hydrocarbons L.P. in September 2004, for up to 75,000 Mcf per day, which provided for a ten-year term with automatic one-year extensions unless terminated earlier. We believe that these arrangements adequately provide for our gas transportation and processing needs in the AWP Olmos area for the foreseeable future.

In the Toledo Bend area, our oil production from the Brookeland, Masters Creek and South Bearhead Creek areas is sold to various purchasers at prevailing market prices. Our natural gas production from the Brookeland and Masters Creek areas is processed under long term gas processing contracts with Eagle Rock Operating, LLC. The processed liquids and residue gas production are sold in the spot market at prevailing prices. South Bearhead Creek gas production is sold into the interstate market on Trunkline Gas Company's pipeline at prevailing market prices.

Our oil production from the Bay de Chene and Cote Blanche Island fields is transported on barges for sales to various purchasers at prevailing market prices. Gas production from both fields is sold into intrastate pipelines with prices tied to monthly and daily gas price indices.

In the newly acquired fields of Bayou Sale, Horseshoe Bayou, High Island and Jeanerette in south Louisiana, we market our own production and sell the oil production to various purchasers at prevailing market prices. Bayou Sale and Horseshoe Bayou oil production is delivered into Plains All-American pipeline. Oil production from High Island and Jeanerette fields is transported to market by truck. Gas production for each of these fields is sold into one or more interstate pipelines at prevailing market prices.

Through 2006, our oil production in New Zealand was sold to BP with prices tied to the Asia Petroleum Price Index (APPI) Tapis posting.

Our natural gas production from our TAWN fields is sold under a long-term fixed price contract with Contact Energy. Our natural gas production from the Rimu field is sold to Genesis Power Ltd. under a long-term fixed price contract that was modified in 2006 and covers approximately 7.2 Bcfe per year for a three-year period. During 2006, additional production volumes from our fields, over the contract maximum, were sold to Contact Energy or Genesis Power Ltd. at prevailing market rates.

Production of NGLs in New Zealand is sold to Rockgas Ltd. under long-term contracts tied to New Zealand's domestic natural gas liquids market.

The following table summarizes sales volumes, sales prices, and production cost information for our net oil and natural gas production for the three-year period ended December 31, 2006:

	Year Ended December 31,		
	2006	2005	2004
Net Sales Volume:			
Oil (MBbls)(1)	7,190	5,159	4,722
Natural Gas Liquids (MBbls)(2)	713	838	1,040
Natural gas (MMcf)(3)	22,788	23,609	23,742
Total (MMcfe)	70,205	59,590	58,319
Average Sales Price:			
Oil (Per Bbl)(1)	$ 64.47	$ 53.63	$ 40.24
Natural Gas Liquids (Per Bbl)(2)	$ 32.15	$ 28.04	$ 22.52
Natural gas (Per Mcf)(3)	$ 5.05	$ 5.23	$ 4.12
Average Production Cost (Per Mcfe)	$ 1.82	$ 1.50	$ 1.23

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(1) Oil production for 2006, 2005, and 2004 includes New Zealand production of 468,813 barrels at an average price per barrel of $67.06, 449,994 barrels at an average price per barrel of $55.57, and 452,753 barrels at an average price per barrel of $42.15, respectively.

(2) Natural gas liquids production for 2006, 2005 and 2004 includes New Zealand production of 252,666 barrels at an average price of $20.22 per barrel, 329,377 barrels with an average price of $18.84 per barrel, and 350,303 barrels with an average price of $17.96 per barrel.
(3) Natural gas production for 2006, 2005 and 2004 includes New Zealand production of 9,184,359 Mcf with an average price of $2.99 per Mcf, 11,869,757 Mcf with an average price of $3.09 per Mcf, and 11,441,954 Mcf with an average price of $2.38 per Mcf.

Risk Management

Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and gas, including blowouts, cratering, pipe failure, casing collapse, fires, and adverse weather conditions, each of which could result in severe damage to or destruction of oil and gas wells, production facilities or other property, or individual injuries. The oil and gas exploration business is also subject to environmental hazards, such as oil spills, gas leaks, and ruptures and discharges of toxic substances or gases that could expose us to substantial liability due to pollution and other environmental damage. See "1A. Risk Factors" of this report for more details and for discussion of other risks. We maintain comprehensive insurance coverage, including general liability insurance, officer and director liability insurance, and property damage insurance. Prior to and at the time of Hurricanes Katrina and Rita, we maintained business interruption insurance as well. Since such time, the cost of such business interruption insurance coverage increased to a level that we believe makes it uneconomical to maintain at this time. We believe that our insurance is adequate and customary for companies of a similar size engaged in comparable operations, but if a significant accident or other event occurs that is uninsured or not fully covered by insurance, it could adversely affect us.

Commodity Risk

The oil and gas industry is affected by the volatility of commodity prices. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. At December 31, 2006, we had price floors in place through the March 2007 contract month for natural gas; these cover a portion of our domestic natural gas production for February 2007 to March 2007. The natural gas price floors cover notional volumes of 800,000 MMBtu, with a weighted average floor price of $7.00 per MMBtu. Our natural gas price floors in place at December 31, 2006 are expected to cover approximately 25% to 30% of our domestic natural gas production from February 2007 to March 2007.

Competition

We operate in a highly competitive environment, competing with major integrated and independent energy companies for desirable oil and gas properties, as well as for equipment, labor, and materials required to develop and operate such properties. Many of these competitors have financial and technological resources substantially greater than ours. The market for oil and gas properties is highly competitive and we may lack technological information or expertise available to other bidders. We may incur higher costs or be unable to acquire and develop desirable properties at costs we consider reasonable because of this competition. Our ability to replace and expand our reserves base depends on our continued ability to attract and retain quality personnel and identify and acquire suitable producing properties and prospects for future drilling and acquisition.

Regulations

Environmental Regulations

Our domestic exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing the discharge of substances into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit by operators before drilling commences, prohibit drilling activities on certain lands lying within wilderness areas, wetlands, and other ecologically sensitive and protected areas, and impose substantial remedial liabilities for pollution resulting from drilling operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of significant investigatory or remedial obligations, and the imposition of injunctive relief that limits or prohibits our operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal, or cleanup requirements could materially adversely affect our operations and financial position, as well as those of the oil and gas industry in general. While we believe that we are in substantial compliance with current environmental laws and regulations and have not experienced any material adverse effect from such compliance, there is no assurance that this trend will continue in the future.

We currently own or lease, and have in the past owned or leased, numerous properties in connection with our domestic operations that have been used for the exploration and production of oil and gas for many years. Although we have used operation and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or other wastes may have been disposed or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon or away from could be subject to stringent and costly investigatory or remedial requirements under applicable laws, some of which are strict liability laws without regard to fault or the legality of the original conduct, including the federal Comprehensive Environmental Response, Compensation, and Liability Act, also known as "CERCLA" or the "Superfund" law, the federal Resource Conservation and Recovery Act or "RCRA," the federal Clean Water Act, the federal Clean Air Act, the federal Oil Pollution Act or "OPA," and analogous state laws. Under such laws and any implementing regulations, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), to perform natural resource mitigation or restoration practices, or to perform remedial plugging or closure operations to prevent future contamination. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury or property damages allegedly caused by the release of petroleum hydrocarbons or other wastes into the environment.

Our domestic operations offshore in the Gulf of Mexico are subject to OPA, which imposes a variety of requirements related to the prevention of oil spills, and liability for damages resulting from such spills in United States waters. The OPA imposes strict, joint and several liability on responsible parties for oil removal costs and a variety of public and private damages, including natural resource damages. Liability limits for offshore facilities require a responsible party to pay all removal costs, plus up to $75 million in other damages. These liability limits do not apply, however, if the spill was caused by gross negligence or willful misconduct of the party, if the spill resulted from violation of a federal safety, construction or operation regulation, or if the party fails to report the spill or cooperate fully in any resulting cleanup. The OPA also requires a responsible party at an offshore facility to submit proof of its financial ability to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. We believe our operations are in substantial compliance with OPA requirements.

Our operations in New Zealand could also potentially be subject to similar foreign governmental controls and restrictions pertaining to protection of human health and the environment. These controls and restrictions may include the need to acquire permits, prohibitions on drilling in certain environmentally sensitive areas, performance of investigatory or remedial actions for any releases of petroleum hydrocarbons or other wastes caused by us or prior operators, closure and restoration of facility sites, and payment of penalties for violations of applicable laws and regulations. While we believe that we are in substantial compliance with current environmental laws and regulations in New Zealand, and have not experienced any material adverse effect from such compliance, there is no assurance that this trend will continue in the future.

United States Federal, State and New Zealand Regulation of Oil and Natural Gas

The transportation and certain sales of natural gas in interstate commerce are heavily regulated by agencies of the federal government and are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The Federal Energy Regulatory Commission ("FERC") is continually proposing and implementing new rules and regulations affecting the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC's jurisdiction. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. Some recent FERC proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines.

Our sales of crude oil, condensate and NGLs are not currently subject to FERC regulation. However, the ability to transport and sell such products is dependent on certain pipelines whose rates, terms and conditions of service are subject to FERC regulation.

Production of any oil and gas by us will be affected to some degree by state regulations. Many states in which we operate have statutory provisions regulating the production and sale of oil and gas, including provisions regarding deliverability. Such statutes, and the regulations promulgated in connection therewith, are generally intended to prevent waste of oil and gas and to protect correlative rights to produce oil and gas between owners of a common reservoir. Certain state regulatory authorities also regulate the amount of oil and gas produced by assigning allowable rates of production to each well or proration unit, which could restrict the rate of production below the rate that a well would otherwise produce in the absence of such regulation. In addition, certain state regulatory authorities can limit the number of wells or the locations where wells may be drilled. Any of these actions could negatively affect the amount or timing of revenues. Likewise, the government of New Zealand regulates the exploration, production, sales, and transportation of oil and natural gas.

Federal Leases

Some of our domestic properties are located on federal oil and gas leases administered by various federal agencies, including the Bureau of Land Management. Various regulations and administrative orders affect the terms of leases, and in turn may affect our exploration and development plans, methods of operation, and related matters.

Litigation

In the ordinary course of business, we have been party to various legal actions, which arise primarily from our activities as operator of oil and gas wells. In our opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations.

Employees

At December 31, 2006, we employed 345 persons. Of these employees, 73 were in New Zealand, including two expatriate employees. Eight of our New Zealand employees are members of a union. None of our other employees are represented by a union. Relations with employees are considered to be good.

Facilities

At December 31, 2006, we occupied approximately 124,000 square feet of office space at 16825 Northchase Drive, Houston, Texas, under a ten-year lease expiring in 2015. The lease requires payments of approximately $240,000 per month. In New Zealand we leased approximately 18,400 square feet of office space, under leases expiring in 2008 and 2009. These New Zealand leases require payments of approximately $20,000 per month. We also have field offices in various locations from which our employees supervise local oil and gas operations.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, amendments to those reports, changes in and stock ownership of our directors and executive officers, together with other documents filed with the Securities and Exchange Commission under the Securities Exchange Act can be accessed free of charge on our web site at www.swiftenergy.com as soon as reasonably practicable after we electronically file these reports with the SEC. All exhibits and supplemental schedules to these reports are available free of charge through the SEC web site at www.sec.gov. In addition, we have adopted a Code of Ethics for Senior Financial Officers and Principal Executive Officer. We have posted this Code of Ethics on our website, where we also intend to post any waivers from or amendments to this Code of Ethics.

Item 1A. Risk Factors

The nature of the business activities conducted by Swift Energy subjects it to certain hazards and risks. The following is a summary of some of the material risks relating to our business activities. Other risks are described in Items 1 and 2 Business and Properties "Competition" and "Regulations" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Our oil and gas exploration and production business involves high risks and we may suffer uninsured losses.

These risks include blowouts, explosions, adverse weather effects and pollution and other environmental damage, any of which could result in substantial losses to the Company due to injury or loss of life, damage to or destruction of wells, production facilities or other property, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. Increased hurricane activity over the past two years has resulted in production curtailments and physical damage to the Company's Gulf Coast operations. Although the Company currently maintains insurance coverage that it considers reasonable and that is similar to that maintained by comparable companies in the oil and gas industry, it is not fully insured against certain of these risks, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance.

Oil and natural gas prices are volatile. A substantial decrease in oil and natural gas prices would adversely affect our financial results.

Our future revenues, net income, cash flow, and the value of our oil and natural gas properties depend primarily upon market prices for oil and natural gas. Oil and natural gas prices historically have been volatile and will likely continue to be volatile in the future. The recent record high oil and natural gas prices may not continue and could drop precipitously in a short period of time. The prices for oil and natural gas are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, worldwide economic conditions, weather conditions, currency exchange rates, and political conditions in major oil producing regions, especially the Middle East. A significant decrease in price levels for an extended period would negatively affect us in several ways:

- our cash flow would be reduced, decreasing funds available for capital expenditures employed to increase production or replace reserves;
- certain reserves would no longer be economic to produce, leading to both lower cash flow and proved reserves;
- our lenders could reduce the borrowing base under our bank credit facility because of lower oil and natural gas reserves values, reducing our liquidity and possibly requiring mandatory loan repayments; and
- access to other sources of capital, such as equity or long term debt markets, could be severely limited or unavailable in a low price environment.

Consequently, our revenues and profitability would suffer.

Our level of debt could reduce our financial flexibility, and we currently have the ability to incur substantially more debt, including secured debt.

As of December 31, 2006, our total debt comprised approximately 32% of our total capitalization. Although our bank credit facility and indentures limit our ability and the ability of our restricted subsidiaries to incur additional indebtedness, we will be permitted to incur significant additional indebtedness, including secured indebtedness, in the future if specified conditions are satisfied. All borrowings under our bank credit facility are effectively senior to our outstanding 7-5/8% senior notes and 9-3/8% senior subordinated notes to the extent of the value of the collateral securing those borrowings. Our level of indebtedness could negatively affect us in several ways:

- require us to dedicate a substantial portion of our cash flow to the payment of interest;

- subject us to a higher financial risk in an economic downturn due to substantial debt service costs;

- limit our ability to obtain financing or raise equity capital in the future; and

- place us at a competitive disadvantage to the extent that we are more highly leveraged than some of our peers.

Higher levels of indebtedness would increase these risks.

Estimates of poved reserves are uncertain, and revenues from production may vary significantly from expectations.

The quantities and values of our proved reserves included in this report are only estimates and subject to numerous uncertainties. Estimates by other engineers might differ materially. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation. These estimates depend on assumptions regarding quantities and production rates of recoverable oil and natural gas reserves, future prices for oil and natural gas, timing and amounts of development expenditures and operating expenses, all of which will vary from those assumed in our estimates. These variances may be significant.

Any significant variance from the assumptions used could result in the actual amounts of oil and natural gas ultimately recovered and future net cash flows being materially different from the estimates in our reserves reports. In addition, results of drilling, testing, production, and changes in prices after the date of the estimates of our reserves may result in substantial downward revisions. These estimates may not accurately predict the present value of net cash flows from our oil and natural gas reserves.

At December 31, 2006, approximately 56% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserves data assumes that we can and will make these expenditures and conduct these operations successfully, which may not occur.

If we cannot replace our reserves, our revenues and financial condition will suffer.

Unless we successfully replace our reserves, our long- term production will decline, which could result in lower revenues and cash flow. When oil and natural gas prices decrease, our cash flow decreases, resulting in less available cash to drill and replace our reserves and an increased need to draw on our bank credit facility. Even if we have the capital to drill, unsuccessful wells can hurt our efforts to replace reserves. Additionally, lower oil and natural gas prices can have the effect of lowering our reserves estimates and the number of economically viable prospects that we have to drill.

Drilling wells is speculative and capital intensive.

Developing and exploring properties for oil and natural gas requires significant capital expenditures and involves a high degree of financial risk, including the risk that no commercially productive oil or gas reservoirs will be encountered. The budgeted costs of drilling, completing, and operating wells are often exceeded and can increse significantly when drilling costs rise. Drilling may be unsuccessful for many reasons, including title problems, weather, cost overruns, equipment shortages, and mechanical difficulties. Moreover, the successful drilling or completion of an oil or gas well does not ensure a profit on investment. Exploratory wells bear a much greater risk of loss than development wells.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition, or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

o hurricanes or tropical storms;

o environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas, or other pollution into the environment, including groundwater and shoreline contamination;

o abnormally pressured formations;

o mechanical difficulties, such as stuck oil field drilling and service. tools and casing collapse;

o fires and explosions;

o personal injuries and death; and

o natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect our financial condition.

We have incurred a write-down of the carrying values of our properties in the past and could incur additional write-downs in the future.

Under the full cost method of accounting, SEC accounting rules require that on a quarterly basis we review the carrying value of our oil and gas properties on a country-by-country basis for possible write-down or impairment. Under these rules, capitalized costs of proved reserves may not exceed a ceiling calculated as the present value of estimated future net revenues from those proved reserves, determined using a 10% per year discount and unescalated prices in effect as of the end of each fiscal quarter. Capital costs in excess of the ceiling must be permanently written down.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

To finance acquisitions, we may need to substantially alter or increase our capitalization through the use of our bank credit facility, the issuance of debt or equity securities, the sale of production payments, or by other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for any such acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Reserves on acquired properties may not meet our expectations, and we may be unable to identify liabilities associated with acquired properties or obtain protection from sellers against associated liabilities.

Property acquisition decisions are based on various assumptions and subjective judgments that are speculative. Although available geological and geophysical information can provide information about the potential of a property, it is impossible to predict accurately a property's production and profitability. In addition, we may have difficulty integrating future acquisitions into our operations, and they may not achieve our desired profitability objectives. Likewise, as is customary in the industry, we generally acquire oil and gas acreage without any warranty of title except through the transferor. In many instances, title opinions are not obtained if, in our judgment, it would be uneconomical or impractical to do so. Losses may result from title defects or from defects in the assignment of leasehold rights. While our current operations are primarily in Louisiana, Texas, and New Zealand, we may pursue acquisitions of properties located in other geographic areas, which would decrease our geographical concentration, and could also be in areas in which we have no or limited experience.

In addition, our assessment of acquired properties may not reveal all existing or potential problems or liabilities, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform, or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of acquired properties in addition to the risk that the properties may not perform in accordance with our expectations.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities, if at all, to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects, or producing fields will be applicable to our drilling prospects. In addition, a variety of factors, including geological and market-related, can cause a well to become uneconomical or only marginally economical. For example, if oil and natural gas prices are much lower after we complete a well than when we identified it as a prospect, the completed well may not yield commercially viable quantities.

In many instances, title opinions on our oil and gas acreage are not obtained if in our judgment it would be uneconomical or impractical to do so.

As is customary in the industry, we generally acquire oil and gas acreage without any warranty of title except as to claims made by, through, or under the transferor. Although we have title to developed acreage examined prior to acquisition in those cases in which the economic significance of the acreage justifies the cost, there can be no assurance that losses will not result from title defects or from defects in the assignment of leasehold rights.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit future revenues from price increases and expose us to risk of financial loss.

We enter into hedging transactions for our oil and natural gas production to reduce exposure to fluctuations in the price of oil and natural gas, primarily to protect against declines in prices. Our hedges at year-end 2006 consisted of natural gas price floors with strike prices higher than the period end prices. Our hedging transactions have also historically consisted of financially settled crude oil and natural gas forward sales contracts with major financial institutions as well as crude oil price floors. We intend to continue to enter into these types of hedging transactions in the foreseeable future. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations, or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions other than floors may limit the benefit we would have otherwise received from increases in the price for oil and natural gas. Additionally, hedging transactions other than floors may expose us to cash margin requirements.

We may have difficulty competing for oil and gas properties or supplies.

We operate in a highly competitive environment, competing with major integrated and independent energy companies for desirable oil and gas properties, as well as for the equipment, labor, and materials required to develop and operate such properties. Many of these competitors have financial and technological resources substantially greater than ours. The market for oil and gas properties is highly competitive and we may lack technological information or expertise available to other bidders. We may incur higher costs or be unable to acquire and develop desirable properties at costs we consider reasonable because of this competition.

Our business depends on oil and natural gas transportation facilities, some of which are owned by others.

The marketability of our oil and natural gas production depends in part on the availability, proximity, and capacity of pipeline systems owned by third parties. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

Governmental laws and egulations are costly and stringent, especially those relating to environmental protection.

Our domestic exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing the discharge of substances into the environment or otherwise relating to environmental protection. These laws and regulations affect the costs, manner, and feasibility of our operations and require us to make significant expenditures in our efforts to comply. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial obligations, and the issuance of injunctions that could limit or prohibit our operations. In addition, some of these laws and regulations may impose joint and several, strict liability for contamination resulting from spills, discharges, and releases of substances, including petroleum hydrocarbons and other wastes, without regard to fault or the legality of the original conduct. Under such laws and regulations, we could be required to remove or remediate previously disposed substances and property contamination, including wastes disposed or released by prior owners or operations. Changes in or additions to environmental laws and regulations occur frequently, and any changes or additions that result in more stringent and costly waste handling, storage, transport, disposal, or cleanup requirements could have a material adverse effect our operations and financial position.

Our operations outside of the United States could also be subject to similar foreign governmental controls and restrictions pertaining to protection of human health and the environment. These controls and restrictions may include the need to acquire permits, prohibitions on drilling in certain environmentally sensitive areas, performance of investigatory or remedial actions for any releases of petroleum hydrocarbons or other wastes caused by us or prior owners or operators, closure, and restoration of facility sites, and payment of penalties for violations of applicable laws and regulations.

We are exposed to the risk of fluctuations in foreign currencies, primarily the New Zealand dollar.

Fluctuations in rates between the New Zealand dollar and U.S. dollar impact our financial results from our New Zealand subsidiaries since we have receivables, liabilities, and natural gas and NGL sales contracts denominated in New Zealand dollars. New Zealand income taxes are also computed in New Zealand dollars. We do not hedge against the risks associated with fluctuations in exchange rates. Although we may use hedging techniques in the future, we may not be able to eliminate or reduce the effects of currency fluctuations. As a result, exchange rate fluctuations could have an adverse impact on our operating results.

Item 1B. Unresolved Staff Comments

None.

Glossary of Abbreviations and Terms

The following abbreviations and terms have the indicated meanings when used in this report:

Bbl -- Barrel or barrels of oil.

Bcf -- Billion cubic feet of natural gas.

Bcfe -- Billion cubic feet of natural gas equivalent (see Mcfe).

BOE -- Barrels of oil equivalent.

Development Well -- A well drilled within the presently proved productive area of an oil or natural gas reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.

Discovery Cost -- With respect to proved reserves, a three-year average (unless otherwise indicated) calculated by dividing total incurred exploration and development costs (exclusive of future development costs) by net reserves added during the period through extensions, discoveries, and other additions.

Dry Well -- An exploratory or development well that is not a producing well.

EBITDA -- Earnings before interest, taxes, depreciation, depletion and amortization.

EBITDAX -- Earnings before interest, taxes, depreciation, depletion and amortization, and exploration expenses. Since Swift uses full-cost accounting for oil and property expenditures, as noted in footnote one of the accompanying consolidated financial statements, exploration expenses are not applicable to Swift.

Exploratory Well -- A well drilled either in search of a new, as yet undiscovered oil or natural gas reservoir or to greatly extend the known limits of a previously discovered reservoir.

FASB -- The Financial Accounting Standards Board.

Gross Acre -- An acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

Gross Well -- A well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned.

MBbl -- Thousand barrels of oil.

Mcf -- Thousand cubic feet of natural gas.

Mcfe -- Thousand cubic feet of natural gas equivalent, which is determined using the ratio of one barrel of oil, condensate, or natural gas liquids to 6 Mcf of natural gas.

MMBbl -- Million barrels of oil.

MMBtu -- Million British thermal units, which is a heating equivalent measure for natural gas and is an alternate measure of natural gas reserves, as opposed to Mcf, which is strictly a measure of natural gas volumes. Typically, prices quoted for natural gas are designated as price per MMBtu, the same basis on which natural gas is contracted for sale.

MMcf -- Million cubic feet of natural gas.

MMcfe -- Million cubic feet of natural gas equivalent (see Mcfe).

Net Acre -- A net acre is deemed to exist when the sum of fractional working interests owned in gross acres equals one. The number of net acres is the sum of fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Net Well -- A net well is deemed to exist when the sum of fractional working interests owned in gross wells equals one. The number of net wells is the sum of fractional working interests owned in gross wells expressed as whole numbers and fractions thereof.

NGL-- Natural gas liquid.

Producing Well -- An exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

* Proved Developed Oil and Gas Reserves -- Reserves that can be expected to be recovered through existing wells with existing equipment and operating

methods.

* Proved Oil and Gas Reserves -- The estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made.

* Proved Undeveloped Oil and Gas Reserves -- Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Proved Undeveloped (PUD) Locations -- A location containing proved undeveloped reserves.

PV-10 Value -- The estimated future net revenues to be generated from the production of proved reserves discounted to present value using an annual discount rate of 10%. These amounts are calculated net of estimated production costs and future development costs, using prices and costs in effect as of a certain date, without escalation and without giving effect to non-property related expenses, such as general and administrative expenses, debt service, future income tax expense, or depreciation, depletion, and amortization.

Reserves Replacement Cost -- With respect to proved reserves, a three-year average (unless otherwise indicated) calculated by dividing total incurred acquisition, exploration, and development costs (exclusive of future development costs) by net reserves added during the period.

SFAS -- Statement of Financial Accounting Standards.

TAWN -- New Zealand producing properties acquired by Swift in January 2002. TAWN is comprised of the Tariki, Ahuroa, Waihapa, and Ngaere fields.

* These definitions regarding various types of proved reserves are only abbreviated versions of the Securities and Exchange Commission's definitions of these terms contained in Rule 4-10(a) of Regulation S-X. See www.sec.gov/divisions/corpfin/forms/regsx.htm#gas for the full text of the SEC's definitions of these terms.

Item 3. Legal Proceedings

No material legal proceedings are pending other than ordinary, routine litigation and claims incidental to our business.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted during the fourth quarter of 2006 to a vote of security holders.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Common Stock, 2005 and 2006

Our common stock is traded on the New York Stock Exchange under the symbol "SFY." The high and low quarterly closing sales prices for the common stock for 2005 and 2006 were as follows:

	2005				2006			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$24.77	$26.22	$37.31	$39.82	$35.48	$35.61	$40.06	$39.10
High	$30.64	$36.75	$48.86	$50.01	$49.50	$45.22	$48.00	$51.84

Since inception, no cash dividends have been declared on our common stock. Cash dividends are restricted under the terms of our credit agreements, as discussed in Note 4 to the consolidated financial statements, and we presently intend to continue a policy of using retained earnings for expansion of our business.

We had approximately 252 stockholders of record as of December 31, 2006.

Equity Compensation Plan Information

Information regarding our equity compensation plans, including both shareholder approved plans and plans not approved by shareholders, is set forth in the Proxy Statement for our annual meeting to be held May 8, 2007 ("Proxy Statement"), which Proxy Statement is to be filed within 120 days after Registrant's fiscal year end of December 31, 2006, and which information is incorporated herein by reference.

Share Performance Graph

The following Share Performance Graph shall not be deemed to be "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filings under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

Date*	Transaction Type	Closing Price**	Beginning No. Of Shares***	Dividend per Share	Dividend Paid	Shares Reinvested	Ending Shares
31-Dec-01	Begin	20.200	4.95				4.950
31-Dec-02	Year End	9.670	4.95				4.950
31-Dec-03	Year End	16.850	4.95				4.950

31-Dec-04	Year End	28.940	4.95	4.950
31-Dec-05	Year End	45.070	4.95	4.950
31-Dec-06	End	44.810	4.95	4.950

* Specified ending dates or ex-dividends dates.
** All Closing Prices and Dividends are adjusted for stock splits and stock dividends.
***'Begin Shares' based on $100 investment.

[GRAPHIC OMITTED]

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Item 6. Selected Financial Data

	2006	2005	2004	
Total Revenues	$615,441,230	$423,226,489	$310,276,774	$
Income (Loss) Before Income Taxes and Change in Accounting Principle (1)	$262,286,165	$178,439,551	$101,440,242	
Net Income (Loss)	$161,565,340	$115,778,456	$68,450,917	
Net Cash Provided by Operating Activities	$424,921,046	$285,333,484	$182,582,887	$
Per Share Data				
Weighted Average Shares Outstanding(1)	29,265,366	28,496,275	27,822,413	
Earnings (Loss) per Share--Basic(1)	$5.52	$4.06	$2.46	
Earnings (Loss) per Share--Diluted(1)	$5.38	$3.95	$2.41	
Shares Outstanding at Year-End	29,742,918	29,009,530	28,089,764	
Book Value per Share at Year-End	$26.83	$20.94	$16.88	
Market Price(1)				
High	$51.84	$50.01	$30.34	
Low	$35.48	$24.77	$15.90	
Year-End Close	$44.81	$45.07	$28.94	
Effect on Net Income and Earnings Per Share From Changes in Accounting Principles (2)				
Cumulative Effect of Change in Accounting Principle (Net of Taxes)	---	---	---	
Effect per Share--Basic	---	---	---	
Effect per Share--Diluted	---	---	---	
Assets				
Current Assets	$92,573,041	$115,055,135	$54,385,996	
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	$1,483,312,165	$1,079,033,739	$923,438,160	$
Total Assets	$1,585,681,758	$1,204,412,622	$990,573,147	$

Liabilities				
Current Liabilities	$145,975,288	$98,421,014	$68,618,291	
Long-Term Debt	$381,400,000	$350,000,000	$357,500,000	$
Total Liabilities	$787,764,786	$597,094,455	$516,401,007	$
Stockholders' Equity	$797,916,972	$607,318,167	$474,172,140	$
Number of Employees	345	311	272	
Producing Wells				
Swift Operated	973	898	835	
Outside Operated	112	69	97	
Total Producing Wells	1,085	967	932	
Wells Drilled (Gross)	63	64	66	
Proved Reserves				
Natural Gas (Mcf)	324,131,417	287,473,150	318,246,294	
Oil, NGL, & Condensate (barrels)	82,119,084	79,053,056	80,267,208	
Total Proved Reserves (Mcf equivalent)	816,845,916	761,791,482	799,849,539	
Production (Mcf equivalent)(3)	70,204,544	59,589,526	58,318,502	
Average Sales Price				
Natural Gas (per Mcf)	$5.05	$5.23	$4.12	
Natural Gas Liquids (per barrel)(4)	$32.15	$28.04	$22.52	
Oil (per barrel)(4)	$64.47	$53.63	$40.24	
Mcf Equivalent	$8.57	$7.11	$5.34	

(1)Amounts have been retroactively restated in all periods presented to give recognition to: (a) the adoption in 1998 of Statement of Financial Accounting Standards No. 128, "Earnings per Share," and (b) the adoption in 2003 of Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections," which affected our presentation of 1999 results by reclassifying the loss on early extinguishment of debt from an extraordinary item to an operating item.

(2)We adopted SFAS No. 143, "Accounting for Asset Retirement Obligations" on January 1, 2003. We adopted SFAS No. 133 "Accounting for Derivative Instruments and Hedging Transactions" on January 1, 2001.

(3)Natural gas production from 1996 to 2000 includes volumes under a production payment agreement ranging from 1.2 Bcfe in 1996 to 0.4 Bcfe in 2000.

(4)Prior to 2002, we combined NGLs with natural gas for reporting purposes.

2001	2000	1999	1998	1997	1996
$183,807,490	$191,624,946	$110,671,007	$82,469,221	$74,712,180	$56,298,026

($34,192,333)	92,449,488	$29,736,151	($73,391,581)	$33,129,606	$28,785,783
($22,347,765)	$59,184,008	$19,286,574	($48,225,204)	$22,310,189	$19,025,450
$139,884,255	$128,197,227	$73,603,426	$54,249,017	$55,255,965	$37,102,578
24,732,099	21,244,684	18,050,106	16,436,972	16,492,856	15,000,901
($0.90)	$2.79	$1.07	($2.93)	$1.35	$1.27
($0.90)	$2.51	$1.07	($2.93)	$1.26	$1.25
24,795,564	24,608,344	20,823,729	16,291,242	16,459,156	15,176,417
$12.61	$13.50	$8.18	$6.71	$9.69	$9.41
$37.70	$43.50	$13.31	$21.00	$34.20	$28.86
$16.66	$9.75	$5.69	$6.94	$16.93	$9.89
$20.20	$37.63	$11.50	$7.38	$21.06	$27.16
($392,868)	---	---	---	---	---
($0.01)	---	---	---	---	---
($0.01)	---	---	---	---	---
$36,752,980	$41,872,879	$50,605,488	$35,246,431	$29,981,786	$101,619,478
$628,304,060	$524,052,828	$392,986,589	$356,711,711	$301,312,847	$200,010,375
$671,684,833	$572,387,001	$454,299,414	$403,645,267	$339,115,390	$310,375,264
$73,245,335	$64,324,771	$34,070,085	$31,415,054	$28,517,664	$32,915,616
$258,197,128	$134,729,485	$239,068,423	$261,200,000	$122,915,000	$115,000,000
$359,032,113	$240,232,846	$283,895,297	$294,282,628	$179,714,470	$167,613,654
$312,652,720	$332,154,155	$170,404,117	$109,362,639	$159,400,920	$142,761,610
209	181	173	203	194	191
854	817	769	836	650	842
381	711	788	917	917	986
1,235	1,528	1,557	1,753	1,567	1,828
53	70	27	75	182	153
324,912,125	418,613,976	329,959,750	352,400,835	314,305,669	225,758,201
53,482,636	35,133,596	20,806,263	13,957,925	7,858,918	5,484,309
645,807,939	629,415,552	454,797,327	436,148,385	361,459,177	258,664,055
44,791,202	42,356,705	42,874,303	39,030,030	25,393,744	19,437,114
$4.23	$4.24	$2.40	$2.08	$2.68	$2.57
---	---	---	---	---	---
$22.64	$29.35	$16.75	$11.86	$17.59	$19.82

$4.05	$4.47	$2.54	$2.05	$2.72	$2.71

Item 7. Management's Discussion and Analysis of
Financial Condition and Results of Operations

You should read the following discussion and analysis in conjunction with our financial information and our audited consolidated financial statements and accompanying notes for the years ended December 31, 2006, 2005, and 2004 included with this report. The following information contains forward-looking statement;, see "Forward-Looking Statements" on page 45 of this report.

Overview

Swift Energy had record net income, cash flow, and production for 2006. Net income increased 40% to $161.6 million and cash flow from operations increased 49% to $425 million, in each case compared to 2005 amounts. Production increased 18% to 70.2 Bcfe over hurricane affected production a year earlier, principally attributable to our continued success in Lake Washington, with our 2006 production increase matching in one year our cumulative production increase over the prior three years. We ended 2006 with total proved reserves of 817 Bcfe, an increase of 7% over year-end 2005 reserves. We also had record revenues of $615.4 million for 2006, an increase of 45% over 2005 levels. Our weighted average sales price increased 20% to $8.57 per Mcfe for 2006 from $7.11 in 2005. Of our $177.8 million increase in oil and gas sales revenues, 60% came from a 2.0 million barrel increase in oil volumes produced, with the remainder attributable to higher oil prices during 2006.

Our capital expenditures more than doubled from 2005 to 2006, principally due to our acquisition of five substantial onshore properties in South Louisiana from BP America Production Company for $167.9 million in cash and the increase in our spending on drilling and development, predominantly in our South Louisiana region. Although the acquisition did not appreciably add to our 2006 production volumes, it added 58 Bcfe of proved reserves, about one-third of which were proved undeveloped, resulting in our proved undeveloped reserves increasing to 56% of total reserves at year-end 2006, compared to 50% the previous year.

Our overall costs and expenses increased in 2006 by 44%. In 2007, we will focus upon our capital efficiency by managing our costs and expenses, always a difficult task in the inflationary cost environment prevalent in the industry over the last several years, and especially over the last year when recent declines in commodity prices have not been matched by comparable declines in prices of oilfield equipment and services. The largest increase in these costs and expenses is due to increased depreciation, depletion and amortization expense, not only due to our larger depletable property base and higher production, but also due to increases in future development costs to reflect industry inflation. We expect cost pressures to continue to affect the industry throughout 2007, with tightening availability of crews as well as increasing costs of services and basic equipment.

Our year-end 2006 proved reserves were 50% crude oil, 40% natural gas, and 10% NGLs, almost identical to the percentage splits a year earlier. Our 2006 production, however, was 61% crude oil, up from 52% in 2005, which allowed us to take advantage of the over 20% increase in oil prices, while natural gas prices fell during the year. Domestic proved reserves increased at year-end 2006 to 710.4 Bcfe (87% of our total proved reserves), while proved reserves in New Zealand decreased to 106.4 Bcfe at year-end 2006, primarily attributable to 2006 production. For 2007, we are considering conducting an expanded 3-D seismic survey in New Zealand prior to continuing drilling activities.

Our financial position remains strong. Our debt to capitalization ratio was 32% at December 31, 2006, compared to 37% at year-end 2005, as debt levels increased in 2006 and retained earnings increased as a result of the current period profit, with net debt per Mcfe of $0.47 per Mcfe at year-end 2006. Our debt to PV-10 ratio increased to 14% at December 31, 2006 compared to 11% at December 31, 2005, primarily due to lower natural gas prices at year-end 2006 and an increase in our total debt, partially offset by higher oil and natural gas reserves volumes. Lower year-end commodity prices, principally natural gas, decreased our PV-10 value and standardized measure at the end of 2006 compared to the prior year-end.

Our current 2007 capital expenditure budget is $350 million to $400 million, net of minor non-core dispositions and excluding any property acquisitions. Approximately 95% of the budget is targeted for domestic activities, predominantly in our South Louisiana region, with about 5% planned for activities in the New Zealand region. For 2007, we are targeting total production to increase 7% to 10% and proved reserves to increase 4% to 6% over 2006 levels. We may also increase our capital expenditure budget if commodity

prices rise during the year or if strategic opportunities warrant. If 2007 capital expenditures exceed our cash flow from operating activities, we can fund these expenditures with our credit facility to fund these expenditures.

During 2007, we plan to further develop our inventory of properties in South Louisiana using our expertise and experience gained in expanding and producing in Lake Washington, together with significant 3-D seismic information, to exploit our other prospect areas covered by similar geological features. This broad prospect inventory will allow us to be selective in choosing drilling opportunities so we can create long-life reserves while at the same time raising our production significantly, which we did during 2006 mainly through organic production growth.

Results of Operations -- Years Ended 2006, 2005, and 2004

Revenues. Our revenues in 2006 increased by 45% compared to revenues in 2005 primarily due to increases in oil production from our Lake Washington area and increases in oil prices, and our revenues in 2005 increased by 36% compared to 2004 revenues due primarily to increases in oil and natural gas prices and in production from our Lake Washington and Rimu/Kauri areas. Revenues from our oil and gas sales comprised substantially all of total revenues for 2006, 2005, and 2004. Crude oil production was 61% of our production volumes in 2006, 52% in 2005, and 49% in 2004. Natural gas production was 32% of our production volumes in 2006, 40% in 2005, and 41% in 2004. Domestic production was 81% of our total production volumes in 2006, and 72% in both 2005 and 2004.

The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the years ended December 31, 2006, 2005, and 2004:

Area	Oil and Gas Sales (In millions) 2006	2005	2004	200
AWP Olmos	$ 53.7	$ 61.7	$ 49.9	7
Brookeland	15.6	20.4	18.0	2
Lake Washington	397.2	229.2	152.3	38
Masters Creek	13.3	17.9	21.0	1
Cote Blanche Island/Bay de Chene	29.3	7.4	0.0	3
Other	28.4	19.3	17.5	3
Total Domestic	$ 537.5	$ 355.9	$ 258.7	56
Rimu/Kauri	36.8	41.6	24.5	6
TAWN	27.2	26.3	28.1	7
Total New Zealand	$ 64.0	$ 67.9	$ 52.6	13
Total	$ 601.6	$ 423.8	$ 311.3	70

Oil and gas sales in 2006 increased by 42%, or $177.8 million, from the level of those revenues for 2005, and our net sales volumes in 2006 increased by 18%, or 10.6 Bcfe, over net sales volumes in 2005. Average prices for oil increased to $64.47 per Bbl in 2006 from $53.63 per Bbl in 2005. Average natural gas prices decreased to $5.05 per Mcf in 2006 from $5.23 per Mcf in 2005. Average NGL prices increased to $32.15 per Bbl in 2006 from $28.04 per Bbl in 2005.

In 2006, our $177.8 million increase in oil, NGL, and natural gas sales resulted from:

- Volume variances that had a $101.1 million favorable impact on sales, with $108.9 million of increases attributable to the 2.0 million Bbl increase in oil sales volumes, offset by a decrease of $3.5 million due to the 0.1 million Bbl decrease in NGL sales volumes, and a decrease of $4.3 million due to the 0.8 Bcf decrease in natural gas sales volumes; and

- Price variances that had a $76.7 million favorable impact on sales, of which $78.0 million was attributable to the 20% increase in average oil prices received, and $2.9 million was attributable to the 15% increase in NGL prices, offset by a decrease of $4.2 million attributable to the 3% decrease in natural gas prices.

Oil and gas sales in 2005 increased by 36%, or $112.5 million, from the level of those revenues for 2004, and our net sales volumes in 2005 increased by 2%, or 1.3 Bcfe, over net sales volumes in 2004. Average prices for oil increased to $53.63 per Bbl in 2005 from $40.24 per Bbl in 2004. Average natural gas prices increased to $5.23 per Mcf in 2005 from $4.12 per Mcf in 2004.

Average NGL prices increased to $28.04 per Bbl in 2005 from $22.52 per Bbl in 2004.

In 2005, our $112.5 million increase in oil, NGL, and natural gas sales resulted from:

- o Price variances that had a $100.0 million favorable impact on sales, of which $69.1 million was attributable to the 33% increase in average oil prices received, $26.3 million was attributable to the 27% increase in natural gas prices and $4.6 million was attributable to the 24% increase in NGL prices; and

- o Volume variances that had a $12.5 million favorable impact on sales, with $17.6 million of increases attributable to the 0.4 million Bbl increase in oil sales volumes, offset by a decrease of $4.6 million due to the 0.2 million Bbl decrease in NGL sales volumes, and a decrease of $0.5 million due to the 0.1 Bcf decrease in natural gas sales volumes.

The following table provides additional information regarding our quarterly oil and gas sales:

	Sales Volume				Average Sales	
	Oil	NGL	Gas	Combined	Oil	NGL
	(MBbl)	(MBbl)	(Bcf)	(Bcfe)	(Bbl)	(Bbl)
2004:						
First....................	1,124	277	5.9	14.3	$ 34.14	$ 22.3
Second...................	1,142	269	5.8	14.3	$ 37.24	$ 18.8
Third....................	1,076	251	6.0	13.9	$ 41.99	$ 23.3
Fourth...................	1,380	243	6.1	15.9	$ 46.33	$ 26.0
Total................	4,722	1,040	23.7	58.3	$ 40.24	$ 22.5
2005:						
First....................	1,321	223	6.3	15.5	$ 47.66	$ 26.7
Second...................	1,426	209	6.1	15.9	$ 50.24	$ 22.9
Third....................	1,059	204	5.9	13.5	$ 59.66	$ 31.8
Fourth...................	1,353	202	5.3	14.7	$ 58.31	$ 30.8
Total................	5,159	838	23.6	59.6	$ 53.63	$ 28.0
2006:						
First....................	1,611	152	6.0	16.5	$ 60.83	$ 30.3
Second...................	1,636	138	5.6	16.3	$ 69.63	$ 29.7
Third....................	1,992	220	5.5	18.8	$ 69.62	$ 36.1
Fourth...................	1,951	203	5.7	18.6	$ 57.88	$ 30.7
Total................	7,190	713	22.8	70.2	$ 64.47	$ 32.1

In 2006, we settled all insurance claims with our insurers relating to hurricanes Katrina and Rita for approximately $30.5 million and entered into a confidential final settlement agreement. The receipt of these amounts resulted in a benefit of $7.7 million in 2006 recorded in "Price-risk management and other, net," for the portion of the above referenced settlement, which we have determined to be non-property damage related claims. Approximately $22.8 million of the above referenced settlement was determined to be property damage related claims. We recorded $14.1 million of the property related settlement as a reduction to "Proved properties" on the accompanying consolidated balance sheet, as this related to reimbursement of capital costs we incurred. We also recorded $8.7 million of the property related settlement as a reduction to "Lease operating cost" on the accompanying consolidated statement of income, as this related to reimbursement of repair costs which had been expensed as incurred. In the accompanying consolidated statement of cash flows, we have recorded the reimbursement which reduced "Proved properties" as a reduction of "Net Cash Used in Investing Activities" and the remainder of the insurance settlement was recorded as an increase to "Net Cash Provided by Operating Activities."

Costs and Expenses. Our expenses in 2006 increased $108.4 million, or 44%, compared to 2005 expenses. The majority of the increase was due to a $61.8 million increase in DD&A, a $23.3 million increase in severance and other taxes, and a $15.2 million increase in lease operating costs, all of which are primarily due to increased production volumes in 2006. Increased commodity prices also increased severance and other taxes, and higher full cost pool

balances increased DD&A, offset somewhat by increased reserves volumes in 2006. Our expenses in 2005 increased $36.0 million, or 17%, compared to 2004 expenses. The majority of the increase was due to a $25.9 million increase in DD&A, an $11.8 million increase in severance and other taxes, and a $6.1 million increase in lease operating costs, all of which are primarily due to increased commodity prices and production volumes in 2005. This increase was partially offset by the absence of $9.5 million of debt retirement costs incurred in 2004.

Our 2006 general and administrative expenses, net, increased $9.1 million, or 41%, from the level of such expenses in 2005, while 2005 general and administrative expenses, net, increased $4.4 million, or 25%, over 2004 levels. The increase in both 2006 and 2005 were primarily due to increased salaries and burdens associated with our expanded workforce. Costs also increased in 2006 as a result of expensing stock options and increased restricted stock grants, and increased in 2005 due to restricted stock compensation. For the years 2006, 2005, and 2004, our capitalized general and administrative costs totaled $28.3 million, $18.8 million, and $13.1 million, respectively. Our net general and administrative expenses per Mcfe produced increased to $0.45 per Mcfe in 2006 from $0.37 per Mcfe in 2005 and $0.30 per Mcfe in 2004. The portion of supervision fees recorded as a reduction to general and administrative expenses was $8.8 million for 2006, $7.8 million for 2005, and 5.8 million for 2004.

DD&A increased $61.8 million, or 58%, in 2006 from 2005 levels, while 2005 DD&A increased $25.9 million, or 32%, from 2004 levels. Domestically, DD&A increased $58.1 million in 2006 due to increases in the depletable oil and gas property base and higher production, partially offset by higher reserves volumes. In New Zealand, DD&A increased by $3.7 million in 2006 due to an increase in the depletable oil and gas property base and lower reserves. In 2005, our domestic DD&A increased $18.8 million due to increases in the depletable oil and gas property base, slightly higher production in the 2005 period and lower reserves volumes. In New Zealand, DD&A increased by $7.1 million in 2005 due to the same reasons. Our DD&A rate per Mcfe of production was $2.41 in 2006, $1.80 in 2005, and $1.40 in 2004, resulting from increases in per unit cost of reserves additions.

We recorded $1.0 million, $0.8 million, and $0.7 million of accretions to our asset retirement obligation in 2006, 2005, and 2004, respectively.

Our lease operating costs per Mcfe produced were $0.89 in 2006, $0.79 in 2005 and $0.71 in 2004. Our lease operating costs in 2006 increased $15.2 million, or 32%, over the level of such expenses in 2005, while 2005 costs increased $6.1 million, or 15% over 2004 levels. Approximately $15.0 million of the increase in lease operating costs during 2006 was related to our domestic operations, which increased primarily due to increased production and was also impacted by increased well insurance premiums. Our lease operating cost in New Zealand increased in 2006 by $0.1 million due to increases in well operating costs and storage and handling costs.

Severance and other taxes increased $23.3 million, or 55%, over 2005 levels, while in 2005 these taxes increased $11.8 million, or 39% over 2004 levels. The increases were due primarily to higher commodity prices and increased Lake Washington production in each of the periods. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than in the other states where we have production. As our percentage of oil production in Louisiana increases, the overall percentage of severance costs to sales also increases. Severance and other taxes, as a percentage of oil and gas sales, were approximately 10.9%, 10.0% and 9.8% in 2006, 2005 and 2004, respectively.

Our total interest cost in 2006 was $32.8 million, of which $9.2 million was capitalized. Our total interest cost in 2005 was $32.1 million, of which $7.2 million was capitalized. Our total interest cost in 2004 was $34.2 million, of which $6.5 million was capitalized. Interest expense on our 7-5/8% senior notes due 2011 issued in June 2004, including amortization of debt issuance costs, totaled $11.9 million in both 2006 and 2005 and $6.2 million in 2004. Interest expense on our 9-3/8% senior subordinated notes due 2012 issued in April 2002, including amortization of debt issuance costs, totaled the same $19.2 million in 2006, 2005, and 2004. Interest expense on our 10-1/4% senior subordinated notes issued in August 1999 and repurchased and retired in 2004, including amortization of debt issuance costs, totaled $7.4 million in 2004. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.5 million in 2006, $1.0 million in 2005, and $1.5 million in 2004. Other interest cost was $0.1 million in 2006. We capitalize a portion of interest related to unproved properties. The decrease of interest expense in 2006 was primarily due to an increase in capitalized interest costs, partially offset by an increase in credit facility interest. The decrease of interest expense in 2005 was primarily due to the lower interest rate applicable to the 7-5/8% notes issued in June 2004 versus the 10-1/4% notes retired at that time.

In 2004, we incurred $9.5 million of debt retirement costs related to the repurchase and redemption of our 10-1/4% senior subordinated notes due 2009. The

costs were comprised of approximately $6.5 million of premiums paid to repurchase the notes, $2.2 million to write-off unamortized debt issuance costs, $0.6 million to write-off unamortized debt discount and approximately $0.2 million of other costs.

Our overall effective tax rate was 38.4% for 2006, 35.1% for 2005 and 32.5% for 2004. The effective tax rate for 2006 was higher than the statutory rate primarily because of state income taxes and a valuation allowance, partially offset by favorable adjustments for the currency effect on the New Zealand deferred tax calculation. For 2005, the effective rate was about the same as the statutory rate as state income taxes and the currency effect adjustments essentially offset. For 2004, the effective rate was less than the statutory rate due to favorable adjustments for currency effect and corrections to tax basis amounts, partially offset by deferred state income taxes.

Net Income. Our net income in 2006 of $161.6 million was 40% higher than our 2005 net income of $115.8 million due to higher oil prices and increased production.

Our net income in 2005 of $115.8 million was 69% higher than our 2004 net income of $68.5 million due to higher commodity prices and increased production.

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter as of December 31, 2006 are as follows:

	2007	2008	2009	2010	20
				(In thousands)	
Non-cancelable operating leases(1)................	$ 5,345	$ 5,321	$ 3,334	$ 3,293	$ 3
Asset retirement obligation(2)....................	1,650	2,313	2,019	2,110	2
Computer System Implementation...................	3,261	--	--	--	
Construction costs.............................	5,223	--	--	--	
Drilling rigs, seismic and pipe inventory.........	28,873	--	--	--	
7-5/8% senior notes due 2011(3)..................	--	--	--	--	150
9-3/8% senior subordinated notes due 2012(3)......	--	--	--	--	
Credit facility(4)..............................	--	--	--	--	31
Total..	$ 44,352	$ 7,634	$ 5,353	$ 5,403	$ 18

(1) Our most significant office lease is in Houston, Texas and it extends until 2015.

(2) Amounts shown by year are the fair values at December 31, 2006.

(3) Amounts do not include the interest obligation, which is paid semiannually.

(4) The credit facility expires in October 2011 and these amounts exclude a $0.8 million standby letter of credit outstanding under this facility.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and are expected to continue to be volatile in the future. The price of oil has increased over the last two years and is at historical highs when compared to longer-term historical prices. Factors such as worldwide supply disruptions, worldwide economic conditions, weather conditions, fluctuating currency exchange rates, and political conditions in major oil producing regions, especially the Middle East, can cause fluctuations in the price of oil. Domestic natural gas prices continue to remain high when compared to longer-term historical prices. North American weather conditions, the industrial and consumer demand for natural gas, storage levels of natural gas, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas.

Income Tax Regulations

The tax laws in the jurisdictions we operate in are continuously changing and professional judgments regarding such tax laws can differ.

Liquidity and Capital Resources

During 2006, we relied upon our net cash provided by operating activities of $424.9 million, credit facility borrowings of $31.4 million, property sales proceeds of $24.7 million, and cash balances to fund capital expenditures of $557.5 million including $194.3 million of acquisitions. During 2005, we largely relied upon our net cash provided by operating activities of $285.3 million to fund capital expenditures of $264.5 million including $28.9 million of acquisitions.

Net Cash Provided by Operating Activities. For 2006, our net cash provided by operating activities was $424.9 million, representing a 49% increase as compared to $285.3 million generated during 2005. The $139.6 million increase in 2006 was primarily due to an increase of $177.8 million in oil and gas sales, attributable to higher oil prices and production, offset in part by higher lease operating costs and severance taxes due to higher oil prices and higher domestic production. In 2005, our net cash provided by operating activities was $285.3 million, representing a 56% increase as compared to $182.6 million generated during 2004. The $102.8 million increase in 2005 was primarily due to an increase of $112.5 million in oil and gas sales, attributable to higher commodity prices and production, offset in part by higher lease operating costs due to higher domestic production and severance taxes as a result of higher commodity prices.

Accounts Receivable. We assess the collectibility of accounts receivable, and, based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At both December 31, 2006 and 2005, we had an allowance for doubtful accounts of less than $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying balance sheets.

Existing Credit Facility. We had borrowings of $31.4 million under our bank credit facility at December 31, 2006, and no outstanding borrowings at December 31, 2005. Our bank credit facility at December 31, 2006 consisted of a $500.0 million revolving line of credit with a $250.0 million borrowing base. The borrowing base is re-determined at least every six months and was reaffirmed by our bank group at $250.0 million, effective November 1, 2006. Under the terms of our bank credit facility, we can increase this commitment amount to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. Our revolving credit facility includes requirements to maintain certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of this agreement.

Our access to funds from our credit facility is not restricted under any "material adverse condition" clause, a clause that is common for credit agreements to include. A "material adverse condition" clause can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have an adverse or material effect on operations, financial condition, prospects or properties, and would impair the ability to make timely debt repayments. Our credit facility includes covenants that require us to report events or conditions having a material adverse effect on our financial condition. The obligation of the banks to fund the credit facility is not conditioned on the absence of a material adverse effect.

Working Capital. Our working capital declined from a surplus of $16.6 million at December 31, 2005, to a deficit of $53.4 million at December 31, 2006. The decrease primarily resulted from a decrease in cash and cash equivalents due to property acquisitions during the fourth quarter of 2006.

Debt Maturities. Our credit facility, with a balance of $31.4 million at December 31, 2006, extends until October 3, 2011. Our $150.0 million of 7-5/8% senior notes mature July 15, 2011, and our $200.0 million of 9-3/8% senior subordinated notes mature May 1, 2012.

On or after May 1, 2007, we are entitled to redeem our $200.0 million of 9-3/8% senior subordinated notes at a redemption price, plus accrued and unpaid interest, of 104.688% of principal. If these notes were redeemed, we would most likely use a combination of drawings upon our credit facility, cash flows from operations, and the use of debt and/or equity offerings to fund any such redemption.

Capital Expenditures. In 2006 we relied upon our net cash provided by operating activities of $424.9, credit facility borrowings of $31.4 million, property sales proceeds of $24.7 million, and cash balances to fund capital expenditures of $557.5 million including $194.3 million of acquisitions. Our total capital expenditures of approximately $557.5 million in 2006 included:

Domestic expenditures of $502.3 million as follows:

- $214.9 million for drilling and developmental activity costs, predominantly in our South Louisiana area;
- $200.5 million for acquisitions of properties, primarily in our South Louisiana area;
- $20.5 million on exploratory drilling;
- $51.1 million of domestic prospect costs, principally prospect leasehold, 3-D seismic activity, and geological costs of unproved prospects;
- $15.3 million primarily for leasehold improvements, computer equipment, software, furniture, and fixtures;

New Zealand expenditures of $55.2 million as follows:

- $28.8 million for drilling costs and developmental activity costs, predominantly in our Rimu/Kauri area;
- $15.7 million on exploratory drilling;
- $10.4 million on prospect costs, principally prospect leasehold, seismic and geological costs of unproved properties;
- $0.3 million for computer equipment, software, furniture, and fixtures.

We continue to spend considerable time and capital on facility capacity upgrades in the Lake Washington field, and increased facility capacity at year-end 2006 to approximately 28,000 barrels per day for crude oil, up from 9,000 barrels per day capacity in the first quarter of 2003. We have upgraded three production platforms, added new compression for the gas lift system, and installed a new oil delivery system and permanent barge loading facility. During 2006, we began planning for the addition of a fourth production platform which will increase our processing capacity another 10,000 barrels per day by mid-2008.

We completed 45 of 63 wells in 2006, for a success rate of 71%. Domestically, we completed 42 of 49 development wells for a success rate of 86% and were unsuccessful on six exploratory wells, including five very shallow exploration wells in the AWP Olmos area which cost $0.5 million in the aggregate, and one non-operated well in Alaska. A total of 21 development wells were drilled in the Lake Washington area, of which 18 were completed, and 15 development wells were drilled in the AWP Olmos area, of which 14 were completed. We also drilled six development wells in the Bay de Chene area, of which three were completed, drilled three successful development wells in each of the Cote Blanche Island and South Bearhead Creek areas, and drilled one successful development well in the Brookeland area. In New Zealand, we completed three of four development wells but were unsuccessful on four exploratory wells.

Our capital expenditures were approximately $264.5 million in 2005 and $171.1 million in 2004. In 2005, we relied upon our net cash provided by operating activities of $285.3 million to fund capital expenditures of $264.5 million, including acquisitions of $28.9 million. During 2004, we relied upon our net cash provided by operating activities of $182.6 million, the issuance of our 7-5/8% senior notes due 2011, proceeds from the sale of non-core properties and equipment of $5.1 million, less the repayment of our 10-1/4% senior subordinated notes due 2009 to fund capital expenditures of $198.3 million, including acquisitions of $27.2 million. Our total capital expenditures in 2005 of approximately $264.5 million included:

Domestic expenditures of $215.8 million as follows:

- $111.0 million for drilling and developmental activity costs, predominantly in our Lake Washington area;

- $29.6 million on property acquisitions, including $28.9 million to acquire properties in the South Bearhead Creek field;
- $36.8 million on exploratory drilling, mainly in our Lake Washington area;
- $34.4 million of prospect costs, principally prospect leasehold, 3-D seismic activity, and geological costs of unproved prospects;
- $3.6 million primarily for a field office building, computer equipment, software, furniture, and fixtures;
- $0.3 million on gas processing plants in the Brookeland and Masters Creek areas; and

- less than $0.1 million on field compression facilities.

New Zealand expenditures of $48.7 million as follows:

- $27.2 million for drilling costs and developmental activity costs, predominantly in our Rimu/Kauri area;
- $13.6 million on exploratory drilling;
- $6.9 million on prospect costs, principally prospect leasehold, seismic and geological costs of unproved properties;
- $0.8 million on gas processing plants; and
- $0.2 million for computer equipment, software, furniture, and fixtures.

In 2005, we participated in drilling 45 domestic development wells and nine domestic exploratory wells, of which 37 development wells and five exploratory wells were completed. In New Zealand we drilled five development wells, of which two were completed, and five exploratory wells, of which one was completed.

New Accounting Pronouncements

Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123 (R), "Share-Based Payment" (SFAS No. 123R) utilizing the modified prospective approach. Prior to the adoption of SFAS No. 123R, we accounted for stock option grants in accordance with Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" (the intrinsic value method), and accordingly, recognized no compensation expense for employee stock option grants. Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006 as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized for the year ended December 31, 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting the new standard. As a result of adopting SFAS No. 123R on January 1, 2006, our income before taxes, net income and basic and diluted earnings per share for the year ended December 31, 2006, were $3.4 million, $2.8 million, $0.09, and $0.09 lower, respectively. Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to one recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in "General and Administrative, net" in the accompanying consolidated statements of income.

In September 2006, the SEC released SAB 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). SAB 108 addresses the process of quantifying financial statement misstatements, such as assessing both the carryover and reversing effects of prior year misstatements on the current year financial statements. SAB 108 became effective for our fiscal year ended December 31, 2006. The adoption of this statement had no impact on our financial position or results of operations.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109." This Interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, "Accounting for Income Taxes." FIN No. 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding derecognition, classification and disclosure of these uncertain tax positions. FIN No. 48 is effective for fiscal years beginning after December 15, 2006. The adoption of this Interpretation is not expected to have a material impact on its financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 addresses how companies should approach measuring fair value when required by GAAP; it does not create or modify any current GAAP requirements to apply fair value accounting. SFAS No. 157 provides a single definition for fair value that is to be applied consistently for all accounting applications, and also generally describes and prioritizes, according to reliability, the methods and inputs used in valuations. SFAS No. 157 prescribes various disclosures about financial statement categories and amounts which are measured at fair value, if such disclosures are not already specified elsewhere in GAAP. The new measurement and disclosure requirements of SFAS No. 157 are effective for us in the first quarter 2008. The Company has not yet determined what impact, if any, this statement will have on its financial position or results of operations.

Proved Oil and Gas Reserves

At year-end 2006, our total proved reserves were 816.8 Bcfe with a PV-10 Value of $2.7 billion (PV-10 is a non-GAAP measure, see the section titled "Oil and Natural Gas Reserves" in our Property section for a reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure). In 2006, our proved natural gas reserves increased 36.7 Bcf, or 13%, while our proved oil reserves increased 4.0 MMBbl, or 6%, and our NGL reserves decreased 0.9 MMBbl, or 6%, for a total equivalent increase of 55.1 Bcfe, or 7%. In 2005, our proved natural gas reserves decreased by 30.8 Bcf, or 10%, while our proved oil reserves decreased by 0.7 MMBbl, or 1%, and our NGL reserves decreased by 0.5 MMBbl, or 3%, for a total equivalent decrease of 38.1 Bcfe, or 5%. We added reserves over the past three years through both our drilling activity and purchases of minerals in place. Through drilling we added 72.8 Bcfe (1.2 Bcfe of which came from New Zealand) of proved reserves in 2006, 31.6 Bcfe (2.0 Bcfe of which came from New Zealand) in 2005, and 7.2 Bcfe (all of which was domestic) in 2004. Through acquisitions we added 77.8 Bcfe of proved reserves in 2006, 28.9 Bcfe in 2005, and 43.4 Bcfe in 2004. At year-end 2006, 44% of our total proved reserves were proved developed, compared with 50% at year-end 2005 and 56% at year-end 2004.

Despite increased reserves volumes, the PV-10 Value of our total proved reserves at year-end 2006 decreased 15% from the PV-10 Value at year-end 2005. Gas prices decreased in 2006 to $5.46 per Mcf from $8.94 per Mcf at year-end 2005, compared to $5.16 per Mcf at year-end 2004. Oil prices increased in 2006 to $60.41 per Bbl from $60.12 per Bbl at year-end 2005, compared to $41.07 in 2004. Under SEC guidelines, estimates of proved reserves must be made using year-end oil and gas sales prices and are held constant for that year's reserves calculation throughout the life of the properties. Subsequent changes to such year-end oil and gas prices could have a significant impact on the calculated PV-10 Value.

Critical Accounting Policies

The following summarizes several of our critical accounting policies. See a complete list of significant accounting policies in Note 1 to the consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires us to make estimates and assumptions that affect the reported amount of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates and assumptions underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage,

- estimates in the calculation of stock compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,
- the estimated future cost and timing of asset retirement obligations, and
- estimates made in our income tax calculations.

While we are not aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as changes in new accounting pronouncements, ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

Property and Equipment. We follow the "full-cost" method of accounting for oil and gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the years 2006, 2005, and 2004, such internal costs capitalized totaled $28.3 million, $18.8 million, and $13.1 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the years 2006, 2005, and 2004, capitalized interest on unproved properties totaled $9.2 million, $7.2 million, and $6.5 million, respectively. Interest not capitalized and general and administrative costs related to production and general overhead are expensed as incurred.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and gas properties (including gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). Our hedges at December 31, 2006 consisted of natural gas price floors with strike prices higher than the period-end price and did not materially affect prices used in this calculation. This calculation is done on a country-by-country basis.

The calculation of the Ceiling Test and provision for DD&A is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered. Our reserves estimates are prepared in accordance with Securities and Exchange Commission guidelines; and, are audited on an annual basis at year-end by a firm of independent petroleum engineers in accordance with standards approved by the Board of Directors of the Society of Petroleum Engineers.

Given the volatility of oil and gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that non-cash write-downs of oil and gas properties could occur in the future. If we have declines in our oil and gas reserves volumes, which also reduce our estimate of discounted future net cash flows from proved oil and gas reserves, a non-cash write-down of our oil and gas properties could occur in the future.

Price-Risk Management Activities. The Company follows SFAS No. 133, which requires that changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The statement also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the balance sheet as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the income statements and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting.

Changes in the fair value of derivatives that do not meet the criteria for hedge accounting, and the ineffective portion of the hedge, are recognized currently in income.

We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. During 2006, 2005 and 2004, we recognized net gains of $4.0 million, and net losses of $1.1 million and $1.3 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. At December 31, 2006, the Company had recorded $0.3 million, net of taxes of less than $0.2 million, of derivative gains in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for 2006, 2005, and 2004 was not material. We expect to reclassify all amounts currently held in "Accumulated other comprehensive income (loss), net of income tax" into the statement of income within the next three months when the forecasted sale of hedged production occurs.

At December 31, 2006, we had in place price floors in effect for February 2007 through the March 2007 contract month for natural gas, that cover a portion of our domestic natural gas production for February 2007 to March 2007. The natural gas price floors cover notional volumes of 800,000 MMBtu, with a weighted average floor price of $7.00 per MMBtu. Our natural gas price floors in place at December 31, 2006 are expected to cover approximately 25% to 30% of our estimated domestic natural gas production from February 2007 to March 2007.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive income (loss), net of income tax." When the hedged transactions are recorded upon the actual sale of the natural gas, these gains or losses are reclassified from "Accumulated other comprehensive income (loss), net of income tax" and recorded in "Price-risk management and other, net" on the accompanying statement of income. The fair value of our derivatives is computed using the Black-Scholes-Merton option pricing model and is periodically verified against quotes from brokers. The fair value of these instruments at December 31, 2006, was $0.7 million and is recognized on the accompanying balance sheet in "Other current assets."

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. Processing costs for natural gas and natural gas liquids ("NGLs") that are paid in-kind are deducted from revenues. The Company uses the entitlement method of accounting in which the Company recognizes its ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying balance sheet. Natural gas balancing receivables are reported in "Other current assets" on the accompanying balance sheet when our ownership share of production exceeds sales. As of December 31, 2006, we did not have any material natural gas imbalances.

Asset Retirement Obligation. In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, "Accounting for Asset Retirement Obligations." The statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. The liability is discounted from the year the well is expected to deplete. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss which increases or decreases the full cost pool. This standard requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values. Based on our experience and analysis of the oil and gas services industry, we have not factored a market risk premium into our asset retirement obligation. SFAS No. 143 was adopted by us effective January 1, 2003.

See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional discussion of commodity risk.

Stock Based Compensation. We have three stock-based compensation plans, which are described more fully in Note 6 to our accompanying consolidated financial statements. We account for those plans under the recognition and measurement principles of SFAS 123R, "Share-Based Compensation," and related interpretations.

Foreign Currency. We use the U.S. Dollar as our functional currency in New Zealand. The functional currency is determined by examining the entities' cash flows, commodity pricing, environment and financing arrangements. We have both assets and liabilities denominated in New Zealand Dollars, the New Zealand

"Deferred income taxes" and a portion of our "Asset Retirement Obligation" on the accompanying balance sheet. For accounts other than "Deferred income taxes," as the currency rate changes between the U.S. Dollar and the New Zealand Dollar, we recognize transaction gains and losses in "Price-risk management and other, net" on the accompanying statements of income. We recognize transaction gains and losses on "Deferred income taxes" in "Provision for Income Taxes" on the accompanying statement of income.

Related-Party Transactions

We were the operator of a number of properties owned by affiliated limited partnerships and, accordingly, charge these entities operating fees. The operating fees charged to the partnerships totaled the same $0.2 million in 2006, 2005 and 2004, and are recorded as reductions of general and administrative, net. We also have been reimbursed for administrative, and overhead costs incurred in conducting the business of the limited partnerships, which totaled $0.1 million per year in 2006 and 2005, and $0.2 million in 2004, and are recorded as reductions in general and administrative, net. As of December 31, 2006, the remaining two partnerships have been dissolved.

We receive research, technical writing, publishing, and website-related services from Tec-Com Inc., a corporation located in Knoxville, Tennessee and controlled and majority owned by the aunt of the Company's Chairman of the Board and Chief Executive Officer. We paid approximately $0.5 million to Tec-Com for such services pursuant to the terms of the contract between the parties in 2006, and $0.4 million per year in 2005 and 2004. The contract was renewed June 30, 2004, on substantially the same terms and expires June 30, 2007. We believe that the terms of this contract are consistent with third party arrangements that provide similar services.

As a matter of corporate governance policy and practice, related party transactions are annually presented and considered by the Corporate Governance Committee of our Board of Directors in accordance with the Committee's charter.

Forward-Looking Statements

The statements contained in this report that are not historical facts are forward-looking statements as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended. Such forward-looking statements may pertain to, among other things, financial results, capital expenditures, drilling activity, development activities, cost savings, production efforts and volumes, hydrocarbon reserves, hydrocarbon prices, liquidity, regulatory matters, and competition. Such forward-looking statements generally are accompanied by words such as "plan," "future," "estimate," "expect," "budget," "predict," "anticipate," "projected," "should," "believe," or other words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions, upon current market conditions, and upon engineering and geologic information available at this time, and is subject to change and to a number of risks and uncertainties, and, therefore, actual results may differ materially. Among the factors that could cause actual results to differ materially are: volatility in oil and natural gas prices, internationally or in the United States; availability of services and supplies; disruption of operations and damages due to hurricanes or tropical storms; fluctuations of the prices received or demand for our oil and natural gas; the uncertainty of drilling results and reserve estimates; operating hazards; requirements for capital; general economic conditions; changes in geologic or engineering information; changes in market conditions; competition and government regulations; as well as the risks and uncertainties discussed in this report and set forth from time to time in our other public reports, filings, and public statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. The effects of such pricing volatility are expected to continue.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. Below is a description of the financial instruments we have utilized to hedge our exposure to price risk.

- Price Floors - At December 31, 2006, we had in place price floors in effect through the March 2007 contract month for natural gas. The natural gas price floors cover notional volumes of 800,000 MMBtu, with a weighted average floor price of $7.00 per MMBtu. Our natural gas price floors in place at December 31, 2006 are expected to cover approximately 25% to 30% of our domestic natural gas production in February 2007 and March 2007. The fair value of these instruments at December 31, 2006, was $0.7 million and is recognized on the accompanying balance sheet in "Other current assets." There are no additional cash outflows for these price floors, as the cash premium was paid at inception of the hedge. The maximum loss that could be sustained from these price floors in 2007 would be their fair value at December 31, 2006 of $0.7 million.

- New Zealand Gas Contracts - All of our gas production in New Zealand is sold under long-term, fixed-price contracts denominated in New Zealand Dollars. These contracts protect against price volatility, and our revenue from these contracts will vary only due to production fluctuations and foreign exchange rates.

Interest Rate Risk. Our senior notes and senior subordinated notes both have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At December 31, 2006, we had borrowings of $31.4 million under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 83 basis points and would not have a material adverse effect on our 2007 cash flows based on this same level or a modest level of borrowing.

Income Tax Carryforwards. We had significant foreign net operating loss carryforwards at December 31, 2006. The foreign net operating losses have no expiration period, but would be cancelled if a change in control occurred at either the subsidiary or ultimate parent company level. Other loss carryforwards consist of state net operating losses and capital losses. The Company has not recorded a valuation allowance against the deferred tax assets attributable to the net operating carryovers at December 31, 2006, as management estimates that it is more likely than not that these assets will be fully utilized before they expire. The foreign net operating loss has no expiration period, but it would be cancelled if a change in control occurred at either the subsidiary or ultimate parent company level. A valuation allowance has been applied against the capital loss carryforward, as detailed in Note 3 of the accompanying consolidated financial statements. Significant changes in estimates caused by changes in oil and gas prices, production levels, capital expenditures, and other variables could impact the Company's ability to utilize the carryover amounts. If we are not able to use our carryforwards, our results of operations and cash flows will be negatively impacted.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2006 and 2005, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of December 31, 2006 and 2005, the fair values of our senior subordinated notes due 2012 were $211.0 million, or 105.5% of face value, and $214.5 million, or 107.25% of face value, respectively. Based upon quoted market prices as of

December 31, 2006 and 2005, the fair values of our senior notes due 2011 were $152.6 million, or 101.75% of face value, and $153.8 million, or 102.5% of face value. The carrying value of our senior subordinated notes due 2012 was $200.0 million at December 31 for both 2006 and 2005. The carrying value of our senior notes due 2011 was $150.0 million at December 31 for both 2006 and 2005.

Foreign Currency Risk. We are exposed to the risk of fluctuations in foreign currencies, most notably the New Zealand Dollar. Fluctuations in rates between the New Zealand Dollar and U.S. Dollar may impact our financial results from our New Zealand subsidiaries since we have receivables, liabilities,

natural gas and NGL sales contracts, and New Zealand income tax calculations, all denominated in New Zealand Dollars. We use the U.S. Dollar as our functional currency in New Zealand and because of this, our results of operations, cash flows and effective tax rate are impacted from fluctuations between the U.S. Dollar and the New Zealand Dollar.

Customer Credit Risk. We are exposed to the risk of financial non-performance by customers. Our ability to collect on sales to our customers is dependent on the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers and seek to minimize exposure to any one customer where other customers are readily available. Due to availability of other purchasers, we do not believe the loss of any single oil or gas customer would have a material adverse effect on our results of operations.

Item 8. Financial Statements and Supplementary Data — Page

Management's Report on Internal Control Over Financial Reporting

Management of Swift Energy Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Company's internal control over financial reporting is a process designed by, or under the supervision of, the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with U. S. generally accepted accounting principles.

Management of the Company assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2006. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control--Integrated Framework. Based on our assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2006.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on management's assessment of the Company's internal control over financial reporting as of December 31, 2006. That report, which expresses unqualified opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 appears on the following page.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of Swift Energy Company

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting that Swift Energy Company and subsidiaries maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control--Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Swift Energy Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Swift Energy Company and subsidiaries maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Swift Energy Company and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Swift Energy Company and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2006 and our report dated February 27, 2007 expressed an unqualified opinion thereon.

ERNST & YOUNG. LLP

Houston, Texas
February 27, 2007

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of Swift Energy Company

We have audited the accompanying consolidated balance sheets of Swift Energy Company and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Swift Energy Company and subsidiaries at December 31, 2006 and 2005, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2006 the Company changed its method of accounting for stock-based compensation.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Swift Energy Company and subsidiaries internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2007 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Houston, Texas
February 27, 2007

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Consolidated Balance Sheets
Swift Energy Company and Subsidiaries

		December 31, 2006
ASSETS		
Current Assets:		
Cash and cash equivalents	$	1,058,05
Accounts receivable-		
Oil and gas sales		63,935,44
Joint interest owners		1,843,82
Other Receivables		1,231,38
Deferred Tax Asset		2,383,17
Other current assets		22,121,16
Total Current Assets		92,573,04
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties		2,264,831,63
Unproved properties		112,136,83
		2,376,968,47
Furniture, fixtures, and other equipment		28,040,40
		2,405,008,87
Less - Accumulated depreciation, depletion, and amortization		(921,696,71
		1,483,312,16
Other Assets:		
Debt issuance costs		7,382,26
Restricted assets		2,414,28
		9,796,55
	$	1,585,681,75
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$	74,425,08
Accrued capital costs		55,282,00
Accrued interest		8,764,27
Undistributed oil and gas revenues		7,503,92
Total Current Liabilities		145,975,28

Long-Term Debt	381,400,00
Deferred Income Taxes	224,966,59
Asset Retirement Obligation	33,694,60
Lease Incentive Obligation	1,728,29
Commitments and Contingencies	
Stockholders' Equity:	
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding	--
Common stock, $.01 par value, 85,000,000 shares authorized, 30,170,004 and 29,458,974 shares issued, and 29,742,918 and 29,009,530 shares outstanding, respectively	301,70
Additional paid-in capital	387,555,79
Treasury stock held, at cost, 427,086 and 449,444 shares, respectively	(6,124,94
Unearned compensation	--
Retained earnings	415,868,09
Accumulated other comprehensive income (loss), net of income tax	316,32
	797,916,972
	$ 1,585,681,75

See accompanying Notes to Consolidated Financial Statements.

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Consolidated Statements of Income
Swift Energy Company and Subsidiaries

	Year Ended December	
	2006	2005
Revenues:		
Oil and gas sales	$ 601,551,368	$ 423,766,245
Price-risk management and other, net	13,889,862	(539,756)
	615,441,230	423,226,489
Costs and Expenses:		
General and administrative, net	31,316,644	22,176,362
Depreciation, depletion, and amortization	169,295,774	107,477,787
Accretion of asset retirement obligation	1,034,322	761,042
Lease operating cost	62,474,619	47,321,841
Severance and other taxes	65,452,043	42,176,505
Interest expense, net	23,581,663	24,873,401
Debt retirement cost	---	---
	353,155,065	244,786,938

Income Before Income Taxes	262,286,165	178,439,551
Provision for Income Taxes	100,720,825	62,661,095
Net Income	$ 161,565,340	$ 115,778,456
Per Share Amounts-		
Basic: Net Income	$ 5.52	$ 4.06
Diluted: Net Income	$ 5.38	$ 3.95
Weighted Average Shares Outstanding	29,265,366	28,496,275

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Stockholders' Equity
Swift Energy Company and Subsidiaries

	Common Stock (1)	Additional Paid-in Capital	Treasury Stock	Unearned Compensation	Retained Earnings
Balance, December 31, 2003	$ 280,111	$ 334,865,204	$ (7,558,093)	$ -	$ 70,073,384
Stock issued for benefit plans (46,150 shares)	-	166,298	661,848	-	-
Stock options exercised (509,105 shares)	5,091	4,260,882	-	-	-
Tax benefits from exercise of stock Options	-	1,956,555	-	-	-
Employee stock purchase plan (50,418 shares)	504	502,097	-	-	-
Grants of restricted stock (100,900 shares)	-	1,785,262	-	(1,785,262)	
Amortization of restricted stock compensation	-	-	-	56,677	-
Comprehensive income:					
Net income	-	-	-	-	68,450,917
Change in fair value of other comprehensive income	-	-	-	-	-
Total comprehensive					

income	-	-	-	-	-
Balance, December 31, 2004	$ 285,706	$ 343,536,298	$ (6,896,245)	$ (1,728,585)	$ 138,524,301
Stock issued for benefit plans (31,424 shares)	-	435,134	450,659	-	-
Stock options exercised (840,847 shares)	8,409	9,804,555	-	-	-
Tax benefits from exercise of stock options	-	4,366,236	-	-	-
Employee stock purchase plan (32,495 shares)	325	642,354	-	-	-
Issuance of restricted stock (15,000 shares)	150	-	-	-	-
Grants of restricted stock (158,500 shares)	-	6,668,608	-	(6,072,008)	-
Forfeitures of restricted stock	-	(367,490)	-	367,490	-
Amortization of restricted stock compensation	-	-	-	1,583,283	-
Comprehensive income:					
Net income	-	-	-	-	115,778,456
Change in fair value of other comprehensive loss	-	-	-	-	-
Total comprehensive income	-	-	-	-	-
Balance, December 31, 2005	$ 294,590	$ 365,085,695	$ (6,445,586)	$ (5,849,820)	$ 254,302,757
Stock issued for benefit plans (22,358 shares)	-	714,049	320,642	-	-
Stock options exercised (652,829 shares)	6,528	11,830,763	-	-	-
Adoption of SFAS No.123R	-	(5,875,280)	-	5,849,820	-
Excess tax benefits from stock-based awards	-	4,811,362	-	-	-
Employee stock purchase plan (22,425 shares)	224	671,106	-	-	-
Issuance of restricted stock (35,776 shares)	358	(358)	-	-	-
Amortization of stock compensation	-	10,318,460	-	-	-
Comprehensive Income:					
Net income	-	-	-	-	161,565,340
Other comprehensive income	-	-	-	-	-
Total comprehensive income	-	-	-	-	-
Balance, December 31, 2006	$ 301,700	$ 387,555,797	$ (6,124,944)	$ -	$ 415,868,097

(1)$.01 par value.

See accompanying Notes to Consolidated Financial Statements.

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Consolidated Statements of Cash Flows
Swift Energy Company and Subsidiaries

	Year Ended December	
	2006	2005
Cash Flows from Operating Activities:		
Net income	$ 161,565,340	$ 115,778,
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion, and amortization	169,295,774	107,477,
Accretion of asset retirement obligation	1,034,322	761,
Deferred income taxes	90,027,972	61,911,
Stock-based compensation expense	6,905,260	1,450,
Debt retirement cost - cash and non-cash	---	
Other	3,225,561	362,
Change in assets and liabilities-		
Increase in accounts receivable	(19,178,818)	(6,778,
Increase in accounts payable and accrued liabilities	10,905,914	5,071,
Increase (decrease) in income taxes payable	883,639	
Increase (decrease) in accrued interest	256,082	(700,
Net Cash Provided by Operating Activities	424,921,046	285,333,
Cash Flows from Investing Activities:		
Additions to property and equipment	(363,222,113)	(235,547,
Proceeds from the sale of property and equipment	24,678,020	7,296,
Acquisition of properties	(194,269,399)	(28,927,
Net cash received as operator of oil and gas properties	9,385,700	17,797,
Net cash received (distributed) as operator of partnerships	409,816	(948,
Other	(528,415)	255,
Net Cash Used in Investing Activities	(523,546,391)	(240,074,
Cash Flows from Financing Activities:		
Proceeds from long-term debt	---	
Payments of long-term debt	---	
Net proceeds from (payments of) bank borrowings	31,400,000	(7,500,
Net proceeds from issuances of common stock	12,508,621	10,325,
Excess tax benefits from stock-based awards	3,327,713	
Payments of debt retirement costs	---	
Payments of debt issuance costs	(557,500)	
Net Cash Provided by Financing Activities	46,678,834	2,825,
Net Increase (Decrease) in Cash and Cash Equivalents	$ (51,946,511)	$ 48,084,

Cash and Cash Equivalents at Beginning of Year	53,004,562	4,920,
Cash and Cash Equivalents at End of Year	$ 1,058,051	$ 53,004,
Supplemental Disclosures of Cash Flows Information:		
Cash paid during year for interest, net of amounts capitalized	$ 22,690,797	$ 24,482,
Cash paid during year for income taxes	$ 9,779,500	$ 750,

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements
Swift Energy Company and Subsidiaries

1. Summary of Significant Accounting Policies

Principles of Consolidation. The accompanying consolidated financial statements include the accounts of Swift Energy Company ("Swift Energy") and its wholly owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and natural gas properties, with a focus on inland waters and onshore oil and natural gas reserves in Louisiana and Texas, as well as onshore oil and natural gas reserves in New Zealand. Our undivided interests in gas processing plants are accounted for using the proportionate consolidation method, whereby our proportionate share of each entity's assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying consolidated financial statements.

Holding Company Structure. In December 2005, we implemented a holding company structure pursuant to Texas and federal law in a manner designed to be a non-taxable transaction. The new parent holding company assumed the Swift Energy Company name and its common stock and continued to trade on the New York Stock Exchange. The purposes of this new holding company structure are to separate Swift Energy's domestic and international operations to better reflect management practices, to improve our economics, and to provide greater administrative and organizational flexibility. Under the new organizational structure, four new subsidiaries were formed with the Texas parent holding company wholly owning four Delaware subsidiaries, which in turn wholly own Swift Energy's operating subsidiaries. Swift Energy Operating, LLC is the operator of record for Swift Energy's domestic properties. Swift Energy's name, charter, bylaws, officers, board of directors, authorized shares and shares outstanding remain substantially identical. The Company's international operations continue to be conducted through Swift Energy International, Inc. Swift Energy made amendments to its bank credit agreement, debt indentures and various other plans and documents to accommodate the internal reorganization, but the Company's day-to-day conduct of business was not impacted. Accordingly, there was no impact on our financial position or results of operations.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires us to make estimates and assumptions that affect the reported amount of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates and assumptions underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage,
- estimates in the calculation of stock compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,
- the estimated future cost and timing of asset retirement obligations, and
- estimates made in our income tax calculations.

While we are not aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as new accounting pronouncements, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

Property and Equipment. We follow the "full-cost" method of accounting for oil and gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and gas reserves are capitalized. Such costs may be incurred

both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the years 2006, 2005, and 2004, such internal costs capitalized totaled $28.3 million, $18.8 million, and $13.1 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the years 2006, 2005, and 2004, capitalized interest on unproved properties totaled $9.2 million, $7.2 million, and $6.5 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

No gains or losses are recognized upon the sale or disposition of oil and gas properties, except in transactions involving a significant amount of reserves or where the proceeds from the sale of oil and gas properties would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. Internal costs associated with selling properties are expensed as incurred.

Future development costs are estimated property-by-property based on current economic conditions and are amortized to expense as our capitalized oil and gas property costs are amortized.

We compute the provision for depreciation, depletion, and amortization ("DD&A") of oil and gas properties by the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties--including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties--by an overall rate determined by dividing the physical units of oil and gas produced during the period by the total estimated units of proved oil and gas reserves at the beginning of the period. This calculation is done on a country-by-country basis, and the period over which we will amortize these properties is dependent on our production from these properties in future years. Furniture, fixtures, and other equipment, recorded at cost, are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between three and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

Geological and geophysical ("G&G") costs incurred on developed properties are recorded in "Proved properties" and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in "Unproved properties" and evaluated as part of the total capitalized costs associated with a prospect.

The cost of unproved properties not being amortized is assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, foreign currency exchange rates, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized. To the extent costs accumulate in countries where there are no proved reserves, any costs determined by management to be impaired are charged to expense.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and gas properties (including gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). Our hedges at December 31, 2006 consisted of natural gas price floors with strike prices higher than the period-end price but did not materially affect prices used in this calculation. This calculation is done on a country-by-country basis.

The calculation of the Ceiling Test and provision for DD&A is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered. Our reserves estimates are prepared in accordance with Securities and Exchange Commission guidelines; and, are audited on an annual basis at year-end by a firm of independent petroleum engineers in accordance with standards approved by the Board of Directors of the Society of Petroleum Engineers.

Given the volatility of oil and gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline from our

period-end prices used in the Ceiling Test, even if only for a short period, it is possible that non-cash write-downs of oil and gas properties could occur in the future.

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. Processing costs for natural gas and natural gas liquids ("NGLs") that are paid in-kind are deducted from revenues. The Company uses the entitlement method of accounting in which the Company recognizes its ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying balance sheet. Natural gas balancing receivables are reported in "Other current assets" on the accompanying balance sheet when our ownership share of production exceeds sales. As of December 31, 2006, we did not have any material natural gas imbalances.

Accounts Receivable. We assess the collectibility of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At December 31, 2006 and 2005, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying balance sheets.

Debt Issuance Costs. Legal and accounting fees, underwriting fees, printing costs, and other direct expenses associated with the public offering in April 2002 of our 9-3/8% senior subordinated notes due 2012, the June 2004 extension of our bank credit facility, and the public offering in June 2004 of our 7-5/8% senior notes due 2011 were capitalized and are amortized on an effective interest basis over the life of each of the respective note offerings and credit facility. The 9-3/8% senior subordinated notes due 2012 mature on May 1, 2012, and the balance of their issuance costs at December 31, 2006, was $3.6 million, net of accumulated amortization of $2.0 million. The issuance costs associated with our revolving credit facility, which was extended in October 2006, have been capitalized and are being amortized over the life of the facility. The balance of revolving credit facility issuance costs at December 31, 2006, was $1.0 million, net of accumulated amortization of $2.0 million. The 7-5/8% senior notes due 2011 mature on July 15, 2011, and the balance of their issuance costs at December 31, 2006, was $2.8 million, net of accumulated amortization of $1.2 million.

Settlement of Insurance Claims. In 2006, we settled all insurance claims with our insurers relating to hurricanes Katrina and Rita for approximately $30.5 million and entered into a confidential final settlement agreement. The receipt of these amounts resulted in a benefit of $7.7 million in 2006 recorded in "Price-risk management and other, net," for the portion of the above referenced settlement, which we have determined to be non-property damage related claims. Approximately $22.8 million of the above referenced settlement was determined to be property damage related claims. We recorded $14.1 million of the property related settlement as a reduction to "Proved properties" on the accompanying consolidated balance sheet, as this related to reimbursement of capital costs we incurred. We also recorded $8.7 million of the property related settlement as a reduction to "Lease operating cost" on the accompanying consolidated statement of income, as this related to reimbursement of repair costs which had been expensed as incurred. In the accompanying consolidated statement of cash flows, we have recorded the reimbursement which reduced "Proved properties" as a reduction of "Net Cash Used in Investing Activities" and the remainder of the insurance settlement was recorded as an increase to "Net Cash Provided by Operating Activities."

Limited Partnerships. In 2006, we served as managing general partner for two private limited partnerships, and during fiscal 2006, less than 1% of our total oil and gas sales was attributable to our general and limited partner interests in those partnerships. These two partnerships were formed between 1996 and 1998, and were dissolved in December 2006.

Price-Risk Management Activities. The Company follows SFAS No. 133, which requires that changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The statement also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the balance sheet as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the income statements and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Changes in the fair value of derivatives that do not meet the criteria for hedge accounting, and the ineffective portion of the hedge, are recognized currently in income.

We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. During 2006, 2005 and 2004, we recognized net gains of

$4.0 million and net losses of $1.1 million and $1.3 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. At December 31, 2006, the Company had recorded $0.3 million, net of taxes of less than $0.2 million, of derivative gains in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for 2006, 2005, and 2004 was not material. We expect to reclassify all amounts currently held in "Accumulated other comprehensive income (loss), net of income tax" into the statement of income within the next three months when the forecasted sale of hedged production occurs.

At December 31, 2006, we had in place price floors in effect for February 2007 through the March 2007 contract month for natural gas, that cover a portion of our domestic natural gas production for February 2007 to March 2007. The natural gas price floors cover notional volumes of 800,000 MMBtu, with a weighted average floor price of $7.00 per MMBtu. Our natural gas price floors in place at December 31, 2006 are expected to cover approximately 25% to 30% of our estimated domestic natural gas production from February 2007 to March 2007.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive income (loss), net of income tax." When the hedged transactions are recorded upon the actual sale of the natural gas, these gains or losses are reclassified from "Accumulated other comprehensive income (loss), net of income tax" and recorded in "Price-risk management and other, net" on the accompanying statement of income. The fair value of our derivatives is computed using the Black-Scholes-Merton option pricing model and is periodically verified against quotes from brokers. The fair value of these instruments at December 31, 2006, was $0.7 million and is recognized on the accompanying balance sheet in "Other current assets."

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees are recorded as a reduction to general and administrative, net based on our estimate of the costs incurred to operate the wells, with the remainder applied as a reduction to lease operating cost. The total amount of supervision fees charged to the wells we operate was $8.8 million in 2006, $7.8 million in 2005, and $5.8 million in 2004.

Inventories. We value inventories at the lower of cost or market value. Cost of crude oil inventory is determined using the weighted average method and all other inventory is accounted for using the first in, first out method ("FIFO"). The major categories of inventories, which are included in "Other current assets" on the accompanying balance sheets, are shown as follows:

	Balance at December 31, 2006 (in thousands)	Balance at December 31, 2005 (in thousands)
Materials, Supplies and Tubulars................	$ 10,611	$ 8,494
Crude Oil	474	916
Total	$ 11,085	$ 9,410

Income Taxes. Under SFAS No. 109, "Accounting for Income Taxes," deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws.

Accounts Payable and Accrued Liabilities. Included in "Accounts payable and accrued liabilities," on the accompanying balance sheets, at December 31, 2006 and 2005 are liabilities of approximately $13.9 million and $9.9 million, respectively, which represent the amounts by which checks issued, but not presented to the Company's banks for collection, exceeded balances in the applicable bank accounts.

Cash and Cash Equivalents. We consider all highly liquid debt instruments with an initial maturity of three months or less to be cash equivalents.

Credit Risk Due to Certain Concentrations. We extend credit, primarily in the form of uncollateralized oil and gas sales and joint interest owners receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected

by changes in economic or other conditions within our industry and may accordingly impact our overall credit risk. However, we believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which we extend credit. During 2006 and 2005, oil and gas sales to Shell Oil Company and affiliates were $180.4 million and $179.9 million, or 30% and 42% of total oil and gas sales, respectively. During 2006, Chevron Corporation and its affiliates accounted for $193.9 million or 32% of our total oil and gas sales. During 2004, oil and gas sales to Shell Oil Company and affiliates, both domestically and in New Zealand, were $149.2 million, or 48% of total oil and gas sales. Credit losses in 2005, 2004 and 2003 have been immaterial.

Environmental Costs. Our operations include activities that are subject to extensive federal and state environmental regulations. Costs associated with redemption projects, which are probable and reasonably estimable, are accrued in advance. Ongoing environmental compliance costs are expensed as incurred.

Restricted Assets. These balances primarily include amounts deposited on plugging bonds in New Zealand, along with amounts held in escrow accounts to satisfy domestic plugging and abandonment obligations. These amounts are restricted as to their current use, and will be released when we have satisfied all plugging and abandonment obligations in certain fields domestically and in New Zealand.

Foreign Currency. We use the U.S. Dollar as our functional currency in New Zealand. The functional currency is determined by examining the entities cash flows, commodity pricing environment and financing arrangements. We have both assets and liabilities denominated in New Zealand Dollars, the New Zealand "Deferred income taxes" and a portion of our "Asset Retirement Obligation" on the accompanying balance sheet. For accounts other than "Deferred income taxes," as the currency rate changes between the U.S. Dollar and the New Zealand Dollar, we recognize transaction gains and losses in "Price-risk management and other, net" on the accompanying statements of income. We recognize transaction gains and losses on "Deferred income taxes" in "Provision for Income Taxes" on the accompanying statement of income.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2006 and 2005, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of December 31, 2006 and 2005, the fair values of our senior subordinated notes due 2012 were $211.0 million, or 105.5% of face value, and $214.5 million, or 107.25% of face value, respectively. Based upon quoted market prices as of December 31, 2006 and 2005, the fair values of our senior notes due 2011 were $152.6 million, or 101.75% of face value, and $153.8 million, or 102.5% of face value. The carrying value of our senior subordinated notes due 2012 was $200.0 million at December 31 for both 2006 and 2005. The carrying value of our senior notes due 2011 was $150.0 million at December 31 for both 2006 and 2005.

Reclassification of Prior Period Balances. Certain reclassifications have been made to prior period amounts to conform to the current year presentation.

Accumulated Other Comprehensive Income (Loss), Net of Income Tax. We follow the provisions of SFAS No. 130, "Reporting Comprehensive Income," which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At December 31, 2006, we recorded $0.3 million, net of taxes of less than $0.2 million, of derivative gains in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying balance sheet. The components of accumulated other comprehensive Income (loss) and related tax effects for 2006 were as follows:

	Gross Value	Tax Effect	Net of T
Other comprehensive loss at December 31, 2005	$ (110,094)	$ 40,625	$
Change in fair value of cash flow hedges	4,672,043	(1,733,328)	
Effect of cash flow hedges settled during the period	(4,059,052)	1,506,128	(
Other comprehensive income at December 31, 2006	$ 502,897	$ (186,575)	$

Total comprehensive income was $162.0 million, $115.3 million, and $69.2 million for 2006, 2005, and 2004, respectively.

Stock Based Compensation. Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123 (R), "Share-Based Payment" (SFAS No. 123R) utilizing the modified prospective approach. Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006 as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized for the year ended December 31, 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting the new standard.

We have three stock-based compensation plans, which are described more fully in Note 6.

Prior to 2006, we accounted for those plans under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. No stock-based employee compensation cost is reflected in net income for employee stock options prior to 2006, as all options granted under those plans had an exercise price equal to the fair market value of the underlying common stock on the date of the grant; or in the case of the employee stock purchase plan, the purchase price is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year or a date during the year chosen by the participant. Had compensation expense for these plans been determined based on the fair value of the options consistent with SFAS No. 123, "Accounting for Stock-Based Compensation," our net income and earnings per share would have been adjusted to the following pro forma amounts:

		2005	2004
Net Income:	As Reported	$115,778,456	$68,450,9
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(2,712,441)	(3,557,5
	Pro Forma	$113,066,015	$64,893,3
Basic EPS:	As Reported	$4.06	$2.
	Pro Forma	$3.97	$2.
Diluted EPS:	As Reported	$3.95	$2.
	Pro Forma	$3.86	$2.

Pro forma compensation cost reflected above may not be representative of the cost to be expected in future years. The fair value of each option grant, as opposed to its exercise price, is estimated on the date of grant using the Black-Scholes-Merton option-pricing model with the following weighted average assumptions in 2006, 2005, and 2004, respectively: no dividend yield; expected volatility factors of 39.3%, 41.6%, and 38.6%; risk-free interest rates of 4.8%, 3.8%, and 3.6%; and expected lives of 4.8, 3.9, and 5.4 years. We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

Asset Retirement Obligation. In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, "Accounting for Asset Retirement Obligations." The statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. The liability is discounted from the year the well is expected to deplete. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss which increases or decreases the full cost pool. This standard requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values. Based on our experience and analysis of the oil and gas services industry, we have not factored a market risk premium into our asset retirement obligation. SFAS No. 143 was adopted by us effective January 1, 2003.

The following provides a roll-forward of our asset retirement obligation:

Asset Retirement Obligation recorded as of January 1, 2004	$ 10,137,473
Accretion expense for 2004	673,654
Liabilities incurred for new wells and facilities construction	712,521
Liabilities incurred for acquisitions	2,941,490
Reductions due to sold and abandoned wells	(1,083,174)
Revisions in estimated cash flows	4,195,474
Increase due to currency exchange rate fluctuations	61,698
Asset Retirement Obligation as of December 31, 2004	$ 17,639,136
Accretion expense for 2005	761,041
Liabilities incurred for new wells and facilities construction	616,206
Liabilities incurred for acquisitions	426,377
Reductions due to sold and abandoned wells	(464,519)
Revisions in estimated cash flows	416,861
Decrease due to currency exchange rate fluctuations	(38,735)
Asset Retirement Obligation as of December 31, 2005	$ 19,356,367
Accretion expense for 2006	1,034,322
Liabilities incurred for new wells and facilities construction	684,175
Liabilities incurred for acquisitions	12,207,480
Reductions due to sold and abandoned wells	(334,591)
Revisions in estimated cash flows	1,467,673
Increase due to currency exchange rate fluctuations	45,027
Asset Retirement Obligation as of December 31, 2006	$ 34,460,453

At December 31, 2006 and 2005, approximately $0.8 million and $0.3 million, respectively, of our asset retirement obligation is classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying consolidated balance sheets.

New Accounting Pronouncements. Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123 (R), "Share-Based Payment" (SFAS No. 123R) utilizing the modified prospective approach. Prior to the adoption of SFAS No. 123R, we accounted for stock option grants in accordance with Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" (the intrinsic value method), and accordingly, recognized no compensation expense for employee stock option grants. Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006 as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized for the year ended December 31, 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting the new standard. As a result of adopting SFAS No. 123R on January 1, 2006, our income before taxes, net income and basic and diluted earnings per share for the year ended December 31, 2006, were $3.4 million, $2.8 million, $0.09, and $0.09 lower, respectively. Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to one recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in "General and Administrative, net" in the accompanying consolidated statements of income.

In September 2006, the SEC released SAB 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). SAB 108 addresses the process of quantifying financial statement misstatements, such as assessing both the carryover and reversing effects of prior year misstatements on the current year financial statements. SAB 108 became effective for our fiscal year ended December 31, 2006. The adoption of this statement had no impact on our financial position or results of operations.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109." This Interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, "Accounting for Income Taxes." FIN No. 48 prescribes a threshold condition that a tax position must meet for any of

the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding derecognition, classification and disclosure of these uncertain tax positions. FIN No. 48 is effective for fiscal years beginning after December 15, 2006. The adoption of this Interpretation is not expected to have a material impact on its financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 addresses how companies should approach measuring fair value when required by GAAP; it does not create or modify any current GAAP requirements to apply fair value accounting. SFAS No. 157 provides a single definition for fair value that is to be applied consistently for all accounting applications, and also generally describes and prioritizes, according to reliability, the methods and inputs used in valuations. SFAS No. 157 prescribes various disclosures about financial statement categories and amounts which are measured at fair value, if such disclosures are not already specified elsewhere in GAAP. The new measurement and disclosure requirements of SFAS No. 157 are effective for us in the first quarter 2008. The Company has not yet determined what impact, if any, this statement will have on its financial position or results of operations.

2. Earnings Per Share

Basic earnings per share ("Basic EPS") have been computed using the weighted average number of common shares outstanding during the respective periods. Diluted earnings per share ("Diluted EPS") for all periods also assumes, as of the beginning of the period, exercise of stock options and restricted stock grants using the treasury stock method. Certain of our stock options and restricted stock that would potentially dilute Basic EPS in the future were also antidilutive for the 2006, 2005, and 2004 periods and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the years ended December 31, 2006, 2005, and 2004:

	2006			2005			
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount	
Basic EPS:							
Net Income and Share Amounts	$161,565,340	29,265,366	$5.52	$115,778,456	8,496,275	$4.06	$
Dilutive Securities:							
Restricted Stock	--	168,759		--	61,516		
Stock Options	--	581,891		--	736,937		
Diluted EPS:							
Net Income and Assumed Share Conversions	$161,565,340	30,016,016	$5.38	$115,778,456	29,294,728	$3.95	$

Options to purchase approximately 1.5 million shares at an average exercise price of $24.59 were outstanding at December 31, 2006, while options to purchase 2.1 million shares at an average exercise price of $21.28 were outstanding at December 31, 2005, and options to purchase 3.0 million shares at an average exercise price of $18.51 were outstanding at December 31, 2004. Approximately 1.0 million, 0.1 million, and 1.1 million options to purchase shares were not included in the computation of Diluted EPS for the years ended December 31, 2006, 2005, and 2004, respectively, because these options were antidilutive, in that the sum of the option price, unrecognized compensation expense and excess tax benefits recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during those periods. Employee restricted stock grants of 334,425 shares, 6,990 shares and 70,900 shares, were not included in the computation of Diluted EPS for the year ended December 31, 2006, 2005, and 2004, respectively, because these restricted stock grants were antidilutive in that the sum of the unrecognized compensation expense and excess tax benefits recognized as proceeds under the treasury stock method was greater than the average closing market price for the common shares during that period. Other restricted stock grants of 15,000 shares, which were issued in 2004, were not included in the computation of Diluted EPS for the year ended December 31, 2005, as performance conditions surrounding the vesting of these shares had not occurred.

3. Provision for Income Taxes

	Year Ended December 31, (in thousands)		
	2006	2005	2004
United States	$ 247,645	$ 155,863	$ 86,001
Foreign	14,641	22,577	15,439
Total	$ 262,286	$ 178,440	$ 101,440

The following is an analysis of the consolidated income tax provision:

	Year Ended December 31, (in thousands)		
	2006	2005	2004
Current - Domestic	$ 2,860	$ 644	$ 469
Deferred - Domestic	94,375	57,605	31,138
- Foreign	3,486	4,412	1,382
Total Deferred	97,861	62,017	32,520
Total	$ 100,721	$ 62,661	$ 32,989

Reconciliations of income taxes computed using the U.S. Federal statutory rate to the effective income tax rates are as follows:

(in thousands)	2006	2005	
Income taxes computed at U.S. statutory rate (35%)	$ 91,800	$ 62,454	$
State tax provisions, net of federal benefits	3,921	2,145	
Effect of foreign operations	(293)	(452)	
Currency exchange impact on foreign tax calculation	(1,346)	(2,769)	
Cumulative impact of adjustments to net state income tax rate	1,547	1,008	
Valuation allowance	3,200	---	
Other, net	1,892	275	
Provision for income taxes	$ 100,721	$ 62,661	$
Effective rate	38.4%	35.1%	

The primary upward adjustment in the effective tax rate above the U.S. statutory rate is the provision for state income taxes (computed net of the offsetting federal benefit), which were $3.9, million, $2.1 million and $1.1 million for 2006, 2005, and 2004, respectively. In 2006 the Company recorded a valuation allowance of $3.2 million discussed further below. Additionally, the Company recorded adjustments to the cumulative state deferred tax liability in the amounts of $1.5 million, $1.0 million, and $0.9 million for 2006, 2005, and 2004, respectively.

Favorable adjustments are primarily attributable to currency exchange impact on foreign operations. The Company's New Zealand subsidiaries use the U.S. Dollar as their functional currency for financial reporting purposes, but

income taxes are calculated from New Zealand Dollar financial statements and re-measured into U.S. Dollars. Volatility in exchange rates creates variable results when computing income in different currencies In aggregate, the Company recognized foreign exchange benefits to tax expense in the amounts of $1.3 million, $2.8 million, and $2.5 million for 2006, 2005, and 2004, respectively.

The New Zealand statutory rate is 33%, which resulted in differences of $0.3 million, $0.5 million, and $0.3 million for 2006, 2005, and 2004 respectively vs. the U.S. statutory rate. The Company does not compute a provision for U.S. taxes on the undistributed earnings of our New Zealand subsidiaries as management has plans to reinvest such earnings outside of the United States indefinitely. As of December 31, 2006, the undistributed earnings of foreign subsidiaries are approximately $58.5 million. If, in the future, these earnings are distributed into the U.S. in the form of dividends or otherwise, we may be subject to U.S. income taxes and New Zealand withholding taxes. It is not practical, however, to estimate the amount of taxes that may be payable if such remittances occur. Presently, there are no foreign tax credits available to reduce the U.S. taxes on such amounts if repatriated.

The tax effects of temporary differences representing the net deferred tax liability (asset) at December 31, 2006 and 2005 were as follows (in thousands):

	2006	
Current deferred tax assets:		
Carryover items net of valuation allowance (Domestic)	$ 2,383	$
Non-Current deferred tax assets:		
Alternative minimum tax credits (Domestic)	$ (2,202)	$
Carryover items (Domestic)	(2,648)	(
Acquired deferred tax asset (Foreign)	(1,204)	
Carryover Items (Foreign)	(55,197)	(
Unrealized stock compensation	(2,680)	
Other (Domestic)	(325)	
Total deferred tax assets	$ (64,256)	$ (
Non-Current deferred tax liabilities:		
Domestic oil and gas exploration and development costs	$ 224,580	$ 1

Foreign oil and gas exploration and development costs	63,254	
Other (Domestic)	1,389	
Total deferred tax liabilities	$ 289,223	$ 2
Net Non-Current deferred tax liabilities	$ 224,967	$ 1

The total change in the net non-current deferred liability from 2005 to 2006 was $95.7 million. Increases in the liability were attributable to deferred tax expense of $97.9 million, reclassification of a carryover item to current assets of $2.4 million and $0.2 million for other adjustments. Reductions were made to the net liability for the tax benefit of stock compensation deductions of $4.8 million, which are recorded as additions to paid-in-capital.

The primary non-current deferred tax asset is $55.2 million for foreign carryover items. This is attributable to cumulative New Zealand net operating losses of $167.3 million. New Zealand tax net operating losses do not expire.

Other non-current deferred tax assets include $2.7 million for unrealized stock compensation, $2.6 million for State of Louisiana net operating loss carryovers, $2.2 million for U.S. Federal alternative minimum tax credits, and $1.5 million for other items. The unrealized stock compensation is attributable to stock compensation expenses accrued for employee stock options and restricted stock that is not realized for income tax purposes until exercise (for stock options) or vesting (for restricted stock). The actual tax deduction realized may be significantly different than the accrued amounts depending on the market value of the stock on the date of exercise or vesting. The Louisiana net operating loss carryforwards are scheduled to expire between 2013 and 2019. The alternative minimum tax credits carryforward indefinitely. These credits are available to reduce future regular tax liability to the extent they exceed the alternative minimum tax otherwise due.

The Company has not recorded any valuation allowance against any of the non-current deferred tax assets as management estimates that it is more likely than not that these assets will be fully utilized in future periods before any applicable expiration dates. Significant changes in estimates caused by changes in oil and gas prices, production levels, capital expenditures, and other variables could impact the Company's ability to utilize the carryover amounts.

The current deferred tax asset of $2.4 million is for capital loss carryforward assets of $6.1 million, offset by a valuation allowance of $3.7 million (an increase of $3.2 million in 2006). The increase in the valuation allowance is due to changes in the Company's property disposition plans. Management expects to realize the net tax asset from a property disposition planned for 2007.

4. Long-Term Debt

Our long-term debt as of December 31, 2006 and 2005, is as follows:

	2006	2005
Bank Borrowings	$ 31,400,000	$ ---
7-5/8% senior notes due 2011	150,000,000	150,000,000
9-3/8% senior subordinated notes due 2012	200,000,000	200,000,000
Long-Term Debt	$ 381,400,000	$ 350,000,000

Bank Borrowings. At December 31, 2006, we had borrowings of $31.4 million under our $500.0 million credit facility with a syndicate of ten banks that has a borrowing base of $250.0 million and expires in October 2011. At December 31, 2005, we had no borrowings under our credit facility. The interest rate is either (a) the lead bank's prime rate (8.25% at December 31, 2006) or (b) the adjusted London Interbank Offered Rate ("LIBOR") plus the applicable margin depending on the level of outstanding debt. The applicable margin is based on the ratio of the outstanding balance to the last calculated borrowing base. In October 2006, we increased, renewed and extended this credit facility, increasing the facility to $500 million from $400 million, increasing the commitment amount under the borrowing base to $250 million from $150 million, and extending its expiration to October 3, 2011 from October 1, 2008. The other terms of the credit facility stayed largely the same. The covenants related to this credit facility changed somewhat with the extension of the facility and are discussed below. We incurred $0.6 million of debt issuance costs related to the extension of this facility in 2006 and $0.4 million of debt issuance costs related to the renewal of this facility in 2004, which is included in "Debt issuance costs" on the accompanying consolidated balance sheets and will be amortized to interest expense over the life of the facility.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $15.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $50.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt or repurchasing our 7-5/8% senior notes due 2011 or 9-3/8% senior subordinated notes due 2012. Since inception, no cash dividends have been declared on our common stock. We are currently in compliance with the provisions of this agreement. The credit facility is secured by our domestic oil and natural gas properties. We have also pledged 65% of the stock in our two New Zealand subsidiaries as collateral for this credit facility. The borrowing base is re-determined at least every six months and was reconfirmed by our bank group at $250.0 million effective November 1, 2006, and the commitment amount was increased to $250.0 million effective October 2, 2006. The next scheduled borrowing base review is in May 2007.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.5 million in 2006, $1.0 million in 2005, and $1.5 million in 2004. The amount of commitment fees included in interest expense, net was $0.6 million in 2006, and $0.5 million in both 2005 and 2004.

Senior Subordinated Notes Due 2009. These notes consisted of $125.0 million of 10-1/4% senior subordinated notes, which were issued at 99.236% of the principal amount on August 4, 1999, and were scheduled to mature on August 1, 2009. These notes were unsecured senior subordinated obligations with interest payable semiannually, on February 1 and August 1. In June 2004, we repurchased $32.1 million of these notes pursuant to a tender offer. In July 2004, we repurchased an additional $0.5 million of these notes, and as of August 1, 2004, we redeemed the remaining $92.5 million in outstanding notes. In 2004, we recorded a charge of $9.5 million related to the repurchase of these notes, which is recorded in "Debt retirement costs" on the accompanying consolidated statement of income. The costs were comprised of approximately $6.5 million of premiums paid to repurchase the notes, $2.2 million to write-off unamortized debt issuance costs, $0.6 million to write-off unamortized debt discount, and approximately $0.2 million of other costs.

Interest expense on the 10-1/4% senior subordinated notes due 2009, including amortization of debt issuance costs and discount, totaled $7.4 million in 2004.

Senior Notes Due 2011. These notes consist of $150.0 million of 7-5/8% senior notes, which were issued on June 23, 2004 at 100% of the principal amount and will mature on July 15, 2011. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and rank senior to all of our existing and future subordinated indebtedness. Interest on these notes is payable semi-annually on January 15 and July 15, and commenced on January 15, 2005. On or after July 15, 2008, we may redeem some or all of the notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.813% of principal, declining to 100% in 2010 and thereafter. In addition, prior to July 15, 2007, we may redeem up to 35% of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.625% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $3.9 million of debt issuance costs related to these notes, which is included in "Debt issuance costs" on the accompanying consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. Upon certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled $11.9 million in both 2006 and 2005, and $6.2 million in 2004.

Senior Subordinated Notes Due 2012. These notes consist of $200.0 million of 9-3/8% senior subordinated notes, which were issued on April 11, 2002 and will mature on May 1, 2012. The notes are unsecured senior subordinated obligations and are subordinated in right of payment to all our existing and future senior debt, including our bank credit facility. Interest on these notes is payable semiannually on May 1 and November 1, with the first interest payment on November 1, 2002. On or after May 1, 2007, we may redeem these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.688% of principal, declining to 100% in 2010. Upon certain changes in control of Swift Energy, each holder of these notes will have the right to require us to repurchase the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these subordinated notes due 2012.

Interest expense on the 9-3/8% senior subordinated notes due 2012, including amortization of debt issuance costs totaled $19.2 million for each of the years 2006, 2005, and 2004.

The maturities on our long-term debt are $0 for 2007, 2008, 2009 and 2010, $181.4 million for 2011, and $200 million thereafter.

We have capitalized interest on our unproved properties in the amount of $9.2 million, $7.2 million, and $6.5 million, in 2006, 2005, and 2004, respectively.

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5. Commitments and Contingencies

Total rental and lease expenses which were included in "General and administrative, net" on our accompanying consolidated statements of income were $3.2 million in 2006, $3.0 million in 2005, and $2.4 million in 2004. Rental and lease expenses which were included in "Lease operating cost" on our accompanying consolidated statements of income were $3.6 million in 2006, $1.9 million in 2005, and $2.2 million in 2004. Our remaining minimum annual obligations under non-cancelable operating lease commitments are $5.3 million for both 2007 and 2008, $3.3 million for both 2009 and 2010, $3.2 million for 2011, and $10.1 million thereafter or $30.6 million in the aggregate. The rental and lease expenses and remaining minimum annual obligations under non-cancelable operating lease commitments primarily relate to the lease of our office space in Houston, Texas which is a ten year lease and expires in 2015.

In the ordinary course of business, we have entered into agreements with drilling contractors for such services and tubing and pipe inventory commitments. The remaining commitments at December 31, 2006 for these services and materials totaled $28.9 million for 2007.

Through December 2006, we were the managing general partner of two private limited partnerships. Because we served as the general partner of these entities, under state partnership law we were contingently liable for the liabilities of these partnerships. These liabilities are not material for any of the periods presented in relation to the partnerships' respective assets. As of December 31, 2006, these partnerships were dissolved.

In the ordinary course of business, we have been party to various legal actions, which arise primarily from our activities as operator of oil and natural gas wells. In management's opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations.

6. Stockholders' Equity

Stock-Based Compensation Plans. We have three stock option plans that awards are currently granted under, the 2005 Stock Compensation Plan, which was adopted by our Board of Directors in March 2005 and was approved by shareholders at the 2005 annual meeting of shareholders, the 2001 Omnibus Stock Compensation Plan, which was adopted by our Board of Directors in February 2001 and was approved by shareholders at the 2001 annual meeting of shareholders, and the

1990 Non-Qualified Stock Option Plan solely for our independent directors. No further grants, other than stock option reload grants, will be made under the 2001 Omnibus Stock Compensation Plan or the 1990 Non-Qualified Stock Option Plan, both of which were replaced by the 2005 Stock Compensation Plan, although options remain outstanding under both plans and are accordingly included in the tables below. In addition, we have an employee stock purchase plan and an employee stock ownership plan.

Under the 2005 plan, incentive stock options and other options and awards may be granted to employees, directors, and consultants to purchase shares of common stock. Under the 2001 plan, incentive stock options and other options and awards may be granted to employees to purchase shares of common stock. Under the 1990 non-qualified plan, non-employee members of our Board of Directors were automatically granted options to purchase shares of common stock on a formula basis. All three plans provide that the exercise prices equal 100% of the fair value of the common stock on the date of grant. Restricted stock grants become vested in various terms ranging from three years to five years, stock options become exercisable in various terms ranging from one year to five years. Options granted typically expire ten years after the date of grant or earlier in the event of the optionee's separation from employment. At the time the stock options are exercised, the cash received is credited to common stock and additional paid-in capital. Options issued under these plans also include a reload feature where additional options are granted at the then current market price when mature shares of Swift Energy common stock are used to satisfy the exercise price of an existing stock option grant. When Swift Energy common stock is used to satisfy the exercise price, the net shares actually issued are reflected in the accompanying Statement of Stockholders' Equity (see note 1 to table below). We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

The employee stock purchase plan, which began in 1993, provides eligible employees the opportunity to acquire shares of Swift Energy common stock at a discount through payroll deductions. Through May 31, 2006, the prior plan year was from June 1 to the following May 31. A transition period from June 1 to

December 31 was used during the second half of 2006 and a new plan year, from January 1 to December 31, began being used in 2007. To date, employees have been allowed to authorize payroll deductions of up to 10% of their base salary during the plan year by making an election to participate prior to the start of a plan year. The purchase price for stock acquired under the plan is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year (or a date during the year chosen by the participant through the plan year, for plan years ending on or before May 31, 2006). Under this plan for the last three years, we have issued 22,425 shares at a price range of $29.84 to $32.80 in 2006, 32,495 shares at a price range of $15.56 to $18.12 in 2005, and 50,418 shares at a price range of $9.98 to $10.83 in 2004. In January 2007, we issued 17,678 shares at a price of $35.00 related to the transition period ended December 31, 2006. As of December 31, 2006, 84,366 shares remained available for issuance under this plan.

As a result of adopting SFAS No. 123R on January 1, 2006, our income before taxes, net income and basic and diluted earnings per share for the year ended December 31, 2006, were $3.4 million, $2.8 million, $0.09, and $0.09 lower, respectively. Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to one recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in "General and Administrative, net" in the accompanying consolidated statements of income.

We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the price at which the stock is sold over the exercise price of the options. In addition, we receive an additional tax deduction when restricted stock vests at a higher value than the value used to recognize compensation expense at the date of grant. Prior to adoption of SFAS No. 123R, we reported all tax benefits resulting from the award of equity instruments as operating cash flows in our consolidated statements of cash flows. In accordance with SFAS No. 123R, we are required to report excess tax benefits from the award of equity instruments as financing cash flows, these benefits totaled $3.3 million for the year ended December 31, 2006, respectively.

Net cash proceeds from the exercise of stock options were $11.8 million for the year ended December 31, 2006. The actual income tax benefit realized from stock option exercises was $4.8 million for the same period.

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees is recorded in "General and Administrative, net" in the accompanying consolidated statements of income, and was $6.3 million, $1.5 million, and less than $0.1 million for the years ended December 31, 2006, 2005, and 2004 respectively. We also capitalized $3.4 million, $1.0 million, and $0.1 million of stock compensation in 2006, 2005, and 2004, respectively.

Our shares available for future grant under our stock compensation plans were 959,063 at December 31, 2006. Each stock option granted reduces the aforementioned total by one share, while each restricted stock grant reduces the shares available for future grant by 1.44 shares.

Stock Options. We use the Black-Scholes-Merton option pricing model to estimate the fair value of stock option awards with the following weighted-average assumptions for the indicated periods.

	Years Ended December 31,	
	2006	2005
Dividend yield	0%	0%
Expected volatility	39.3%	41.6%
Risk-free interest rate	4.8%	3.8%
Expected life of options (in years)	4.8	3.9
Weighted-average grant-date fair value	$ 18.03	$ 12.84

The expected term has been calculated using the Securities and Exchange Commission Staff's shortcut approach from Staff Accounting Bulletin No. 107. We have analyzed historical volatility and based on an analysis of all relevant factors use a three-year period to estimate expected volatility of our stock option grants.

At December 31, 2006, $3.6 million of unrecognized compensation cost related to stock options is expected to be recognized over a weighted-average period of 1.5 years.

The following table represents stock option activity for the years ended December 31, 2006, 2005 and 2004:

	2006		2005	
	Shares	Wtd. Avg. Exer. Shares	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	2,118,179	$ 21.28	2,998,668	$ 18.51
Options granted	234,110	$ 45.73	176,262	$ 35.17
Options canceled	(51,739)	$ 22.25	(45,142)	$ 18.94
Options exercised(1)	(751,410)	$ 22.02	(1,011,609)	$ 9.78
Options outstanding, end of period	1,549,140	$ 24.59	2,118,179	$ 21.28
Options exercisable, end of period	884,876	$ 22.60	1,085,509	$ 20.98

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at December 31, 2006 was $31.9 million and 5.5 years and $19.8 million and 4.5 years, respectively. The total intrinsic value of options exercised during the year ended December 31, 2006 was $18.4 million.

The following table summarizes information about stock options outstanding at December 31, 2006:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/06	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable At 12/31/06	Wtd. Avg. Exercise Price
$8.00 to $21.99	747,779	5.4	$ 13.56	452,555	$ 13.40
$22.00 to $37.99	513,566	5.3	$ 28.73	374,736	$ 30.09
$38.00 to $51.84	287,795	6.2	$ 45.84	57,585	$ 46.21
$8.00 to $51.84	1,549,140	5.5	$ 24.59	884,876	$ 22.60

1 The plans allow for the use of a "stock swap" in lieu of a cash exercise for options, under certain circumstances. The delivery of Swift Energy common stock, held by the optionee for a minimum of six months, which are considered

mature shares, with a fair market value equal to the required purchase price of the shares to which the exercise relates, constitutes a valid "stock swap." Options issued under a "stock swap" also include a reload feature where additional options are granted at the then current market price when mature shares of Swift stock are used to satisfy the exercise price of an existing stock option grant. The terms of the plans provide that the mature shares delivered, as full or partial payment in a "stock swap", shall again be available for awards under the plans. In 2006, 2005 and 2004 respectively, 98,581, 170,762 and 81,716 mature shares were delivered in "stock swap" transactions, which resulted in the issuance of an equal number of reload option grants.

Restricted Stock. In 2006, 2005 and 2004, the Company issued 324,640, 158,500 and 70,900 shares, respectively, of restricted stock to employees and directors. These shares vest over a three-year to five-year period and remain subject to forfeiture if vesting conditions are not met. The fair value of these shares when issued in 2006, 2005 and 2004 was approximately $43, $38 and $25 per share.

The compensation expense for these awards was determined based on the market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of December 31, 2006, we have unrecognized compensation expense of approximately $13.9 million associated with

these awards which are expected to be recognized over a weighted-average period of 2.2 years. The total fair value of shares vested during the year ended December 31, 2006 was $1.6 million.

The following is a summary of our restricted stock issued to employees and directors under these plans as of December 31, 2006, 2005, and 2004:

	2006		2005	
	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	236,950	$ 34.79	100,900	$ 23.92
Restricted shares granted	324,640	$ 43.21	158,500	$ 38.31
Restricted shares canceled	(22,630)	$ 38.01	(7,450)	$ 39.03
Restricted shares vested	(35,776)	$ 24.57	(15,000)	$ ---
Restricted shares outstanding, end of period	503,184	$ 40.04	236,950	$ 34.79

Employee Stock Ownership Plan. In 1996, we established an Employee Stock Ownership Plan ("ESOP") effective January 1, 1996. All employees over the age of 21 with one year of service are participants. This plan has a five-year cliff vesting. The ESOP is designed to enable our employees to accumulate stock ownership. While there will be no employee contributions, participants will receive an allocation of stock that has been contributed by Swift Energy. Compensation expense is recognized upon vesting when such shares are released to employees. The plan may also acquire Swift Energy common stock, purchased at fair market value. The ESOP can borrow money from Swift Energy to buy Swift Energy common stock. ESOP payouts will be paid in a lump sum or installments, and the participants generally have the choice of receiving cash or stock. At December 31, 2006, 2005, and 2004, all of the ESOP compensation was earned. Our contribution to the ESOP plan totaled $0.4 million for the year ended December 31, 2006, and $0.2 million for the years ended December 31, 2005 and 2004, and were made all in common stock, and are recorded as "General and administrative, net" on the accompanying consolidated statements of income. The shares of common stock contributed to the ESOP plan totaled 8,927, 4,438, and 6,911 shares for the 2006, 2005, and 2004 contributions, respectively.

Employee Savings Plan. We have a savings plan under Section 401(k) of the Internal Revenue Code. Eligible employees may make voluntary contributions into the 401(k) savings plan with Swift contributing on behalf of the eligible employee an amount equal to 100% of the first 2% of compensation and 75% of the next 4% of compensation based on the contributions made by the eligible employees. Our contributions to the 401(k) savings plan were $1.0 million for 2006, $0.8 million for 2005, and $0.7 million for 2004, and are recorded as "General and administrative, net" on the accompanying consolidated statements of income. The contributions in 2006, 2005, and 2004 were made all in common stock. The shares of common stock contributed to the 401(k) savings plan totaled 23,890, 17,920, and 24,513 shares for the 2006, 2005, and 2004 contributions, respectively.

Treasury Shares. In March 1997, our Board of Directors approved a common stock repurchase program that terminated as of June 30, 1999. Under this program, we spent approximately $13.3 million to acquire 927,774 shares in the open market at an average cost of $14.34 per share. At December 31, 2006, 427,086 shares remain in treasury (net of 500,688 shares used to fund the ESOP, 401(k) contributions and acquisitions) with a total cost of $6.1 million and are included in "Treasury stock held, at cost" on the accompanying consolidated balance sheet.

Shareholder Rights Plan. Our Rights Agreement was initially adopted by the Board of Directors in 1997 for a ten year term. The Board of Directors renewed and extended the Rights Agreement for an additional ten year term from December 21, 2006. Pursuant to the Rights Agreement as amended, for each share of Swift Energy common stock a holder has the right to purchase one one-thousandth of a share of Swift Energy preferred stock for $250 upon the occurance of certain events triggered when a person or entity purchases 15% or more beneficial ownership of Swift Energy's outstanding common stock. The rights are not exercisable by such 15% or more beneficial owner.

7. Related-Party Transactions

We were the operator of a number of properties owned by private limited partnerships and, accordingly, charge these entities operating fees. The operating supervision fees charged to the partnerships totaled approximately $0.2 million in 2006, 2005, and 2004, and are recorded as reductions of "General and administrative, net." We also have been reimbursed for administrative, and overhead costs incurred in conducting the business of the private limited partnerships, which totaled $0.1 million per year in 2006 and 2005, and $0.2 million in 2004, and are recorded as reductions in "General and administrative, net." As of December 31, 2006, the remaining two partnerships have been dissolved.

We receive research, technical writing, publishing, and website-related services from Tec-Com Inc., a corporation located in Knoxville, Tennessee and controlled and majority owned by the aunt of the Company's Chairman of the Board and Chief Executive Officer. We paid approximately $0.5 million to Tec-Com for such services pursuant to the terms of the contract between the parties in 2006, and $0.4 million per year in 2005 and 2004. The contract was renewed June 30, 2004 on substantially the same terms and expires June 30, 2007. We believe that the terms of this contract are consistent with third party arrangements that provide similar services.

As a matter of corporate governance policy and practice, related party transactions are annually presented and considered by the Corporate Governance Committee of our Board of Directors in accordance with the Committee's charter.

8. Foreign Activities

As of December 31, 2006, our gross capitalized oil and gas property costs in New Zealand totaled approximately $349.1 million. Approximately $332.5 million has been included in the "Proved properties" portion of our oil and gas properties, while $16.6 million is included as "Unproved properties." Our functional currency in New Zealand is the U.S. Dollar. Net assets of our New Zealand operations total $261.3 million at December 31, 2006. Our capital expenditures on oil and gas property in New Zealand were approximately $56.7 million in 2006.

9. Acquisitions and Dispositions

In October 2006, we acquired interests in five South Louisiana fields. The property interests are located in: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), High Island field in Cameron Parish and Bayou Penchant field in Terrebonne Parish. We paid approximately $167.9 million in cash for these interests. After taking into account internal acquisition costs of $4.0 million, our total cost was $171.9 million. We allocated $143.1 million of the acquisition price to "Proved Properties," $28.8 million to "Unproved Properties," and recorded a liability for $11.5 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. These acquisitions were accounted for by the purchase method of accounting. We made these acquisitions to increase our exploration and development opportunities in South Louisiana. The revenues and expenses from these properties have been included in our accompanying consolidated statements of income from the date of acquisition forward; however, given the acquisitions closed in the fourth quarter of 2006, these amounts were not material to our full year 2006 results.

In December 2006, we acquired additional interests in our Lake Washington field. We paid approximately $20.0 million in cash for these interests. After taking into account internal acquisition costs of $0.4 million, our total cost was $20.4 million. We allocated $17.9 million of the acquisition price to "Proved Properties," $2.5 million to "Unproved Properties," and recorded a liability for $0.8 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. This acquisition was accounted for by the purchase method of accounting. We made this acquisition to increase our exploration and development opportunities in South Louisiana. The revenues and expenses from this acquisition have been included in our accompanying consolidated statements of income from the date of acquisition forward; however, given the acquisition closed in December 2006, these amounts were not material to our full year 2006 results.

In April 2006, we sold our minority interest in the Brookeland natural gas processing plants for approximately $20.3 million in cash. Under the "full-cost" method of accounting for oil and gas property and equipment costs, the proceeds of this sale were applied against our oil and gas properties and equipment balance, and no gain or loss was recognized on this transaction.

In November 2005, we acquired interests in the South Bearhead Creek field in Central Louisiana. This field is approximately 50 miles south of our Masters Creek field. We paid approximately $24.3 million in cash for these interests. After taking into account internal acquisition costs of $2.6 million and assumed liabilities of $1.4 million, our total cost was $28.3 million. We allocated $26.2 million of the acquisition price to "Proved Properties," $2.5 million to "Unproved Properties," and recorded a liability for $0.4 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. In December 2006, we acquired additional interests in this field. We paid approximately $4.5 million in cash for these additional interests. After taking into account internal acquisition costs of $0.1 million, our total cost was $4.6 million. We allocated $4.1 million of the acquisition price to "Proved Properties" and $0.5 million to "Unproved Properties" on our accompanying consolidated balance sheet. These acquisitions were accounted for by the purchase method of accounting. We made these acquisitions to increase our exploration and development opportunities in this area. The revenues and expenses from these properties have been included in our accompanying consolidated statements of income from the date the acquisition closed. However, given the acquisitions closed in November 2005 and December 2006, these amounts were immaterial for both the 2005 and 2006 periods.

In December 2004, we acquired interests in two fields in South Louisiana, the Bay de Chene and Cote Blanche Island fields. We paid approximately $27.7 million in cash for these interests. After taking into account internal acquisition costs of $2.8 million, our total cost was $30.5 million. We allocated $27.8 million of the acquisition price to "Proved properties" and $5.1 million to "Unproved properties" we also recorded $0.5 million to "Restricted assets" and recorded a liability of $2.9 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. This acquisition was accounted for by the purchase method of accounting. We made this acquisition to increase our exploration and development opportunities in South Louisiana. The revenues and expenses from these properties have been included in our accompanying consolidated statements of income from the date the acquisition closed. However, given the acquisition closed in late December 2004, these amounts were immaterial for that year.

10. Condensed Consolidating Financial Information

In December 2005, we amended the indenture for our 9-3/8% Senior Subordinated Notes due 2012 and our 7-5/8% Senior Notes due 2011 to reflect our new holding company organizational structure (as discussed in Note 1). As part of this restructuring our indentures were amended so that both Swift Energy Company and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) became co-obligors of these senior notes and senior subordinated debt. The co-obligations are full and unconditional and are joint and several. Prior to this restructure, Swift Energy Company was the sole obligor. The following is condensed consolidating financial information for Swift Energy Company, Swift Energy Operating, LLC, and other subsidiaries:

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Condensed Consolidating Balance Sheets

(in 000's)	December 31, 2006			
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	E
ASSETS				
Current assets	$ ---	$ 75,270	$ 17,303	$
Property and equipment	---	1,239,722	243,590	
Investment in subsidiaries (equity method)	797,917	---	590,720	
Other assets	---	42,519	705	
Total assets	$ 797,917	$ 1,357,511	$ 852,318	$
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities	$ ---	$ 137,016	$ 8,959	$
Long-term liabilities	---	629,775	45,442	
Stockholders' equity	797,917	590,720	797,917	
Total liabilities and stockholders' equity	$ 797,917	$ 1,357,511	$ 852,318	$

(in 000's)	December 31, 2005			
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	E
ASSETS				
Current assets	$ ---	$ 92,788	$ 22,267	$
Property and equipment	---	862,717	216,316	
Investment in subsidiaries (equity method)	607,318	---	410,612	
Other assets	---	31,955	682	
Total assets	$ 607,318	$ 987,460	$ 649,877	$

LIABILITIES AND STOCKHOLDERS' EQUITY

Current liabilities	$ ---	$ 85,472	$ 12,949	$
Long-term liabilities	---	491,376	29,610	
Stockholders' Equity	607,318	410,612	607,318	
Total liabilities and stockholders' equity	$ 607,318	$ 987,460	$ 649,877	$

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(in 000's)

	December 31, 2004			
	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations	Swi C
ASSETS				
Current assets	$ 38,713	$ 15,673	$ ---	$
Property and equipment	719,209	204,229	---	
Investment in subsidiaries (equity method)	104,003	---	(104,003)	
Other assets	116,537	2,364	(106,152)	
Total assets	$ 978,462	$ 222,265	$ (210,155)	$
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities	$ 60,160	$ 8,458	$ ---	$
Long-term liabilities	444,130	109,805	(106,152)	
Stockholders' Equity	474,172	104,003	(104,003)	
Total liabilities and stockholders' equity	$ 978,462	$ 222,265	$ (210,155)	$

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Condensed Consolidating Statements of Income

(in 000's)

	Year Ended December 31, 200			
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	E

Revenues	$ ---	$ 550,540	$ 64,901	$
Expenses	---	302,232	50,923	
Income (loss) before the following:	---	248,308	13,978	
Equity in net earnings of subsidiaries	161,565	---	151,075	
Income before income taxes	161,565	248,308	165,052	
Income tax provision (benefit)	---	97,234	3,487	
Net income	$ 161,565	$ 151,074	$ 161,565	$

(in 000's)	Year Ended December 31, 200			
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	E
Revenues	$ ---	$ 354,367	$ 68,893	$
Expenses	---	198,237	46,583	
Income (loss) before the following:	---	156,130	22,309	
Equity in net earnings of subsidiaries	115,778	---	97,880	
Income before income taxes	115,778	156,130	120,190	
Income tax provision (benefit)	---	58,249	4,412	
Net income	$ 115,778	$ 97,881	$ 115,778	$

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(in 000's)	Year Ended December 31, 2004			
	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Elminations	Swi Co
Revenues	$ 256,608	$ 53,817	$ (147)	$
Expenses	171,147	37,838	(147)	
Income (loss) before the following:	85,461	15,979	---	
Equity in net earnings of subsidiaries	14,733	---	(14,733)	
Income before income taxes	100,194	15,979	(14,733)	
Income tax provision (benefit)	31,743	1,247	---	

Net income	$ 68,451	$ 14,733	$ (14,733)	$ -

Condensed Consolidating Statements of Cash Flow

(in 000's)	Year Ended December 31, 2006			
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Elmin
Cash flow from operations	$ ---	$ 383,241	$ 41,680	$
Cash flow from investing activities	---	(474,781)	(59,881)	
Cash flow from financing activities	---	46,679	11,115	
Net decrease in cash	---	(44,861)	(7,086)	
Cash, beginning of period	---	44,911	8,094	
Cash, end of period	$ ---	$ 50	$ 1,008	$

(in 000's)	Year Ended December 31, 2005			
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Elmin
Cash flow from operations	$ ---	$ 236,790	$ 48,543	$
Cash flow from investing activities	---	(194,909)	(48,837)	
Cash flow from financing activities	---	2,825	3,672	
Net increase in cash	$ ---	$ 44,706	$ 3,379	$
Cash, beginning of period	---	205	4,715	
Cash, end of period	$ ---	$ 44,911	$ 8,094	$

(in 000's)	Year Ended December 3
	Swift Energy Co. (Parent and

	Issuer)	Other Subsidiaries	E
Cash flow from operations	$ 147,114	$ 35,469	$
Cash flow from investing activities	(158,308)	(35,878)	
Cash flow from financing activities	10,357	5,100	
Net increase (decrease) in cash	(837)	4,691	
Cash, beginning of period	1,042	24	
Cash, end of period	$ 205	$ 4,715	$

11. Segment Information

The Company has two reportable segments, one domestic and one foreign, which are in the business of crude oil and natural gas exploration and production. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate our performance based on profit or loss from oil and gas operations before price-risk management and other, net, general and administrative, net, interest expense, net and debt retirement costs. Our reportable segments are managed separately based on their geographic locations. Financial information by operating segment is presented below:

	2006		
	Domestic	New Zealand	Total
Oil and gas sales	$ 537,512,509	$ 64,038,859	$ 601,551,368
Costs and Expenses:			
Depreciation, depletion, and amortization	(139,244,630)	(30,051,144)	(169,295,774)
Accretion of asset retirement obligation	(884,105)	(150,217)	(1,034,322)
Lease operating cost	(49,948,039)	(12,526,580)	(62,474,619)
Severance and other taxes	(61,234,906)	(4,217,137)	(65,452,043)
Income from oil and gas operations	$ 286,200,829	$ 17,093,781	$ 303,294,610
Price-risk management and other, net			13,889,862
General and administrative, net			(31,316,644)
Interest expense, net			(23,581,663)
Income before Income Taxes			$ 262,286,165

Property and Equipment, net	$1,255,331,575	$ 227,980,590	$ 1,483,312,165
Total Assets	1,349,684,402	235,997,356	1,585,681,758
Capital Expenditures	$ 502,342,254	$ 55,149,258	$ 557,491,512

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	2005		
	Domestic	New Zealand	Total
Oil and gas sales	$ 355,872,616	$ 67,893,629	$ 423,766,245
Costs and Expenses:			
Depreciation, depletion, and amortization	(81,123,588)	(26,354,199)	(107,477,787)
Accretion of asset retirement obligation	(626,134)	(134,908)	(761,042)
Lease operating cost	(34,941,430)	(12,380,411)	(47,321,841)
Severance and other taxes	(37,805,742)	(4,370,763)	(42,176,505)
Income from oil and gas operations	$ 201,375,722	$ 24,653,348	$ 226,029,070
Price-risk management and other, net			(539,756)
General and administrative, net			(22,176,362)
Interest expense, net			(24,873,401)
Income before Income Taxes			$ 178,439,551
Property and Equipment, net	$ 863,154,295	$ 215,879,444	$ 1,079,033,739
Total Assets	962,469,183	241,943,439	1,204,412,622
Capital Expenditures	$ 215,785,080	$ 48,689,826	$ 264,474,906

	2004		
	Domestic	New Zealand	Total
Oil and gas sales	$ 258,663,936	$ 52,621,236	$ 311,285,172
Costs and Expenses:			
Depreciation, depletion, and amortization	(62,283,350)	(19,297,478)	(81,580,828)
Accretion of asset retirement obligation	(505,174)	(168,480)	(673,654)

Lease operating cost	(30,191,889)	(11,022,367)	(41,214,256)
Severance and other taxes	(26,713,592)	(3,687,701)	(30,401,293)
Income from oil and gas operations	$ 138,969,931	$ 18,445,210	$ 157,415,141
Price-risk management and other, net			(1,008,398)
General and administrative, net			(17,787,125)
Interest expense, net			(27,643,108)
Debt retirement costs			(9,536,268)
Income before Income Taxes			$ 101,440,242
Property and Equipment, net	$ 731,890,068	$ 191,548,092	$ 923,438,160
Total Assets	778,611,100	211,962,047	990,573,147
Capital Expenditures	$ 162,535,617	$ 35,755,820	$ 198,291,437

Supplementary Information

Swift Energy Company and Subsidiaries
Oil and Gas Operations (Unaudited)

Capitalized Costs. The following table presents our aggregate capitalized costs relating to oil and gas producing activities and the related depreciation, depletion, and amortization:

	Total	Domestic
December 31, 2006:		
Proved oil and gas properties	$ 2,264,831,638	$ 1,932,336,298
Unproved oil and gas properties	112,136,836	95,569,089
	2,376,968,474	2,027,905,387
Accumulated depreciation, depletion, and amortization	(915,397,437)	(808,708,770
Net capitalized costs	$ 1,461,571,037	$ 1,219,196,617
December 31, 2005:		
Proved oil and gas properties	$ 1,731,866,298	$ 1,468,981,981
Unproved oil and gas properties	87,553,220	58,196,531
	1,819,419,518	1,527,178,512
Accumulated depreciation, depletion, and amortization	(748,327,443)	(671,117,089
Net capitalized costs	$ 1,071,092,075	$ 856,061,423

Of the $95.6 million of domestic Unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2006, excluded from the amortizable base, $68.3 million was incurred in 2006, $13.3 million was incurred in 2005, $8.9 million was incurred in 2004, and $5.1 million was incurred in prior years. When we are in an active drilling mode, we evaluate the majority of these unproved costs within a two to four year time frame.

Of the $16.6 million of New Zealand Unproved property costs at December 31, 2006, excluded from the amortizable base, $8.0 million was incurred in 2006, $2.1 million was incurred in 2005, $1.7 million was incurred in 2004, and $4.8 million was incurred in prior years. We expect to continue drilling in New Zealand to delineate our prospects there within a two to four year time frame.

Capitalized asset retirement obligations have been included in the Proved properties as of December 31, 2006, 2005, and 2004.

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Costs Incurred. The following table sets forth costs incurred related to our oil and gas operations:

	Year Ended December 31,	
	Total	Domestic
Acquisition of proved and unproved properties	$ 212,499,280	$ 212,499,280
Lease acquisitions and prospect costs(1)	79,183,368	68,594,051
Exploration	29,285,958	13,224,894
Development (2)	261,142,220	231,085,290
Total acquisition, exploration, and development (3),(4)	$ 582,110,826	$ 525,403,515

	Year Ended December 31	
	Total	Domestic
Acquisition of proved and unproved properties	$ 31,429,343	$ 31,429,343
Lease acquisitions and prospect costs(1)	41,397,277	34,502,163
Exploration	52,350,339	38,424,995
Development (2)	141,081,231	111,057,945
Total acquisition, exploration, and development (3),(4)	$ 266,258,190	$ 215,414,446

	Year Ended December 31	
	Total	Domestic
Acquisition of proved and unproved properties	$ 31,771,094	$ 31,771,094
Lease acquisitions and prospect costs(1)	34,545,393	27,713,059
Exploration	17,430,265	16,714,982

Development (2)	108,259,091	79,338,697
Total acquisition, exploration, and development (3),(4)	$ 192,005,843	$ 155,537,832

(1)These are actual amounts as incurred by year, including both proved and unproved lease costs. The annual lease acquisition amounts added to proved oil and gas properties in 2006, 2005, and 2004 were $70.5 million, $30.4 million, and $17.8 million, respectively. Domestic costs for seismic data acquisition, included above, were $23.1 million, 4.2 million, and $1.0 million in 2006, 2005 and 2004, respectively. New Zealand costs for seismic data acquisition, included above were $3.8 million in 2006.

(2)Facility construction costs and capital costs have been included in development costs, and totaled $16.5 million, $26.9 million, and $12.6 million for the years ended December 31, 2006, 2005 and 2004.

(3)Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $28.3 million, $18.8 million, and $13.1 million in 2006, 2005, and 2004, respectively. In addition, total includes $9.2 million, $7.2 million, and $6.5 million in 2006, 2005, and 2004, respectively, of capitalized interest on unproved properties.

(4)Asset retirement obligations incurred have been included in exploration, development and acquisition costs as applicable for the years ended December 31, 2006, 2005, and 2004.

Results of Operations.

	Year Ended December 31, 2006		
	Total	Domestic	New Zea
Oil and gas sales	$ 601,551,368	$ 537,512,509	$ 64,
Lease operating cost	(62,474,619)	(49,948,039)	(12,
Severance and other taxes	(65,452,043)	(61,234,906)	(4,
Depreciation, depletion, and amortization	(166,518,190)	(136,826,013)	(29,
Accretion of asset retirement obligation	(1,034,322)	(884,105)	(
	306,072,194	288,619,446	17,
Provision for income taxes	117,531,722	110,829,867	6,
Results of producing activities	$ 188,540,472	$ 177,789,579	$ 10,
Amortization per physical unit of production (equivalent Mcf of gas)	$ 2.37	$ 2.41	$

	Year Ended December 31, 2005		
	Total	Domestic	New Zea
Oil and gas sales	$ 423,766,245	$ 355,872,616	$ 67,
Lease operating cost	(47,321,841)	(34,941,430)	(12,
Severance and other taxes	(42,176,505)	(37,805,742)	(4,
Depreciation, depletion and amortization	(106,037,775)	(79,926,245)	(26,
Accretion of asset retirement obligation	(761,042)	(626,134)	(
	227,469,082	202,573,065	24,
Provision for income taxes	79,878,043	74,953,611	4,
Results of producing activities	$ 147,591,039	$ 127,619,454	$ 19,
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.78	$ 1.86	$

	Year Ended December 31, 2004		
	Total	Domestic	New Zea
Oil and gas sales	$ 311,285,172	$ 258,663,936	$ 52,
Lease operating cost	(41,214,256)	(30,191,889)	(11,
Severance and other taxes	(30,401,293)	(26,713,592)	(3,
Depreciation, depletion and amortization	(80,504,043)	(61,478,364)	(19,
Accretion of asset retirement obligation	(673,654)	(505,174)	(
	158,491,926	139,774,917	18,7
Provision for income taxes	53,093,022	51,576,944	1,5
Results of producing activities	$ 105,398,904	$ 88,197,973	$ 17,2
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.38	$ 1.46	$

These results of operations do not include the gains from our hedging activities of $4.0 million in 2006, and losses from our hedging activities of $1.1 million and $1.3 million for 2005 and 2004, respectively. Our lease operating costs per Mcfe produced were $0.89 in 2006, $0.79 in 2005, and $0.71 in 2004.

The accretion of asset retirement obligation has been included in the 2006, 2005 and 2004 periods.

We used our effective tax rate in each country to compute the provision for income taxes in each year presented.

Supplementary Reserves Information. The following information presents estimates of our proved oil and gas reserves. Reserves were determined by us and audited by H. J. Gruy and Associates, Inc. ("Gruy"), independent petroleum consultants. Gruy has audited 100% of our proved reserves. Gruy's audit was conducted according to standards approved by the Board of Directors of the Society of Petroleum Engineers, Inc. and included examination, on a test basis, of the evidence supporting our reserves. Gruy's audit was based upon review of production histories and other geological, economic, and engineering data provided by us. Gruy's report dated January 23, 2007, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 2006, and includes definitions and assumptions that served as the basis for the audit of proved reserves and future net cash flows. Such definitions and assumptions should be referred to in connection with the following information:

Estimates of Proved Reserves	Total		Domestic	
	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)	Natural Gas (Mcf)	Oil, NG and Condens (Bbls)
Proved reserves as of December 31, 2003	335,804,862	80,759,903	242,321,275	67,015
Revisions of previous estimates(1)	(3,306,705)	(1,117,715)	(1,619,531)	695
Purchases of minerals in place	9,808,953	5,602,508	9,808,953	5,602
Sales of minerals in place	(2,524,760)	(44,803)	(2,524,760)	(44
Extensions, discoveries, and other additions	2,205,670	830,111	2,205,670	830
Production	(23,741,726)	(5,762,796)	(12,299,772)	(4,959
Proved reserves as of December 31, 2004	318,246,294	80,267,208	237,891,835	69,139
Revisions of previous estimates(1)	(21,461,605)	(2,199,673)	(13,751,124)	(1,023
Purchases of minerals in place	9,336,088	3,262,761	9,336,088	3,262
Sales of minerals in place	(3,737,714)	(100,121)	(3,737,714)	(100
Extensions, discoveries, and other additions	8,699,329	3,819,595	7,275,207	3,722
Production	(23,609,242)	(5,996,714)	(11,739,485)	(5,217
Proved reserves as of December 31, 2005	287,473,150	79,053,056	225,274,807	69,783
Revisions of previous estimates(1)	(33,631,025)	3,127,635	(34,542,219)	3,135
Purchases of minerals in place	60,187,095	2,922,553	60,187,095	2,922
Sales of minerals in place	(6,122,283)	(708,691)	(6,122,283)	(708
Extensions, discoveries, and other additions	39,012,428	5,627,297	38,466,980	5,512
Production	(22,787,948)	(7,902,766)	(13,603,589)	(7,181
Proved reserves as of December 31, 2006	324,131,417	82,119,084	269,660,791	73,464
Proved developed reserves: (2)				
December 31, 2003	210,119,927	45,525,366	138,173,341	38,767
December 31, 2004	193,310,761	42,037,852	140,549,052	36,628
December 31, 2005	152,001,133	37,989,821	125,367,690	35,298
December 31, 2006	151,276,834	34,956,469	133,815,108	33,345

(1)Revisions of previous estimates are related to upward or downward variations based on current engineering information for production rates, volumetrics, and reservoir pressure. Additionally, changes in quantity estimates are affected by the increase or decrease in crude oil, NGL, and natural gas prices at each year-end. Proved reserves, as of December 31, 2006, were based upon prices in effect at year-end. Our hedges at year-end 2006 consisted of natural gas price floors with strike prices higher than the period end price and thus would not materially affect prices used in these calculations. The weighted average of 2006 year-end prices for total, domestic, and New Zealand were $5.46, $5.84, and $3.59 per Mcf of natural gas, $60.41, $60.07, and $63.51 per barrel of oil, and $30.93, $31.54 and $26.84 per barrel of NGL, respectively. This compares to $8.94, $10.36, and $3.79 per Mcf of natural gas, $60.12, $60.00, and $60.98 per barrel of oil, and $31.40, $33.28 and $19.20 per barrel of NGL as of December 31, 2005, for total, domestic, and New Zealand, respectively. The weighted average of 2004 year-end prices for total, domestic, and New Zealand were $5.16, $5.87, and $3.07 per Mcf of natural gas, $41.07, $42.21, and $33.60 per barrel of oil, and $25.48, $26.49 and $20.48 per barrel of NGL, respectively.

(2)At December 31, 2006, 44% of our reserves were proved developed, compared to 50% at December 31, 2005, 56% at December 31, 2004, and 59% at December 31, 2003.

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Standardized Measure of Discounted Future Net Cash Flows. The standardized measure of discounted future nt cash flows relating to proved oil and gas reserves is as follows:

	Year Ended December 31,	
	Total	Domestic
Future gross revenues	$ 6,341,394,321	$ 5,659,084,913
Future production costs	(1,393,634,094)	(1,167,117,123)
Future development costs	(935,003,617)	(886,842,793)
Future net cash flows before income taxes	4,012,756,610	3,605,124,997
Future income taxes	(1,187,858,603)	(1,137,617,295)
Future net cash flows after income taxes	2,824,898,007	2,467,507,702
Discount at 10% per annum	(956,238,277)	(835,593,066)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,868,659,730	$ 1,631,914,636

	Year Ended December 31,	
	Total	Domestic
Future gross revenues	$ 6,917,103,123	$ 6,194,560,214
Future production costs	(1,334,822,738)	(1,122,637,935)
Future development costs	(710,343,331)	(667,526,650)

Future net cash flows before income taxes	4,871,937,054	4,404,395,629
Future income taxes	(1,538,799,956)	(1,461,577,946)
Future net cash flows after income taxes	3,333,137,098	2,942,817,683
Discount at 10% per annum	(1,173,767,635)	(1,048,193,951)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 2,159,369,463	$ 1,894,623,732

	Year Ended December 31,	
	Total	Domestic
Future gross revenues	$ 4,711,060,300	$ 4,122,705,861
Future production costs	(1,029,449,670)	(819,035,166)
Future development costs	(480,093,684)	(434,305,537)
Future net cash flows before income taxes	3,201,516,946	2,869,365,158
Future income taxes	(896,135,438)	(866,598,544)
Future net cash flows after income taxes	2,305,381,508	2,002,766,614
Discount at 10% per annum	(840,436,013)	(746,227,690)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,464,945,495	$ 1,256,538,924

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions.

2. The estimated future gross revenues of proved reserves are priced on the basis of year-end prices, except in those instances where fixed and determinable gas price escalations are covered by contracts limited to the price we reasonably expect to receive.

3. The future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, as well as asset retirement obligation costs, net of salvage value, based on year-end cost estimates and the estimated effect of future income taxes.

4. Future income taxes are computed by applying the statutory tax rate to future net cash flows reduced by the tax basis of the properties, the estimated permanent differences applicable to future oil and gas producing activities, and tax carry forwards.

The estimates of cash flows and reserves quantities shown above are based on year-end oil and gas prices for each period. Our hedges at year-end 2006 consisted mainly of natural gas price floors with strike prices higher than the period end price and did not materially affect prices used in these calculations. Subsequent changes to such year-end oil and gas prices could have a significant impact on discounted future net cash flows. Under Securities and Exchange Commission rules, companies that follow the full-cost accounting method are required to make quarterly Ceiling Test calculations using hedge adjusted prices in effect as of the period end date presented (see Note 1 to the consolidated financial statements). Application of these rules during periods of relatively low oil and gas prices, even if of short-term seasonal duration, may result in non-cash write-downs.

The standardized measure of discounted future net cash flows is not intended to present the fair market value of our oil and gas property reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves in excess of proved reserves, anticipated future changes in prices and costs, an allowance for return on investment, and the risks inherent in reserves estimates.

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	Year Ended December 31,		
	2006	2005	
Beginning balance	$ 2,159,369,463	$ 1,464,945,495	$ 1
Revisions to reserves proved in prior years--			
Net changes in prices, and production costs	(658,283,413)	1,232,876,998	
Net changes in future development costs	(166,890,534)	(173,219,347)	
Net changes due to revisions in quantity estimates	(60,713,716)	(138,969,442)	
Accretion of discount	314,344,631	199,799,374	
Other	(98,478,730)	17,191,849	
Total revisions	(670,021,762)	1,137,679,432	
New field discoveries and extensions, net of future production and development costs	212,629,383	152,461,162	
Purchases of minerals in place	289,338,576	99,129,117	
Sales of minerals in place	(20,378,583)	(10,164,069)	
Sales of oil and gas produced, net of production costs	(473,624,706)	(334,267,899)	
Previously estimated development costs incurred	187,133,510	100,614,837	
Net change in income taxes	184,213,849	(451,028,612)	
Net change in standardized measure of discounted future net cash flows	(290,709,733)	694,423,968	
Ending balance	$ 1,868,659,730	$ 2,159,369,463	$ 1

Selected Quarterly Financial Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2006 and 2005:

	Revenues	Income Before Income Taxes	Net Income	Basic EPS Net Income	Diluted EPS Net Income
2006:					
First	$ 136,168,931	$ 57,774,996	$ 37,314,506	$ 1.28	$ 1.24
Second	147,177,246	60,189,700	38,168,448	1.31	1.27
Third	173,458,852	82,209,164	50,811,567	1.74	1.68
Fourth	158,636,201	62,112,305	35,270,819	1.19	1.16
Total	$ 615,441,230	$ 262,286,165	$ 161,565,340	$ 5.52	$ 5.38
2005:					
First	$ 95,620,684	$ 39,758,619	$ 25,689,152	$ 0.91	$ 0.89
Second	104,299,925	41,778,041	27,881,658	0.98	0.96
Third	100,853,505	42,901,655	27,506,899	0.96	0.92
Fourth	122,452,375	54,001,236	34,700,747	1.20	1.16
Total	$ 423,226,489	$ 178,439,551	$ 115,778,456	$ 4.06	$ 3.95

There were no extraordinary items in 2006 or 2005.

The sum of the individual quarterly net income per common share amounts may not agree with year-to-date net income per common share as each quarterly computation is based on the weighted average number of common shares outstanding during that period. In addition, certain potentially dilutive securities were not included in certain of the quarterly computations of diluted net income per common share because to do so would have been antidilutive.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

The Company's chief executive officer and chief financial officer have evaluated the Company's disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") as of the end of the period covered by this report. Based on that evaluation, they have concluded that such disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to the Company required under the Exchange Act to be disclosed in this report. There were no significant changes in the Company's internal controls that could significantly affect such controls subsequent to the date of their evaluation.

Management's Report On Internal Control Over Financial Reporting as of December 31, 2006 is included in Item 8. Financial Statements and Supplementary Data. The Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting is also included in Item 8.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required under Item 10 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 8, 2007, annual shareholders' meeting is incorporated herein by reference.

Item 11. Executive Compensation

The information required under Item 11 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 8, 2007, annual shareholders' meeting is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required under Item 12 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 8, 2007, annual shareholders' meeting is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required under Item 13 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 8, 2007, annual shareholders' meeting is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required under Item 14 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 8, 2007, annual shareholders' meeting is incorporated by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

o 1. The following consolidated financial statements of Swift Energy Company together with the report thereon of Ernst & Young LLP dated February 27, 2007, and the data contained therein are included in Item 8 hereof:

o Financial Statement Schedules

[None]

3. Exhibits

2	Plan and Agreement and Articles of Merger to Form Holding Company, dated as of December 21, 2005, but effective at 9:00 a.m., local time in Austin, Texas on December 28, 2005, by and among Swift Energy Company, New Swift Energy Company and Swift Energy Operating, LLC (incorporated by reference as Exhibit 2.1 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
3.1	Restated Articles of Incorporation of Swift Energy Company (incorporated by reference as Exhibit 3.3 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
3.2	Amended and Restated Bylaws of Swift Energy Company, as amended through December 28, 2005 (incorporated by reference as Exhibit 3.5 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
3.3	Certificate of Designation of Series A Junior Participating Preferred Stock of Swift Energy Company (incorporated by reference as Exhibit 3.4 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
4.1	Indenture dated as of April 16, 2002, between Swift Energy Company and Bank One, N.A., as Trustee (incorporated by reference as Exhibit 4.1 to Swift

Energy Company's Form 8-K filed April 16, 2002, File No. 1-08754).

4.2	First Supplemental Indenture dated as of April 16, 2002, between Swift Energy Company and Bank One, N.A., including the form of 9 3/8% Senior Subordinated Notes due 2012 (incorporated by reference as Exhibit 4.2 to Swift Energy Company's Form 8-K filed April 16, 2002, File No. 1-08754).

4.3	Second Supplemental Indenture dated as of December 28, 2005, between Swift Energy Company and J.P. Morgan Trust Company, National Association as successor Trustee to Bank One, NA (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
4.4	Indenture dated as of June 23, 2004, between Swift Energy Company and Wells Fargo Bank, National Association, as Trustee (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed June 25, 2004, File No. 1-08754).
4.5	First Supplemental Indenture dated as of June 23, 2004, between Swift Energy Company and Wells Fargo Bank, National Association, as Trustee, including the form of 7 5/8% Senior Notes (incorporated by reference as Exhibit 4.2 to Swift Energy Company's Form 8-K filed June 25, 2004, File No. 1-08754).
4.6	Second Supplemental Indenture dated as of December 28, 2005, between Swift Energy Company and Wells Fargo Bank. National Association, as Trustee (incorporated by reference as Exhibit 4.2 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
4.7	Amended and Restated Rights Agreement between Swift Energy Company and American Stock Transfer & Trust Company, dated March 31, 1999 (incorporated by reference to Swift Energy Company's Amendment No. 1 to Form 8-A filed April 7, 1999, File No. 1-08754).
4.8	Amendment No. 1 to the Rights Agreement dated December 12, 2005 between Swift Energy Company and American Stock Transfer & Trust Company, as Rights Agent (incorporated by reference as Exhibit 4.3 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
4.9	Assignment, Assumption, Amendment and Novation Agreement between Swift Energy Company, New Swift Energy Company and American Stock Transfer & Trust Company, as Rights Agent effective at 9:00 a.m. local time in Austin, Texas on December 28, 2005

	(incorporated by reference as Exhibit 4.4 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
4.10	Amendment No. 2 to the Rights Agreement dated December 21, 2006 between Swift Energy Company and American Stock Transfer & Trust Company, as Rights Agent (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed December 22, 2006, File No. 1-08754).
10.1+	Amended and Restated Swift Energy Company 1990 Nonqualified Stock Option Plan, as of May 13, 1997 (incorporated by reference from Swift Energy Company's definitive proxy statement for the annual shareholders meeting filed April 14, 1997, File No. 1-08754).
10.2+	Amended and Restated Swift Energy Company 1990 Stock Compensation Plan, as of May 13, 1997 (incorporated by reference from Swift Energy Company's definitive proxy statement for the annual shareholders meeting filed April 14, 1997, File No. 1-08754).
10.3+	Amendment to the Swift Energy Company 1990 Stock Compensation Plan, as of May 9, 2000 (incorporated by reference as Exhibit 4.2 to the Swift Energy Company registration statement No. 333-67242 on Form S-8 filed August 10, 2001, File No. 1-08754).
10.4+	Swift Energy Company 2001 Omnibus Stock Compensation Plan, as of January 1, 2001 (incorporated by reference as Exhibit 4.3 to the Swift Energy Company registration statement no. 333-67242 on Form S-8 filed August 10, 2001, File No. 1-08754).

10.5+	Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to the Swift Energy Company Form 8-K filed May 12, 2005, File No. 1-08754).
10.6+	Amendment No. 1 to the Swift Energy Company 2005 Stock Compensation Plan, as of May 9, 2006 (incorporated by reference as Exhibit 10.1 to the Swift Energy Company Form 8-K filed May 12, 2006).
10.7+	Employee Stock Purchase Plan (incorporated by reference as Exhibit 4(a) to Swift Energy Company's Registration Statement No. 33-80228 on Form S-8 filed June 15, 1994, File No. 1-08754).
10.8+	Amended and Restated Employee Stock Purchase Plan dated June 1, 2006 (incorporated by reference to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, File

	No. 1-08754).
10.9*	Form of Indemnity Agreement for Swift Energy Company officers.
10.10*	Form of Indemnity Agreement for Swift Energy Company directors.
10.11+	Amended and Restated Employment Agreement dated as of November 15, 2000 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and A. Earl Swift (incorporated by reference as Exhibit 10.12 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2000, File No. 1-08754).
10.12+	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and Terry E. Swift (incorporated by reference as Exhibit 10.2 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-08754).
10.13+	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and James M. Kitterman (incorporated by reference as Exhibit 10.6 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-08754).
10.14+	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and Bruce H. Vincent (incorporated by reference as Exhibit 10.4 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-08754).
10.15+	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and Joseph A. D'Amico (incorporated by reference as Exhibit 10.3 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-08754).
10.16+	Employment Agreement dated as of May 9, 2001 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and Victor R. Moran (incorporated by reference as Exhibit 10.7 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-08754).
10.17+	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and Alton D. Heckaman, Jr. (incorporated by reference as Exhibit 10.5 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30,

2001, File No. 1-08754).

10.18+	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company and Donald L. Morgan (incorporated by reference as Exhibit 10.8 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-08754).
10.19+	Consulting Agreement between Swift Energy Company and A. Earl Swift effective as of July 1, 2006 (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006, File No. 1-08754).
10.20+	Consulting Agreement between Swift Energy Company and Virgil N. Swift effective as of July 1, 2006 (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006, File No. 1-08754).
10.21+	Fourth Amended and Restated Agreement and Release by and between Swift Energy Company and Virgil Neil Swift, dated November 20, 2000 (incorporated by reference as Exhibit 10.13 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2000, File No. 1-08754).
10.22+	Description of executive officers' compensation arrangements (incorporated by reference as Exhibit 10.25 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2004, File No. 1-08754).
10.23+	Description of non-employee directors' compensation arrangements (incorporated by reference as Exhibit 10.16 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2004, File No. 1-08754).
10.24	+ Forms of agreements for grant of incentive and non-qualified stock options and forms of agreement for grant of restricted stock under Swift Energy Company 2001 Omnibus Stock Compensation Plan (incorporated by reference as Exhibit 10.17 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2004, File No. 1-08754).
10.25+	Forms of agreements for grant of incentive stock options and forms of agreement for grant of restricted stock under Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as

	Exhibit 10.19 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2005, File No. 1-08754).
10.26	First Amended and Restated Credit Agreement effective as of June 29, 2004, among Swift Energy Company and Bank One, NA as Administrative Agent, Wells Fargo Bank, National Association as Syndication Agent, BNP Paribas, as Syndication Agent, Caylon, as Documentation agent, Societe Generale, as Documentation Agent and the Lenders Signatory Hereto and Banc One Capital Markets, Inc., as Sole Lead Arranger and Sole Book Runner (incorporated by reference as Exhibit 10.2 to the Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, File No. 1-08754).
10.27	First Amendment to First Amended and Restated Credit Agreement effective as of November 1, 2005 by and among Swift Energy Company, JP Morgan Chase Bank, N.A. as Administrative Agent, J.P. Morgan Securities, Inc. as Sole Lead Arranger and Sole Book Runner, Wells Fargo Bank, National Association, as Sydication Agent, BNP Paribas, as Syndication Agent, Caylon, as Documentation Agent, and Societe Generale, as Documentation Agent. (incorporated by reference as Exhibit 10.1 to the Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2005, File No. 1-08754).

10.28	Second Amendment to First Amended and Restated Credit Agreement effective as of December 28, 2005, by and among Swift Energy Company and Swift Energy Operating, LLC, and, J.P. Morgan Chase Bank, N.A., as Administrative Agent, J.P. Morgan Securities, Inc. as Sole Lead Arranger and Sole Book Runner, Wells Fargo Bank, National Association, as Syndication Agent, BNP PARIBAS, as Syndication Agent, Calyon as Documentation Agent and Societe Generale as Documentation Agent (incorporated by reference as Exhibit 10.23 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2005, File No. 1-08754).
10.29*	Third Amendment to First Amended and Restated Credit Agreement effective as of October 2, 2006, by and among Swift Energy Company and Swift Energy Operating, LLC, and, J.P. Morgan Chase Bank, N.A., as Administrative Agent, J.P. Morgan Securities, Inc. as Sole Lead Arranger and Sole Book Runner, Wells Fargo Bank, National Association, as Syndication Agent, BNP PARIBAS, as Syndication Agent, Calyon as Documentation Agent and Societe Generale as Documentation Agent (incorporated by reference to

	Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2006, File No. 1-08754).
10.30	Eighth Amendment to Lease Agreement between Swift Energy Company and Greenspoint Plaza Limited Partnership dated as of June 30, 2004 (incorporated by reference as Exhibit 10.1 to the Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, File No. 1-08754).
10.31*	Purchase and Sale Agreement dated as of August 24, 2006 but effective as of April 1, 2006, between Swift Energy Operating, LLC and BP America Production Company.
12*	Swift Energy Company Ratio of Earnings to Fixed Charges.
21 *	List of Subsidiaries of Swift Energy Company.
23.1 *	The consent of H.J. Gruy and Associates, Inc.
23.2	* Consent of Ernst & Young LLP as to incorporation by reference regarding Forms S-8 and S-3 Registration Statements.
31.1	* Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	* Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	* Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	* The summary of H.J. Gruy and Associates, Inc. report, dated January 23, 2007.

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* Filed herewith.

\+ Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant, Swift Energy Company, has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SWIFT ENERGY COMPANY

By /s/ Terry E. Swift

Terry E. Swift
Chairman of the Board

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant, Swift Energy Company, and in the capacities and on the dates indicated:

Signatures	Title	Date
---------------------------- Terry E. Swift	Director Chief Executive Officer	February 28, 2007
---------------------------- Alton D. Heckaman, Jr.	Executive Vice-President Principal Financial Officer	February 28, 2007
---------------------------- David W. Wesson	Controller Principal Accounting Officer	February 28, 2007
---------------------------- Deanna L. Cannon	Director	February 28, 2007
---------------------------- Raymond E. Galvin	Director	February 28, 2007

----------------------------	Director	February 28, 2007

Douglas J. Lanier

---------------------------- Greg Matiuk	Director	February 28, 2007
---------------------------- Henry C. Montgomery	Director	February 28, 2007
---------------------------- Clyde W. Smith, Jr.	Director	February 28, 2007
---------------------------- Charles J. Swindells	Director	February 28, 2007
---------------------------- Bruce H. Vincent	Director	February 28, 2007

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SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

EXHIBITS

TO

FORM 10-K REPORT

FOR THE

YEAR ENDED DECEMBER 31, 2006

SWIFT ENERGY COMPANY

16825 NORTHCHASE DRIVE, SUITE 400

HOUSTON, TEXAS 77060

EXHIBIT INDEX

10.9	Form of Indemnity Agreement for Swift Energy Company officers.
10.10	Form of Indemnity Agreement for Swift Energy Company directors.
10.31	Purchase and Sale Agreement dated as of August 24, 2006 but effective as of April 1, 2006, between Swift Energy Operating, LLC and BP America Production Company.
12	Swift Energy Company Ratio of Earnings to Fixed Charges.
21	List of Subsidiaries of Swift Energy Company.
23.1	The consent of H.J. Gruy and Associates, Inc.
23.2	Consent of Ernst & Young LLP as to incorporation by reference regarding Forms S-8 and S-3 Registration Statements.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2003.
31.2	Certification of Chief Financial Officer pursuant to Section 3-2 of the Sarbanes-Oxley Act of 2002.
32	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	The summary of H.J. Gruy and Associates, Inc. report, dated January 23, 2007.

Exhibit 10.9

SWIFT ENERGY COMPANY

INDEMNIFICATION AGREEMENT

THIS INDEMNIFICATION AGREEMENT (the "Agreement"), is made and entered into as of ___________________, by and between Swift Energy Company, a Texas corporation (the "Company"), and ___________________ (the "Indemnitee").

BACKGROUND

A. The Company is aware that, in order to induce highly competent persons to serve or continue to serve the Company as officers or in other capacities, the Company must provide such persons with adequate protection through insurance and indemnification against risks of claims and actions against them arising out of their service to and activities on behalf of the Company.

B. The Company has adopted bylaws (the "Bylaws") providing for indemnification of the directors, officers, employees and other agents of the Company, including persons serving at the request of the Company in these capacities with other corporations or enterprises, to the full extent permitted under the applicable law of the State of Texas, which is currently the Texas Business Corporation Act (the "Act").

C. The Act expressly provides that the indemnification provided in the Bylaws is not exclusive, and expressly permits contracts between the Company and its directors, officers and employees and other agents with respect to indemnification.

D. The Board of Directors of the Company (the "Board") has determined that (1) it is essential to the best interests of the Company's shareholders that the Company act to assure such persons that there will be increased certainty of such protection in the future, and that (2) it is reasonable, prudent and necessary for the Company contractually to obligate itself to indemnify and to advance expenses to such persons to the fullest extent permitted by applicable law, so that they will continue to serve the Company free from undue concern that they will not be so indemnified.

E. The Indemnitee is willing to serve, continue to serve, or take on additional service for or on behalf of the Company provided that he or she is furnished with the indemnification set forth in this Agreement.

AGREEMENT

The parties hereto, intending to be legally bound, hereby agree as follows:

1. Definitions. The following terms shall have the meanings referenced below for purposes of this Agreement.

(a) "Agent" shall mean any person who is or was (i) an officer of the Company, or (ii) at the request of, for the convenience of, or to represent the interests of the Company, serving as a director, manager, officer, trustee, general partner, member, venturer, fiduciary,

employee, other agent or similar functionary of a Subsidiary; or (iii) at the request of, for the convenience of, or to represent the interest of the Company or a Subsidiary of the Company, serving as a director, manager, officer, trustee, general partner, member, venturer, fiduciary, employee other agent of another corporation, limited liability company, partnership, joint venture, trust, employee benefit plan or other enterprise, in each case (i) whether or not the person was serving in that capacity at the time any liability or expense is incurred and (ii) whether the basis for any Proceeding brought against the person is alleged action in an official capacity as a director, manager, officer, trustee, general partner, member, venturer, fiduciary, employee or agent or any other capacity while serving as a director, manager, officer, trustee, general partner, member, venturer, fiduciary, employee or other agent.

(b) "Expenses" means all out-of-pocket expenses or costs of any type or nature whatsoever (including, without limitation, all court costs, attorneys' fees and related disbursements and any deductibles that Indemnitee might be required to pay under applicable insurance policies), actually and reasonably incurred by the Indemnitee in connection with the investigation with respect to, or the defense or appeal of, a Proceeding, or establishing or enforcing a right to indemnification under this Agreement or the Act or otherwise, but excluding all judgments, fines, ERISA excise taxes or penalties, or amounts paid in settlement of a Proceeding.

(c) "Proceeding" means any threatened, pending, or completed action, suit or other proceeding, whether civil, criminal, administrative, or investigative, any appeal in such an action, suit or proceeding, and any inquiry or investigation that could lead to such an action, suit or proceeding.

(d) "Subsidiary" means any foreign or domestic corporation, partnership, limited liability company, employee benefit plan, other enterprise or other entity of which more than fifty percent (50%) of the outstanding voting securities or interests is owned directly or indirectly by the Company.

2. Scope. Notwithstanding any other provision of this Agreement, the Company hereby agrees to indemnify the Indemnitee to the fullest extent permitted by law for the indemnification of directors, notwithstanding that such indemnification is not specifically authorized by the other provisions of this Agreement, the Articles of Incorporation, the Bylaws or by statute.

3. Mandatory Indemnification. Subject to the limitations of Section 6 of this Agreement:

(a) Indemnification for Expenses of a Party Who is Wholly or Partly Successful.

(i) To the extent that the Indemnitee is, by reason of the fact that he or she is or was an Agent, a party to and is successful, on the merits or otherwise, in any Proceeding

(including an action by or in the right of the Company), the Company shall indemnify the Indemnitee against all Expenses actually and reasonably incurred by his or her or on his or her behalf in connection therewith. If the Indemnitee is not wholly successful in defense of any Proceeding but is successful, on the merits or otherwise, as to one or more but less than all claims, issues or matters in such Proceeding, the Company shall indemnify the Indemnitee against all Expenses actually and reasonably incurred by his or her or on his or her behalf in connection with each such claim, issue or matter as to which the Indemnitee is successful, on the merits or otherwise. For purposes of this Section 3(a)(i), the term "successful, on the merits or otherwise," shall include (A) the termination of any claim, issue or matter in a Proceeding by withdrawal or dismissal, with or without prejudice, (B) termination of any claim, issue or matter in a Proceeding by any other means without any express finding of liability or guilt against the Indemnitee, with or without prejudice, (C) the expiration of 120 days after the making of a claim or threat of a Proceeding without the institution of the same and without any promise or payment made to induce a settlement or (D) the settlement of any claim, issue or matter in a Proceeding pursuant to which the Indemnitee pays less than $100,000.

(ii) In no event shall the Indemnitee be entitled to indemnification under Section 3(a)(i) above with respect to a claim, issue or matter to the extent (A) applicable law prohibits the indemnification, or (B) an admission is made by the Indemnitee in writing to the Company or in such Proceeding or a determination is made by a court of competent jurisdiction from which all appeals have been exhausted that the standard of conduct required for indemnification under this Agreement has not been met with respect to such claim, issue or matter.

(b) Third-Party Actions. If the Indemnitee was or is a party or is threatened to be made a party to any Proceeding (other than a proceeding brought by or in the right of the Company) by reason of the fact that he or she is or was an Agent, or by reason of anything done or not done by him or her in any such capacity, then the Company shall indemnify the Indemnitee against any and all Expenses and any judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement in connection with the investigation, defense, settlement or appeal of such Proceeding, unless the Indemnitee: (i) did not conduct himself or herself in good faith; (ii) did not reasonably believe: (A) in the case of conduct in his or her official capacity as an officer of the Company, that his or her conduct was in the Company's best interests; and (B) in all other cases, that his or her conduct was at least not opposed to the Company's best interests; or (iii) in the case of any criminal proceeding, had no reasonable cause to believe his or her conduct was unlawful. The termination of any Proceeding by judgment, order, settlement or conviction, or upon a plea of nolo contendere or its equivalent, shall not, of itself, create a presumption that Indemnitee did not satisfy the foregoing standard of conduct to the extent applicable thereto. A person shall be deemed to have been found liable in respect of any claim, issue or matter only

after the person shall have been so adjudged by a court of competent jurisdiction after exhaustion of all appeals therefrom.

(c) Derivative Actions. If the Indemnitee was or is a party or is threatened to be made a party to any Proceeding in a derivative action by or in the right of the Company, because he or she is or was an Agent, or because of anything done or not done by him or her in any such capacity, then the Company shall indemnify the Indemnitee against all Expenses, as well as any judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement in connection with the investigation, defense, settlement or appeal of such Proceeding, unless the Indemnitee: (i) did not conduct himself or herself in good faith; (ii) did not reasonably believe: (A) in the case of conduct in his or her official capacity as an officer of the Company, that his or her conduct was in the Company's best interests; and (B) in all other cases, that his or her conduct was at least not opposed to the Company's best interests; or (iii) in the case of any criminal proceeding, had no reasonable cause to believe his or her conduct was unlawful. The termination of any Proceeding by judgment, order, settlement or conviction, or upon a plea of nolo contendere or its equivalent, shall not, of itself, create a presumption that Indemnitee did not satisfy the foregoing standard of conduct to the extent applicable thereto. A person shall be deemed to have been found liable in respect of any claim, issue or matter only after the person shall have been so adjudged by a court of competent jurisdiction after exhaustion of all appeals therefrom.

(d) Actions where Indemnitee is Deceased. If the Indemnitee was or is a party or is threatened to be made a party to any Proceeding because he or she is or was an Agent, or because of anything done or not done by him or her in any such capacity, and if prior to, during the pendency of or after completion of such Proceeding, Indemnitee dies, then the Company shall indemnify the Indemnitee's heirs, devisees, executors and administrators against any and all Expenses, and any judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement in connection with the investigation, defense, settlement or appeal of such Proceeding, to the extent Indemnitee would have been entitled to indemnification pursuant to Sections 3(a), 3(b), or 3(c) of this Agreement if the Indemnitee was still alive.

4. Partial Indemnification and Contribution.

(a) Partial Indemnification. If the Indemnitee is entitled under any provision of this Agreement to indemnification by the Company for some or a portion of any Expenses or other liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement) incurred by him or her in the investigation, defense, settlement or appeal of a Proceeding, but not entitled to indemnification for all of the total amount hereof, the Company shall indemnify the Indemnitee for such total amount less that portion to which the Indemnitee is not entitled.

(b) Contribution. If the indemnification provided in Section 3 is unavailable and may not be paid to Indemnitee for any reason, then in respect to any Proceeding in which the Company and all officers, directors and employees of the Company other than the Indemnitee are jointly liable with Indemnitee (or would be if joined in such Proceeding), the Company shall contribute to the amount of Expenses and other liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement) in connection with the investigation, defense, settlement or appeal of such Proceeding, in such proportion as is appropriate to reflect the relative benefits received by the Company and all officers, directors and employees of the Company other than the Indemnitee, who are jointly liable with the Indemnitee (or would be if joined in such Proceeding), on the one hand, and the Indemnitee, on the other hand, from the transaction from which such Proceeding arose. The proportion determined on the basis of relative benefit may, to the extent necessary to conform to law, be further adjusted to reflect the relative fault of the Company and all officers, directors and employees of the Company other than the Indemnitee who are jointly liable with the Indemnitee (or would be if joined in such Proceeding), on the one hand, and of Indemnitee, on the other hand, in connection with the events that resulted in such Expenses or other liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement) in connection with the investigation, defense, settlement or appeal of such Proceeding, as well as any other relevant equitable considerations. The relative fault of the Company and all officers, directors and employees of the Company other than the Indemnitee who are jointly liable with the Indemnitee (or would be if joined in such Proceeding), on the one hand, and of Indemnitee, on the other hand, shall be determined by reference to, among other things, the parties' relative intent, knowledge, access to information and opportunity to correct or prevent the circumstances resulting in such Expenses, judgments, fines or settlement amounts. The Company agrees that it would not be just and equitable if contribution pursuant to this Section 4(b) were determined by pro rata allocation or any other method of allocation that does not take account of the foregoing equitable considerations.

5. Mandatory Advancement of Expenses.

(a) Subject to the provisions of Section 7 of this Agreement, the Company shall advance all Expenses incurred by the Indemnitee in connection with the investigation, defense, settlement or appeal of any Proceeding to which the Indemnitee is a party or is threatened to be made a party by reason of the fact that the Indemnitee is or was an Agent; provided, however, that if Indemnitee is at that time an officer of the Company, prior to the advancement of Expenses to the Indemnitee in connection with the Proceeding, the Indemnitee shall provide the Company with a written affirmation by the Indemnitee of his or her good faith belief that he or she has met the standard of conduct necessary for indemnification stated in the relevant provision of Section 3 of this Agreement, together with a written undertaking to repay the amount paid or reimbursed if it is ultimately determined that the Indemnitee has

not met the standard of conduct necessary for indemnification or if it is ultimately determined that indemnification of the Indemnitee against Expenses incurred by him or her in connection with the Proceeding would have been prohibited by Section E of Article 2.02-1 of the Act if Indemnitee is treated as if he or she were serving as a director of the Company. The advances to be made hereunder shall be paid from time to time by the Company to the Indemnitee within thirty (30) days following delivery of a written request therefor by the Indemnitee to the Company, together with reasonable evidence of such Expenses. Any advances and undertakings to repay pursuant to this Section 5 shall not be secured, shall not bear interest and shall provide that, if

Indemnitee has commenced or thereafter commences legal proceedings in a court of competent jurisdiction to secure a determination that Indemnitee should be indemnified under applicable law with respect to such Proceeding, Indemnitee shall not be required to reimburse the Company for any advancement of Expenses in respect of such Proceeding until so determined by a court of competent jurisdiction after exhaustion of all appeals therefrom.

(b) Subject to the provisions of Section 7(c) and 7(d) of this Agreement, the Company shall advance all Expenses incurred by the Indemnitee in connection with the Indemnitee's appearance as a witness in, or in responding to a subpoena to testify or serve as a witness in or in connection with, a Proceeding in which the Indemnitee is not named as a defendant or respondent.

6. Defense of the Underlying Proceeding.

(a) Indemnitee shall notify the Company promptly upon being served with or receiving any summons, citation, subpoena, complaint, indictment, information, notice, request or other document relating to any Proceeding which may result in the right to indemnification or the advance of Expenses hereunder; provided, however, that the failure to give any such notice shall not disqualify Indemnitee from the right, or otherwise affect in any manner any right of Indemnitee, to indemnification or the advance of Expenses under this Agreement unless the Company's ability to defend in such Proceeding or to obtain proceeds under any insurance policy is materially and adversely prejudiced thereby, and then only to the extent the Company is thereby actually so prejudiced.(b) If, at the time of the receipt of a notice of the commencement of a Proceeding pursuant to Section 6(a) hereof, the Company has a directors' and officers' liability insurance policy in effect, the Company shall give prompt notice of the commencement of such Proceeding to the insurers in accordance with the procedures set forth in the respective policies. The Company shall thereafter take all necessary or desirable action to cause such insurers to pay, on behalf of the Indemnitee, all amounts payable as a result of such Proceeding in accordance with the terms of such policies.

(b) Subject to the provisions of the last sentence of this Section 6(c) and of Section 6(d) below, the Company shall have the right to defend Indemnitee in any Proceeding which may give rise to indemnification

hereunder with counsel approved by Indemnitee, which approval shall not be unreasonably withheld; provided, however, that the Company shall notify Indemnitee of any such decision to defend within 15 calendar days following receipt of notice of any such Proceeding under Section 6(a) above. The Company shall not, without the prior written consent of Indemnitee, which shall not be unreasonably withheld or delayed, consent to the entry of any judgment against Indemnitee or enter into any settlement or compromise which (i) includes an admission of fault of Indemnitee or (ii) does not include, as an unconditional term thereof, the full release of Indemnitee from all liability in respect of such Proceeding, which release shall be in form and substance reasonably satisfactory to Indemnitee. This Section 6 shall not apply to a Proceeding brought by Indemnitee under Section 9.

(c) Notwithstanding the provisions of Section 6(c) above, if in a

Proceeding for which the Company has notified Indemnitee that it intends to defend Indemnitee, (i) Indemnitee reasonably concludes, based upon an opinion of counsel approved by the Company, which approval shall not be unreasonably withheld, that he or she may have separate defenses or counterclaims to assert with respect to any issue which may not be consistent with other defendants in such Proceeding, (ii) Indemnitee reasonably concludes, based upon an opinion of counsel approved by the Company, which approval shall not be unreasonably withheld, that an actual or apparent conflict of interest or potential conflict of interest exists between Indemnitee and the Company, or (iii) if the Company fails to assume the defense of such Proceeding in a timely manner, Indemnitee shall be entitled to be represented by separate legal counsel of Indemnitee's choice, subject to the prior approval of the Company, which shall not be unreasonably withheld, at the expense of the Company. In addition, if the Company fails to comply with any of its obligations under this Agreement or in the event that the Company or any other person takes any action to declare this Agreement void or unenforceable, or institutes any Proceeding to deny or to recover from Indemnitee the benefits intended to be provided to Indemnitee hereunder, Indemnitee shall have the right to retain counsel of Indemnitee's choice, subject to the prior approval of the Company, which shall not be unreasonably withheld, at the expense of the Company, to represent Indemnitee in connection with any such matter.

7. Exceptions. Any other provision herein to the contrary notwithstanding, the Company shall not be obligated pursuant to the terms of this Agreement:

(a) Claims Initiated by Indemnitee. To advance to the Indemnitee Expenses or indemnify Expenses or any other liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement) with respect to Proceedings or claims initiated or brought voluntarily by the Indemnitee and not by way of defense, unless:

(i) such indemnification is expressly required to be made by law;

(ii) the Proceeding was authorized by the Board;

(iii) such indemnification is provided by the Company, in its sole discretion, pursuant to the powers vested in the Company under the Act or the Bylaws; or

(iv) a counterclaim or cross claim is asserted against Indemnitee for which Indemnitee otherwise would be entitled to indemnity by Company.

(b) Lack of Good Faith. To indemnify the Indemnitee for any Expenses or any other liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement) incurred by the Indemnitee (i) with respect to any Proceeding instituted by the Indemnitee to enforce or interpret this Agreement, if a court of competent jurisdiction determines that each of the material assertions made by the Indemnitee in such Proceeding was not made in good faith or was frivolous, or (ii) with respect to any Proceeding if the Indemnitee is found liable by a court of competent jurisdiction after exhaustion of all appeals for willful or intentional misconduct in the performance of his or her duty to the Company;

(c) Unauthorized Settlements. To indemnify the Indemnitee under this Agreement for any amounts paid in settlement of a Proceeding unless the Company consents to such settlement, which consent shall not be unreasonably withheld; or

(d) No Duplication of Payments. To indemnify the Indemnitee for Expenses or liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement) for which payment is actually made to Indemnitee under a valid and collectible directors' and officers' liability insurance policy, or under a valid and enforceable indemnity clause of the Bylaws or other agreement.

8. Non-exclusivity. The provisions for advancement of Expenses and indemnification of Expenses and any judgments, fines, ERISA excise taxes and amounts paid in settlement set forth in this Agreement shall not be deemed exclusive of any other rights which the Indemnitee may have under any provision of law, the Company's Articles of Incorporation, as amended and restated from time to time, or Bylaws, the vote of the Company's shareholders or disinterested directors, any employment agreement between the Company and Indemnitee, other agreements, or otherwise, both as to action in his or her official capacity and to action in another capacity while occupying his or her position as an Agent.

9. Remedies of Indemnitee.

(a) If (i) a determination is made that Indemnitee is not entitled to indemnification under this Agreement, (ii) advance of Expenses is not timely made pursuant to Section 5 of this Agreement, or (iii) payment of indemnification is not made pursuant to Section 3 of this Agreement within 30 days after receipt by the Company of a written request

therefor, Indemnitee shall be entitled to an adjudication in an appropriate court located in the State of Texas, or in any other court of competent jurisdiction, of his or her entitlement to such indemnification or advance of Expenses.

(b) In any judicial proceeding commenced pursuant to this Section 9 the Company shall have the burden of proving that Indemnitee is not entitled to indemnification or advance of Expenses, as the case may be.

(c) If a determination shall have been made that Indemnitee is entitled to indemnification, the Company shall be bound by such determination in any judicial proceeding commenced pursuant to this Section 9, absent a misstatement by Indemnitee of a material fact, or an omission of a material fact necessary to make Indemnitee's statement not materially misleading, in connection with the request for indemnification.

(d) In the event that Indemnitee, pursuant to this Section 9, seeks a judicial adjudication to enforce his or her rights under, or to recover damages for breach of, this Agreement, Indemnitee, if successful in such enforcement action in whole or in part, shall be entitled to recover from the Company, and shall be indemnified by the Company for, any and all Expenses actually and reasonably incurred by him or her in such judicial adjudication or arbitration, including any claim or counterclaim brought by the Company in connection therewith. If it shall be determined in such judicial adjudication or arbitration that Indemnitee is entitled to receive part but not all of the indemnification or advance of Expenses sought, the Expenses incurred by Indemnitee in connection with such judicial adjudication or arbitration shall be appropriately prorated.

(e) The Company shall be precluded from asserting in any Proceeding, including, without limitation, an action under Section 9(a) above, that the provisions of this Agreement are not valid, binding and enforceable or that there is insufficient consideration for this Agreement and shall stipulate in court that the Company is bound by all the provisions of this Agreement.

(f) The failure of the Company (including its Board of Directors or any committee thereof, independent legal counsel, or shareholders) to make a determination concerning the permissibility of the payment of indemnifiable amounts or the advance of Expenses under this Agreement shall not be a defense in any action brought under Section 9(a) above, and shall not create a presumption that such payment or advance is not permissible.

10. Determination of "Good Faith".

(a) For purposes of any determination of "good faith" under this Agreement, the Indemnitee shall be deemed to have acted in good faith if in taking such action the Indemnitee relied on the records or books of account of the Company or a Subsidiary or affiliate of the Company, including

financial statements, or on information, opinions, reports or statements provided to the Indemnitee by the officers or other employees of the Company or a Subsidiary or affiliate of the Company in the course of their duties, or on the advice of legal counsel for the Company or a Subsidiary or affiliate of the Company, or on information or records given or reports made to the Company or a Subsidiary or affiliate of the Company by an independent certified public accountant or by an appraiser or other expert selected by the Company or a Subsidiary or affiliate of the Company, or by any other person (including legal counsel, accountants and financial advisors) as to matters the Indemnitee reasonably believes are within such other person's professional or expert competence and who has been selected with reasonable care by or on behalf of the Company. In connection with any determination as to whether the Indemnitee is entitled to be indemnified under this Agreement, the person or court making the determination shall presume that the Indemnitee has satisfied the applicable standard of conduct and shall be entitled to indemnification, and the burden of proof shall be on the Company to establish that the Indemnitee is not so entitled. The provisions of this Section 9 shall not be deemed to be exclusive or to limit in any way the other circumstances in which the Indemnitee may be deemed to have met the applicable standard of conduct set forth in this Agreement. In addition, the knowledge and/or actions, or failures to act, of any other person serving the Company or a Subsidiary or affiliate of the Company as an indemnifiable person shall not be imputed to the Indemnitee for purposes of determining the right to indemnification under this Agreement.

(b) The determination as to whether an Indemnitee has met the applicable standard of conduct set forth in Section 3 hereof shall be made in accordance with Section F. of Article 2.02-1 of the Act. If for purposes of making such determination there are no directors who at the time are not named defendants or respondents in the Proceeding for which indemnification or reimbursement is sought, then such determination may be made by independent legal counsel (who may be the outside counsel regularly employed by the Company) in a written opinion.

11. Subrogation. If payment is made under this Agreement, the Company shall be subrogated to the extent of such payment to all of the rights of recovery of Indemnitee from any third parties, the Indemnitee shall execute all documents reasonably required and shall do all acts that may be reasonably necessary to secure such rights and to enable the Company to effectively bring suit to enforce such rights.

12. Continuation of Obligations.

(a) After Service as an Agent. All agreements and obligations of the Company contained herein shall continue during the period Indemnitee is an Agent and shall continue thereafter so long as Indemnitee shall be subject to any possible Proceeding, by reason of the fact that Indemnitee was serving in the capacity referred to herein.

(b) Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of and be enforceable by the parties hereto and their respective successors, assigns (including any direct or indirect successor by merger, consolidation, or otherwise to all or substantially all of the business or assets of the Corporation), and personal and legal representatives. The Company shall require any such successor to the Company to expressly to assume and agree to perform this Agreement in the same manner and to the same extent that the Company would be required to perform if no such succession had taken place.

13. Severability. If any provision or provisions of this Agreement shall be held to be invalid, illegal or unenforceable for any reason whatsoever, then:

(a) the validity, legality and enforceability of the remaining provisions of the Agreement (including, without limitation, all portions of any paragraphs of this Agreement containing any such provision held to be invalid, illegal or unenforceable, that are not themselves invalid, illegal or unenforceable) shall not in any way be affected or impaired thereby; and

(b) to the fullest extent possible, the provisions of this Agreement (including, without limitation, all portions of any provision of this Agreement containing any such provision held to be invalid, illegal or unenforceable, that are not themselves invalid, illegal or unenforceable) shall be construed so as to give effect to the intent manifested by the provision held invalid, illegal or unenforceable and to give effect to Section 11 hereof.

14. Modification and Waiver. No supplement, modification or amendment of

this Agreement shall be binding unless executed in writing by the parties hereto. No waiver of any provision of this Agreement shall be deemed or shall constitute a waiver of any other provision hereof (whether or not similar) nor shall such waiver constitute a continuing waiver.

15. Notices. All notices, consents, waivers and other communications under this Agreement must be in writing and will be deemed to have been duly given when:

(a) delivered by hand (with written confirmation of receipt);

(b) sent by facsimile (with written confirmation of receipt), provided that a copy is also promptly mailed by registered mail, return receipt requested; or

(c) when received by the addressee, if sent by a nationally recognized overnight delivery service (receipt requested),

in each case to the appropriate addresses and facsimile numbers set forth on the signature page hereof, as the case may be (or to such other addresses and facsimile numbers as a party may designate by notice to the other party).

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16. Governing Law. This Agreement shall be governed exclusively by and construed according to the laws of the State of Texas as applied to contracts between Texas residents entered into and to be performed entirely within Texas without giving effect to any conflict of laws provisions.

17. Consent to Jurisdiction. The Company and the Indemnitee each hereby irrevocably consent to the jurisdiction of the state or federal courts in Harris County, Texas and venue in Harris County, Texas with respect to any Proceeding that arises out of or relates to this Agreement.

COMPANY:

SWIFT ENERGY COMPANY

By:

Terry E. Swift, Chief Executive Officer
Address: 16825 Northchase Dr., Suite 400
Houston, Texas 77060
281-874-2808 (facsimile no.)

INDEMNITEE:

Name:
Address:

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Exhibit 10.10

SWIFT ENERGY COMPANY
INDEMNIFICATION AGREEMENT

THIS INDEMNIFICATION AGREEMENT (the "Agreement"), is made and entered into as of __________________, by and between Swift Energy Company, a Texas corporation (the "Company"), and ______________ (the "Indemnitee").

BACKGROUND

A. The Company is aware that, in order to induce highly competent persons to serve or continue to serve the Company as directors or in other capacities, the Company must provide such persons with adequate protection through insurance and indemnification against risks of claims and actions against them arising out of their service to and activities on behalf of the Company.

B. The Company has adopted bylaws (the "Bylaws") providing for indemnification of the directors, officers, employees and other agents of the Company, including persons serving at the request of the Company in these capacities with other corporations or enterprises, to the full extent permitted under the applicable law of the State of Texas, which is currently the Texas Business Corporation Act (the "Act").

C. The Act expressly provides that the indemnification provided in the Bylaws is not exclusive, and expressly permits contracts between the Company and its directors, officers and employees and other agents with respect to indemnification.

D. The Board of Directors of the Company (the "Board") has determined that (1) it is essential to the best interests of the Company's shareholders that the Company act to assure such persons that there will be increased certainty of such protection in the future, and that (2) it is reasonable, prudent and necessary for the Company contractually to obligate itself to indemnify and to advance expenses to such persons to the fullest extent permitted by applicable law, so that they will continue to serve the Company free from undue concern that they will not be so indemnified.

E. The Indemnitee is willing to serve, continue to serve, or take on additional service for or on behalf of the Company provided that he or she is furnished with the indemnification set forth in this Agreement.

AGREEMENT

The parties hereto, intending to be legally bound, hereby agree as follows:

1. Definitions. The following terms shall have the meanings referenced below for purposes of this Agreement.

(a) "Agent" shall mean any person who is or was (i) a director, manager, officer, trustee, general partner, member, venturer, fiduciary, employee, other agent or similar functionary; or (ii) at the request of, for the convenience of, or to represent the interests of the

Company, serving as a director, manager, officer, trustee, general partner, member, venturer, fiduciary, employee, other agent or similar functionary of a Subsidiary; or (iii) at the request of, for the convenience of, or to represent the interest of the Company or a Subsidiary of the Company, serving as a director, manager, officer, trustee, general partner, member, venturer, fiduciary, employee other agent of another corporation, limited liability company, partnership, joint venture, trust, employee benefit plan or other enterprise, in each case (i) whether or not the person was serving in that capacity at the time any liability or expense is incurred and (ii) whether the basis for any Proceeding brought against the person is alleged action in an official capacity as a director, manager, officer, trustee, general partner, member, venturer, fiduciary, employee or agent or any other capacity while serving as a director, manager, officer, trustee, general partner, member, venturer, fiduciary, employee or other agent.

(b) "Expenses" means all out-of-pocket expenses or costs of any type or nature whatsoever (including, without limitation, all court costs, attorneys' fees and related disbursements and any deductibles that Indemnitee might be required to pay under applicable insurance policies), actually and reasonably incurred by the Indemnitee in connection with the investigation with respect to, or the defense or appeal of, a Proceeding, or establishing or enforcing a right to indemnification under this Agreement or the Act or otherwise, but excluding all judgments, fines, ERISA excise taxes or penalties, or amounts paid in settlement of a Proceeding.

(c) "Proceeding" means any threatened, pending, or completed action, suit or other proceeding, whether civil, criminal, administrative, or investigative, any appeal in such an action, suit or proceeding, and any inquiry or investigation that could lead to such an action, suit or proceeding.

(d) "Subsidiary" means any foreign or domestic corporation, partnership, limited liability company, employee benefit plan, other enterprise or other entity of which more than fifty percent (50%) of the outstanding voting securities or interests is owned directly or indirectly by the Company.

2. Scope. Notwithstanding any other provision of this Agreement, the Company hereby agrees to indemnify the Indemnitee to the fullest extent permitted by law, notwithstanding that such indemnification is not specifically authorized by the other provisions of this Agreement, the Articles of Incorporation, the Bylaws or by statute. If after the date of this Agreement, there is a change in any applicable law, statute, or rule which expands the right of a Texas corporation to indemnify a member of its board of directors then such changes shall be, ipso facto, within the purview of Indemnitee's rights and Company's obligations under this Agreement.

3. Mandatory Indemnification. Subject to the limitations of Section 6 of this Agreement:

(a) Indemnification for Expenses of a Party Who is Wholly or Partly Successful.

(i) To the extent that the Indemnitee is, by reason of the fact that he or she is or was an Agent, a party to and is successful, on the merits or otherwise, in any Proceeding (including an action by or in the right of the Company), the Company shall indemnify the Indemnitee against all Expenses actually and reasonably incurred by his or her or on his or her behalf in connection therewith. If the Indemnitee is not wholly successful in defense of any Proceeding but is successful, on the merits or otherwise, as to one or more but less than all claims, issues or matters in such Proceeding, the Company shall indemnify the Indemnitee against all Expenses actually and reasonably incurred by his or her or on his or her behalf in connection with each such claim, issue or matter as to which the Indemnitee is successful, on the merits or otherwise. For purposes of this Section 3(a)(i), the term "successful, on the merits or otherwise," shall include (A) the termination of any claim, issue or matter in a Proceeding by withdrawal or dismissal, with or without prejudice, (B) termination of any claim, issue or matter in a Proceeding by any other means without any express finding of liability or guilt against the Indemnitee, with or without prejudice, (C) the expiration of 120 days after the making of a claim or threat of a Proceeding without the institution of the same and without any promise or payment made to induce a settlement or (D) the settlement of any claim, issue or matter in a Proceeding pursuant to which the Indemnitee pays less than $100,000.

(ii) In no event shall the Indemnitee be entitled to indemnification under Section 3(a)(i) above with respect to a claim, issue or matter to the extent (A) applicable law prohibits the indemnification, or (B) an admission is made by the Indemnitee in writing to the Company or in such Proceeding or a determination is made by a court of competent jurisdiction from which all appeals have been exhausted that the standard of conduct required for indemnification under this Agreement has not been met with respect to such claim, issue or matter.

(b) Third-Party Actions. If the Indemnitee was or is a party or is threatened to be made a party to any Proceeding (other than a proceeding brought by or in the right of the Company) by reason of the fact that he or she is or was an Agent, or by reason of anything done or not done by him or her in any such capacity, then the Company shall indemnify the Indemnitee against any and all Expenses and any

judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement in connection with the investigation, defense, settlement or appeal of such Proceeding, unless the Indemnitee: (i) did not conduct himself or herself in good faith; (ii) did not reasonably believe: (A) in the case of conduct in his or her official capacity as a director of the Company, that his or her conduct was in the Company's best interests; and (B) in all other cases, that his or her conduct was at least not opposed to the Company's best interests; or (iii) in the case of any criminal proceeding, had no reasonable cause to believe his or her conduct was unlawful. The termination of any Proceeding by judgment, order, settlement or conviction, or upon a plea of nolo contendere or its equivalent, shall not, of itself, create a presumption that Indemnitee did not satisfy the foregoing standard of conduct to the extent applicable thereto. A person shall be deemed to have been found liable in respect of any claim, issue or matter only after the person shall have been so adjudged by a court of competent jurisdiction after exhaustion of all appeals therefrom.

(c) Derivative Actions. If the Indemnitee was or is a party or is threatened to be made a party to any Proceeding in a derivative action by or in the right of the Company, because he or she is or was an Agent, or because of anything done or not done by him or her in any such capacity, then the Company shall indemnify the Indemnitee against all Expenses, as well as any judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement in connection with the investigation, defense, settlement or appeal of such Proceeding, unless the Indemnitee: (i) did not conduct himself or herself in good faith; (ii) did not reasonably believe: (A) in the case of conduct in his or her official capacity as a director of the Company, that his or her conduct was in the Company's best interests; and (B) in all other cases, that his or her conduct was at least not opposed to the Company's best interests; or (iii) in the case of any criminal proceeding, had no reasonable cause to believe his or her conduct was unlawful. The termination of any Proceeding by judgment, order, settlement or conviction, or upon a plea of nolo contendere or its equivalent, shall not, of itself, create a presumption that Indemnitee did not satisfy the foregoing standard of conduct to the extent applicable thereto. A person shall be deemed to have been found liable in respect of any claim, issue or matter only after the person shall have been so adjudged by a court of competent jurisdiction after exhaustion of all appeals therefrom.

(d) Actions where Indemnitee is Deceased. If the Indemnitee was or is a party or is threatened to be made a party to any Proceeding because he or she is or was an Agent, or because of anything done or not done by him or her in any such capacity, and if prior to, during the pendency of or after completion of such Proceeding, Indemnitee dies, then the Company shall indemnify the Indemnitee's heirs, devisees, executors and administrators against any and all Expenses, and any judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement in connection with the investigation, defense, settlement or appeal of such Proceeding, to the extent Indemnitee would have been entitled to indemnification pursuant to Sections 3(a), 3(b), or 3(c) of this Agreement if the Indemnitee was still alive.

4. Partial Indemnification and Contribution.

(a) Partial Indemnification. If the Indemnitee is entitled under any provision of this Agreement to indemnification by the Company for some or a portion of any Expenses or other liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement) incurred by him or her in the investigation, defense, settlement or appeal of a Proceeding, but not entitled to indemnification for all of the total amount hereof, the Company shall indemnify the Indemnitee for such total amount less that portion to which the Indemnitee is not entitled.

(b) Contribution. If the indemnification provided in Section 3 is unavailable and may not be paid to Indemnitee for any reason, then in respect to any Proceeding in which the Company and all officers, directors and employees of the Company other than the Indemnitee are jointly liable with Indemnitee (or would be if joined in such Proceeding), the Company shall contribute to the amount of Expenses and other liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement) in connection with the investigation, defense, settlement or appeal of such Proceeding, in such proportion as is appropriate to reflect the relative benefits received by the Company and all officers, directors and employees of the Company other than the Indemnitee, who are jointly liable with the Indemnitee (or would be if joined in such Proceeding), on the one hand, and the Indemnitee, on the other hand, from the transaction from which such Proceeding arose. The proportion determined on the basis of relative benefit may, to the extent necessary to conform to law, be further adjusted to reflect the relative fault of the Company and all officers, directors and employees of the Company other than the Indemnitee who are jointly liable with the Indemnitee (or would be if joined in such Proceeding), on the one hand, and of Indemnitee, on the other hand, in connection with the events that resulted in such Expenses or other liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement) in connection with the investigation, defense, settlement or appeal of such Proceeding, as well as any other relevant equitable considerations. The relative fault of the Company and all officers, directors and employees of the Company other than the Indemnitee who are jointly liable with the Indemnitee (or would be if joined in such Proceeding), on the one hand, and of Indemnitee, on the other hand, shall be determined by reference to, among other things, the parties' relative intent, knowledge, access to information and opportunity to correct or prevent the circumstances resulting in such Expenses, judgments, fines or settlement amounts. The Company agrees that it would not be just and equitable if contribution pursuant to this Section 4(b) were determined by pro rata allocation or any other method of allocation that does not take account of the foregoing equitable considerations.

5. Mandatory Advancement of Expenses.

(a) Subject to the provisions of Section 7 of this Agreement, the Company shall advance all Expenses incurred by the Indemnitee in connection with the investigation, defense, settlement or appeal of any Proceeding to which the Indemnitee is a party or is threatened to be made a party by reason of the fact that the Indemnitee is or was an Agent; provided, however, that if Indemnitee is at that time a director of the Company, prior to the advancement of Expenses to the Indemnitee in connection with the Proceeding, the Indemnitee shall provide the Company with a written affirmation by the Indemnitee of his or her good faith belief that he or she has met the standard of conduct necessary for indemnification stated in the relevant provision of Section 3 of this Agreement, together with a written undertaking to repay the amount paid or reimbursed if it is ultimately determined that the Indemnitee has not met the standard of conduct necessary for indemnification or if it is ultimately determined that indemnification of the Indemnitee against Expenses incurred by him or her in connection with the Proceeding is prohibited by Section E of Article 2.02-1 of the Act. The advances to be made hereunder shall be paid from time to time by the Company to the

Indemnitee within thirty (30) days following delivery of a written request therefor by the Indemnitee to the Company, together with reasonable evidence of such Expenses. Any advances and undertakings to repay pursuant to this Section 5 shall not be secured, shall not bear interest and shall provide that, if Indemnitee has commenced or thereafter commences legal proceedings in a court of competent jurisdiction to secure a determination that Indemnitee should be indemnified under applicable law with respect to such Proceeding, Indemnitee shall not be required to reimburse the Company for any advancement of Expenses in respect of such Proceeding until so determined by a court of competent jurisdiction after exhaustion of all appeals therefrom.

(b) Subject to the provisions of Section 7(c) and 7(d) of this Agreement, the Company shall advance all Expenses incurred by the Indemnitee in connection with the Indemnitee's appearance as a witness in, or in responding to a subpoena to testify or serve as a witness in or in connection with, a Proceeding in which the Indemnitee is not named as a defendant or respondent.

6. Defense of the Underlying Proceeding.

(a) Indemnitee shall notify the Company promptly upon being served with or receiving any summons, citation, subpoena, complaint, indictment, information, notice, request or other document relating to any Proceeding which may result in the right to indemnification or the advance of Expenses hereunder; provided, however, that the failure to give any such notice shall not disqualify Indemnitee from the right, or otherwise affect in any manner any right of Indemnitee, to indemnification or the advance of Expenses under this Agreement unless the Company's ability to defend in such Proceeding or to obtain proceeds under any insurance policy is materially and adversely prejudiced thereby, and then only to the extent the Company is thereby actually so prejudiced.

(b) If, at the time of the receipt of a notice of the commencement of a Proceeding pursuant to Section 6(a) hereof, the Company has a directors' and officers' liability insurance policy in effect, the Company shall give prompt notice of the commencement of such Proceeding to the insurers in accordance with the procedures set forth in the respective policies. The Company shall thereafter take all necessary or desirable action to cause such insurers to pay, on behalf of the Indemnitee, all amounts payable as a result of such Proceeding in accordance with the terms of such policies.

(c) Subject to the provisions of the last sentence of this Section 6(c) and of Section 6(d) below, the Company shall have the right to defend Indemnitee in any Proceeding which may give rise to indemnification hereunder with counsel approved by Indemnitee, which approval shall not be unreasonably withheld; provided, however, that the Company shall notify Indemnitee of any such decision to defend within 15 calendar days following receipt of notice of any such Proceeding under Section 6(a) above. The Company shall not, without the prior written consent of Indemnitee, which shall not be unreasonably withheld or delayed, consent to the entry of any judgment against Indemnitee or enter into any settlement or compromise which (i) includes an admission of fault of Indemnitee or (ii) does not include, as an unconditional term thereof, the full release of Indemnitee from all liability in respect of such Proceeding, which release shall be in form and substance reasonably satisfactory to Indemnitee. This Section 6 shall not apply to a Proceeding brought by Indemnitee under Section 9.

(d) Notwithstanding the provisions of Section 6(c) above, if in a Proceeding for which the Company has notified Indemnitee that it intends to defend Indemnitee, (i) Indemnitee reasonably concludes, based upon an opinion of counsel approved by the Company, which approval shall not be unreasonably withheld, that he or she may have separate defenses or counterclaims to assert with respect to any issue which may not be consistent with other defendants in such Proceeding, (ii) Indemnitee reasonably concludes, based upon an opinion of counsel approved by the Company, which approval shall not be unreasonably withheld, that an actual or apparent conflict of interest or potential conflict of interest exists between Indemnitee and the Company, or (iii) if the Company fails to assume the defense of such Proceeding in a timely manner, Indemnitee shall be entitled to be represented by separate legal counsel of Indemnitee's choice, subject to the prior approval of the Company, which shall not be unreasonably withheld, at the expense of the Company. In addition, if the Company fails to comply with any of its obligations under this Agreement or in the event that the Company or any other person takes any action to declare this Agreement void or unenforceable, or institutes any Proceeding to deny or to recover from Indemnitee the benefits intended to be provided to Indemnitee hereunder, Indemnitee shall have the right to retain counsel of Indemnitee's choice, subject to the prior approval of the Company, which shall not be unreasonably withheld, at the expense of the Company, to represent Indemnitee in connection with any such matter.

7. Exceptions. Any other provision herein to the contrary notwithstanding, the Company shall not be obligated pursuant to the terms of this Agreement:

(a) Claims Initiated by Indemnitee. To advance to the Indemnitee Expenses or indemnify Expenses or any other liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement) with respect to Proceedings or claims initiated or brought voluntarily by the Indemnitee and not by way of defense, unless:

(i) such indemnification is expressly required to be made by law;

(ii) the Proceeding was authorized by the Board;

(iii) such indemnification is provided by the Company, in its sole discretion, pursuant to the powers vested in the Company under the Act or the Bylaws; or

(iv) a counterclaim or cross claim is asserted against Indemnitee for which Indemnitee otherwise would be entitled to indemnity by Company.

(b) Lack of Good Faith. To indemnify the Indemnitee for any Expenses or any other liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement) incurred by the Indemnitee (i) with respect to any

Proceeding instituted by the Indemnitee to enforce or interpret this Agreement, if a court of competent jurisdiction determines that each of the material assertions made by the Indemnitee in such Proceeding was not made in good faith or was frivolous, or (ii) with respect to any Proceeding if the Indemnitee is found liable by a court of competent jurisdiction after exhaustion of all appeals for willful or intentional misconduct in the performance of his or her duty to the Company;

(c) Unauthorized Settlements. To indemnify the Indemnitee under this Agreement for any amounts paid in settlement of a Proceeding unless the Company consents to such settlement, which consent shall not be unreasonably withheld; or

(d) No Duplication of Payments. To indemnify the Indemnitee for Expenses or liabilities of any type whatsoever (including, but not limited to, judgments, fines, ERISA excise taxes and penalties, and amounts paid in settlement) for which payment is actually made to Indemnitee under a valid and collectible directors' and officers' liability insurance policy, or under a valid and enforceable indemnity clause of the Bylaws or other agreement.

8. Non-exclusivity. The provisions for advancement of Expenses and indemnification of Expenses and any judgments, fines, ERISA excise taxes and amounts paid in settlement set forth in this Agreement shall not be deemed exclusive of any other rights which the Indemnitee may

have under any provision of law, the Company's Articles of Incorporation, as amended and restated from time to time, or Bylaws, the vote of the Company's shareholders or disinterested directors, any employment agreement between the Company and Indemnitee, other agreements, or otherwise, both as to action in his or her official capacity and to action in another capacity while occupying his or her position as an Agent.

9. Remedies of Indemnitee.

(a) If (i) a determination is made that Indemnitee is not entitled to indemnification under this Agreement, (ii) advance of Expenses is not timely made pursuant to Section 5 of this Agreement, or (iii) payment of indemnification is not made pursuant to Section 3 of this Agreement within 30 days after receipt by the Company of a written request therefor, Indemnitee shall be entitled to an adjudication in an appropriate court located in the State of Texas, or in any other court of competent jurisdiction, of his or her entitlement to such indemnification or advance of Expenses.

(b) In any judicial proceeding commenced pursuant to this Section 9 the Company shall have the burden of proving that Indemnitee is not entitled to indemnification or advance of Expenses, as the case may be.

(c) If a determination shall have been made that Indemnitee is entitled to indemnification, the Company shall be bound by such determination in any judicial proceeding commenced pursuant to this Section 9, absent a misstatement by Indemnitee of a material fact, or an omission of a material fact necessary to make Indemnitee's statement not materially misleading, in connection with the request for indemnification.

(d) In the event that Indemnitee, pursuant to this Section 9, seeks a judicial adjudication to enforce his or her rights under, or to recover damages for breach of, this Agreement, Indemnitee, if successful in such enforcement action in whole or in part, shall be entitled to recover from the Company, and shall be indemnified by the Company for, any and all Expenses actually and reasonably incurred by him or her in such judicial adjudication or arbitration, including any claim or counterclaim brought by the Company in connection therewith. If it shall be determined in such judicial adjudication or arbitration that Indemnitee is entitled to receive part but not all of the indemnification or advance of Expenses sought, the Expenses incurred by Indemnitee in connection with such judicial adjudication or arbitration shall be appropriately prorated.

(e) The Company shall be precluded from asserting in any Proceeding, including, without limitation, an action under Section 9(a) above, that the provisions of this Agreement are not valid, binding and enforceable or that there is insufficient consideration for this Agreement and shall stipulate in court that the Company is bound by all the provisions of this Agreement.

(f) The failure of the Company (including its Board of Directors or any committee thereof, independent legal counsel, or shareholders) to make a determination concerning the permissibility of the payment of indemnifiable amounts or the advance of Expenses under this Agreement shall not be a defense in any action brought under Section 9(a) above, and shall not create a presumption that such payment or advance is not permissible.

10. Determination of "Good Faith".

(a) For purposes of any determination of "good faith" under this Agreement, the Indemnitee shall be deemed to have acted in good faith if in taking such action the Indemnitee relied on the records or books of account of the Company or a Subsidiary or affiliate of the Company, including financial statements, or on information, opinions, reports or statements provided to the Indemnitee by the officers or other employees of the Company or a Subsidiary or affiliate of the Company in the course of their duties, or on the advice of legal counsel for the Company or a Subsidiary or affiliate of the Company, or on information or records given or reports made to the Company or a Subsidiary or affiliate of the Company by an independent certified public accountant or by an appraiser or other expert selected by the Company or a Subsidiary or affiliate of the Company, or by any other person (including legal counsel, accountants and financial advisors) as to matters the Indemnitee reasonably believes are within such other person's professional or expert competence and who has been selected with reasonable care by or on behalf of the Company. In connection with any determination as to whether the Indemnitee is entitled to be indemnified under this Agreement, the person or court making the determination shall presume that the Indemnitee has satisfied the applicable standard of conduct and shall be entitled to indemnification, and the burden of proof shall be on the Company to establish that the Indemnitee is not so entitled. The provisions of this Section 9 shall not be deemed to be exclusive or to limit in any way the other circumstances in which the Indemnitee may be deemed to have met the applicable standard of conduct set forth in this

Agreement. In addition, the knowledge and/or actions, or failures to act, of any other person serving the Company or a Subsidiary or affiliate of the Company as an indemnifiable person shall not be imputed to the Indemnitee for purposes of determining the right to indemnification under this Agreement.

(b) The determination as to whether an Indemnitee has met the applicable standard of conduct set forth in Section 3 hereof shall be made in accordance with Section F. of Article 2.02-1 of the Act. If for purposes of making such determination there are no directors who at the time are not named defendants or respondents in the Proceeding for which indemnification or reimbursement is sought, then such determination may be made by independent legal counsel (who may be the outside counsel regularly employed by the Company) in a written opinion.

11. Subrogation. If payment is made under this Agreement, the Company shall be subrogated to the extent of such payment to all of the rights of recovery of Indemnitee from any third parties, the Indemnitee shall execute all documents reasonably required and shall do all acts that may be reasonably necessary to secure such rights and to enable the Company to effectively bring suit to enforce such rights.

12. Continuation of Obligations.

(a) After Service as an Agent. All agreements and obligations of the Company contained herein shall continue during the period Indemnitee is an Agent and shall continue thereafter so long as Indemnitee shall be subject to any possible Proceeding, by reason of the fact that Indemnitee was serving in the capacity referred to herein.

(b) Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of and be enforceable by the parties hereto and their respective successors, assigns (including any direct or indirect successor by merger, consolidation, or otherwise to all or substantially all of the business or assets of the Corporation), and personal and legal representatives. The Company shall require any such successor to the Company to expressly to assume and agree to perform this Agreement in the same manner and to the same extent that the Company would be required to perform if no such succession had taken place.

13. Severability. If any provision or provisions of this Agreement shall be held to be invalid, illegal or unenforceable for any reason whatsoever, then:

(a) the validity, legality and enforceability of the remaining provisions of the Agreement (including, without limitation, all portions of any paragraphs of this Agreement containing any such provision held to be invalid, illegal or unenforceable, that are not themselves invalid, illegal or unenforceable) shall not in any way be affected or impaired thereby; and

(b) to the fullest extent possible, the provisions of this Agreement (including, without limitation, all portions of any provision of this Agreement containing any such provision held to be invalid, illegal or unenforceable, that are not themselves invalid, illegal or unenforceable) shall be construed so as to give effect to the intent manifested by the provision held invalid, illegal or unenforceable and to give effect to Section 11 hereof.

14. Modification and Waiver. No supplement, modification or amendment of this Agreement shall be binding unless executed in writing by the parties hereto. No waiver of any provision of this Agreement shall be deemed or shall constitute a waiver of any other provision hereof (whether or not similar) nor shall such waiver constitute a continuing waiver.

15. Notices. All notices, consents, waivers and other communications under this Agreement must be in writing and will be deemed to have been duly given when:

(a) delivered by hand (with written confirmation of receipt);

(b) sent by facsimile (with written confirmation of receipt), provided that a copy is also promptly mailed by registered mail, return receipt requested; or

(c) when received by the addressee, if sent by a nationally recognized overnight delivery service (receipt requested),

in each case to the appropriate addresses and facsimile numbers set forth on the signature page hereof, as the case may be (or to such other addresses and facsimile numbers as a party may designate by notice to the other party).

16. Governing Law. This Agreement shall be governed exclusively by and construed according to the laws of the State of Texas as applied to contracts between Texas residents entered into and to be performed entirely within Texas without giving effect to any conflict of laws provisions.

17. Consent to Jurisdiction. The Company and the Indemnitee each hereby irrevocably consent to the jurisdiction of the state or federal courts in Harris County, Texas and venue in Harris County, Texas with respect to any Proceeding that arises out of or relates to this Agreement.

COMPANY:

SWIFT ENERGY COMPANY

By:

Terry E. Swift, Chief Executive Officer
Address: 16825 Northchase Dr., Suite 400
Houston, Texas 77060
281-874-2808 (facsimile no.)

INDEMNITEE:

Name:
Address:

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Exhibit 10.31

PURCHASE AND SALE AGREEMENT

BY AND BETWEEN

BP AMERICA PRODUCTION COMPANY

AND

SWIFT ENERGY OPERATING, LLC

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EXHIBITS

SCHEDULES

PURCHASE AND SALE AGREEMENT

THIS PURCHASE AND SALE AGREEMENT (this "AGREEMENT") dated August 24, 2006, is by and between BP AMERICA PRODUCTION COMPANY, A Delaware corporation, with an office at 501 WestLake Park Boulevard, Houston, Texas 77079 ("SELLER") and SWIFT ENERGY OPERATING, LLC, a limited liability company, with an office at 16825 Northchase Drive, Suite 400, Houston, Texas 77060 ("BUYER") (individually, a "Party" and collectively, the "PARTIES").

WHEREAS, Seller desires to sell and deliver to Buyer, and Buyer desires to purchase and accept Seller's interests in certain oil and gas properties and related assets; and

WHEREAS, the Parties have reached agreement regarding the sale and purchase,

NOW, THEREFORE, for and in consideration of the mutual covenants herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree to all the terms and conditions in this Agreement:

ARTICLE I
DEFINITIONS

1.1 DEFINITIONS. Unless otherwise provided in this Agreement, each capitalized term in this Agreement has the meaning given to it IN THIS Article. All defined terms include the singular and the plural. All references to Articles refer to Articles in this Agreement, and all references to Exhibits and Schedules refer to the Exhibits and Schedules which are attached to and by this reference are made a part of this Agreement. When a term is defined as one part of speech (e.g., noun), any other part of speech (e.g., verb) with respect to the term has a comparable meaning.

"AAA" has the meaning given it in Article 18.1.

"ACCOUNTING REFEREE" means the accounting firm of Deloitte & Touche, LLP or any other nationally recognized United States based accounting firm on which the Parties agree.

"ADJUSTED PURCHASE PRICE" has the meaning given it in Article 2.2,

"AFFILIATE" means any entity that, directly or indirectly, through one or more intermediaries, controls or is controlled by or is under common control with the entity specified. For the purpose of this definition, the term "CONTROL" means ownership of fifty percent (50%) or more of voting rights (stock or otherwise) or ownership interest or the power to direct or cause the direction of the management and policies of the entity in question.

"AGREEMENT" has the meaning given it in the introductory paragraph of this Agreement and includes all Exhibits and Schedules hereto, as the same may be amended from time to time by the Parties.

"ALLEGED ADVERSE CONDITION" means an individual environmental condition

associated with the Properties that: (a) was not disclosed to Buyer in the electronic data room Seller established with Merrill Corporation for the

Properties (the "DATA ROOM"), (b) is asserted by Buyer in accordance with Article 5.2, (c) is not in compliance with Environmental Laws in effect as of the Effective Time, and (d) requires an expenditure to remedy exceeding two hundred fifty thousand dollars (US $250,000) net to Seller's interests in the Property affected by such individual condition.

"ALLEGED TITLE DEFECT" means an individual Title Defect that is not disclosed on Exhibit "C" and that is (a) is asserted by Buyer in accordance with Article 4.2, and (b) requires an expenditure to cure or has a value (whichever is less) exceeding fifty thousand dollars (US $50,000) net to Seller's interests in the Properties affected by such individual Title Defect.

"ARBITRABLE DISPUTE" means, except as set forth below, any and all disputes, claims, counterclaims, demands, causes of action, controversies and other matters in question arising out of or relating to this Agreement or the alleged breach hereof, or in any way relating to matters that are the subject of this Agreement or the transactions contemplated hereby or the relationship between the Parties created by this Agreement, regardless of whether (a) allegedly extra-contractual in nature, (b) sounding in contract, tort or otherwise, (c) provided for by Law or otherwise, or (d) seeking damages or any other relief, whether at Law, in equity or otherwise; provided, however, that the term "ARBITRABLE DISPUTE" does not include disputes that by the terms of this Agreement (i) will be determined by the Accounting Referee, or (ii) relate to breach of confidentiality obligations, or (iii) concern either Party's right to terminate this Agreement.

"ASSUMED OBLIGATIONS" has the meaning given it in Article 12.3.

"BUSINESS DAY" means between 8:00 a.m. Central Time and 4:00 p.m., Central Time, on a Day when federally chartered banks in the State of Texas generally are open for business.

"BUYER" has the meaning set forth in the introductory paragraph of this Agreement.

"BUYER GROUP" means each and all of: (a) Buyer and its members, partners, officers, directors, agents, consultants and employees, and (b) Buyer's Affiliates and their members, partners, officers, directors, agents, consultants and employees.

"CASUALTY LOSS" means physical damage to the Properties that (a) occurs between execution of this Agreement and Closing, (b) is not the result of normal wear and tear, mechanical failure or gradual structural deterioration of materials, equipment, and infrastructure, downhole failure (including (i) failures arising or occurring during drilling or completing operations, (ii) junked or lost holes, or (iii) sidetracking or deviating a well) or reservoir changes, and (c) has an adverse effect on the value of the affected Properties in an amount that exceeds two hundred fifty thousand dollars (US $250,000).

"CERTIFICATE" means a document in the form of Exhibit "E".

"CHARGES" means with respect to the Properties:

(a) to the extent attributable to services performed or provided during the time period specified: (i) invoices and bills received under contracts, including joint interest billings, in the ordinary course of business, (ii) other ordinary course of business charges for operating and maintaining material, equipment, other personal property and fixtures, leases, easements, rights-of-way, servitudes, subsurface leases, licenses and permits, (iii) charges for utilities and insurance, and (iv) field personnel salaries, wages and employee benefits;

(b) charges for the acquisition of materials, equipment, other personal property and fixtures, leases, easements, rights-of-way servitudes, subsurface leases, licenses and permits (in each case) to the extent that such items were acquired during the time period specified;

(c) producing, drilling, construction, marketing and overhead costs charged by Third Parties under joint interest billings or otherwise to the extent attributable to services performed or provided during the time period specified; and

(d) taxes and similar assessments of governmental authorities (other than income taxes, and Sales Tax, if any, on the transactions contemplated by this Agreement) to the extent attributable to the time period specified;

provided that Charges do not include (1) royalties (including overriding royalties and other burdens on production); (2) costs and expenses relating to Imbalances or Suspense Funds; or (3) any costs and expenses incurred outside of the ordinary course of business in connection with the performance of services (such as costs and expenses attributable to personal injuries, environmental liabilities and/or property damages).

"CLAIM NOTICE" means a notice of Third Party Claim or Loss provided in accordance with Article 8.7.

"CLAIMANT" has the meaning set forth in Article 18.1.

"CLOSE" or CLOSING" means consummation of the transactions contemplated by this Agreement, including execution and delivery of all documents and other consideration as provided in this Agreement.

"CLOSING DATE" means (a) October 2, 2006, or (b) any other date agreed by the Parties.

"CLOSING STATEMENT" refers to the document described in Article 16.1.

"COMPUTED INTEREST" means simple interest at a rate per annum equal to the lesser of (i) three percent (3%) per annum using a 365 Day year or (ii) the maximum rate of interest allowed by Law.

"CONFIDENTIALITY AGREEMENT" means the Confidentiality Agreement dated May 31, 2006, between Seller and Buyer, as the same may be amended from time to time.

"DATA ROOM" has the meaning given it in the definition of Alleged Adverse Condition.

"DAY" means a calendar day consisting of twenty-four (24) hours from midnight to midnight.

"DEED, ASSIGNMENT AND BILL OF SALE" means a document substantially in the form of Exhibit "D".

"DEFENSIBLE TITLE" means such title to the Properties held by Seller that (except for the Permitted Encumbrances):

(a) with respect to the leases, contractual interests, overriding royalty interests, units or wells set forth on Exhibit "A" or "A-l", as applicable, entitles Seller to receive, as of the Effective Time, not less than the Net Revenue Interest (NRI) for such lease, contractual interest, overriding royalty interest, well or unit set forth on Exhibit "A" or "A-1", as applicable, except decreases resulting from operations where Seller is a non-consenting party and decreases required to allow other working interest owners to make up past underproduction or pipelines to make up past under-deliveries;

(b) with respect to the leases, contractual interests, units or wells set forth on Exhibit "A" or "A- 1", as applicable, obligates Seller to bear, as of the Effective Time, not greater than the Working Interest (WI) for such well or unit set forth on Exhibit "A" or "A-l", as applicable, unless there is a corresponding increase in the associated Net Revenue Interest (NRI), or such increase results from contribution requirements with respect to defaulting co-owners; and

(c) is free of liens and other encumbrances.

"EFFECTIVE TIME" as to each Property, means April 1, 2006, at 7:00 a.m., local time where the Properties are located.

"ENVIRONMENTAL CLAIMS" means all Third Party Claims based on a violation of Environmental Laws with respect to the Properties; provided that only with respect to Third Party Claims for which Seller owes an obligation of indemnity to Buyer, the term "ENVIRONMENTAL CLAIMS" is limited to Third Party Claims based on a violation of Environmental Laws as such Laws were in effect at the Effective Time.

"ENVIRONMENTAL LAWS" means any and all Laws that relate to (a) prevention of pollution or environmental damage, (b) removal or remediation of pollution or environmental damage, or (c) protection of the environment, public health or safety.

"EXCLUDED PROPERTIES" means the items, properties and matters that are set forth in Exhibit "B" or that are otherwise excepted, reserved or retained by Seller under the terms of this Agreement.

"FINAL ACCOUNTING SETTLEMENT" means the post-Closing accounting activities conducted in accordance with Article 6 which shall be conducted in accordance with generally accepted accounting principles, as applied by Seller with respect to the Properties on the date the Final Accounting Statement is prepared.

"FINAL ACCOUNTING STATEMENT" means a statement prepared by Seller and delivered to Buyer in accordance with Article 6.5 setting forth the adjustments applicable to the period between the Effective Time and the Closing Date.

"HSR ACT" means the Hart-Scott-Rodino Antitrust improvements Act of 1976, as amended.

"IMBALANCE" means over-production or under-production or over-deliveries or under-deliveries with respect to hydrocarbons produced from or allocated to the Properties, regardless of whether such over-production or under-production, or over-deliveries or under-deliveries arise at the platform, wellhead, pipeline, gathering system, transportation or other location and regardless of whether the same arise under contract or by operation of Law.

"INCLUDING", whether or not capitalized, means including without limitation.

"INDEMNIFIED PARTY" has the meaning set forth in Article 8.7.

"INDEMNIFYING PARTY" has the meaning set forth in Article 8.7.

"INTERIM PERIOD" means the period between the date of this Agreement and the Closing Date.

"KNOWLEDGE" (whether or not capitalized) means, in the case of Seller, the actual knowledge of Seller's Disposition Team.

"LAWS" means any and all applicable laws, statutes, codes, constitutions, ordinances, permits, licenses, authorizations, agreements, decrees, orders, judgments, rules or regulations (including, for the avoidance of doubt, Environmental Laws) that are promulgated, issued or enacted by a governmental or tribal entity or authority having appropriate jurisdiction of the Properties or the Parties.

"LETTERS-IN-LIEU" means a document in the form of Exhibit "F" in connection with oil production from the Properties which shall be prepared by Seller, signed by the Parties and delivered to purchasers of production from the Properties at such time as is mutually agreed by the Parties.

"LOSS" means any and all claims of any kind or character, including demands, suits, causes of action, rights of action, suits, legal or administrative proceedings, regulatory actions, losses, risk of losses, impairment of rights, damages, liabilities, subordinations, fines, or penalties and all expenses and costs (including interest, attorneys' fees, costs of litigation and court costs) associated therewith, whether known or unknown, direct or indirect, excluding Third Party Claims.

"MATERIAL ADVERSE EFFECT" means an event or circumstance that,

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individually or in the aggregate with all other events and circumstances, results in a material adverse effect on the ownership, operations, or value of the Properties, taken as a whole and as currently operated as of the date of this Agreement or a material adverse effect on the ability of Seller to consummate the transactions contemplated by this Agreement; provided, however, that none of the following shall be deemed to constitute a Material Adverse Effect: (i) any effect resulting from changes in general market, economic, financial or political conditions in the area in which the Properties are located, the United States or worldwide, or any outbreak of hostilities or war, (ii) any effect resulting from a change in Laws; (iii) any changes in the prices of hydrocarbons; and/or (iv) natural declines in well performance.

"NET REVENUE INTEREST" or ~ with respect to any Property that is a lease, unit or well, means the interest in and to all oil, gas and associated liquids and gaseous hydrocarbons produced, saved, and sold from such unit or well, after giving effect to all royalties, overriding royalties, production payments, carried interests, net profits interests, reversionary interests, and other burdens upon, measured by, or payable out of production therefrom.

"NON-ENVIRONMENTAL CLAIMS" means all Third Party Claims, except for Environmental Claims.

"NON-FOREIGN CERTIFICATE" means a document in the form of Exhibit "G".

"NORM" means naturally occurring radioactive materials.

"OPERATING REVENUES" means sales proceeds for oil, gas and other hydrocarbons produced from the Properties, net of royalties, excise, severance and other production taxes and marketing costs (which include for purposes of this definition, costs of gathering, treating, processing, compression, and transportation), to the extent such items are not treated as "CHARGES" under Article 6, and all other operating revenues attributable to the Properties, excluding producing, drilling and construction overhead receipts Seller receives under operating agreements with Third Parties and further excluding proceeds in cash or from sale of production in settlement of Imbalances prior to the Closing Date.

"PARTIES" has the meaning given it in the introductory paragraph of this Agreement.

"PARTY" has the meaning given it in the introductory paragraph of this Agreement.

"PERFORMANCE DEPOSIT" HAS THE MEANING given it IN Article 2.3.

"PERMITTED ENCUMBRANCES" MEANS any and all:

(a) royalties, overriding royalties, sliding scale royalties, production payments, reversionary interests, convertible interests, net profits interests and similar burdens encumbering any Property to the extent the net cumulative effect of such burdens does not operate to reduce the Net Revenue interest of such Property, as of the Effective Time to less than the Net Revenue Interest (NRI) for such Property set forth in Exhibit "A" "A- 1", as applicable, or increase the Working

Interest of such Property, as of the Effective Time, above the Working interest (WI) for such Property set forth in Exhibit "A" or "A-l", as applicable, without a corresponding and proportionate increase in the associated Net Revenue interests for such Property;

(b) consents to assignment and similar contractual provisions affecting the Properties; (c) preferential rights to purchase and similar contractual provisions affecting the Properties;

(c) preferential rights to purchase and similar contractual provisions affecting the Properties;

(d) rights to consent by, required notices to, and filings with a governmental entity or authority associated with the conveyance of the Properties;

(e) rights reserved to or vested in a governmental or tribal entity or authority having jurisdiction to control or regulate the Properties in any manner whatsoever, and all Laws of such governmental entities or authorities;

(f) easements, rights-of-way, servitudes, surface leases, grazing rights, logging rights, ponds, lakes, waterways, canals, ditches, reservoirs, equipment, pipelines, utility lines, railways, streets, roads and structures on, over, under and through the Properties;

(g) the terms and conditions of unitizations, communitizations, poolings, agreements, instruments, licenses and permits affecting the Properties;

(h) liens for taxes or assessments not yet delinquent or, if delinquent, are being contested by Seller in good faith;

(i) liens of operators relating to obligations not yet delinquent or, if delinquent, are being contested by Seller;

(j) matters that would otherwise be Alleged Title Defects but that do not meet the individual threshold and aggregate deductible amounts set forth in the definition of Alleged Title Defect and in Article 4.2, respectively, or that Buyer waives in accordance with Article 4.3, or for which a Purchase Price adjustment is made or another remedy provided pursuant to Article 4.2;

(k) matters that would otherwise be Alleged Adverse Conditions but that do not meet the individual threshold and aggregate deductible amounts set forth in the definition of Alleged Adverse Conditions and in Article 5.2, respectively, or that Buyer waives in accordance with Article 5.3, or for which a Purchase Price adjustment is made or another remedy provided pursuant to Article 5.2;

(l) Imbalances;

(m) Suspense Funds;

(n) any rights of ingress and egress or other access rights

reserved by or granted to Seller and/or its Affiliates under this Agreement;

(o) matters that Buyer waives in writing;

(p) terms and conditions of governmental licenses and permits affecting the Properties;

(q) matters specifically listed on Exhibit "A" or "A-1" or otherwise disclosed on a Schedule to this Agreement; and

(r) such defects or irregularities in the title to the Properties that do not materially interfere with the ownership, operation, or use of the Properties affected thereby as such Properties were owned, operated or used as of the Effective Time.

"PLUGGING AND ABANDONMENT" means all decommissioning activities and obligations as are required by Laws, contracts associated with the Properties, this Agreement (expressly including, such activities described and defined as of the Effective Time and as may be amended thereafter, in 30 Code of Federal Regulations 250.1700 et seq.) and further including all well plugging, replugging and abandonment; facility dismantlement and removal; pipeline and flowline removal; dismantlement and removal of any and all platforms and other property of any kind related to or associated with operations or activities conducted on the Properties; and site clearance, site restoration and site remediation.

"PPR" means a preferential right to purchase any Property arising out of an agreement covering such Property.

"PROCESS SAFETY MANAGEMENT" means Process Safety Management of Highly Hazardous Chemicals; Explosives and Blasting Agents (29 CFR 1910), as amended, that is associated with the Properties.

"PROPERTIES" means all of Seller's right, title and interests (real, personal, mixed, contractual or otherwise) in, to and under or derived from the following, excluding the Excluded Properties:

(a) all oil and gas leasehold interests, royalty interests, overriding royalty interests, production payments, reversionary interests, options, carried working interests, beneficial interests and net profits interests that are attributable to the interests described in Exhibit "A" or "A-1", and the production of oil, gas and other hydrocarbon substances attributable thereto;

(b) all unitization, communitization and pooling declarations, orders and agreements (including all units formed by voluntary agreement and those formed under the rules, regulations, orders or other official acts of any governmental entity or authority having jurisdiction) to the extent they relate to any of the interests described in Exhibit "A" or "A-1", or the production of oil, gas or other hydrocarbon substances attributable thereto;

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(c) to the extent assignable, all product sales contracts, processing contracts, gathering contracts, transportation contracts, easements, rights-of-way, servitudes, surface leases, farm-in and farm-out contracts, areas of mutual interest, operating agreements, balancing contracts, permits, licenses and other files, contracts, agreements and instruments to the extent they relate to any of the interests described in Exhibit "A" or "A-1", or the production of oil, gas or other hydrocarbon substances attributable thereto;

(d) all (i) tangible personal property, improvements, fixtures and other appurtenances, to the extent situated upon and exclusively used, or situated upon and held exclusively for use, by Seller (or the Operator of the Property) in connection with the ownership, operation, maintenance or repair of the interests described on Exhibit "A" or "A-1" or the production of oil, gas or other hydrocarbon substances attributable thereto, including all gathering and processing systems, platforms, buildings, compressors, meters, tanks, equipment, machinery and tools and; (ii) wells (whether producing, shut-in, injection, disposal, water supply, temporarily abandoned, plugged and abandoned or otherwise) and pipelines (whether or not in use);

(e) all partnerships (tax, state law or otherwise) affecting any Properties;

(f) all Imbalances; and

(g) all Suspense Funds.

"PURCHASE PRICE" has the meaning set forth in Article 2.2.

"RECORDS" means, except as excluded in Exhibit "B" or otherwise excluded or retained by Seller under the terms of this Agreement, an original or a copy (hard copy, electronic or otherwise) of Seller's books, records, data (including, without limitation, technical and digital data) and files to the extent primarily related to the Properties.

"RESPONDENT" has the meaning set forth in Article 18.1.

"SALES TAX" means any and all transfer, sales, gross receipts, compensating use, use or similar taxes, and any associated penalties and interest.

"SELLER" has the meaning set forth in the introductory paragraph of this Agreement.

"SELLER GROUP" means each and all of: (a) Seller and its officers, directors, agents, consultants and employees, and (b) Seller's Affiliates and their members, partners, officers, directors, agents, consultants and employees.

"SELLER'S DISPOSITION TEAM" means Steve Choate (Project Manager, Mergers and Acquisitions), Hal Bogdanski (Senior Negotiator -- Business Development), Hodge Walker (Resource Manage -- Gulf Coast), and Johnathan Wengel (HSSE Business Development Support Manager).

"SHARED SYSTEMS IP" has the meaning given to it in Exhibit "J".

"SUSPENSE FUNDS" means proceeds of production and associated penalties and interest in respect of any of the Properties that are payable to Third Parties and are being held in suspense by Seller as the operator of such Properties.

"SYSTEMS IP LICENSE" means a document in the form of Exhibit "K".

"THIRD PARTY CLAIMS" means any and all claims of any kind or character, including demands, suits, causes of action, rights of action, regulatory actions, losses, risk of losses, impairment of rights, damages, liabilities, subordinations, fines, or penalties and all expenses and costs (including attorneys' fees, costs of litigation and court costs) associated therewith, whether known or unknown, direct or indirect, and whether an Environmental Claim or a Non-Environmental Claim, that are brought by, on behalf of or owed to a Third Party.

"THIRD PARTY-OWNED TECHNOLOGY" means technology, including software, licensed from a Third Party for use in connection with the Properties or the operation thereof.

"TITLE BENEFIT" means any right, circumstance or condition that operates to (i) increase the Net Revenue Interest (NRI) of Seller in any Property above that set forth in Exhibit "A" or "A-1", as applicable, without causing a greater than proportionate increase in the Working Interest (WI) above that shown in Exhibit "A" or "A-1", as applicable, or (ii) decrease the Working Interest (WI) of Seller in a Property below that set forth in Exhibit "A" or "A-1", as applicable, without decreasing the Net Revenue Interest (NRI) for such Property below that shown in Exhibit "A" or "A-1", as applicable.

"TITLE DEFECT" means an individual defect in Seller's title to one or more Properties that would cause Seller not to have Defensible Title to such Property or Properties, and notwithstanding anything in this Agreement to the contrary, does not include the failure of a Party to obtain regulatory approval to conduct a drilling operation, including the right to drill an increased density or infill well.

"TRANSITION AGREEMENT" means a document in the form of Exhibit "H".

"TRANSITION PERIOD" means the period beginning on the Closing Date and ending on the date on which the Transition Agreement terminates.

"WORKING INTEREST" or "~" with respect to any Property that is a lease, unit or well, the interest in and to such unit or well that is burdened with the obligation to bear and pay costs and expenses of maintenance, development and operations on or in connection with such lease. unit or well, but without regard to the effect of any royalties, overriding royalties, production payments, net profits interests and other similar burdens upon, measured by, or payable out of production therefrom.

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ARTICLE II
SALE OF PROPERTIES

2.1 SALE AND PURCHASE. On the Closing Date, but effective as of the Effective Time, and upon the terms and conditions of this Agreement: (a) Seller shall sell and assign the Properties to Buyer, and (b) Buyer shall purchase and accept the Properties from Seller; provided, however, that Seller expressly excepts, reserves and retains, unto itself and its Affiliates, successors and assigns, the Excluded Properties.

2.2 PURCHASE PRICE. The total consideration for the Properties, subject to adjustments as described below, is (a) the payment by Buyer to Seller of One Hundred Seventy-Five Million Two Hundred Thousand no/100 United States Dollars (US $175,200,000.00) ("PURCHASE PRICE"), payable in full at Closing in immediately available funds, and (b) Buyer's assumption of the Assumed Obligations. The Purchase Price shall be adjusted as follows:

2.2.1 increased by Computed interest on the Purchase Price for the period from the Effective Time through the Closing Date;

2.2.2 decreased by the amount of the Performance Deposit, paid by Buyer to Seller, together with Computed Interest on the Performance Deposit calculated from the date of deposit with Seller through the Closing Date;

2.2.3 decreased by the amount of Operating Revenues to which Buyer is entitled under Article 6.2 but which are collected and retained by Seller, together with Computed Interest thereon, calculated from the date of receipt of such revenues by Seller through the Closing

Date;

2.2.4 increased by the amount set forth in Article 6.2.2 per month (pro-rated on a daily basis for any partial month) from the Effective Time through the Closing Date;

2.2.5 increased by the amount of Charges for which Buyer is responsible under Article 6.2 but which are paid by Seller;

2.2.6 decreased by the amount of Charges for which Seller is responsible under Article 6.2 but which are paid by Buyer;

2.2.7 increased by amounts to which Seller is entitled pursuant to Article 6.1;

2.2.8 increased by the amount of taxes and assessments for which Buyer is responsible under Article 6.3 but which are paid by Seller;

2.2.9 decreased by the amount of taxes or assessments for which Seller is responsible under Article 6.3 but which are paid by Buyer;

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2.2.10 decreased by the agreed or arbitrated net adjustment, if any, for Alleged Title Defects pursuant to Article 4.2, and increased by the agreed or arbitrated net adjustment, if any, for Title Benefits pursuant to Article 4.4;

2.2.11 decreased by the agreed or arbitrated net adjustment, if any, to which Buyer is entitled for Alleged Adverse Conditions pursuant to Article 5.2 and decreased or increased, as appropriate, by any adjustments made for Properties excluded pursuant to Article 5.2.1;

2.2.12 decreased or increased, as appropriate, by any adjustments made for Properties excluded pursuant to Article 3.1;

2.2.13 decreased for any agreed reduction in value pursuant to Article 7.2;

2.2.14 increased by the amount of all capital expenditures incurred (or the obligation to incur the capital expenditures was undertaken) by Seller which expenditures have been disclosed to Buyer in respect of the Properties within six (6) months prior to the Effective Time; and

2.2.15 increased or decreased, as the case may be, by any other amount mutually agreed to by the Parties in writing.

The Purchase Price, as so adjusted, is the "ADJUSTED PURCHASE PRICE."

2.3 PERFORMANCE DEPOSIT. UPON EXECUTION OF THIS AGREEMENT AND PRIOR TO ITS DELIVERY TO BUYER, BUYER SHALL DEPOSIT WITH SELLER CASH EQUAL TO TEN PERCENT (10%) OF THE UNADJUSTED PURCHASE PRICE ("PERFORMANCE DEPOSIT"), PROVIDED HOWEVER, THAT IF THIS AGREEMENT IS EXECUTED ON A DAY OTHER THAN A BUSINESS DAY, BUYER SHALL DELIVER THE PERFORMANCE DEPOSIT TO SELLER ON THE NEXT BUSINESS DAY.

2.4 FINANCIAL ASSURANCES. If, no later than seven (7) Days prior to the date of execution of this Agreement, Seller provided Buyer a written notification requiring Buyer to provide a parent guaranty, letter of credit or other assurances of Buyer's performance under this Agreement or of Buyer's financial capability to undertake its obligations under this Agreement ("ASSURANCE"), then upon execution of this Agreement and prior to its delivery to Buyer, Buyer shall provide Seller with the Assurance, in form and substance satisfactory to Seller in Seller's sole discretion.

ARTICLE III
PREFERENTIAL RIGHTS

3.1 PREFERENTIAL RIGHTS TO PURCHASE. Seller shall use Buyer's good faith allocation of the Purchase Price set forth in Exhibit "A" or "A-1", as applicable, to provide any required preferential right to purchase notifications in connection with the transactions contemplated hereby, using a Preference Purchase Right Notice Letter substantially in the form attached as Exhibit "I". If ,as of the Closing Date, (a) a holder of a preferential purchase right

("PPR") has notified Seller that it elects to exercise its PPR with respect to the Properties to which its PPR applies (in accordance with the agreement in which the PPR arises, as determined by Seller) or (b) the time for exercising such PPR has not expired, then the Properties covered by that PPR will not be sold to the Party originally executing this Agreement as "Buyer" (subject to the remaining provisions in this Article), and the Purchase Price will be reduced by the value allocated to such Properties in Exhibit "A" or "A-1", as applicable. In accordance with the terms of this Agreement, Buyer remains obligated to purchase the remainder of the Properties not affected by an exercised PPR or a PPR for which the time to exercise has expired prior to Closing,

3.1.1 After the Closing, if for any reason the purchase and sale of the Properties covered by the PPR is not or cannot be consummated with the holder of the PPR that exercised its PPR or if the time for exercising the PPR expires without exercise by any holder of the PPR, Seller may so notify Buyer and within ten (10) Business Days after Buyer's receipt of such notice or after such expiration, Seller shall sell, assign and convey to Buyer and Buyer shall purchase and accept from Seller such Properties pursuant to the terms of this Agreement and for the value allocated to such Properties in Exhibit "A" or "A-1", as applicable (except the Closing Date with respect to such Properties will be the date of assignment of such Properties from Seller to Buyer).

3.1.2 Any PPR must be exercised subject to all the terms and conditions of this Agreement.

ARTICLE IV
TITLE REVIEW

4.1 REVIEW OF TITLE RECORDS. After execution and delivery of this Agreement, Seller shall make available (during Seller's regular business hours and at their current location(s)) for Buyer's review, Records in Seller's and its Affiliates' possession relating to title to the Properties. If Buyer requests copies of title Records, Seller shall use its commercially reasonable efforts to provide the requested copies to Buyer at Buyer's expense. Buyer shall conduct its review of Records in accordance with the terms of the Confidentiality Agreement.

4.2 ALLEGED TITLE DEFECTS.

4.2.1 As soon as reasonably practicable (and on an ongoing basis), but no later than the earlier of (i) four (4) Business Days before the Closing Date or (ii) thirty (30) Days after the date the Parties execute this Agreement, Buyer shall notify Seller in writing of any Title Defects. Buyer's notice asserting Title Defects must include a description and full explanation (including any and all supporting documentation) of each Title Defect claimed, the Properties affected thereby, and the value Buyer in good faith attributes to the Title Defect. Buyer and Seller shall meet from time to time to attempt to agree on resolution with respect to Alleged Title Defects, including any Purchase Price adjustment with respect thereto.

4.2.2 Seller shall have the right, but not the obligation, to attempt, at Seller's sole cost, to cure or remove on or before the

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Closing Date any Alleged Title Defects of which it has been advised by Buyer. If prior to Closing, Seller has commenced curing the Alleged Title Defect and pursues such effort diligently, then Seller may, by notice to Buyer prior to Closing, continue attempting to cure such defect to completion for up to one hundred eighty (180) Days after the Closing Date. If Seller does not cure an Alleged Title Defect prior to Closing and fails to provide notice that it shall continue attempting to cure such Alleged Title Defect after Closing, or if such notice is provided but such Alleged Title Defect is not cured on or before one hundred eighty (180) Days following Closing, then within thirty (30) Days following Seller's receipt of written notice from Buyer of such failure or non-completion and either (i) Seller's and Buyer's agreement upon the existence and value of the Alleged Title Defect or (ii) a resolution by binding arbitration in accordance with Article 18.1 of any dispute regarding the existence or value of the uncured Alleged Title Defect, Seller shall pay to Buyer an amount equal to the value if any of such Alleged Title Defect, as so agreed or as determined in arbitration.

4.2.3 The cumulative adjustments and payments associated with the Alleged Title Defects may not exceed the value allocated to the affected Property in Exhibit "A" or "A-1", as applicable, but notwithstanding the foregoing, if an Alleged Title Defect is reasonably susceptible of being cured, the adjustments or payments with respect to that Alleged Title Defect shall not exceed the reasonable costs of cure. If the Parties are unable to agree on a resolution associated with any Alleged Title Defects raised by Buyer before Closing, the Parties shall Close without Purchase Price adjustment; provided, however, that within thirty (30) Days after the Closing Date, either Party may initiate binding arbitration in accordance with the provisions set forth in Article 1 8.1 to resolve the dispute.

4.2.4 Any claim with respect to an Alleged Title Defect not referred to arbitration within thirty (30) Days following Closing as provided in Article 4.2.3 (or, with respect to any Alleged Title Defect for which Seller provides notice that it will continue attempting to cure after Closing, within thirty (30) Days after the one hundred eighty (180) Day period cure period following Closing has expired) shall be deemed waived by Buyer for all purposes.

4.2.5 Notwithstanding anything contained in this Agreement to the contrary, Buyer shall not be entitled to an adjustment or other remedy relating to an Alleged Title Defect unless and until the aggregate value of all Alleged Title Defects not cured or indemnified against by Seller exceeds one percent (1%) of the Purchase Price, and then only to the extent such aggregate value exceeds one percent (1%) of the Purchase Price, and Buyer shall be solely responsible for and bear all costs and expenses associated with any and all Alleged Title Defects up to one percent (1%) of the Purchase Price. No payment shall be due with respect to any Alleged Title Defect for which Seller, at its option, delivers to Buyer an indemnity agreement in favor of Buyer with respect to such Alleged Title Defect.

4.3 WAIVER. BUYER (ON BEHALF OF BUYER GROUP AND THEIR SUCCESSORS AND ASSIGNS) HEREBY WAIVES FOR ALL PURPOSES ALL OBJECTIONS AND DEFECTS (WHETHER KNOWN OR UNKNOWN) ASSOCIATED WITH THE TITLE TO THE PROPERTIES (INCLUDING ALLEGED TITLE DEFECTS) EXCEPT FOR: (A) BUYER'S RIGHTS WITH RESPECT TO SELLER'S

REPRESENTATION SET FORTH IN SECTION 10.1.6, AND (B) ALLEGED TITLE DEFECTS RAISED BY BUYER TO SELLER BY PROPER NOTICE WITHIN THE APPLICABLE TIME PERIOD SPECIFIED IN, AND AS OTHERWISE REQUIRED by, ARTICLE 4.2, EXCEPT TO THE EXTENT SUCH ALLEGED TITLE DEFECTS ARE SETTLED BY WRITTEN AGREEMENT OF THE PARTIES OR BY ARBITRATION, AS PROVIDED IN ARTICLE 4.2.

4.4 TITLE BENEFITS. If Buyer or Seller discovers any Title Benefit on or before Closing, such Party, as soon as practicable, but in any event prior to Closing, shall deliver to the other Party a notice including a specific description of the Title Benefit, and the Properties affected, and a value such Party in good faith attributes to, the Title Benefit.

4.4.1 With respect to each Property affected by Title Benefits reported under Article 4.4 above (or of which Buyer had knowledge and should have reported under Article 4.4), then, if, prior to Closing, Seller and Buyer have agreed upon the existence and value of the Title Benefit or any disputes regarding the existence or the value of the Title Benefit have been resolved by binding arbitration in accordance with Article 18.1, the Purchase Price at Closing shall be increased by an amount equal to the increase in the Exhibit "A" or "A-1", as applicable, allocation for such Property caused by such Title Benefits.

4.4.2 If prior to Closing the Parties are unable to agree on a resolution associated with any Title Benefit, the Parties shall Close without Purchase Price adjustment; provided however, that within thirty (30) Days after the Closing Date, either Party may initiate binding arbitration in accordance with the provisions set forth in Article 18.1 to resolve the dispute. Within five (5) Days following the earlier to occur of (i) Seller's and Buyer's agreement upon the existence and value of the Title Benefit or (ii) resolution of any dispute regarding the existence or value of the Title Benefit by binding arbitration in accordance with Article 18.1, Buyer shall pay to Seller an amount equal to the value of the Title Benefit, if any, as so agreed or determined in arbitration.

ARTICLE V
CONDITION OF THE PROPERTIES

5.1 CONDITION OF THE PROPERTIES. AFTER EXECUTION AND DELIVERY OF THIS AGREEMENT, SELLER SHALL PROVIDE BUYER ACCESS (DURING SELLER'S REGULAR BUSINESS HOURS) TO SELLER-OPERATED PROPERTIES, AND SELLER WILL REQUEST PERMISSION FOR BUYER TO GAIN ACCESS TO THIRD PARTY-OPERATED PROPERTIES, TO CONDUCT A VISUAL INSPECTION OF THE SAME. As part of the visual inspection of each of the Seller-operated Properties, Buyer or its agents and consultants may request information and ask questions regarding the condition of the Properties and Seller will attempt to provide the requested information and answer such questions, although not necessarily during the site visit. Buyer may review all pertinent Records of Seller to the extent pertaining to the Properties for the purpose of detecting the presence of hazardous or toxic substances, pollutants or other contaminants, environmental hazards, naturally occurring radioactive material (NORM), and produced water or hydrocarbons contamination of the surface or subsurface. The time(s) of review of such Records shall be mutually agreed by the Parties and the place(s) for the review will be specified by Seller to Buyer.

5.1.1 Such inspection shall be conducted in accordance with the terms of the Confidentiality Agreement and subject to any releases or other agreements required by the operator of the Properties. Buyer may not operate equipment or conduct testing or sampling of materials during such inspection unless Seller and Buyer otherwise agree in writing. Buyer shall be responsible for arranging, at its own cost, transportation to and from the Properties.

5.1.2 Buyer's access to the Properties shall be at Buyer's sole risk and expense; and Buyer hereby releases Seller Group from and shall fully indemnify, defend, protect and hold Seller Group harmless from and against any and all Losses and Third Party Claims directly or indirectly arising out of or connected with Buyer's inspection of the Properties or travel to or from or presence on the Properties in connection with the transactions contemplated by this Agreement To the extent there is any conflict between this indemnity (including Article 19.14) and the indemnity in Section 10 of the Confidentiality Agreement, the provisions of this indemnity prevail.

5.2 ALLEGED ADVERSE CONDITIONS. As soon as reasonably practical (and on an ongoing basis), but no later than the earlier of (i) four (4) Business Days before the Closing Date, or (ii) thirty (30) Days after the Parties have executed this Agreement, Buyer shall notify Seller of any conditions that might constitute Alleged Adverse Conditions. Buyer's notice of such conditions must include (i) a complete description of each individual condition to which Buyer takes exception (including any and all supporting documentation) and (ii) an estimate of the costs Buyer in good faith attributes to bringing such condition into compliance with applicable Environmental Laws. Seller and Buyer shall meet from time to time to attempt to agree on a resolution of Alleged Adverse Conditions.

5.2.1 If the Parties are unable to agree on resolution of any Alleged Adverse Conditions on or before three (3) Days before the Closing Date, Seller has the option, in its sole discretion, to either (a) exclude the affected Properties from this Agreement and reduce the Purchase Price by the positive value allocated to such Properties in Exhibit "A" or "A-1", as applicable, if any, or increase the Purchase Price by the negative value allocated to such Properties in Exhibit "A" or "A- 1", applicable, if any, as applicable; (b) bring the Alleged

Adverse Condition into compliance with Environmental Laws (as in effect as of the Effective Time); or (c) indemnify Buyer against such Alleged Adverse Condition.

5.2.2 If Seller elects on or before the Closing Date to attempt, at its sole cost, to bring any Alleged Adverse Condition into compliance with Environmental Laws (as in effect as of the Effective Time), Seller may, by notice to Buyer prior to Closing, elect to continue attempting to remediate such condition to completion for up to one hundred eighty (180) Days after the Closing Date. If Seller does not remediate an Alleged Adverse Condition prior to Closing and fails to provide notice that Seller elects to continue attempting to remediate such Alleged Adverse Condition after Closing, or if such

notice is provided but such Alleged Adverse Condition is not remediated on or before one hundred eighty (180) Days following Closing, Buyer shall give Seller written notice of such failure or non-completion and within five (5) Business Days following the earlier to occur of the date that (i) Seller and Buyer agree in writing on the existence and value of the Alleged Adverse Condition or (ii) resolution by binding arbitration in accordance with Article 18.1 of any dispute regarding the existence or value of the Alleged Adverse Condition, Seller shall pay to Buyer an amount equal to the value of such Alleged Adverse Condition, if any, as so agreed or determined in arbitration.

5.2.3 The cumulative adjustments and payments associated with Alleged Adverse Conditions may not exceed the value allocated to the affected Property in Exhibit "A" of "A-1", as applicable, but notwithstanding the foregoing, if an Alleged Adverse Condition can be remediated, the adjustments or payments with respect to that Alleged Adverse Condition shall not exceed the reasonable costs of remediation. If the Parties are unable to agree on a resolution associated with any Alleged Adverse Conditions raised by Buyer before Closing, the Parties shall Close without a Purchase Price adjustment; provided, however, that within thirty (30) Days after the Closing Date, either Party may initiate binding arbitration in accordance with the provisions set forth in Article 18.1 to resolve the dispute.

5.2.4 Any claim with respect to an Alleged Adverse Condition not referred to arbitration within thirty (30) Days after the Closing Date as provided in Article 5.2.3 (or, with respect to any Alleged Adverse Condition for which Seller provides notice that it will continue attempting to cure after Closing, within thirty (30) Days after the one hundred eighty (180) Day period cure period following Closing has expired) shall be deemed waived for all purposes by Buyer.

5.2.5 Notwithstanding anything contained in this Agreement to the contrary, Buyer shall not be entitled to an adjustment or other remedy relating to any Alleged Adverse Condition unless and until the aggregate costs associated with remedying all Alleged Adverse Conditions so raised that are not remediated or indemnified against by Seller exceeds two and one half percent (2.5%) of the Purchase Price, and then only to the extent such aggregate cost exceeds two and one half percent (2.5%) of the Purchase Price; and Buyer shall be solely responsible for and bear all costs and expenses associated with any and all Alleged Adverse Conditions up to two and one half percent (2.5%) of the Purchase Price. No payment shall be due with respect to any Alleged Adverse Condition for which Seller, at its option, delivers to Buyer an indemnity agreement in favor of Buyer with respect to such Alleged Adverse Condition.

5.3 WAIVER. BUYER (ON BEHALF OF BUYER GROUP AND THEIR SUCCESSORS AND ASSIGNS) WAIVES FOR ALL PURPOSES ALL OBJECTIONS AND CLAIMS (WHETHER KNOWN OR UNKNOWN) ASSOCIATED WITH ENVIRONMENTAL, PHYSICAL, CONTRACTUAL AND ANY OTHER CONDITIONS (WHETHER SIMILAR OR DISSIMILAR) ON, AFFECTING OR PERTAINING TO THE PROPERTIES (INCLUDING ALLEGED ADVERSE CONDITIONS) EXCEPT FOR (A) BUYER'S RIGHTS WITH RESPECT TO SELLER'S INDEMNITY UNDER ARTICLE 8.4, (B) ALLEGED ADVERSE CONDITIONS BUYER RAISED TO SELLER BY PROPER NOTICE WITHIN THE APPLICABLE TIME PERIOD SPECIFIED IN, AND AS OTHERWISE REQUIRED BY, ARTICLE 5.2, OTHER THAN TO THE EXTENT THAT SUCH ALLEGED ADVERSE CONDITIONS ARE SETTLED BY WRITTEN AGREEMENT OF THE PARTIES OR BY ARBITRATION AS PROVIDED IN ARTICLE 5.2.2.

ARTICLE VI
ACCOUNTING

6.1 PRODUCTS. Merchantable oil and liquid hydrocarbon substances associated with the Properties and stored in tanks and vessels will be gauged to the bottom of the unloading flange as of the Effective Time. Buyer shall purchase from Seller at Closing, all such oil and liquid hydrocarbon substances, all at a price equal to the average price received by Seller from sales during the month of March, 2006, for comparable oil and liquid hydrocarbon substances from each field that is part of the Properties from which such substances were produced, net of royalties, excise, severance and other production taxes, and marketing costs (which include for purposes hereof, among other things, costs of gathering, treating, processing, compression, and transportation), to the extent such items are not treated as Charges under this Article 6. Oil and liquid hydrocarbon substances in treating and separation equipment upstream of pipeline connections, as of the Effective Time, will not be considered merchantable and will become the property of Buyer at Closing. Actual amounts shall be accounted for in the Final Accounting Settlement.

6.2 REVENUES, EXPENSES AND CAPITAL EXPENDITURES. Except as expressly provided otherwise in this Agreement:

6.2.1 Seller is entitled to all its share of Operating Revenues attributable to the Properties for the period prior to the Effective Time and is responsible for all its share of Charges attributable to the Properties for the period prior to the Effective Time;

6.2.2 Seller also is entitled to a sum per month of One Hundred Fifty Thousand Dollars (US $150,000) (prorated on a daily basis for any partial month) as an agreed reimbursement in lieu of Seller's actual overhead attributable to the Properties, including Seller's personnel salaries, wages and employee benefits for the period from the Effective Time through the Closing Date with such amount allocated to the Properties as set forth on Schedule 6.2.2; and

6.2.3 Buyer is entitled to all Operating Revenues (except producing, drilling and overhead charges payable to Seller or its Affiliates where applicable and the sum per month specified in Article 6.2.2) attributable to the Properties for the period on and after the

Effective Time and is responsible for all Charges attributable to the Properties for the period on and after the Effective Time.

Actual amounts, including any adjustments for Imbalances owed pursuant to Article 12.7.2 shall be accounted for in the Final Accounting Settlement, unless previously accounted for under the Transition Agreement. Whether Charges and Operating Revenues are attributable to periods before or after the Effective Time shall be determined in accordance with United States generally accepted accounting principles (as published by the Financial Accounting Standards Board) and Council of Petroleum Accountants Societies (COPAS) standards, based on the accrual method of accounting. Notwithstanding anything contained in this

Agreement to the contrary, Buyer shall assume and be solely responsible for any and all capital expenditures associated with the Properties that were disclosed to Buyer prior to the date of this Agreement to the extent such capital expenditures were incurred (or the obligation to incur the capital expenditures was undertaken) by Seller within six (6) months prior to the Effective Time, and the Final Accounting Statement shall include a reimbursement of Seller for any such capital expenditures paid by Seller.

6.3 TAXES. Seller shall bear all taxes and assessments, including excise taxes, severance or other production taxes, ad valorem taxes and any other federal, state or local taxes or assessments attributable to ownership or operation of the Properties prior to the Effective Time; and all deductions, credits or refunds pertaining to the aforementioned taxes and assessments, no matter when received, belong to Seller. Provided that Closing has occurred, Buyer shall bear all taxes and assessments, including sales taxes, excise taxes, severance or other production taxes, ad valorem taxes and any other federal, state or local taxes and assessments attributable to ownership or operation of the Properties on and after the Effective Time (excluding Seller's income taxes from the Effective Time through Closing); and all deductions, credits and refunds pertaining to the aforementioned taxes and assessments, no matter when received, belong to Buyer. Ad valorem or property or other taxes based on revenue from the Properties shall apply to the tax year for which the tax rendition is issued and shall be prorated based on the percentage of the assessment period occurring before and after the Effective Time. Actual amounts shall be accounted for in the Final Accounting Settlement. Buyer shall be responsible for and pay any and all Sales Tax on the transactions contemplated by this Agreement. Each Party is responsible for filing any tax returns and handling payment of any tax due under Law during the period when it holds title to the Properties.

6.4 CREDITS. Provided Closing has occurred, Buyer shall reimburse Seller for any and all prepaid insurance premiums, utility charges, rentals, deposits and any other prepays (excluding taxes) applicable to the period on and after the Effective Time that are attributable to the Properties. Actual amounts shall be accounted for in the Final Accounting Settlement.

6.5 FINAL ACCOUNTING SETTLEMENT. As soon as reasonably practicable, but no later than one hundred fifty (150) Days after the end of the Transition Period, Seller shall deliver the Final Accounting Statement to Buyer. Buyer will have reasonable access to supporting documentation as necessary to evaluate the Final Accounting Statement, as Buyer shall reasonably request.

6.5.1 As soon as reasonably practicable, but no later than thirty (30) Days after Buyer receives the Final Accounting Statement, Buyer may deliver to Seller a written report containing any changes

Buyer proposes to such statement. Any adjustments covered by the Final Accounting Statement as delivered by Seller to which Buyer fails to object in the written report within the thirty (30) Day time period shall be deemed correct and are final and binding on the Parties and not subject to further review, audit or arbitration.

6.5.2 As soon as reasonably practicable, but no later than thirty (30) Days after Seller receives Buyer's written report, the Parties shall meet to attempt to agree on any adjustments to the Final Accounting Statement. If the Parties fail to agree on final adjustments within that thirty (30) Day period, either Party may submit the

disputed items to the Accounting Referee. The Parties shall direct the Accounting Referee to resolve the disputes within thirty (30) Days after its receipt of relevant materials pertaining to the dispute (and the Parties agree to use their respective reasonable efforts to deliver such materials promptly to the Accounting Referee).

6.5.3 The Final Account Statement, whether as agreed between the Parties or as determined by a decision of the Accounting Referee, shall be binding on and non-appealable by the Parties. The Accounting Referee shall act as an expert for the limited purpose of determining the specific disputed adjustments submitted by either Party and may not award damages or penalties to either Party with respect to any matter. Seller and Buyer shall share equally the Accounting Referee's fees and expenses.

6.5.4 Any amounts owed by one Party to the other under the Final Accounting Settlement shall be paid within thirty (30) Days after the earlier of: (i) the date that the amounts are agreed by the Parties, and (ii) the date that the Parties receive the Accounting Referee's decision; and the revenues and expenses included in the Final Accounting Settlement (including any and all Operating Revenues and Charges received and booked by Seller prior to Seller's delivery of the Final Accounting Statement to Buyer) shall be final and binding on the Parties and not subject to further review, audit or arbitration.

6.6 POST-FINAL ACCOUNTING SETTLEMENT REVENUES.

6.6.1 Buyer shall pay Seller any and all Operating Revenues received by Buyer (to the extent not accounted for in the Final Accounting Settlement or the Transition Agreement) for the period prior to the Effective Time, and

6.6.2 Seller shall pay Buyer any and all Operating Revenues received by Seller (to the extent not accounted for in the Final Accounting Settlement or the Transition Agreement) for the period after the Effective Time, except producing, drilling and overhead payable to Seller or its Affiliates and the sum per month specified in Article 6.2.2 both of which are to be retained by Seller.

6.6.3 The Party responsible for making payment in Article 6.6.1 or Article 6.6.2 shall make full payment to the other Party within thirty (30) Days after receipt of the Operating Revenues in question.

6.7 POST-FINAL ACCOUNTING SETTLEMENT EXPENSES.

6.7.1 Seller shall reimburse Buyer for any and all Charges paid by Buyer (to the extent not accounted for in the Final Accounting Settlement or the Transition Agreement) prior to the Effective Time; and

6.7.2 Buyer shall reimburse Seller for any and all Charges paid by Seller (to the extent not accounted for in the Final Accounting Settlement or the Transition Agreement) after the Effective Time.

6.7.3 The Party responsible for making payment in Article 6.7.1 or Article 6.7.2 shall make full payment to the other Party within thirty (30) Days after receipt of an applicable invoice and proof that such invoice was paid for the Charges in question.

6.8 JOINT INTEREST AUDITS. Seller is entitled (at Seller's expense) to resolve all joint interest audits or other contractual audits (whether or not be conducting as of the Effective Time) that are applicable to any periods or amounts for which Seller is responsible under this Agreement and to pay or receive (as applicable) any amounts due or receivable attributable to Seller's operation of, or current interest in, the Properties that are subject to such audits.

ARTICLE VII
LOSS, CASUALTY AND CONDEMNATION

7.1 NOTICE OF LOSS. Seller shall promptly notify Buyer of all instances of Casualty Loss that occur and become known to Seller between the date of this Agreement and Closing.

7.2 CASUALTY LOSS. If, prior to Closing, any Properties are impacted by a Casualty Loss, Seller and Buyer shall meet to attempt to agree on an adjustment to the Purchase Price reflecting the reduction in value of the Properties because of such Casualty Loss. For this purpose "reduction in value" is based on the principle that Seller should generally bear the costs of repairing the Properties to the state existing immediately prior to the Casualty Loss, and if such repair results in equipment or facilities that are newer than or upgraded from that which existed immediately prior to the Casualty Loss, Buyer should bear a portion of such costs as is equitable, given the benefit to Buyer of such newer or upgraded equipment or facilities. No adjustment associated with a Casualty Loss will exceed the value allocated to the affected Property in Exhibit "A" or "A-1 ", as applicable.

7.2.1 If the Parties are unable to agree on resolution of a Casualty Loss, the Parties shall Close without a Purchase Price adjustment; provided, however, that within thirty (30) Days after the Closing Date, either Party may initiate binding arbitration in accordance with Article 18.1 to resolve the dispute. ANY CLAIM WITH RESPECT TO a Casualty LOSS NOT REFERRED TO ARBITRATION WITHIN THIRTY (30) DAYS FOLLOWING CLOSING (OR, WITH RESPECT TO ANY CASUALTY LOSS FOR WHICH SELLER PROVIDES NOTICE THAT IT WILL CONTINUE ATTEMPTING TO CURE AFTER CLOSING, WITHIN THIRTY (30) DAYS AFTER THE ONE HUNDRED EIGHTY (180) DAY PERIOD CURE PERIOD FOLLOWING CLOSING HAS EXPIRED) SHALL BE DEEMED WAIVED BY BUYER FOR ALL PURPOSES.

7.2.2 Notwithstanding the foregoing, if the aggregate Casualty Losses exceed fifty percent (50%) of the Purchase Price, either Party may, by notice to the other at least one Business Day prior to Closing, elect to terminate this Agreement under Article 17.1.6.

7.2.3 All insurance proceeds and other payments associated with or attributable to any Casualty Losses shall be payable to the Party that ultimately bears the costs for the repair of the damages for which such insurance proceeds or payments are attributable.

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ARTICLE VIII
ALLOCATION OF RESPONSIBILITIES AND INDEMNITIES

8.1 OPPORTUNITY FOR REVIEW. Each Party represents that it has had an adequate opportunity to review all waiver, release, indemnity and defense provisions in this Agreement, including the opportunity to submit the same to legal counsel for review and advice. Based on the foregoing representation, the Parties agree to the provisions set forth below.

8.2 SELLER'S NON-ENVIRONMENTAL INDEMNITY OBLIGATION. SUBJECT TO THE LIMITATIONS SET FORTH IN THIS AGREEMENT, SELLER SHALL PROTECT, DEFEND, INDEMNIFY AND HOLD BUYER GROUP HARMLESS FROM AND AGAINST ALL NON-ENVIRONMENTAL CLAIMS TO THE EXTENT RELATING TO, ARISING OUT OF, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, SELLER'S OWNERSHIP OR OPERATION OF THE PROPERTIES OR ANY PART THEREOF PRIOR TO THE EFFECTIVE TIME, INCLUDING NON-ENVIRONMENTAL CLAIMS RELATING TO: (A) INJURY OR DEATH OF ANY PERSONS WHOMSOEVER, (B) PAYMENT OF ROYALTIES, OVERRIDING ROYALTIES OR OTHER BURDENS ON PRODUCTION; (C) DAMAGES TO OR LOSS OF ANY PROPERTY, (D) BREACH OF CONTRACT, (E) COMMON LAW CAUSES OF ACTION SUCH AS NEGLIGENCE, STRICT LIABILITY, NUISANCE OR TRESPASS, AND (F) FAULT IMPOSED BY LAW OR OTHERWISE.

8.2.2 SUBJECT TO THE LIMITATIONS SET FORTH IN THIS AGREEMENT, SELLER SHALL PROTECT, DEFEND, INDEMNIFY AND HOLD BUYER GROUP HARMLESS FROM AND AGAINST ALL LOSSES OF BUYER RESULTING FROM ANY BREACH by SELLER OF (A) ANY OF ITS REPRESENTATIONS AND/OR WARRANTIES SET FORTH IN ARTICLE 10 OR THE CORRESPONDING REPRESENTATIONS SET FORTH IN THE CERTIFICATE DELIVERED BY SELLER TO BUYER PURSUANT TO ARTICLE 16.2.2 OR (B) ITS COVENANTS CONTAINED IN THIS AGREEMENT.

8.2.3 NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THIS AGREEMENT, SELLER RETAINS SOLE RESPONSIBILITY AND LIABILITY FOR ALL MATTERS EXPRESSLY RETAINED BY SELLER PURSUANT TO ARTICLE 12.3, AND SELLER RELEASES BUYER GROUP FROM AND SHALL PROTECT, DEFEND, INDEMNIFY AND HOLD BUYER GROUP HARMLESS FROM AND AGAINST ALL NON-ENVIRONMENTAL CLAIMS AND ENVIRONMENTAL CLAIMS RELATING TO SUCH MATTERS TO THE EXTENT RELATING TO, ARISING OUT OF, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, SUCH MATTERS TO THE EXTENT SUCH MATTERS RELATE TO THE PERIOD PRIOR TO THE EFFECTIVE TIME. Buyer shall use its reasonable efforts to cooperate with Seller in all respects in connection Seller's retention and defense of such matters.

8.3 LIMITATIONS ON SELLER'S NON-ENVIRONMENTAL AND OTHER INDEMNITIES. NOTWITHSTANDING ANYTHING IN THIS AGREEMENT TO THE CONTRARY, SELLER HAS NO OBLIGATION UNDER THIS AGREEMENT OR OTHERWISE TO PROTECT, DEFEND, INDEMNIFY, AND HOLD BUYER GROUP HARMLESS FROM AND AGAINST ANY ONE OR MORE OF THE FOLLOWING:

8.3.1 NON-ENVIRONMENTAL CLAIMS UNDER 8.2.1 FOR WHICH BUYER HAS NOT PROVIDED SELLER NOTICE IN ACCORDANCE WITH ARTICLE 8.7 WITHIN TWENTY-FOUR (24) MONTHS AFTER THE CLOSING DATE (AND BUYER ASSUMES AND

IS SOLELY RESPONSIBLE FOR ALL NON-ENVIRONMENTAL CLAIMS NOT SO RAISED WITHIN SUCH TWENTY-FOUR (24) MONTH PERIOD);

8.3.2 LOSSES UNDER ARTICLE 8.2.2 RESULTING FROM SELLER'S BREACH OF (A) ITS REPRESENTATIONS AND/OR WARRANTIES SET FORTH IN ARTICLE 10 OR (B) ITS COVENANTS UNDER THIS AGREEMENT, FOR WHICH IN THE CASE OF (A) AND (B) BUYER HAS NOT PROVIDED SELLER NOTICE IN ACCORDANCE WITH ARTICLE 8.7 WITHIN THE TIME SPECIFIED IN ARTICLE 19.6; AND

8.3.4 NON-ENVIRONMENTAL CLAIMS AND LOSSES COVERED BY ARTICLE 8.2.1 AND ARTICLE 8.2.2 THAT, IN THE AGGREGATE, DO NOT EXCEED ONE PERCENT (1%) OF THE PURCHASE PRICE, AND BUYER ASSUMES AND IS SOLELY RESPONSIBLE FOR ALL NON-ENVIRONMENTAL.

8.4 SELLER'S ENVIRONMENTAL INDEMNITY OBLIGATION. SUBJECT TO THE LIMITATIONS SET FORTH IN THIS AGREEMENT, SELLER SHALL PROTECT, DEFEND, INDEMNIFY AND HOLD BUYER GROUP HARMLESS FROM AND AGAINST ALL ENVIRONMENTAL CLAIMS TO THE EXTENT RELATING TO, ARISING OUT of, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, SELLER'S OWNERSHIP OR OPERATION OF THE PROPERTIES OR ANY PART THEREOF PRIOR TO THE EFFECTIVE TIME.

8.5 LIMITATIONS ON SELLER'S ENVIRONMENTAL INDEMNITIES. NOTWITHSTANDING ANYTHING IN THIS AGREEMENT TO THE CONTRARY, SELLER HAS NO OBLIGATION UNDER THIS AGREEMENT OR OTHERWISE TO PROTECT, DEFEND, INDEMNIFY, AND HOLD BUYER GROUP HARMLESS FROM AND AGAINST ANY ONE OR MORE OF THE FOLLOWING:

8.5.1 ENVIRONMENTAL CLAIMS (EXCEPT FOR ANY SUCH MATTERS RETAINED BY SELLER PURSUANT TO ARTICLE 12.3) FOR WHICH BUYER HAS NOT PROVIDED SELLER WITH NOTICE IN ACCORDANCE WITH ARTICLE 8.7 WITHIN TWELVE (12) MONTHS AFTER THE CLOSING DATE; AND BUYER ASSUMES AND IS SOLELY RESPONSIBLE FOR ANY AND ALL ENVIRONMENTAL CLAIMS NOT RAISED WITHIN SUCH TWELVE (12) MONTH PERIOD; AND

8.5.2 ENVIRONMENTAL CLAIMS (EXCEPT FOR ANY SUCH MATTERS RETAINED BY SELLER PURSUANT TO ARTICLE 12.3) IN AGGREGATE UP TO ONE PERCENT (1%) OF THE PURCHASE PRICE, AND BUYER ASSUMES AND IS SOLELY RESPONSIBLE FOR ANY AND ALL ENVIRONMENTAL CLAIMS UP TO ONE PERCENT (1%) OF THE PURCHASE PRICE.

8.6 BUYER'S INDEMNITY OBLIGATION. EXCEPT AS PROVIDED ELSEWHERE IN THIS AGREEMENT, BUYER RELEASES SELLER GROUP FROM AND SHALL PROTECT, DEFEND, INDEMNIFY AND HOLD SELLER GROUP HARMLESS FROM AND AGAINST AND ASSUMES

(i) ALL LOSSES AND THIRD PARTY CLAIMS RELATING TO, ARISING OUT OF, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, OWNERSHIP OR OPERATION OF THE PROPERTIES OR ANY PART THEREOF PRIOR TO THE EFFECTIVE TIME (NO MATTER WHEN ASSERTED) FOR WHICH SELLER'S INDEMNITY AND DEFENSE OBLIGATIONS IN ARTICLE 8.2 OR ARTICLE 8.4 HAVE CEASED, TERMINATED (IN ACCORDANCE WITH ARTICLE 8.3, ARTICLE 8.5 OR OTHERWISE) OR DO NOT APPLY,

(ii) ALL THIRD PARTY CLAIMS ARISING AGAINST SELLER GROUP FROM BUYER'S ALLOCATION OF THE PURCHASE PRICE FOR THE PURPOSES OF ARTICLE 3,

(iii) ALL LOSSES OF SELLER RESULTING FROM ANY BREACH by BUYER OF (A) ANY OF ITS REPRESENTATIONS AND/OR WARRANTIES SET FORTH IN ARTICLE 11 OR THE CORRESPONDING REPRESENTATIONS SET FORTH IN THE CERTIFICATE DELIVERED by BUYER TO SELLER PURSUANT TO ARTICLE 16.3.3 OR (B) ITS COVENANTS CONTAINED IN THIS AGREEMENT,

(iv) ALL LOSSES AND THIRD PARTY CLAIMS RELATING TO, ARISING OUT OF, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, OWNERSHIP OR OPERATION OF THE PROPERTIES OR ANY PART THEREOF ON AND AFTER THE EFFECTIVE TIME (NO MATTER WHEN ASSERTED),

AND IN THE CASE OF (i), (ii) (iii) AND (iv) ABOVE, INCLUDING LOSSES OR THIRD PARTY CLAIMS RELATING TO (A) INJURY OR DEATH OF ANY PERSONS WHOMSOEVER, (B) PAYMENT OF ROYALTIES, OVERRIDING ROYALTIES OR OTHER BURDENS ON PRODUCTION; (C) DAMAGES TO OR LOSS OF ANY PROPERTY, (D) BREACH OF CONTRACT, (E) COMMON LAW CAUSES OF ACTION SUCH AS NEGLIGENCE, STRICT LIABILITY, NUISANCE OR TRESPASS, (F) FAULT IMPOSED BY LAW OR OTHERWISE AND/OR (G) ENVIRONMENTAL CLAIMS.

8.7 NOTICE OF THIRD PARTY CLAIMS. If a Third Party Claim or Loss is asserted against a Party for which the other Party may have an obligation of payment, indemnity and/or defense (whether under this Article 8 or any other provision of this Agreement), the Party seeking payment or indemnification ("INDEMNIFIED PARTY") shall give the Party from which the Indemnified Party seeks payment or indemnification ("INDEMNIFYING PARTY") prompt written notice of the Third Party Claim or Loss, setting forth the particulars associated with the Third Party Claim or Loss (including a copy of the written Third Party Claim, if any) as then known by the Indemnified Party ("CLAIM NOTICE").

8.8 DEFENSE OF THIRD PARTY CLAIMS. Within thirty (30) Days after the Indemnifying Party receives a Claim Notice, the Indemnifying Party shall notify the Indemnified Party advising whether or not the Indemnifying Party will assume responsibility for defense (if applicable) and payment of the Third Party Claim or Loss. In connection with any Third Party Claim, the Indemnified Party is authorized, prior to and during such thirty (30) day period, to file any motion, pleading or other answer that it deems necessary or appropriate to protect its interests, or those of the Indemnifying Party, provided that it is not prejudicial to the Indemnifying Party. If the Indemnifying Party elects not to assume responsibility for defense and payment of the Third Party Claim, the Indemnified Party may defend against, or enter into any settlement with respect to, the Third Party Claim as it deems appropriate without relieving the Indemnifying Party of any indemnification obligations the Indemnifying Party may have with respect to such Third Party Claim. The Indemnifying Party's failure to respond in writing to a Claim Notice within the thirty (30) Day period shall be deemed an election by the Indemnifying Party not to assume responsibility for defense (if applicable) and payment of the Third Party Claim or Loss, as applicable. If the Indemnifying Party elects to assume responsibility for defense (if applicable) and payment of the Third Party Claim or Loss, as applicable: (a) the Indemnifying Party shall defend the Indemnified Party against the Third Party Claim with counsel of the Indemnifying Party's choice (reasonably acceptable to Indemnified Party which shall cooperate with the Indemnifying Party in all reasonable respects in such defense), (b) the

Indemnifying Party shall pay any judgment entered or settlement with respect to such Third Party Claim, (c) the Indemnifying Party shall not consent to entry of any judgment or enter into any settlement with respect to the Third Party Claim that (i) does not include a provision whereby the plaintiff or claimant in the matter releases the Indemnified Party from all liability with respect to the Third Party Claim or (ii) contains terms that may materially and adversely affect the Indemnified Party (other than as a result of money damages covered by the indemnity), (d) the Indemnified Party shall not consent to entry of any judgment or enter into any settlement with respect to the Third Party Claim without the Indemnifying Party's prior written consent and (e) pay the Indemnified Party the costs and expenses resulting from the Loss. In all instances the Indemnified Party may employ separate counsel and participate in defense of a Third Party Claim, but the Indemnified Party shall bear all fees and expenses of counsel employed by the Indemnified Party.

8.9 DUPLICATION OF REMEDIES. In no event shall either Party be entitled to duplicate compensation or other remedies with respect to any matter (including any Third Party Claim. Loss or any breach of a representation, warranty or agreement herein) asserted under the terms of this Agreement or in connection with the transaction contemplated hereby, even though such matter may be asserted under more than one provision of this Agreement or otherwise.

8.10 WAIVER OF CERTAIN DAMAGES. EACH PARTY IRREVOCABLY WAIVES AND AGREES NOT TO SEEK INDIRECT, CONSEQUENTIAL, LOSS OF PROFITS, PUNITIVE OR EXEMPLARY DAMAGES OF ANY kind IN CONNECTION WITH ANY DISPUTE ARISING OUT OF OR RELATED TO THIS AGREEMENT (INCLUDING THE BREACH THEREOF) OR THE TRANSACTIONS CONTEMPLATED HEREBY. FOR THE AVOIDANCE OF DOUBT, THIS ARTICLE 8.10 DOES NOT DIMINISH OR OTHERWISE AFFECT THE PARTIES' RIGHTS AND OBLIGATIONS TO BE INDEMNIFIED AGAINST, AND PROVIDE INDEMNITY FOR, INDIRECT, CONSEQUENTIAL, LOSS OF PROFITS, PUNITIVE OR EXEMPLARY DAMAGES AWARDED TO ANY THIRD PARTY FOR WHICH INDEMNIFICATION IS PROVIDED IN THIS AGREEMENT OR SELLER'S RIGHT TO RECEIVE LIQUIDATED DAMAGES, INCLUDING THE PERFORMANCE DEPOSIT, PURSUANT TO THE TERMS OF ARTICLE 17.2.

8.11 EXCLUSIVE REMEDIES. NOTWITHSTANDING ANYTHING TO THE CONTRARY CONTAINED IN THIS AGREEMENT, (I) ARTICLES 8.2 AND 8.4 AND (II) ANY INDEMNITY AGREEMENT GIVEN BY SELLER FOR ANY ALLEGED TITLE DEFECT PURSUANT TO ARTICLE 4.2.5 OR ALLEGED ADVERSE CONDITION PURSUANT TO ARTICLE 5.2.5 SET FORTH BUYER'S EXCLUSIVE REMEDIES AGAINST SELLER AND ITS AFFILIATES WITH RESPECT TO THE TRANSACTIONS CONTEMPLATED HEREBY, INCLUDING BREACHES OF THE REPRESENTATIONS, WARRANTIES, COVENANTS AND AGREEMENTS OF SELLER CONTAINED IN THIS AGREEMENT. EXCEPT FOR THE REMEDIES CONTAINED IN (A) ARTICLE 8.2 AND 8.4, (B) ANY INDEMNITY AGREEMENT GIVEN BY SELLER FOR ANY ALLEGED TITLE DEFECT PURSUANT TO ARTICLE 4.2.5 OR ALLEGED ADVERSE CONDITION PURSUANT TO ARTICLE 5.2.5, EFFECTIVE AS OF CLOSING. BUYER, ON BEHALF OF BUYER GROUP, HEREBY RELEASES, REMISES AND FOREVER DISCHARGES SELLER GROUP FROM ANY AND ALL LOSSES WHICH BUYER GROUP MIGHT NOW OR SUBSEQUENTLY MAY HAVE, BASED ON, RELATING TO OR ARISING OUT OF THIS AGREEMENT, THE OWNERSHIP, USE OR OPERATION OF THE PROPERTIES, OR THE CONDITION, QUALITY, STATUS OR NATURE OF THE PROPERTIES, INCLUDING RIGHTS TO CONTRIBUTION UNDER THE COMPREHENSIVE ENVIRONMENTAL RESPONSE, COMPENSATION, AND LIABILITY ACT OF 1980, AS AMENDED, BREACHES OF STATUTORY OR IMPLIED WARRANTIES, NUISANCE OR OTHER TORT ACTIONS, RIGHTS TO PUNITIVE DAMAGES, COMMON LAW RIGHTS OF CONTRIBUTION, AND RIGHTS UNDER INSURANCE MAINTAINED BY SELLER OR ANY OF ITS AFFILIATES, EXCLUDING, HOWEVER, ANY (I) CONTRACTUAL RIGHTS EXISTING AS OF THE DATE HEREOF (APART FROM THIS

AGREEMENT) BETWEEN (A) BUYER OR ANY OF BUYER'S AFFILIATES, ON THE ONE HAND AND (B) SELLER OR ANY OF SELLER'S AFFILIATES, ON THE OTHER HAND, UNDER CONTRACTS (IF ANY) BETWEEN THEM RELATING TO THE PROPERTIES AND (II) ANY CONTRACT ENTERED INTO ON OR AFTER THE CLOSING BETWEEN SUCH PARTIES AND RELATING TO THE PROPERTIES.

8.12 OTHER CONTRACTS BETWEEN THE PARTIES. THE PARTIES ACKNOWLEDGE THAT BUYER OR AN AFFILIATE OF BUYER CURRENTLY MAY OWN INTERESTS IN CERTAIN OF THE LANDS, LEASES AND OTHER ASSETS INCLUDED IN THE PROPERTIES. THE ASSUMPTION, PROTECTION, DEFENSE, INDEMNIFICATION AND RELEASES IN THIS AGREEMENT ARE NOT INTENDED TO WAIVE OR MODIFY IN ANY MANNER ANY EXISTING CONTRACTUAL RIGHTS OR OBLIGATIONS BETWEEN ANY MEMBER OF SELLER GROUP AND ANY MEMBER OF BUYER GROUP UNDER OPERATING AGREEMENTS, UNIT AGREEMENTS, SERVICE CONTRACTS OR OTHER AGREEMENTS TO THE EXTENT ANY SUCH FOREGOING AGREEMENT IS NOT ENTERED INTO AND DELIVERED IN CONNECTION WITH THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREUNDER, AND THE PROTECTION, DEFENSE, INDEMNIFICATION AND RELEASES IN THIS ARTICLE 8 SHALL NOT RELEASE OR ELIMINATE ANY OF BUYER'S OBLIGATIONS AS A CO-OWNER IN ANY LANDS, LEASES AND OTHER ASSETS INCLUDED IN THE PROPERTIES.

ARTICLE IX
DISCLAIMERS

9.1 DISCLAIMERS.

9.1.1 BUYER ACKNOWLEDGES THAT CERTAIN OF THE PROPERTIES HAVE SUSTAINED HURRICANE DAMAGE AS RECENTLY AS 2005, AND HAS SATISFIED ITSELF AS TO THE PRESENT CONDITION OF THE PROPERTIES.

9.1.2 EXCEPT AS EXPRESSLY STATED IN ARTICLE 10.1.6 IN THIS AGREEMENT:

(A) AT CLOSING SELLER SHALL ASSIGN THE PROPERTIES TO BUYER "AS-IS, WHERE-IS", AND WITH ALL FAULTS AND DEFECTS IN THEIR PRESENT CONDITION AND STATE OF REPAIR, WITHOUT RECOURSE, EVEN FOR THE RETURN OF THE PURCHASE PRICE, AND

(B) SELLER DISCLAIMS ANY AND ALL REPRESENTATIONS AND WARRANTIES WITH RESPECT TO THE PROPERTIES, EXPRESS, STATUTORY, IMPLIED OR OTHERWISE, INCLUDING ANY WARRANTY AS TO (i) TITLE, (II) COMPLIANCE WITH LAWS, (III) EXISTENCE OF ANY AND ALL PROSPECTS OR RECOMPLETION OPPORTUNITIES, (IV) GEOGRAPHIC, GEOLOGIC OR GEOPHYSICAL CHARACTERISTICS, (V) EXISTENCE, QUALITY, QUANTITY OR RECOVERABILITY OF HYDROCARBON SUBSTANCES, (VI) ABILITY TO PRODUCE, INCLUDING PRODUCTION OR DECLINE RATES, (VII) COSTS, EXPENSES, REVENUES, RECEIPTS, PRICES, ACCOUNTS RECEIVABLE OR ACCOUNTS PAYABLE, (VIII) CONTRACTUAL, ECONOMIC OR FINANCIAL INFORMATION AND DATA, (IX) CONTINUED FINANCIAL VIABILITY, INCLUDING PRESENT OR FUTURE VALUE OR ANTICIPATED INCOME OR PROFITS, (X) ENVIRONMENTAL OR PHYSICAL CONDITION (SURFACE AND SUBSURFACE, (XI) FEDERAL, STATE, OR LOCAL INCOME OR OTHER TAX CONSEQUENCES, (X) ABSENCE OF PATENT OR LATENT DEFECTS, (XII) SAFETY, (XIII) STATE OF REPAIR, (XIV) MERCHANTABILITY, (XV) FITNESS FOR A PARTICULAR PURPOSE AND (XVI) CONFORMITY TO MODELS OR SAMPLES OF MATERIALS; AND BUYER (ON BEHALF OF BUYER GROUP AND THEIR SUCCESSORS AND ASSIGNS) IRREVOCABLY WAIVES ANY

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AND ALL CLAIMS THEY MAY HAVE AGAINST SELLER GROUP ASSOCIATED WITH (I) THROUGH (XVI) HEREINABOVE, EXCEPT FOR THE BUYER'S RIGHT TO ASSERT THE EXISTENCE OF ALLEGED ADVERSE CONDITIONS IN ACCORDANCE WITH ARTICLE 5.2 AND BUYER'S RIGHT TO CLAIM BREACH OF REPRESENTATIONS AND WARRANTIES WITHIN THE TIME PERIOD SPECIFIED IN ARTICLE 19.6.

9.2 DISCLAIMER OF STATEMENTS AND INFORMATION, SELLER EXPRESSLY DISCLAIMS ANY AND ALL LIABILITY AND RESPONSIBILITY FOR AND ASSOCIATED WITH THE QUALITY, ACCURACY, COMPLETENESS OR MATERIALITY OF INFORMATION, DATA AND

MATERIALS SHOWN TO OR FURNISHED (ELECTRONICALLY, ORALLY, IN WRITING OR ANY OTHER MEDIUM AND WHETHER OR NOT SHOWN OR FURNISHED BEFORE OR AFTER EXECUTION OF THIS AGREEMENT) TO BUYER GROUP AND ASSOCIATED WITH THE PROPERTIES OR THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT; AND BUYER (ON BEHALF OF BUYER GROUP AND THEIR SUCCESSORS AND ASSIGNS) IRREVOCABLY WAIVES ANY AND ALL CLAIMS THEY MAY HAVE AGAINST SELLER GROUP ASSOCIATED WITH THE SAME.

ARTICLE X
SELLER'S REPRESENTATIONS AND WARRANTIES

10.1 SELLER'S REPRESENTATIONS AND WARRANTIES. Seller represents and warrants to Buyer that:

10.1.1 ORGANIZATION AND GOOD STANDING. Seller is a corporation duly organized, validly existing and in good standing under the Laws of the State of Delaware and has all requisite corporate power and authority to own the Properties. Seller is duly licensed or qualified to do business as a foreign corporation and is in good standing in all jurisdictions in which the Properties are located.

10.1.2 CORPORATE AUTHORITY; AUTHORIZATION OF AGREEMENT. Seller has all requisite corporate power and authority to execute and deliver this Agreement, to consummate the transactions contemplated by this Agreement and to perform all obligations placed on Seller in this Agreement. This Agreement, when executed and delivered by Seller, constitutes the valid and binding obligation of Seller, enforceable against it in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency or other Laws relating to or affecting the enforcement of creditors' rights and general principles of equity (regardless of whether such enforceability is considered in a proceeding at law or in equity).

10.1.3 No VIOLATIONS. Subject to the receipt of all consents, approvals and waivers from Third Parties in connection with the transactions contemplated hereby and assuming compliance with the provisions of the HSR Act (if required) in connection with such transactions, Seller's execution and delivery of this Agreement and consummation of the transactions contemplated by this Agreement will not:

(a) conflict with or require consent of any person or entity under any terms, conditions or provisions of Seller's certificate of incorporation or bylaws;

(b) violate any provision of, or require any consent or approval under any Law applicable to Seller (except for consents and approvals of governmental or tribal entities or authorities customarily obtained subsequent to transfer of title); or

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(c) result in the creation or imposition of any lien or encumbrance on any of the Properties;

except as would not have a Material Adverse Effect.

10.1.4 LITIGATION. Except as set forth in Exhibit "C" or otherwise disclosed to Buyer in writing by Seller before the Closing Date, there are no litigation, claims, actions or other proceedings by a Third Party or before any governmental entity or authority that are pending against Seller or, to Seller's knowledge, threatened against Seller that would (in either case) have a Material Adverse Effect.

10.1.5 BANKRUPTCY. There are no bankruptcy or receivership proceedings pending against, being contemplated by or, to Seller's knowledge, threatened against Seller.

10.1.6 SPECIAL WARRANTY OF TITLE. As of Closing, Seller shall warrant title to the Properties against adverse claims of title by, through or under Seller but not otherwise, subject to the Permitted Encumbrances.

10.1.7 TAXES. To the best of Seller's knowledge, all ad valorem, property, production, severance, windfall profits, excise and similar taxes and assessments based on or measured by the ownership of property or the production of hydrocarbons or the receipt of proceeds therefrom on the Properties that have become due and payable through the Effective Date, have been properly paid or are being contested in good faith.

10.1.8 CALLS. Except as provided herein, no person has any call upon, option to purchase, or similar rights with respect to any portion of the production from the Properties.

10.1.9 INFORMATION. Seller either owns or otherwise has the right to disclose all of the data set forth in the Merrill Corporation electronic data room created in connection with the transaction contemplated by this Agreement.

10.1.10 COMPLIANCE WITH LAWS. To the Knowledge of Seller and with respect to the Properties, Seller is in compliance with all Laws, except for any failures to comply as would not have a Material Adverse Effect.

ARTICLE XI
BUYER'S REPRESENTATIONS AND WARRANTIES

11.1 BUYER'S REPRESENTATIONS AND WARRANTIES. Buyer represents and warrants to Seller that:

11.1.1 ORGANIZATION AND GOOD STANDING. Buyer is a limited liability company duly organized, validly existing and in good standing under the Laws of Texas and has all requisite power and authority to

own the Properties. Buyer is duly licensed or qualified to do business as a foreign limited liability company and is in good standing in all jurisdictions in which the Properties are located.

11.1.2 CORPORATE AUTHORITY: AUTHORIZATION OF AGREEMENT. Buyer has all requisite [corporate] power and authority to execute and deliver this Agreement, to consummate the transactions contemplated by this Agreement and to perform all of the obligations placed on Buyer in this Agreement. This Agreement, when executed and delivered by Buyer, constitutes the valid and binding obligation of Buyer, enforceable against it in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency or other Laws relating to or affecting the enforcement of creditors' rights and general principles of equity (regardless of whether such enforceability is considered in a proceeding at law or in equity).

11.1.3 No VIOLATIONS. Assuming compliance with the provisions of the HSR Act (if required) in connection with the transactions contemplated by this Agreement, Buyer's execution and delivery of this Agreement and consummation of the transactions contemplated by this Agreement will not:

(a) conflict with or require the consent of any person or entity under any of the terms, conditions or provisions of Buyer's certificate of incorporation or bylaws; or

(b) violate any provision of, or require any consent or approval under any Law applicable to Buyer (except for consents and approvals of governmental or tribal entities or authorities customarily obtained subsequent to transfer of title).

11.1.4 SEC DISCLOSURE. Buyer is acquiring the Properties for its own account for use in its trade or business, and not with a view toward or for sale associated with any distribution thereof, nor with any present intention of making a distribution thereof within the meaning of the Securities Act of 1933, as amended.

11.1.5 LITIGATION. There is no litigation, action or proceeding pending against Buyer or, to Buyer's knowledge, threatened against Buyer that would prevent timely consummation of the transactions contemplated by this Agreement.

11.1.6 INDEPENDENT EVALUATION. Buyer is sophisticated in evaluation, purchase, ownership and operation of oil and gas properties and related facilities similar to the Properties, and in making its decision to enter into this Agreement and to consummate the transactions contemplated herein, Buyer (a) relied solely on its own independent investigation and evaluation of the Properties and the advice of its engineers, contractors, geological and geophysical advisors, lawyers and accountants and not on any comments, statements, reports, projections or other documents or materials provided by or for Seller or its agents, whether before or after execution of this Agreement, and (b) satisfied itself as to the environmental, physical and other condition of, and contractual arrangements affecting, the Properties.

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11.1.7 BANKRUPTCY. There are no bankruptcy or receivership proceedings pending against, being contemplated by or, to Buyer's knowledge, threatened against Buyer.

11.1.8 FINANCIAL ASSURANCES. Buyer has (or as of Closing will have) available financial resources to discharge all obligations assumed by Buyer hereunder.

11.1.9 CONSENTS. There are no consents that would be applicable in connection with the consummation by Buyer of the transactions contemplated by this Agreement.

ARTICLE XII

ADDITIONAL COVENANTS

12.1 SUBSEQUENT OPERATIONS. SELLER MAKES NO REPRESENTATIONS OR WARRANTIES TO BUYER AS TO TRANSFERABILITY OR ASSIGNABILITY OF OPERATORSHIP OF ANY PROPERTIES THAT SELLER CURRENTLY OPERATES. Rights and obligations associated with operatorship of the Properties are governed by operating and similar agreements covering the Properties and will be decided in accordance with the terms of such agreements.

12.2 RIGHTS OF NON-EXCLUSIVE USE. If Closing occurs, Buyer, to the extent it has the authority to do so, shall grant to Seller (and, if requested by Seller, to Seller's Affiliates and/or Seller's and its Affiliates' contractors) from time to time, as requested by Seller a non-exclusive cost-free right-of-way, surface use or other right on, over, under and through the Properties (including pipeline, utility and road usage rights, facilities sharing arrangement and all reasonable rights of use and ingress and egress) as appropriate or convenient for Seller and its Affiliates (i) to conduct operations on, over, under and across the Properties in connection with properties not being conveyed from Seller to Buyer in the transactions covered by this Agreement and (ii) to exercise Seller's retained rights and retained obligations under this Agreement. At Seller's request, either at or after Closing, Buyer shall execute instruments in recordable form that Seller deems appropriate to further delineate or evidence the rights granted herein.

12.3 BUYER'S ASSUMPTION OF OBLIGATIONS.

If Closing occurs, and subject only to Seller's indemnities in Article 8.2, 8.4 and 19.3.1 and the retention of liability set forth in the next following sentence, Buyer hereby assumes, shall pay and shall timely perform and discharge all of Seller's duties and obligations associated with the Properties arising prior to, on or after the Closing (including any and all contractual duties and obligations arising therefrom) (collectively, the "ASSUMED OBLIGATIONS"), and in fulfilling these obligations, Buyer shall comply with all Laws. In addition to Seller's indemnity obligations under this Agreement, Seller shall retain sole responsibility for prosecuting or defending, as the case may be, all litigation matters with respect to the Properties that are pending as of the date of this Agreement and all liabilities for costs, judgments, settlements and otherwise associated therewith to the extent the foregoing litigation and liabilities relate to any period prior to the Effective Time.

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12.4 ASBESTOS AND NORM. The Properties may currently or have in the past contained asbestos and NORM, and special procedures associated with assessment, remediation, removal, transportation or disposal of asbestos and NORM may be necessary. NOTWITHSTANDING ANYTHING CONTAINED IN THIS AGREEMENT TO THE CONTRARY, INCLUDING ARTICLE 5 AND ARTICLE 8, IF CLOSING OCCURS:

12.4.1 Buyer accepts sole responsibility for and agrees to pay any and all costs and expenses associated with assessment, remediation, removal, transportation and disposal of asbestos and NORM associated with the Properties, and may not claim the fact that assessment, remediation, removal, transportation or disposal of asbestos and NORM are not complete or that additional costs and expenses are required in connection with assessment, remediation, removal, transportation or disposal of asbestos and NORM as an Alleged Adverse Condition or a breach of Seller's representations or warranties under this Agreement or the basis for any other redress against Seller or its Affiliates, and Buyer (on behalf of Buyer Group and their successors and assigns) irrevocably waives any and all Losses and Third Party Claims they may have against Seller Group associated with the same; and

12.4.2 BUYER RELEASES SELLER GROUP FROM AND SHALL FULLY PROTECT, DEFEND, INDEMNIFY, AND HOLD SELLER GROUP HARMLESS FROM AND AGAINST ANY AND ALL LOSSES AND THIRD PARTY CLAIMS RELATING TO, ARISING OUT OF, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, THE ASSESSMENT, REMEDIATION, REMOVAL, TRANSPORTATION AND DISPOSAL OF ASBESTOS AND NORM ASSOCIATED WITH THE PROPERTIES, NO MATTER WHETHER ARISING BEFORE, ON OR AFTER THE EFFECTIVE TIME.

12.5 PLUGGING AND ABANDONMENT. The Properties may contain wells and facilities that have been shut in or temporarily or permanently abandoned. NOTWITHSTANDING ANYTHING CONTAINED IN THIS AGREEMENT TO THE CONTRARY, INCLUDING ARTICLE 5 AND ARTICLE 8, IF CLOSING OCCURS:

12.5.1 Buyer hereby expressly assumes and accepts sole and exclusive responsibility for and agrees to pay all costs and expenses associated with Plugging and Abandonment of all facilities associated with the Properties, and may not claim the fact that Plugging and Abandonment operations are not complete or that additional costs and expenses are required to complete Plugging and Abandonment operations as an Alleged Adverse Condition or a breach of Seller's representations or warranties under this Agreement or the basis for any other redress against Seller or its Affiliates, and Buyer (on behalf of Buyer Group and their successors and assigns) irrevocably waives any and all Losses and Third Party Claims they may have against Seller Group associated with the same; and

12.5.2 BUYER RELEASES SELLER GROUP FROM AND SHALL FULLY PROTECT, DEFEND, INDEMNIFY, AND HOLD SELLER GROUP HARMLESS FROM AND AGAINST ANY AND ALL LOSSES AND THIRD PARTY CLAIMS RELATING TO, ARISING OUT OF, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, PLUGGING AND ABANDONMENT OPERATIONS, NO MATTER WHETHER ARISING BEFORE, ON OR AFTER THE EFFECTIVE TIME.

12.5.3 To the extent that Buyer or its assignees discharge any Third Party Claim for Plugging and Abandonment of the Properties, and to the maximum extent permitted by Law, Buyer and its successors and assigns waive all rights of legal subrogation to Third Party Claims asserted or held by that Third Party against Seller, arising from or related to the Plugging and Abandonment of the Properties.

12.6 PROCESS SAFETY MANAGEMENT. Buyer acknowledges that Process Safety Management is an ongoing process. NOTWITHSTANDING ANYTHING CONTAINED IN THIS AGREEMENT TO THE CONTRARY, INCLUDING ARTICLE 5 AND ARTICLE 8, IF CLOSING OCCURS, (A) BUYER ACCEPTS SOLE RESPONSIBILITY FOR AND AGREES TO PAY ALL COSTS AND EXPENSES ASSOCIATED WITH PROCESS SAFETY MANAGEMENT (INCLUDING IDENTIFICATION, EVALUATION AND REMEDIATION), AND MAY NOT CLAIM THE FACT THAT THE PROCESS SAFETY MANAGEMENT IS NOT COMPLETE OR THAT ADDITIONAL COSTS AND EXPENSES WILL BE REQUIRED TO COMPLY WITH OR COMPLETE PROCESS SAFETY MANAGEMENT AS AN ALLEGED ADVERSE CONDITION OR A BREACH OF SELLER'S REPRESENTATIONS OR WARRANTIES UNDER THIS AGREEMENT OR THE BASIS FOR ANY OTHER REDRESS AGAINST SELLER; AND BUYER (ON BEHALF OF THE BUYER GROUP AND THEIR SUCCESSORS AND ASSIGNS) IRREVOCABLY WAIVES ANY AND ALL LOSSES AND THIRD PARTY CLAIMS THEY MAY HAVE AGAINST SELLER GROUP ASSOCIATED WITH THE SAME; AND (B) BUYER RELEASES SELLER GROUP FROM AND SHALL FULLY PROTECT, DEFEND, INDEMNIFY AND HOLD SELLER GROUP HARMLESS FROM AND AGAINST

ANY AND ALL LOSSES AND THIRD PARTY CLAIMS RELATING TO, ARISING OUT OF, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, PROCESS SAFETY MANAGEMENT ASSOCIATED WITH THE PROPERTIES, NO MATTER WHETHER ARISING BEFORE, ON OR AFTER THE EFFECTIVE TIME.

12.7 IMBALANCES.

12.7.1. Buyer acknowledges that Imbalances may exist on one or more of the Properties and that all Imbalances (whether for over-production, over-delivery, under-production or under-delivery) will pass to Buyer at Closing, and Buyer shall thereupon be entitled to all rights and obligations with respect to any and all Imbalances. Notwithstanding anything to the contrary in this Agreement (including Article 8), except as provided in Article 12.7.2: (i) no amounts shall be paid to or by either Party to the other as a Purchase Price adjustment, as part of the Final Accounting Settlement or otherwise, based on Imbalances; and (ii) from and after Closing:

(a) Buyer accepts sole responsibility for and agrees to pay all costs and expenses (if any) associated with Imbalances, and Buyer (on behalf of Buyer Group and their successors and assigns) irrevocably waives any and all claims it and they may have against Seller Group associated Imbalances; and Seller agrees that Buyer will receive all benefits (if any) associated with Imbalances.

(b) BUYER RELEASES SELLER GROUP FROM AND SHALL FULLY PROTECT, DEFEND, INDEMNIFY AND HOLD SELLER GROUP HARMLESS FROM AND AGAINST ANY AND ALL CLAIMS RELATING TO, ARISING OUT OF, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, IMBALANCES, NO MATTER WHETHER ARISING BEFORE OR AFTER THE EFFECTIVE TIME. THIS INDEMNITY AND DEFENSE OBLIGATION WILL APPLY REGARDLESS OF CAUSE OR OF ANY NEGLIGENT ACTS OR OMISSIONS (INCLUDING

SOLE NEGLIGENCE, CONCURRENT NEGLIGENCE OR STRICT LIABILITY), BREACH OF DUTY (STATUTORY OR OTHERWISE), VIOLATION OF LAW, OR OTHER FAULT OF SELLER GROUP, OR ANY PRE-EXISTING DEFECT.

12.7.2. The following adjustment is the sole adjustment that will be made between the Parties with respect to Imbalances:

(i) if Seller's Imbalance for an individual Property as of the Effective Time varies from the amount for such Property as set forth in Schedule 12.7.2 to the detriment of Buyer (as owner of the Property after Closing) by more than 10,000 mcf, then Seller shall pay Buyer S2.50 per mcf for each mcf over the aforesaid variance as part of the Final Accounting Settlement; or

(ii) if Seller's Imbalance for an individual Property as of the Effective Time varies from that amount for such Property as set forth in Schedule 12.7.2 to the benefit of Buyer (as owner of the Property after Closing) by more than 10,000 mcf, then Buyer shall pay Seller S2.50 per mcf for each mcf above the aforesaid variance as part of the Final Accounting Settlement.

EACH PARTY WAIVES ANY REMEDIES FOR UNDER PRODUCTION, UNDER DELIVERY, OVER PRODUCTION OR OVER DELIVERY VARIANCES, EXCEPT AS STATED IN ARTICLE 12.7.2(i) AND (ii) AND NO ADJUSTMENTS WILL BE MADE WITH RESPECT TO IMBALANCES AFTER AGREEMENT TO, OR DETERMINATION BY THE ACCOUNTING REFEREE OF (AS APPLICABLE), THE FINAL

ACCOUNTING SETTLEMENT, EVEN IF SUCH IMBALANCES ARE NOT DISCOVERED UNTIL AFTER SUCH AGREEMENT OR DETERMINATION.

12.8 SUSPENSE FUNDS. Buyer acknowledges that Suspense Funds may exist as of the Effective Time. Seller shall transfer at Closing any Suspense Funds held by Seller as operator of any Properties and the obligations with respect thereto to Buyer. This transfer shall be accounted for in the Final Accounting Statement. NOTWITHSTANDING ANYTHING CONTAINED IN THIS AGREEMENT TO THE CONTRARY, INCLUDING ARTICLE 6 AND ARTICLE 8, IF CLOSING OCCURS:

12.8.1 BUYER ACCEPTS SOLE RESPONSIBILITY FOR AND AGREES TO PAY ALL COSTS AND EXPENSES ASSOCIATED WITH THE SUSPENSE FUNDS, AND BUYER (ON BEHALF OF BUYER GROUP AND THEIR SUCCESSORS AND ASSIGNS) IRREVOCABLY WAIVES ANY AND ALL CLAIMS THEY MAY HAVE AGAINST SELLER GROUP ASSOCIATED WITH THE SAME; AND

12.8.2 BUYER RELEASES SELLER GROUP FROM AND SHALL FULLY PROTECT, DEFEND, INDEMNIFY AND HOLD SELLER GROUP HARMLESS FROM AND AGAINST ANY AND ALL LOSSES AND THIRD PARTY CLAIMS RELATING TO, ARISING OUT of, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, THE SUSPENSE FUNDS, NO MATTER WHETHER ARISING BEFORE, ON OR AFTER THE EFFECTIVE TIME.

12.9 SALES TAX. The Parties agree that this sale is an occasional sale of assets by Seller in which it does not trade in the ordinary course of business. The Parties shall take commercially reasonable actions to assert and establish the occasional sale exemption from Sales Tax associated with the transactions contemplated hereby. If Sales Tax is due and owing as a result of Seller's transfer of the Properties to Buyer, Buyer shall be solely responsible and liable for any and all such Sales Tax. Before the Closing Date, Buyer and

Seller shall agree on the value of the tangible personal property being transferred and Buyer shall provide Seller with documentation detailing the basis for Buyer's allocation of the Purchase Price to any such Properties that are subject to Sales Tax. Buyer shall provide Seller with an exemption certificate for any tangible personal property included in the Properties for which it claims a Sales Tax exemption. Seller shall invoice, and Buyer shall pay, any Sales Tax on Buyer's acquisition of all nonexempt tangible personal property and Seller shall remit the Sales Tax to the applicable governmental entity or authority. If Seller is later required to pay any additional Sales Tax, interest, or penalty thereon, Buyer shall reimburse Seller within thirty (30) Days after receipt of Seller's written notice of the payment. NOTWITHSTANDING ANYTHING CONTAINED IN THIS AGREEMENT TO THE CONTRARY (INCLUDING ARTICLE 6 OR ARTICLE 8), BUYER RELEASES SELLER GROUP FROM AND SHALL FULLY PROTECT, DEFEND, INDEMNIFY AND HOLD SELLER GROUP HARMLESS FROM AND AGAINST ANY AND ALL LOSSES AND THIRD PARTY CLAIMS (NO MATTER WHEN ASSERTED) RELATING TO, ARISING OUT OF, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, SALES TAX RESULTING FROM OR ASSOCIATED WITH SELLER'S TRANSFER OF PROPERTIES TO BUYER.

12.10 TRANSITION AGREEMENT. Buyer and Seller shall execute and deliver the Transition Agreement at Closing.

12.11 INTERIM PERIOD. During the Interim Period, Seller shall maintain and operate the Properties and dispose of production from the Properties in the ordinary course of business consistent with the Seller's ordinary practices with respect to the Properties.

12.11.1 Without the consent of Buyer (which shall not be unreasonably withheld or delayed), during the Interim Period, Seller shall not, with respect to the Properties:

(a) except with respect to matters, if any, for which Seller has provided an indemnity to Buyer, waive, compromise or settle any right or claim which reasonably would be expected to have a Material Adverse Effect;

(b) incur any obligation in excess of Fifty Thousand Dollars (US $50,000) with respect to the Properties for which Buyer would be responsible after Closing, other than in connection with transactions in the normal, usual and customary manner, of a nature and in an amount consistent with ordinary practices of Seller with respect to the Properties and/or in connection with situations believed in good faith by Seller to constitute an emergency (in which case Seller's obligation is limited to notifying Buyer as soon as reasonably practicable of such emergency and obligations);

(c) encumber, sell, lease, or otherwise dispose of any of the Properties (excluding sales of hydrocarbons therefrom), except to the extent replaced by equivalent property or to the extent used, consumed or abandoned in the normal operations of the Properties; or

(d) enter into a contract or commitment for any capital expenditure or acquisition or construction of fixed assets in either

case for which Buyer would be responsible after Closing in an amount individually in excess of Fifty Thousand Dollars (US $50,000), except in connection with situations believed in good faith by Seller to constitute an emergency (in which case Seller's obligation is limited to notifying Buyer as soon as reasonably practicable of such emergency and obligations).

12.11.2 Regardless of whether all of the operations conducted by Seller during the Interim Period with respect to any of the Properties have been fully completed by Seller prior to Closing, upon Closing Buyer shall assume full responsibility for the completion of all such operations applicable to the Properties, subject, however, to the terms of the Transition Agreement during the Transition Period.

12.11.3 Buyer acknowledges Seller owns undivided interests in certain of the Properties and that Seller does not operate all of the Properties, and Buyer agrees that the acts or omissions of Third Party working interests owners (including Third Party operators) will not constitute a breach of the provisions of this Article 12.11, nor shall any action required by a vote of working interest owners constitute such a breach so long as Seller has voted its interest in a manner that complies with the provisions of this Article 12.11. Furthermore. Seller shall not be deemed or held to be in breach of any of Seller's representations, warranties, covenants or other agreements contained in this Agreement to the extent that any such breach arises out of or in connection with the actions of Buyer or Buyer's Affiliates as operators or co-owners of any of the Properties prior to the Closing.

12.12 CONSENTS TO ASSIGN. Prior to the Closing Date, Seller shall use its reasonable efforts to obtain consents necessary to assign the Properties to Buyer at Closing.

12.13 NOTIFICATION OF BREACHES. Until Closing:

12.13.1 Buyer shall notify Seller promptly upon Buyer's knowledge that any of Seller's representations or warranties in this Agreement are untrue in any material respect or will be untrue in any material respect as of the Closing Date or that any covenant or agreement to be performed or observed by Seller prior to or on the Closing Date has not been so performed or observed in any material respect or that any Title Defect or noncompliance with any Environmental Law exists.

12.13.2 Seller shall notify Buyer promptly upon Seller's knowledge that any of Buyer's representations or warranties in this Agreement are untrue in any material respect or will be untrue in any material respect as of the Closing Date or that any covenant or agreement to be performed or observed by Buyer prior to or on the Closing Date has not been so performed or observed in a material respect.

12.13.3 If any of Buyer's or Seller's representations or warranties are untrue or will become untrue in any material respect between the date of execution of this Agreement and the Closing Date, or if any of Buyer's or Seller's covenants or agreements to be performed or observed prior to or on the Closing Date shall not have been so performed or observed in any material respect, but if such

breach of representation, warranty, covenant or agreement shall (if curable) be cured by the Closing, then such breach shall be considered not to have occurred for all purposes of this Agreement.

12.14 THIRD PARTY-OWNED TECHNOLOGY.

12.14.1 Buyer shall be responsible for the purchase of all Third Party-Owned Technology that is needed or is appropriate for Buyer's operation of the Properties as currently operated by Seller.

12.14.2 Seller shall use reasonable efforts to obtain for Buyer the rights (by seeking and obtaining relevant vendor consents) to access and use (or permit Seller to access and use on Buyer's behalf) all Third Party-Owned Technology during the Transition Period only, and Buyer shall bear all of Seller's costs in so doing as well as all other costs and fees, if any, to procure such consents and shall reimburse Seller in the Final Accounting Settlement for any such costs or fees incurred by Seller in connection therewith.

12.14.3 Buyer acknowledges that Buyer's rights to access and use Third Party-Owned Technology under Third Party consents so procured by Seller will expire at the end of the Transition Period, and Buyer agrees to obtain its own licenses for all Third Party-Owned Technology that Buyer deems necessary or appropriate in connection with the operation of the Properties after the Transition Period.

12.14.4 Upon termination of the Transition Period, Buyer shall certify to Seller in writing that all Third Party-Owned Technology for which consents were obtained for it by Seller either has been de-installed or have been licensed by Buyer from the applicable vendor.

Seller shall have the right to confirm, at Seller's expense, that post-Transition Period use by Buyer of all Third Party-Owned Technology has either ceased or continues under license(s) Buyer has acquired from the applicable vendors.

12.15 SHARED SYSTEMS IP LICENSE. The Parties shall sign and deliver the Shared Systems IP License at Closing.

12.16 FINANCIAL AUDIT FOR SEC FILINGS. In the event required by Buyer, both prior to and after the Closing, Seller shall provide Buyer with access during normal business hours to Seller's financial records for the Properties for the calendar years 2004 and 2005 previously made available to Seller's auditors for purposes of preparing Seller's annual audited and quarterly reviewed financial statements for those years with respect to the Properties and to Seller's corresponding financial records for any portion of 2006 prior to the Closing, including (in each case) records with respect to direct lease operating costs with respect to each of the Properties and the gross revenues from such Properties and such other information relating to the Properties as is needed for Buyer to make any required filings with the Securities and Exchange Commission ("SEC") with respect to the Properties and the transactions contemplated by this Agreement. The cost incurred by Seller and its Affiliates in providing the financial data to Buyer and assisting Buyer therewith shall be borne by Buyer. BUYER RELEASES SELLER GROUP FROM AND SHALL FULLY PROTECT,

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DEFEND, INDEMNIFY AND HOLD SELLER GROUP HARMLESS FROM AND AGAINST ANY AND ALL CLAIMS, LOSSES AND LIABILITIES RELATING TO, ARISING OUT OF, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, FURNISHING ANY SUCH RECORDS TO BUYER, ANY ACTIONS, REPRESENTATIONS OR CERTIFICATIONS OF SELLER'S AND ITS AFFILIATES' PERSONNEL OR AUDITORS WITH RESPECT TO THE INFORMATION CONTAINED IN SUCH RECORDS, OR BUYER'S OR BUYER'S AFFILIATE'S USE OF THE INFORMATION CONTAINED IN SUCH FINANCIAL RECORDS.

ARTICLE XIII
HSR ACT

13.1 HSR FILINGS. If compliance with the HSR Act is required in connection with the transactions contemplated by this Agreement, as promptly as practicable and in any event not more than thirty (30) Days after the date of this Agreement, both Parties shall file with the Federal Trade Commission and the Department of Justice, as applicable, the required notification and report forms and shall as promptly as practicable furnish any supplemental information that may be requested in connection therewith. Each Party shall take all reasonable steps to achieve early termination of applicable waiting periods. Each Party shall bear its own filing and other fees and costs associated with compliance with the HSR Act.

ARTICLE XIV
PERSONNEL

14.1 EMPLOYEE LIST. Seller has no obligation to provide Buyer an opportunity to interview for employment any individuals who support the Properties, and Buyer has no obligation to hire any such individuals. Seller has no obligation to provide Buyer any information about such individuals, including personnel records.

14.2 RESTRICTION ON SOLICITATION. Buyer may not (without obtaining the prior written consent of Seller), for a period of twelve (12) months after the

Closing Date, solicit employment of or contact (except for such contact as may be necessary in respect to litigation, claims or other business matters unrelated to the solicitation of employment) any of Seller's employees directly or indirectly engaged in operation of the Properties as of the date hereof and as of the Closing Date or engaged in the negotiation or Closing of the transactions contemplated by this Agreement. For purposes of this Article 14.2, a general published solicitation or advertisement for employment (whether in print or on-line) shall not be a breach hereof.

ARTICLE XV
CONDITIONS PRECEDENT TO CLOSING

15.1 CONDITIONS PRECEDENT TO SELLER'S OBLIGATION TO CLOSE. Seller shall, subject to satisfaction or waiver of the conditions to Closing in Article 15.3, consummate the sale of the Properties on the Closing Date, provided the following conditions precedent have been satisfied or have been waived in writing by Seller:

15.1.1 all of Buyer's representations and warranties given in this Agreement are true and correct in all material respects with the

same force and effect as though such representations and warranties had been made or given on and as of the Closing Date;

15.1.2 Buyer shall have complied in all material respects with all of Buyer's material obligations, covenants and conditions in this Agreement to be performed or complied with prior to Closing;

15.1.3 Buyer shall have provided Seller evidence satisfactory to Seller that Buyer is as of Closing in full compliance with all governmental requirements for ownership and operation of the Properties, if any (except consents by governmental or tribal entities or authorities customarily obtained subsequent to transfer of title); and

15.1.4 Buyer shall have provided Seller with copies of any other necessary or appropriate consents, permits, insurance, approvals, authorizations and similar items required of Buyer to purchase, receive, own and/or operate the Properties as of the Closing and to otherwise transact business in the applicable jurisdiction and in accordance with contracts assigned to Buyer at Closing.

15.2 CONDITIONS PRECEDENT TO BUYER'S OBLIGATION TO CLOSE. Buyer shall, subject to satisfaction or waiver of the conditions to Closing set forth in Article 15.3, consummate the purchase of the Properties contemplated by this Agreement on the Closing Date, provided the following conditions precedent have been satisfied or have been waived in writing by Buyer:

15.2.1 all of Seller's representations and warranties given in this Agreement are true and correct in all material respects with the same force and effect as though such representations and warranties had been made or given on and as of the Closing Date; and

15.2.2 Seller shall have complied in all material respects with all of Seller's material obligations, covenants and conditions in this Agreement to be performed or complied with prior to Closing.

15.3 CONDITIONS PRECEDENT TO OBLIGATION OF EACH PARTY TO CLOSE. The Parties shall, subject to waiver or satisfaction of the conditions to Closing set forth in Articles 15.1 and 15.2, consummate the sale and purchase of the Properties on the Closing Date, provided the following conditions precedent have been satisfied or have been waived in writing by both Parties:

15.3.1 if applicable, consummation of the transactions contemplated by this Agreement is not prevented by (and the required waiting period, if any, has expired under) the HSR Act and the rules and regulations of the Federal Trade Commission and the Department of Justice;

15.3.2 no injunction, order or award restraining, enjoining or otherwise prohibiting consummation of or granting material damages associated with the transactions contemplated by this Agreement or sale of any one or more of the Properties has been issued by any court, governmental entity or authority or an arbitrator of competent

jurisdiction, and no suits, actions or other proceedings are pending before any such court, governmental entity or arbitrator in which a Third Party seeks to restrain, enjoin or otherwise prohibit consummation of or obtain material damages associated with the transactions contemplated by this Agreement or sale of any one or more of the Properties; nor to either Party's knowledge are there any pending investigations by a governmental entity or authority that would be likely to result in any a suit, action or other proceedings to restrain, enjoin or otherwise prohibit consummation of the transactions contemplated by this Agreement or sale of any one or more of the Properties; provided that if such an injunction, order, award, suit, action or other proceeding applicable to some (but not all) of the Properties is pending on the Closing Date, Closing with respect to the unaffected Properties shall proceed and the Parties shall conduct a second closing for the affected Properties if and when the above-referenced condition to Closing is removed. If the above-referenced condition to Closing is not removed as to the affected Properties within one hundred twenty (120) Days after the Closing Date, the affected Properties (automatically and without need for amendment of this Agreement) shall be removed from this Agreement, and Buyer shall not be obligated to make payment to Seller for that portion of the Purchase Price allocated to such Properties in Exhibit "A" or "A-1", as applicable, and the Parties shall have no further obligations to each other with respect to the same;

15.3.3 all material consents and approvals (except for consents and approvals of governmental entities or authorities customarily obtained subsequent to transfer of title) have been obtained; provided, however, if on the Closing Date material consents applicable to some (but not all) of the Properties have not been obtained, Closing with respect to the unaffected Properties shall proceed, and the Parties shall conduct one or more subsequent closings to convey the affected Properties, if and when the above-referenced condition to Closing is removed. If the above-referenced condition to Closing is not removed as to an affected Property within one hundred eighty (180) Days after the Closing Date, that affected Property (automatically and without need for amendment of this Agreement) shall be removed from this Agreement, and Buyer shall not be obligated to make payment to Seller for that portion of the Purchase Price allocated to such Property in Exhibit "A" or "A-1", as applicable, and the Parties shall have no further obligations to each other with respect to the same; and

15.3.4 PPRs applicable to the Properties either have been exercised or waived or the time to exercise such PPRs has expired, and Properties exercised upon have been excluded from the Closing in accordance with Article 3.1.

ARTICLE XVI
THE CLOSING

16.1 CLOSING. No later than three (3) Business Days prior to the Closing Date, Seller shall provide Buyer a statement setting forth the Adjusted Purchase Price ("CLOSING STATEMENT"). Seller also shall provide Buyer wiring instructions designating the account(s) to which Buyer shall deliver the Purchase Price. Closing shall be held on the Closing Date in Seller's office at 200 WestLake Park Boulevard, Houston, Texas 77079 or such other place as Seller may notify Buyer before the Closing Date. Seller shall furnish to Buyer with the Closing Statement a copy of the applicable authorizations for expenditure or

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other customary documentation as reasonably necessary for Buyer to confirm the amounts of any capital expenditures that are reflected in the cash flows set forth in the Closing Statement.

16.2 SELLER'S OBLIGATIONS AT CLOSING. At Closing, Seller shall deliver to Buyer, unless waived by Buyer, the following:

16.2.1 a document substantially in the form of the Deed, Assignment and Bill of Sale, assigning all of Seller's right, title and interests in the Properties, executed by an Attorney-in-Fact of Seller and acknowledged, in four (4) multiple originals (or such greater number as the Parties agree);

16.2.2 four (4) originals of the Certificate executed by an authorized officer or an Attorney-in-Fact of Seller;

16.2.3 four (4) originals of the Non-Foreign Certificate executed by an Attorney-in-Fact of Seller;

16.2.4 four (4) originals of a Secretary's Certificate or Assistant Secretary's Certificate certifying as to the due authorization of Seller's signatory to the documents signed at Closing;

16.2.5 four (4) originals of the Transition Agreement executed by an Attorney-in-Fact of Seller, if applicable;

16.2.6 State of Louisiana change of operator forms for the Properties of which Seller is the operator in such number as required by the government plus additional copies as the Parties agree;

16.2.7 four (4) originals of the Shared Systems IP License executed by an authorized officer or an Attorney-in-Fact of Seller; and

16.2.8 any other instruments and agreements (including ratification or joinder instruments required to transfer Properties from Seller to Buyer and deeds) as are necessary or appropriate to comply with Seller's obligations under this Agreement.

16.3 BUYER'S OBLIGATIONS AT CLOSING. At Closing, Buyer shall deliver to Seller, unless waived by Seller, the following:

16.3.1 the Adjusted Purchase Price, as set forth on the Closing Statement, by wire transfer of immediately available funds to the account(s) designated by Seller in accordance with this Agreement;

16.3.2 the documents referred to in Articles 16.2.1, 16.2.5, 16.2.6,16.2.7, and 16.2.8, executed by an authorized officer or an Attorney-in-Fact of Buyer and acknowledged;

16.3.3 four (4) originals of the Certificate executed by an authorized officer or an Attorney-in-Fact of Buyer;

16.3.4 four (4) originals of (i) certificates of the appropriate governmental authorities, dated as of a date not earlier than two (2) Business Days prior to the Closing Date, evidencing Buyer's existence and good standing in the States of Texas and Louisiana, and (ii) certificates of the Secretary or Assistant Secretary of Buyer, dated on the Closing Date, certifying (A) that a true and correct copy of the resolutions of Buyer's board of directors authorizing this Agreement and the transactions contemplated hereby are attached thereto have been duly adopted and are in full force and effect; (B) that true and correct copies of the articles of incorporation, all amendments thereto and bylaws of Buyer are attached thereto; and (C) as to the incumbency and authorization of Buyer's signatory executing on behalf of Buyer this Agreement and the other documents executed in connection herewith;

16.3.5 evidence that Buyer is at Closing in full compliance with all governmental requirements for posting plugging and other applicable bonds and filings related to the Properties or their operation, if any;

16.3.6 the sales tax exemption certificate referred to in Article 12.9; and

16.3.7 any other instruments and agreements (including ratification or joinder instruments required to transfer the Properties from Seller to Buyer and deeds) as necessary or appropriate to comply with Buyer's obligations under this Agreement.

ARTICLE XVII
TERMINATION

17.1 GROUNDS FOR TERMINATION. This Agreement may be terminated (except for the individual provisions specifically referenced in Article 17.2 below) at any time prior to Closing (unless another date is stated below):

17.1.1 by the Parties' mutual written agreement;

17.1.2 by either Party, if consummation of the transactions contemplated by this Agreement would violate any non-appealable final order, decree or judgment of any state or federal court or agency enjoining, restraining, prohibiting or awarding substantial damages in connection with (a) Seller's proposed sale of Properties to Buyer, or (b) consummation of the transactions contemplated by this Agreement;

17.1.3 by Seller, if Buyer refuses or fails for any reason to give Seller the Performance Deposit in accordance with and at the time specified in Article 2.3;

17.1.4 by either Party, if such Party becomes aware that any condition precedent to a Party's obligation to Close cannot be satisfied prior to the Closing Date, provided, however, that the terminating Party shall have given the other Party at least five (5)

Business Days ("CURE PERIOD") to cure the situation and at the end of such cure period, the relevant condition precedent remains unsatisfied prior to the Closing Date;

17.1.5 notwithstanding anything contained in this Agreement to the contrary, by Seller, if Closing has not occurred on or before October 31, 2006; or

17.1.6 by either Party, pursuant to Section 7.2.2.

17.2 EFFECT OF TERMINATION. Except as otherwise provided in this Article 17.2, this Agreement is terminated in accordance with Article 1 7.1, such termination is without liability to either Party, except performance of obligations in this Article 17.2, Articles 5.1.2, 14.2, 17.3, 17.4, 18.1, 19.1, 19.3, 19.7, 19.8, 19.9, 19, 10, 19.12, 19.13,19.14, 19.15, 19.16, 19.17, 19.18, 19.19, 19.21 and 19.22, all of which provisions survive termination of this Agreement.

17.2.2 If Closing does not occur, Seller shall refund the Performance Deposit together with Computed Interest to Buyer unless Closing did not occur because of (i) Buyer's breach of this Agreement or (ii) Buyer's failure or refusal to Close that is not permitted by the terms of this Agreement, and in the case of either (i) or (ii) hereinabove Seller is entitled to retain the Performance Deposit together with all interest earned thereon as liquidated damages and not a penalty. The foregoing remedies are the sole remedies for either Party in connection with failure of Closing to occur, except in the case of willful breach of a Party, in which case the other Party has any remedies available to it at law or in equity.

17.3 DISPUTE OVER RIGHT TO TERMINATE. If there is a dispute over the right of a Party to terminate this Agreement, Closing shall not occur on the Closing Date, and the Party that disputes the right of the other Party to terminate is entitled, within thirty (30) Business Days after the Closing Date, to initiate litigation to resolve the dispute. If the Party that disputes the other Party's right to terminate this Agreement does not initiate litigation within the thirty (30) Business Day period, this Agreement shall be deemed properly terminated as of the original date of termination (without prejudice to Seller's right to retain the Performance Deposit together with any interest earned thereon pursuant to Article 17.2.2), AND THE PARTY THAT DISPUTES OR HAS a RIGHT TO DISPUTE TERMINATION OF THIS AGREEMENT, ON BEHALF OF ITSELF, ITS AFFILIATES, AND THE OFFICERS, DIRECTORS, AGENTS, EMPLOYEES, SUCCESSORS AND ASSIGNS OF ITSELF AND ITS AFFILIATES, IRREVOCABLY WAIVES ANY AND ALL CLAIMS IT

AND THEY MAY HAVE AGAINST THE TERMINATING PARTY FOR TERMINATION OF THIS AGREEMENT.

17.4 CONFIDENTIALITY. Notwithstanding the termination of this Agreement or any other provision of this Agreement to the contrary, the terms of the Confidentiality Agreement remain in full force and effect, provided that if and when Closing occurs and effective on the Closing Date, the Confidentiality Agreement shall terminate to the extent (and only to the extent) it applies to the Properties conveyed to Buyer at Closing and shall remain in full force and effect as to all Excluded Properties and other assets, properties or information of Seller Group not conveyed to Buyer pursuant to this Agreement.

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ARTICLE XVIII
ARBITRATION

18.1 ARBITRATION. Arbitrable Disputes must be resolved through use of binding arbitration using three (3) arbitrators, in accordance with the Commercial Arbitration Rules of the American Arbitration Association (the "AAA") as in effect on the date of this Agreement, as supplemented to the extent necessary to determine any procedural appeal questions by the Federal Arbitration Act (Title 9 of the United States Code). If there is any inconsistency between this Article and the Commercial Arbitration Rules or the Federal Arbitration Act, this Article shall control. Arbitration must be initiated within the applicable time limits set forth in this Agreement and not thereafter or if no time limit is given, within the time period allowed by the applicable statute of limitations. Arbitration, if initiated, must be initiated by a Party ("CLAIMANT") serving written notice on the other Party ("RESPONDENT") that the Claimant elects to refer the Arbitrable Dispute to binding arbitration. Claimant's notice initiating arbitration must identify the arbitrator Claimant has appointed. The Respondent shall respond to Claimant within thirty (30) Days after receipt of Claimant's notice, identifying the arbitrator Respondent has appointed. If the Respondent does not name an arbitrator within the thirty (30) Day period, the Houston office of the AAA will name the arbitrator for Respondent's account. The two (2) arbitrators so chosen shall select a third arbitrator within thirty (30) Days after the second arbitrator has been appointed. If the Party-appointed arbitrators cannot reach agreement upon the third arbitrator within the thirty (30) Day period, the Houston office of the AAA shall appoint an independent arbitrator. The Parties each shall pay one-half of the compensation and expenses of the arbitrators. All arbitrators must (a) be neutral persons who have never been officers, directors, employees, or consultants or had other business or personal relationships with the Parties or any of their Affiliates, officers, directors or employees, and (b) have not less than seven (7) years experience in the U.S. oil and gas industry. The hearing will be conducted in Houston, Texas, and commence within thirty (30) Days after the selection of the third arbitrator. The Parties and the arbitrators should proceed diligently and in good faith so that the award can be made as promptly as possible. Except as provided in the Federal Arbitration Act, the decision of the arbitrators shall be binding on and non-appealable by the Parties. The arbitrators shall have no right or authority to grant or award indirect, consequential, punitive or exemplary damages of any kind.

ARTICLE XIX
MISCELLANEOUS

19.1 NOTICES. All notices and other communications required or desired to be given hereunder must be in writing and sent (properly addressed as set forth below) by (a) certified or registered U.S. mail, return receipt requested, with all postage and other charges fully prepaid, (b) hand or courier delivery, or (c) facsimile transmission. Date of service by mail and delivery is the date on which such notice is received by the addressee and by facsimile is the date sent (as evidenced by fax machine generated confirmation of transmission) if

received during normal business hours on a Business Day; provided, however, if not received during normal business hours on a Business Day, then date of receipt will be on the next date that is a Business Day. Each Party may change its address by notifying the other Party in writing of such address change, and the change will be effective thirty (30) Days after such notification is received by the other Party.

To Seller:

BP America Production Company
501 WestLake Park Boulevard
Houston, Texas 77079
Facsimile: 281-388-7583
Attn: Assistant General Counsel, Legal Group

To Buyer:

Swift Energy Operating, LLC
16825 Northchase Drive, Suite 400
Houston, Texas 77060
Facsimile: (281) 874-8033
Attn: James P. Mitchell
Senior Vice President -- Commercial Transactions & Land

19.2 COSTS AND POST-CLOSING CONSENTS. Notwithstanding other provisions of this Agreement, Buyer shall be responsible for recording and filing documents associated with assignment of the Properties to it and for all costs and fees associated therewith, including filing the assignments in the appropriate parishes, provided, however, that Seller shall file with the applicable State of Louisiana agency the change of operator forms referred to in Article 16.2.6. As soon as practicable after recording or filing, Buyer shall furnish Seller all recording data and evidence of all required filings made by Buyer. Buyer shall be responsible for obtaining all consents and approvals of governmental entities or authorities customarily obtained subsequent to transfer of title and all costs and fees associated therewith (provided, however, Seller will exercise reasonable efforts to assist Buyer, where applicable, at Buyer's sole cost and expense, in obtaining such consents and approvals). Except as expressly provided otherwise in this Agreement, all fees, costs and expenses incurred by the Parties in negotiating this Agreement and in consummating the transactions contemplated by this Agreement shall be paid in full by the Party that incurred such fees, costs and expenses.

19.3 BROKERS, AGENTS AND FINDERS.

19.3.1. Neither Seller nor any of its Affiliates has retained any brokers, agents or finders in connection with the transactions contemplated hereby for which Buyer or its Affiliates shall have any liability. Seller releases BUYER GROUP FROM AND SHALL FULLY PROTECT, INDEMNIFY AND DEFEND BUYER GROUP AND HOLD THEM HARMLESS FROM AND AGAINST ANY AND ALL CLAIMS RELATING TO, ARISING OUT of, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, COMMISSIONS, FINDERS' FEES OR OTHER REMUNERATION DUE TO ANY AGENT, BROKER OR FINDER CLAIMING BY, THROUGH OR

UNDER SELLER OR its AFFILIATES.

19.3.2 Neither Buyer nor any of its Affiliates retained any agents, brokers or finders for Buyer associated with the transactions contemplated hereby for which Seller or any of its Affiliates shall

have any liability. BUYER RELEASES SELLER GROUP FROM AND SHALL FULLY PROTECT, INDEMNIFY AND DEFEND SELLER GROUP AND HOLD THEM HARMLESS FROM AND AGAINST ANY AND ALL CLAIMS RELATING TO, ARISING OUT of, OR CONNECTED WITH, DIRECTLY OR INDIRECTLY, COMMISSIONS, FINDERS' FEES OR OTHER REMUNERATION DUE TO ANY AGENT, BROKER OR FINDER CLAIMING BY, THROUGH OR UNDER BUYER OR ITS AFFILIATES.

19.4 RECORDS.

19.4.1. At Closing, Seller shall grant Buyer reasonable access to the Records. As soon as reasonably practicable after Closing, and in any even within sixty (60) Days after the end of the Transition Period or if there is no Transition Period, within ninety (90) Days after the Closing Date, (except as provided below), Seller shall furnish Buyer the Records that are maintained by Seller; provided, however, Seller may retain: originals or copies of any or all Records, including originals of (i) any Records associated with litigation or other proceedings pending or threatened by or against Seller Group, (ii) tax records, (iii) Records in connection with the Final Accounting Settlement until payments made thereunder have been agreed and paid in full, (iv) Records required in connection with any Transition Period activities (until the end of the Transition Period), and (v) Records associated with any properties not conveyed to Buyer pursuant to this Agreement.

19.4.2. Seller is not obligated to create any Records for Buyer or to provide them in a form or format other than the form or format in which they exist as of the date hereof. Seller shall use all reasonable efforts to provide Records in the priority designated in writing to Seller by Buyer. If Buyer desires copies of Records prior to the time by which Seller is obligated to deliver the Records to Buyer hereunder, Seller will use reasonable efforts to cause the copies requested by Buyer to be made and delivered to Buyer, provided, however, that Seller shall have no obligation to provide Buyer Records prior to Closing and if Seller is willing to provide any such Records, Buyer shall reimburse Seller for all costs of copying and provision of such Records to Buyer

19.4.3 Buyer shall maintain the Records received from Seller for seven (7) years after the Closing Date, and afford Seller full access to the Records and a right to copy the Records at Seller's expense as reasonably requested by Seller. If Buyer desires to destroy the Records, it shall notify Seller prior to such destruction, and provide Seller an opportunity to take possession of them at Seller's sole cost. In addition, Buyer shall afford Seller full access to records and data produced after the Closing Date and reasonably requested by Seller in connection with any claim by Buyer for indemnity or breach of Seller's representations, warranties or covenants under this Agreement (excluding, however, attorney work product and attorney-client communications entitled to legal privilege), and a right to copy such records and data at Seller's sole cost.

19.5 FURTHER ASSURANCES. After Closing and on an on-going basis:

19.5.1 Buyer shall execute and deliver or use reasonable efforts to cause to be executed and delivered any other instruments of

conveyance and take any other actions as Seller reasonably requests to more effectively put Seller in possession of any property that was not intended to be (i) a Property or (ii) conveyed or was conveyed in error (including reassignment at Seller's cost from Buyer to Seller of any Properties that were conveyed in violation of valid preferential purchase rights or material consents to assignment), or to implement Buyer's assumption of obligations pursuant to Article 12.3; and

19.5.2 Seller shall execute and deliver or use reasonable efforts to cause to be executed and delivered any other instruments of conveyance and take any other actions as Buyer reasonably requests to more effectively put Buyer in possession of the Properties conveyed or intended to have been conveyed in accordance with the terms of this Agreement.

19.6 SURVIVAL OF CERTAIN OBLIGATIONS. The representations and warranties of the Parties in Articles 10 and 11 (except Articles 11.1.4, 11.1.6 and 11.1.8) and the covenants and agreements of the Parties to be fully performed prior to the Closing (including the covenants and agreements in Article 12.11) shall survive the Closing for a period of twelve (12) months. Subject to the foregoing and as set forth in Article 19.6.1, the remainder of this Agreement (including Articles 5.1.2, 8. 11.1.4, 11.1.6, 11.1.8, 12.3, 12.4, 12.5, 12.6, 12.7, 12.8 and 19.3) shall survive the Closing without time limit. Representations, warranties, covenants and agreements shall be of no further force and effect after the date of their expiration, provided that there shall be no termination of any bona fide claim that was asserted in accordance with this Agreement with respect to such a representation, warranty, covenant or agreement prior to its expiration date.

19.6.1 The indemnities in Articles 8.2 and 8.4 shall terminate as of the termination dates set forth in Article 8.3 and 8.5 (respectively) or, if no termination date is set forth in those Articles, then as of the termination date of each representation, warranty, covenant or agreement that is subject to indemnification thereunder, except in each case as to matters for which a specific Claim Notice has been delivered to the Indemnifying Party on or before such termination date. Buyer's indemnities in Articles 8.6, 12.4, 12.5, 12.6, 12.8, and 12.9 shall be deemed covenants running with the Properties (provided that Buyer and its successors and assigns shall not be released from any of, and shall remain jointly and severally liable to the Seller Group for the obligations or liabilities of Buyer under such Articles of this Agreement upon any transfer or assignment of any Property).

19.7 AMENDMENTS AND SEVERABILITY. No amendments, waivers or other modifications of terms of this Agreement shall be effective or binding on the Parties unless they are written and signed by both Parties. Invalidity of any provisions in this Agreement shall not affect the validity of this Agreement as a whole, and in case of such invalidity, this Agreement shall be construed as if the invalid provision had not been included herein.

19.8 SUCCESSORS AND ASSIGNS. Except as expressly provided otherwise in this Agreement, this Agreement may not be assigned, (in whole or in part), without the express prior written consent of the non-assigning Party, except

that Seller may assign its rights and obligations hereunder to any one or more of Seller's Affiliates without Buyer's consent and may freely assign its rights to proceeds hereunder. The non-assigning Party's consent to assign shall not be unreasonably withheld or delayed. The terms, covenants and conditions contained in this Agreement are binding upon and inure to the benefit of the Parties and their permitted successors and assigns. Buyer shall not sell, transfer, convey, assign or otherwise dispose of the Properties without first obtaining financial assurances of performance in favor of Seller from such successor in interest in form and substance reasonably satisfactory to Seller. No assignment of this Agreement by Buyer shall relieve Buyer of any of its obligations hereunder; and any assignment made without Seller's written consent is void ab initio.

19.9 HEADINGS. Titles and headings in this Agreement have been included solely for ease of reference and shall not be considered in interpretation or construction of this Agreement.

19.10 GOVERNING LAW. THIS AGREEMENT (INCLUDING ADMINISTRATION OF BINDING ARBITRATION PURSUANT TO ARTICLE 18) IS GOVERNED BY THE LAWS OF THE STATE OF TEXAS, EXCLUDING ANY CHOICE OF LAW RULES THAT WOULD DIRECT APPLICATION OF LAWS OF ANOTHER JURISDICTION. ANY ACTION PERMITTED BY THIS AGREEMENT TO BE COMMENCED IN COURT SHALL BE BROUGHT AND MAINTAINED EXCLUSIVELY IN FEDERAL OR STATE COURT LOCATED IN HARRIS COUNTY, TEXAS, AND EACH PARTY HEREBY WAIVES ANY OBJECTION IT MAY HAVE THERETO.

19.11 NO PARTNERSHIP CREATED. It is not the purpose or intention of this Agreement to create (and it shall not be construed as creating) a joint venture, partnership or any type of association, and neither Party is authorized to act as an agent or principal for the other Party with respect to any matter related hereto.

19.12 PUBLIC ANNOUNCEMENTS. Seller (on behalf of Seller Group) and Buyer (on behalf of Buyer Group) agree not to issue any public statement or press release concerning this Agreement or the transactions contemplated by it (including price or other terms) without the prior written consent of the other Party, except for public statements that are required by Law to be made in which case the Party required to make such statement will provide reasonable prior notice to and consultation with -the other Party before issuing such statement.

19.13 NO THIRD PARTY BENEFICIARIES. Nothing contained in this Agreement entitles anyone other than Seller or Buyer or their permitted successors and assigns to any claim, cause of action, remedy or right of any kind whatsoever, except with respect to waivers and indemnities or other provisions in this Agreement that expressly provide for waivers or indemnification of Buyer Group or Seller Group, in which case members of such groups are considered third party beneficiaries for the sole purposes of those waiver and indemnity provisions.

19.14 INDEMNITIES APPLICABILITY. NOTWITHSTANDING ANYTHING TO THE CONTRARY CONTAINED IN THIS AGREEMENT, THE RELEASE, DEFENSE, INDEMNIFICATION AND HOLD HARMLESS PROVISIONS PROVIDED FOR IN THIS AGREEMENT SHALL BE APPLICABLE WHETHER OR NOT THE CLAIMS, DEMANDS, SUITS, CAUSES OF ACTION, LOSSES, DAMAGES, LIABILITIES, FINES, PENALTIES AND COSTS (INCLUDING ATTORNEYS' FEES AND COSTS OF LITIGATION) IN QUESTION AROSE SOLELY OR IN PART FROM THE ACTIVE, PASSIVE OR CONCURRENT NEGLIGENCE, STRICT LIABILITY, BREACH OF DUTY (STATUTORY OR

OTHERWISE), VIOLATION OF LAW, OR OTHER FAULT OF ANY INDEMNIFIED PARTY, OR FROM

ANY PRE-EXISTING DEFECT, BUT SHALL NOT BE APPLICABLE TO THE EXTENT OF ANY GROSS NEGLIGENCE OR WILLFUL MISCONDUCT ON THE PART OF AN INDEMNIFIED PARTY.

19.15 WAIVER OF CONSUMER RIGHTS. AS PARTIAL CONSIDERATION FOR THE PARTIES ENTERING INTO THIS AGREEMENT, EACH PARTY CAN AND DOES HEREBY WAIVE THE PROVISIONS OF THE TEXAS DECEPTIVE TRADE PRACTICES CONSUMER PROTECTION ACT, ARTICLE 17.41 ET SEQ., TEXAS BUSINESS AND COMMERCE CODE, A LAW THAT GIVES CONSUMERS SPECIAL RIGHTS AND PROTECTION, AND ALL OTHER CONSUMER PROTECTION LAWS OF THE STATE OF TEXAS, OR OF ANY OTHER STATE THAT MAY BE APPLICABLE TO THIS TRANSACTION, THAT MAY BE WAIVED BY SUCH PARTY. IT IS NOT THE INTENT OF EITHER PARTY TO WAIVE, AND NEITHER PARTY DOES WAIVE, ANY LAW OR PROVISION THEREOF THAT IS PROHIBITED BY LAW FROM BEING WAIVED. EACH PARTY REPRESENTS THAT IT HAS HAD AN ADEQUATE OPPORTUNITY TO REVIEW THE PRECEDING WAIVER PROVISION, INCLUDING THE OPPORTUNITY TO SUBMIT THE SAME TO LEGAL COUNSEL FOR REVIEW AND ADVICE, AND AFTER CONSULTATION WITH AN ATTORNEY OF ITS OWN SELECTION VOLUNTARILY CONSENTS TO THIS WAIVER AND UNDERSTANDS THE RIGHTS BEING WAIVED HEREIN.

19.16 REDHIBITION WAIVER. BUYER EXPRESSLY

(i) WAIVES THE WARRANTY OF FITNESS FOR INTENDED PURPOSES AND GUARANTEE AGAINST HIDDEN OR LATENT REDHIBITORY VICES UNDER LOUISIANA LAW, INCLUDING LOUISIANA CIVIL CODE ARTICLE 2520 (1870) THROUGH 2548 (1870);

(ii) WAIVES ALL RIGHTS IN REDHIBITION PURSUANT TO LOUISIANA CIVIL CODE ARTICLE 2420, ET SEQ., INCLUDING THE WARRANTY IMPOSED BY LOUISIANA CIVIL CODE ARTICLE 2475 (1870);

(iii) ACKNOWLEDGES THAT THIS EXPRESS WAIVER SHALL BE A MATERIAL AND INTEGRAL PART OF THIS SALE AND THE CONSIDERATION THEREOF; AND (IV) ACKNOWLEDGES THAT THIS WAIVER HAS BEEN BROUGHT TO THE ATTENTION OF BUYER AND EXPLAINED IN DETAIL AND THAT BUYER HAS VOLUNTARILY AND KNOWINGLY CONSENTED GENERALLY AND SPECIFICALLY TO THIS WAIVER OF WARRANTY OF FITNESS AND/OR WARRANTY AGAINST REDHIBITORY VICES AND DEFECTS FOR THE PROPERTIES.

ALL ASSIGNMENTS TO BE DELIVERED BY SELLER AT CLOSING SHALL EXPRESSLY SET FORTH THE DISCLAIMERS OF REPRESENTATIONS AND WARRANTIES CONTAINED IN THIS ARTICLE 19.16.

19.17 UTPCPL WAIVER. TO THE EXTENT APPLICABLE TO THE PROPERTIES OR ANY PORTION THEREOF, BUYER HEREBY WAIVES THE PROVISIONS OF THE LOUISIANA UNFAIR TRADE PRACTICES AND CONSUMER PROTECTION LAW (LA. R.S. 51-1402, ET SEQ.). BUYER WARRANTS AND REPRESENTS THAT BUYER (i) IS EXPERIENCED AND KNOWLEDGEABLE WITH RESPECT TO THE OIL AND GAS INDUSTRY GENERALLY AND WITH TRANSACTIONS OF THIS TYPE SPECIFICALLY, (ii) POSSESSES AMPLE KNOWLEDGE, EXPERIENCE AND EXPERTISE TO EVALUATE INDEPENDENTLY THE MERITS AND RISKS OF THE TRANSACTIONS HEREIN CONTEMPLATED, AND (iii) IS NOT IN A SIGNIFICANTLY DISPARATE BARGAINING POSITION.

19.18 NOT TO BE CONSTRUED AGAINST DRAFTER. EACH PARTY HAS HAD AN ADEQUATE OPPORTUNITY TO REVIEW EACH AND EVERY PROVISION OF THIS AGREEMENT AND TO SUBMIT THE SAME TO LEGAL COUNSEL FOR REVIEW AND ADVICE. BASED ON THE FOREGOING,

THE RULE OF CONSTRUCTION, IF ANY, THAT A CONTRACT is CONSTRUED AGAINST THE DRAFTER SHALL NOT APPLY TO INTERPRETATION OR CONSTRUCTION OF THIS AGREEMENT.

19.19 CONSPICUOUSNESS OF PROVISIONS. THE PARTIES AGREE THAT PROVISIONS OF THIS AGREEMENT IN "BOLD" OR ALL CAPITALIZED TYPE SATISFY ANY REQUIREMENT OF THE "EXPRESS NEGLIGENCE RULE" AND OTHER REQUIREMENT AT LAW OR IN EQUITY THAT PROVISIONS BE CONSPICUOUSLY MARKED OR HIGHLIGHTED.

19.20 POSSIBLE EXCHANGE. Seller reserves the right to structure the transactions contemplated under the terms of this Agreement as a non-simultaneous like-kind exchange pursuant to Section 1031 of the Internal Revenue Code of 1986, as amended. If Seller elects to so structure this transaction, the Parties shall execute all documents reasonably necessary for Seller to effectuate the non-simultaneous like-kind exchange.

19.21 EXECUTION IN COUNTERPARTS. This Agreement may be executed in counterparts, that when taken together constitute one valid and binding agreement.

19.22 ENTIRE AGREEMENT. This Agreement (including the agreements, once completed and executed, attached hereto as Exhibits) and the Confidentiality Agreement supersede all prior and contemporaneous negotiations, understandings, letters of intent, understandings and agreements (whether oral or written) between the Parties or their Affiliates relating to the terms of purchase and sale of the Properties and constitute the entire understanding and agreement between the Parties with respect to the sale, assignment and conveyance of the Properties and other transactions contemplated by this Agreement.

The Parties have caused this Agreement to be executed by their duly authorized representatives on the day and year first set forth above.

SELLER	BUYER
BP AMERICA PRODUCTION COMPANY	SWIFT ENERGY OPERATING, LLC
By: /s/ Thalia R. Gelbs	By: /s/ Bruce H. Vinent
Name: Thalia R. Gelbs	Name: Bruce H. Vincent
Title: Attorney-in-Fact	Title: President

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Exhibit 12

SWIFT ENERGY COMPANY

RATIO OF EARNINGS TO FIXED CHARGES

	2002	2003	2004

GROSS G&A	26,074,408	29,803,405	37,850,281
NET G&A	10,564,849	14,097,066	17,787,125
INTEREST EXPENSE, NET	23,274,969	27,268,524	27,643,108
RENTAL & LEASE EXPENSE	1,923,451	2,173,313	2,375,598
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	18,408,289	50,739,178	101,440,242
CAPITALIZED INTEREST	6,973,480	6,835,983	6,489,763
CALCULATED DATA			
EXPENSED OR NON-CAPITAL G&A (%)	40.52%	47.30%	46.99%
NON-CAPITAL RENT EXPENSE	779,345	1,027,981	1,116,374
1/3 NON-CAPITAL RENT EXPENSE	259,782	342,660	372,125
FIXED CHARGES	30,508,231	34,447,167	34,504,996
EARNINGS	41,943,040	78,350,362	129,455,475
	1.37	2.27	3.75

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Exhibit 21

Swift Energy Company - Significant Subsidiaries

Swift Energy International, Inc.
Swift Energy New Zealand Limited
Southern Petroleum (NZ) Exploration Limited
Swift Energy Operating, LLC

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Exhibit 23.1

CONSENT OF H.J. GRUY AND ASSOCIATES, INC.

We hereby consent to the use of the name H.J. Gruy and Associates, Inc. and of references to H.J. Gruy and Associates, Inc. and to the inclusion of and references to our report, or information contained therein, dated January 23, 2007, prepared for Swift Energy Company in the Annual Report on Form 10-K of Swift Energy Company for the filing dated on or about February 28, 2006.

H.J. GRUY AND ASSOCIATES, INC.

by: /s/ Robert Rasor

Robert Rasor, P.E.
Executive Vice President
Engineering Manager

Houston, Texas
February 28, 2007

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Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements (Form S-3 Nos. 333-112041 and 333-12831) and related Prospectuses of Swift Company Energy Company and subsidiaries, and on the following Registration Statements on form S-8:

Form S-8 No.	Pertaining to:
333-134807	Swift Energy Company 2005 Stock Compensation Plan
333-130548	Swift Energy Company 2005 Stock Compensation Plan
333-112042	Swift Energy Company 2001 Omnibus Stock Compensation Plan
333-67242	Swift Energy Company 2001 Omnibus Stock Compensation Plan
	Swift Energy Company 1990 Stock Compensation Plan
333-45354	Swift Energy Company 1990 Stock Compensation Plan
	Swift Energy Company 1990 Nonqualified Stock Option Plan
	Swift Energy Company Employee Savings Plan
033-80228	Swift Energy Company Employee Stock Purchase Plan

of our reports dated February 27, 2007, with respect to the consolidated financial statements of Swift Energy Company and subsidiaries, Swift Energy Company management's assessment of the effectiveness of internal control over financial reporting, and the effectiveness of internal control over financial reporting of Swift Energy Company and subsidiaries, included in the Annual Report (Form 10-K) for the year ended December 31, 2006.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 28, 2007

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Exhibit 31.1

CERTIFICATION

I, Terry E. Swift, certify that:

1. I have reviewed this Annual Report on Form 10-K for the period ended December 31, 2006 of Swift Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15(d)-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting, to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our

most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2007

/s/ Terry E. Swift

Terry E. Swift
Chief Executive Officer

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Exhibit 31.2

CERTIFICATION

I, Alton D. Heckaman, Jr., certify that:

1. I have reviewed this Annual Report on Form 10-K for the period ended December 31, 2006 of Swift Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15(d)-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting, to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2007

/s/ Alton D. Heckaman, Jr.

Alton D. Heckaman, Jr.
Executive Vice President and
Chief Financial Officer

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Exhibit 32

Certification of Chief Executive Officer and Chief Financial Officer

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the accompanying Annual Report on Form 10-K for the period ended December 31, 2006 (the "Report") of Swift Energy Company ("Swift") as filed with the Securities and Exchange Commission on February 28, 2007, the undersigned, in his capacity as an officer of Swift, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Swift.

Dated: February 28, 2007

/s/ Alton D. Heckaman, Jr.

Alton D. Heckaman, Jr.
Executive Vice President &
Chief Financial Officer

Dated: February 28, 2007

/s/ Terry E. Swift

Terry E. Swift
Chairman of the Board &
Chief Executive Officer

Exhibit 99.1

H.J. GRUY AND ASSOCIATES, INC.

333 Clay Street, Suite 3850, Houston, Texas 77002 o TEL. (713) 739-1000
o FAX (713) 739-6112

January 23, 2007

Swift Energy Company
16825 Northchase Drive, Suite 400
Houston, Texas 77060

Re: Year-End 2006 R
Reserves Audit

Gentlemen:

At your request, we have independently audited the estimates of oil, natural gas, and natural gas liquid reserves and future net cash flows as of December 31, 2006, that Swift Energy Company (Swift) attributes to net interests owned by Swift. Based on our audit, we consider the Swift estimates of net reserves and net cash flows to be in reasonable agreement, in the aggregate, with those estimates that would result if we performed a completely independent evaluation effective December 31, 2006.

The Swift estimated net reserves, future net cash flow, and discounted future net cash flow are summarized below:

Domestic and International
Proved Reserves

	Estimated Net Reserves		Estima Future Net C
	Oil, NGL, & Condensate (Barrels)	Gas (Mcf)	Not Discounted
Proved Developed	34,956,469	151,276,834	$ 1,972,358,040
Proved Undeveloped	47,162,615	172,854,583	$ 2,193,155,963
Total Proved	82,119,084	324,131,417	$ 4,165,514,003

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Domestic
Proved Reserves

	Estimated Net Reserves		Estimat Future Net Ca
	Oil, NGL, & Condensate (Barrels)	Gas (Mcf)	Not Discounted
Proved Developed	33,345,567	133,815,108	$ 1,875,382,590
Proved Undeveloped	40,118,964	135,845,683	$ 1,873,638,977
Total Proved	73,464,531	269,660,791	$ 3,749,021,567

New Zealand
Proved Reserves

	Estimated Net Reserves		Estimat Future Net Ca
	Oil, NGL, & Condensate (Barrels)	Gas (Mcf)	Not Discounted

Proved Developed	1,610,902	17,461,726	$	96,975,450	$
Proved Undeveloped	7,043,650	37,008,900	$	319,516,986	$
New Zealand Total	8,654,552	54,470,626	$	416,492,436	$

The discounted future net cash flows summarized in the above tables are computed using a discount rate of 10 percent per annum. Proved reserves are estimated in accordance with the definitions contained in Securities and Exchange Commission Regulation S-X, Rule 4-10(a). The reserves discussed herein are estimates only and should not be construed as exact quantities. Future economic or operating conditions may affect recovery of estimated reserves and cash flows, and reserves of all categories may be subject to revision as more performance data become available.

Swift represents that the future net cash flows discussed herein were computed using prices received for oil, natural gas, and natural gas liquids as of December 31, 2006. Domestic oil and condensate prices are based on a year-end 2006 reference price of $61.05 per barrel. Natural gas price is based on a

year-end 2006 reference price of $6.299 per MMBtu. New Zealand oil and condensate prices are based on a year-end 2006 reference price of $65.57 per barrel. The New Zealand gas prices are based on existing contract prices. The sales price for natural gas liquids is based on a reference price of $1.45 per gallon adjusted as necessary for existing local market contracts. A differential is applied to the oil, condensate, natural gas, and natural gas liquids reference prices to adjust for transportation, geographic property location, and quality or energy content. Product prices, direct operating costs, and future capital expenditures are not escalated and therefore remain constant for the projected life of each property. Swift represents that the provided product sales prices and operating costs are in accordance with Securities and Exchange Commission guidelines.

This audit has been conducted according to the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information approved by the Board of Directors of the Society of Petroleum Engineers, Inc. Our audit included examination, on a test basis, of the evidence supporting the reserves discussed herein. In conducting our audit, we investigated each property to the level of detail that we deem reasonably appropriate to form the judgements expressed herein. We recognize the methods and procedures employed by Swift to accumulate and evaluate the necessary information and to document and reconcile reserves, annual production, and ownership interests are effective and are in accordance with generally accepted practices.

Based on our investigations, it is our judgement that Swift used appropriate engineering, geologic, and evaluation principles and methods that are consistent with practices generally accepted in the petroleum industry. Reserve estimates are based on extrapolation of established performance trends, material balance calculations, volumetric calculations, analogy with the performance of comparable wells, or a combination of these methods. Reserve estimates from volumetric calculations or from analogies may be less certain than reserve estimates based on well performance obtained over a period during which a substantial portion of the reserve was produced.

Estimates of net cash flow and discounted net cash flow should not be interpreted to represent the fair market value for the audited reserves. The estimated reserves and cash flows discussed herein have not been adjusted for uncertainty.

Future net cash flow as presented herein is defined as the future cash inflow attributable to the evaluated interest less, if applicable, future operating costs, ad valorem taxes, and future capital expenditures. Future cash inflow is defined as gross cash inflow less, if applicable, royalties and severance taxes. Future cash inflow and future net cash flow stated in this report exclude consideration of state or federal income tax. Future costs of facility and well abandonments and the restoration of producing properties to satisfy environmental standards are not deducted from cash flow.

In conducting this audit, we relied on data supplied by Swift. The extent and character of ownership, oil and natural gas sales prices, operating costs, future capital expenditures, historical production, accounting, geological, and engineering data were accepted as represented, and we have assumed the authenticity of all documents submitted. No independent well tests, property inspections, or audits of operating expenses were conducted by our staff in conjunction with this work. We did not verify or determine the extent, character, status, or liability, if any, of production imbalances, hedging activities, or any current or possible future detrimental environmental site conditions.

In order to audit the reserves and future cash flows estimated by Swift, we have relied in part on geological, engineering, and economic data furnished by our client. Although we instructed our client to provide all pertinent data, and we made a reasonable effort to analyze it carefully with methods accepted by the petroleum industry, there is no guarantee that the volumes of hydrocarbons or the cash flows projected will be realized. The reserve and cash flow projections discussed in this report may require revision as additional data become available.

If investments or business decisions are to be made in reliance on these judgements by anyone other than our client, such person, with the approval of our client, is invited to visit our offices at his expense so that he can evaluate the assumptions made and the completeness and extent of the data available on which our opinions are based. This report is for general guidance only, and responsibility for subsequent decisions resides with the decision maker.

Any distribution or publication of this work or any part thereof must include this letter in its entirety.

Yours very truly,

H.J. GRUY AND ASSOCIATES,INC.
Texas Registration Number F-000637

by: /s/ Marilyn Wilson

Marilyn Wilson, P.E.
President and Chief Operating Officer

Attachment

MW:pab

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ATTACHMENT I

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DEFINITIONS OF PROVED OIL AND GAS RESERVES(1)

PROVED OIL AND GAS RESERVES

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquid which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

PROVED DEVELOPED OIL AND GAS RESERVES

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

PROVED UNDEVELOPED RESERVES

Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir. ------------------------

(1) Contained in Securities and Exchange Commission Regulation S-X, Rule 4-10 (a)