RELIANT RESOURCES INC
Form 10-K/A
May 01, 2003

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

Form 10-K/A

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2002

or

[_] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________

Commission File Number 1-16455

Reliant Resources, Inc.
(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	76-0655566 (I.R.S. Employer Identification No.)
1111 Louisiana Street Houston, Texas 77002 (Address and Zip Code of Principal Executive Offices)	(713) 497-3000 (Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $.001 per share, and associated rights to purchase Series A Preferred Stock	New York Stock Exchange

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

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 (or for such shorter period that the Registrant was required to file such reports), 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 the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K/A or any amendment to this Form 10-K/A. [_]

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes [X] No [_]

The aggregate market value of the voting stock held by non-affiliates of the Registrant was $433,427,759 as of June 28, 2002 (computed by reference to the closing sale price of the Registrant's common stock on the New York Stock Exchange on that date), using the definition of beneficial ownership contained in Rule 13d-3 promulgated pursuant to the Securities Exchange Act of 1934 and excluding shares held by directors and executive officers. As of June 28, 2002, the Registrant had 289,663,717 shares of common stock outstanding, excluding 10,140,283 shares of common stock held by the Registrant as treasury stock.

Portions of the definitive proxy statement relating to the 2003 Annual Meeting of Stockholders of the Registrant's, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2002, are incorporated by reference in Item 10, Item 11, Item 12 and Item 13 of Part III of this Form 10-K/A.

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We hereby amend our original Form 10-K for the year ended December 31, 2002, to include Schedule I--Condensed Financial Information of Reliant Resources, Inc. and Exhibits 4.3 and 10.42. Except for the foregoing, no attempt has been made in this Form 10-K/A to modify or update other disclosures as presented in the original Form 10-K.

Table of Contents

	Page
Cautionary Statement Regarding Forward-Looking Information......	1
Glossary of Terms..	1
PART I	
ITEM 1. Business...	5
Our Business...	5
General...	5
Formation, IPO and Distribution......................	5
Orion Power Acquisition.............................	5
Disposition of European Energy Operations.............	6
Retail Energy..	6
Residential and Small Commercial Services.............	7
Large Commercial, Industrial and Institutional Services	8
Provider of Last Resort..............................	8
Retail Energy Supply.................................	8
ERCOT...	9

	Competition	9
	Wholesale Energy	10
	Overview of Wholesale Energy Market	10
	Power Generation Operations	10
	Mid-Atlantic Region	12
	New York Region	13
	Midwest Region	14
	Southeast Region	15
	West Region	15
	ERCOT Region	17
	Long-term Purchase and Sale Agreements	17
	Commercial Operations	17
	Regulation	19
	Competition	20
	European Energy	21
	European Power Generation and Supply	21
	European Trading and Origination	22
	Regulation	22
	Competition	22
	Other Operations	22
	Environmental Matters	23
	General	23
	Air Quality Matters	23
	Water Quality Matters	24
	Liability for Preexisting Conditions and Remediations	25
	Other European Environmental Matters	26
	Employees	27
	Executive Officers	27
ITEM 2.	Properties	28
	Character of Ownership	28
	Retail Energy	28
	Wholesale Energy	28
	European Energy	28
	Other Operations	28
ITEM 3.	Legal Proceedings	28
ITEM 4.	Submission of Matters to a Vote of Security Holders	28

		Page
	PART II	
ITEM 5.	Market for Our Common Equity and Related Stockholder Matters	2
ITEM 6.	Selected Financial Data	3
ITEM 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	3
	Overview	3
	Consolidated Results of Operations	3
	2002 Compared to 2001	3
	2001 Compared to 2000	3
	EBIT by Business Segment	3
	Retail Energy	3
	Wholesale Energy	4
	European Energy	4
	Other Operations	5
	Trading and Marketing Operations	5

	Related-Party Transactions	6
	Agreements With CenterPoint	6
	Risk Factors	6
	Risks Related to Our Retail Energy Operations	6
	Risks Related to Our Wholesale Energy Operations	6
	Risks Related to Our European Energy Operations	7
	Risks Related to Our Businesses Generally	7
	Risks Related to Our Corporate and Financial Structure	7
	Risks Related to the Sale of Our European Energy Operations	7
	Liquidity and Capital Resources	7
	Historical Cash Flows	7
	Consolidated Capital Requirements	8
	Consolidated Future Uses and Sources of Cash and Certain Factors Impacting Future Uses and Sources of Cash	8
	Off-Balance Sheet Transactions	9
	New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates	9
	New Accounting Pronouncements	9
	Significant Accounting Policies	9
	Critical Accounting Estimates	9
ITEM 7A.	Quantitative and Qualitative Disclosures About Market Risk	9
	Market Risk	9
	Trading Market Risk	10
	Non-trading Market Risk	10
	Risk Management Structure	10
ITEM 8.	Financial Statements and Supplementary Data	F-
ITEM 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	III-2
	PART III	
ITEM 10.	Directors and Executive Officers	III-2
ITEM 11.	Executive Compensation	III-2
ITEM 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	III-2
ITEM 13.	Certain Relationships and Related Transactions	III-2
ITEM 14.	Controls and Procedures	III-2
	Evaluation of Disclosure Controls and Procedures	III-2
	Changes in Internal Controls	III-2
	PART IV	
ITEM 15.	Exhibits, Financial Statement Schedules and Reports on Form 8-K	IV-

Cautionary Statement Regarding Forward-Looking Information

This Form 10-K/A includes statements concerning expectations, assumptions, beliefs, plans, projections, objectives, goals, strategies and future events or performance that are intended as "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can identify our forward-looking statements by the words "anticipates," "believes," "continue," "could," "estimates," "expects," "forecast," "goal," "intends," "may," "objective," "plans," "potential," "predicts," "projection," "should," "will" and similar words.

We have based our forward-looking statements on management's beliefs and assumptions based on information available at the time the statements are made. We caution you that assumptions, beliefs, expectations, intentions and projections about future events and performance may and often do vary materially from actual results. Therefore, actual results may differ materially from those expressed or implied by our forward-looking statements. For more information regarding the risks and uncertainties that could cause our actual results to differ materially from those expressed or implied in our forward-looking statements, see "Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Factors" in Item 7 of this Form 10-K/A.

You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and we undertake no obligation to publicly update or revise any forward-looking statements.

Glossary of Terms

In this Form 10-K/A, "Reliant Resources" refers to Reliant Resources, Inc., and "we," "us" and "our" refer to Reliant Resources, Inc. and its subsidiaries, unless we specify or the context indicates otherwise. In addition, the following terms are used in this Form 10-K/A:

Alliance RTO.....	the proposed RTO for all or parts of Missouri, Illinois, Indiana, Michigan, Ohio, Kentucky, West Virginia, Pennsylvania, Tennessee, Virginia and North Carolina.
APB No. 25.......	Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees."
Bcf..............	one billion cubic feet of natural gas.
Cal ISO..........	California Independent System Operator.
Cal PX...........	California Power Exchange.
CDWR.............	California Department of Water.
CenterPoint......	CenterPoint Energy, Inc., on and after August 31, 2002 and Reliant Energy, Incorporated prior to August 31, 2002.
CenterPoint Plans	CenterPoint Long-Term Incentive Compensation Plan and certain other incentive compensation plans of CenterPoint.
CERCLA...........	Comprehensive Environmental Response Corporation and Liability Act of 1980.
CFTC.............	Commodity Futures Trading Commission.
Channelview......	Reliant Energy Channelview L.P.
CPUC.............	California Public Utility Commission.
Distribution.....	the distribution of approximately 83% of our common stock owned by CenterPoint to its stockholders on September 30, 2002.
EBIT.............	earnings (loss) before interest expense, interest income and income taxes.

EBITDA.........	earnings (loss) before interest expense, interest income, income taxes, depreciation and amortization expense.
ECAR...........	East Central Area Reliability Coordination Council.
ECAR Market....	the wholesale electric market operated by ECAR.
EFL............	Electricity Facts Label.
EITF...........	Emerging Issues Task Force.
EITF No. 02-03.	EITF No. 02-03, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities."
EITF No. 94-3..	EITF No. 94-3, "Liability Recognition for Certain Employee

	Termination Benefits and Other Costs to Exit an Activity."
EITF No. 98-10.	EITF No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities."
Enron..........	Enron Corp. and its subsidiaries.
EPA............	Environmental Protection Agency.
ERCOT..........	Electric Reliability Council of Texas.
ERCOT ISO......	ERCOT Independent System Operator.
ERCOT Region...	the electric market operated by ERCOT.
ESPP...........	Reliant Resources Employee Stock Purchase Plan.
EURIBOR........	inter-bank offered rate for Euros.
FASB...........	Financial Accounting Standards Board.
FERC...........	Federal Energy Regulatory Commission.
FIN No. 45.....	FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Direct Guarantees of Indebtedness of Others."
FIN No. 46.....	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51."
FPSC...........	Florida Public Service Commission.
GAAP...........	United States generally accepted accounting principles.
GridFlorida RTO	the FERC approved RTO for Florida.
GW.............	gigawatt.
GWh............	gigawatt hour.
Headroom.......	the difference between the price to beat and the sum of (a) the charges, fees and transportation and distribution utility rates approved by the PUCT and (b) the price paid for electricity to serve price to beat customers.
IPO............	our initial public offering in May 2001.
ISO............	independent system operator.
KWh............	kilowatt hour.
LEP............	Liberty Electric Power, LLC.
Liberty........	Liberty Electric PA, LLC.
LIBOR..........	London inter-bank offered rated.
MAIN...........	Mid-America Interconnected Network.
MAIN Market....	the wholesale electric market operated by MAIN.
MISO...........	Midwest Independent Transmission System Operator.
MMbtu..........	one million British thermal units.
Mmcf...........	million cubic feet.
MW.............	megawatt.
MWh............	megawatt hour.
NEA............	NEA, B.V., formerly the coordinating body for the Dutch electric generating sector.
NLG............	Dutch Guilders.
Nuon...........	N.V. Nuon, a Netherlands-based electricity distributor.

NYISO..........	New York Independent System Operator.
NY Market......	the wholesale electric market operated by NYISO.
Orion Capital..	Orion Power Capital, LLC.
Orion MidWest..	Orion Power MidWest, L.P.
Orion NY.......	Orion Power New York, L.P.
Orion Power....	Orion Power Holdings, Inc., one of our subsidiaries that we acquired in February 2002.
OTC............	over-the-counter market.
PGET...........	PG&E Energy Trading-Power, L.P.
PJM............	PJM Interconnection, LLC.
PJM Market.....	the wholesale electric market operated by PJM regional transmission

	organization in all or part of Delaware, the District of Columbia, Maryland, New Jersey and Virginia.
PJM West Market	the wholesale electric market operated by PJM in the Midwest.
Protocols......	structure, agreements, tariffs, rules, regulations, mechanisms and requirements that govern rates, terms and conditions for electricity services.
PUCT...........	Public Utility Commission of Texas.
PUHCA..........	Public Utility Holding Company Act of 1935.
QSPE...........	qualified special purpose entity.
REDB...........	Reliant Energy Desert Basin, LLC, one of our subsidiaries.
Reliant Energy.	Reliant Energy, Incorporated and its subsidiaries.
REMA...........	Reliant Energy Mid-Atlantic Power Holdings, LLC, one of our subsidiaries, and its subsidiaries.
REPG...........	Reliant Energy Power Generation, Inc., one of our subsidiaries.
REPGB..........	Reliant Energy Power Generation Benelux, N.V., one of our subsidiaries.
RERC Corp......	Reliant Energy Resources Corp.
RTO............	regional transmission organizations.
RTO West.......	the FERC approved RTO for Idaho, Montana, Nevada, Oregon, Utah and Washington.
SEC............	Securities and Exchange Commission.
SeTrans RTO....	the FERC approved RTO for all or parts of Georgia, Alabama, Louisiana, Mississippi, Arkansas and eastern Texas.
SMD............	the standard market design for the wholesale electric market proposed by the FERC.
SFAS...........	Statement of Financial Accounting Standards.
SFAS No. 5.....	SFAS No. 5, "Accounting for Contingencies."
SFAS No. 87....	SFAS No. 87, "Employers' Accounting for Pensions."
SFAS No. 106...	SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions."
SFAS No. 115...	SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities."
SFAS No. 123...	SFAS No. 123, "Accounting for Stock Based Compensation."
SFAS No. 133...	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.
SFAS No. 140...	SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities."
SFAS No. 141...	SFAS No. 141, "Business Combinations."
SFAS No. 142...	SFAS No. 142, "Goodwill and Other Intangible Assets."
SFAS No. 143...	SFAS No. 143, "Accounting for Asset Retirement Obligations."

SFAS No. 144....................	SFAS No. 144, "Accounting for Impairment or Disposal of Long-Liv Assets."
SFAS No. 145....................	SFAS No. 145, "Rescission of FASB Statements Nos. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections."
SFAS No. 148....................	SFAS No. 148, "Accounting for Stock Based Compensation--Transition and Disclosure."
Spark spread....................	the difference between power prices and natural gas fuel costs.
SRP.............................	Saltwater River Project Agricultural Improvement and Power Distr the State of Arizona.
TCE.............................	Texas Commercial Energy, a retail electric provider to ERCOT.
Texas electric restructuring law	Texas Electric Choice Plan adopted by the Texas legislature in J 1999.
Texas Genco.....................	Texas Genco Holdings, Inc., a subsidiary of CenterPoint, and its subsidiaries.

Transition Plan................	Reliant Resources Transition Stock Plan, governing CenterPoint a held by our employees.
West Connect RTO................	the FERC approved RTO for all or part of Colorado, Arizona, New Mexico and a portion of Texas.

PART I

ITEM 1. Business.

Our Business

General

Our business operations consist of the following four business segments:

- Retail energy--provides electricity and related services to retail customers primarily in Texas and acquires and manages the electric energy, capacity and ancillary services associated with supplying these retail customers;
- Wholesale energy--provides electric energy and energy services in the competitive segments of the United States wholesale energy markets;
- European energy--includes power generation assets in the Netherlands and a related trading and origination business; and
- Other operations--includes our venture capital investment portfolio and unallocated corporate costs.

For information about the revenues, operating income, assets and other financial information relating to our business segments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations--Earnings Before Interest and Income Taxes by Segment" in Item 7 of this Form 10-K/A and note 20 to our consolidated financial statements. For information about the risks and uncertainties relating to our business, see "Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Factors" in Item 7 of this Form 10-K/A.

Our website address is www.reliant.com. The information on our website is not incorporated into this Form 10-K/A. A copy of this Form 10-K/A will be available on our website. You may request a copy of this Form 10-K/A, at no cost, by writing or telephoning us at 713-497-7000. Our executive offices are located at 1111 Louisiana Street, Houston, Texas 77002.

Formation, IPO and Distribution

In June 1999, the Texas legislature adopted an electric restructuring law that amended the regulatory structure governing electric utilities in Texas in order to allow retail electric competition with respect to all customer classes beginning in January 2002. In response to this legislation, CenterPoint, formerly Reliant Energy, adopted a business separation plan in order to separate its regulated and unregulated operations. Under the business separation plan, we were incorporated in Delaware in August 2000, and CenterPoint transferred substantially all of its unregulated businesses to us. We completed an IPO of approximately 20% of our common stock in May 2001 and received net proceeds from our IPO of $1.7 billion. We used $147 million of the net proceeds of our IPO to repay certain indebtedness that we owed to

CenterPoint. We used the remainder of the net proceeds of our IPO for repayment of third party borrowings, capital expenditures, repurchases of our common stock and general corporate purposes. In September 2002, the Distribution was completed and, as a result, we are no longer a subsidiary of CenterPoint. For additional information regarding our IPO, see notes 1 and 10(a) to our consolidated financial statements. For additional information regarding agreements and transactions between us and CenterPoint, see "Management's Discussion and Analysis of Financial Condition and Results of Operations --Related-Party Transactions" in Item 7 of this Form 10-K/A and notes 3 and 4 to our consolidated financial statements.

Orion Power Acquisition

In February 2002, we acquired all of the outstanding common stock of Orion Power for $2.9 billion and assumed debt obligations of $2.4 billion. Orion Power is an independent electric power generating company with

a diversified portfolio of generating assets, both geographically across the states of New York, Pennsylvania, Ohio and West Virginia, and by fuel type, including gas, oil, coal and hydro. The Orion Power facilities constitute our New York regional portfolio and the majority of our Midwest regional portfolio. For additional information regarding our acquisition of Orion Power and its operations, see "--Wholesale Energy--New York Region" and "--Midwest Region," in Item 1 and "Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Factors" in Item 7 of this Form 10-K/A and note 5(a) to our consolidated financial statements.

Disposition of European Energy Operations

In February 2003, we signed a share purchase agreement to sell our European energy operations to Nuon. Upon consummation of the sale, we expect to receive cash proceeds from the sale of approximately $1.2 billion (Euro 1.1 billion). As additional consideration for the sale, we will also receive 90% of the dividends and other distributions in excess of approximately $115 million (Euro 110 million) paid by NEA to REPGB following the consummation of the sale. The purchase price payable at closing assumes that our European energy operations will have, on the sale consummation date, net cash of at least $121 million (Euro 115 million). If the amount of net cash is less on such date, the purchase price will be reduced accordingly. The sale is subject to the approval of the Dutch and German competition authorities. We anticipate that the consummation of sale will occur in the summer of 2003. For further information regarding the disposition of our European energy operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Factors" in Item 7 of the Form 10-K/A and note 21(b) to our consolidated financial statements.

Retail Energy

We are a certified retail electric provider in Texas, which allows us to provide electricity to residential, small commercial and large commercial, industrial and institutional customers. In January 2002, we began to provide retail electric service to all customers of CenterPoint that did not take action to select another retail electric provider and to customers that selected us to provide them electric service. All classes of customers of most investor-owned Texas utilities can choose their retail electric provider. The law also allows municipal utilities and electric cooperatives to participate in the competitive marketplace, but to date, none have chosen to do so.

Our retail energy segment provides standardized electricity and related products and services to residential and small commercial customers with an aggregate peak demand for power up to one MW (i.e., small and mid-sized business customers) and offers customized electric commodity and energy management services to large commercial, industrial and institutional customers with an aggregate peak demand for power in excess of one MW (e.g., refineries, chemical plants, manufacturing facilities, real estate management firms, hospitals, universities, school systems, governmental agencies, multi-site retailers, restaurants, and other facilities under common ownership or franchise arrangements with a single franchiser, which aggregate to one MW or greater of peak demand).

We currently provide retail electric service only in Texas. We have no near-term plans to provide retail electric service to residential customers outside of Texas; however, we are taking steps to provide electricity and related products and services to large commercial, industrial and institutional customers in certain other states. In New Jersey, we are registered as an "electric power supplier," and in Pennsylvania, we are registered as an "electric generation supplier."

For information about the risks and uncertainties relating to our retail energy segment, see "Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Factors--Risks Related to Our Retail Energy Operations" in Item 7 of this Form 10-K/A.

Residential and Small Commercial Services

We have approximately 1.5 million residential customers and over 200,000 small commercial accounts in Texas, making us the second largest retail electric provider in Texas. The majority of our customers are in the Houston metropolitan area, but we also have customers in other metropolitan areas, including Dallas and Corpus Christi, Texas.

In general, the Texas regulatory structure permits retail electric providers to procure electricity from wholesale generators at unregulated rates, sell the electricity at generally unregulated prices to retail customers and pay the local transmission and distribution utilities a regulated tariff rate for delivering the electricity to the customers. By allowing retail electric providers to provide retail electricity at any price, the Texas electric restructuring law is designed to encourage competition among retail electric providers. However, retail electric providers which are affiliates of, or successors in interest to, electric utilities are restricted in the prices they may charge to residential and small commercial customers within the affiliated transmission and distribution utility's traditional service territory. We are deemed to be the affiliated retail electric provider in Centerpoint's Houston area service territory, and we are an unaffiliated retail electric provider in all other areas. The prices that affiliated retail electric providers charge are subject to a specified price, or "price to beat" and the affiliated retail electric providers are not permitted to sell electricity to residential and small commercial customers in the service territory of the affiliated transmission and distribution utility at a price other than the price to beat until January 2005, unless before that date 40% or more electricity consumed in 2000 by the relevant class of customers in the affiliated transmission and distribution utility service territory is committed to be served by other retail electric providers. Unaffiliated retail electric providers may sell electricity to residential and small commercial customers at any price.

In addition, the Texas electric restructuring law requires the affiliated retail electric provider to make the price to beat available to residential and small commercial customers in the affiliated transmission and distribution utility's traditional service territory until January 1, 2007. The price to beat only applies to electric services provided to residential and small commercial customers (i.e., customers with an aggregate peak demand at or below one MW).

The PUCT's regulations allow an affiliated retail electric provider to adjust the price to beat based on the wholesale energy supply cost component or "fuel factor" included in its price to beat. The PUCT's current regulations allow us to request an adjustment of our fuel factor based on the percentage change in the forward price of natural gas or as a result of changes in the price of purchased energy up to two times a year. In a purchased energy request, we may adjust the fuel factor to the extent necessary to restore the amount of headroom that existed at the time the initial price to beat fuel factor was set by the PUCT. During 2002, we requested, and the PUCT approved two such adjustments to our price to beat fuel factor. In January 2003, we requested, and the PUCT approved in March 2003, an increase of our price to beat fuel factor. We cannot estimate with any certainty the magnitude and timing of future adjustments required, if any, or the impact of such adjustments on our headroom. To the extent that a requested adjustment is not received on a timely basis, our results of operations, financial condition and cash flows may be adversely affected. For additional information regarding adjustments to our price to beat fuel factor, see "Management's Discussion and Analysis of Financial Condition and Results of Operations--EBIT by Business Segment" in Item 7 of this Form 10-K/A.

In March 2003, the PUCT approved a revised price to beat rule. The changes from the previous rule include an increase in the number of days used to calculate the natural gas price average from ten to 20, and an increase in the threshold of what constitutes a significant change in the market price of natural gas and purchased energy from 4% to 5%, except for filings made after November 15/th/ of a given year that must meet a 10% threshold. The revised rule also provides that the PUCT will, after reaching a determination of stranded costs in 2004, make downward adjustments to the price to beat fuel factor if natural gas prices drop below the prices embedded in the then-current price to beat fuel factor. In addition, the revised rule also specifies that the base rate portion of the price to beat will be adjusted to account for changes in the non-bypassable rates that result from the utilities' final stranded cost determination in 2004. Adjustments to the price to beat will be made following the utilities' final stranded cost determination in 2004.

To the extent that our price to beat for electric service to residential and small commercial customers in CenterPoint's Houston service territory during 2002 and 2003 exceeds the market price of electricity, we may be required to make a significant payment to CenterPoint in 2004. As of December 31, 2002, our estimate for the payment related to residential customers is between $160 million and $190 million, with a most probable estimate of $175 million. For additional information regarding this payment, see note 14(e) to our consolidated financial statements.

Large Commercial, Industrial and Institutional Services

We provide electricity and energy services to large commercial, industrial and institutional customers (i.e., customers with an aggregate peak demand of greater than one MW) in Texas with whom we have signed contracts. As of December 31, 2002, the average contract term for these contracts was 15 months. In addition, we provide electricity to those large commercial, industrial and institutional customers in CenterPoint's service territory who have not entered into a contract with any retail electric provider. We also provide customized energy solutions, including risk management and energy services products, and demand side and energy information services to our large commercial, industrial and institutional customers.

Our large commercial, industrial and institutional customers include refineries, chemical plants, manufacturing facilities, real estate management firms, hospitals, universities, school systems, governmental agencies, multi-site retailers, restaurants, and other facilities under common ownership or franchise arrangements with a single franchiser, which aggregate to one MW or greater of peak demand. Excluding those parts of Texas not currently open to competition, the large commercial, industrial and institutional segment in Texas consists of approximately 2,700 buying organizations consuming an estimated aggregate of approximately 17,000 MW of electricity at peak demand. Our contracts with customers represent a peak demand of approximately 5,500 MW at approximately 24,000 metered locations.

Provider of Last Resort

In Texas, a provider of last resort is required to offer a standard retail electric service with no interruption of service, except in the event of non-payment, to any customer requesting electric service, to any customer whose certified retail electric provider has failed to provide electric service or to any customer that voluntarily requests this type of service. Through a competitive bid process administered by the PUCT, we were appointed to serve as the provider of last resort in many regions of the state. We do not expect to serve a large number of customers in this capacity, as many customers are expected to subsequently select a retail electric provider. We will serve a two-year term as the provider of last resort ending December 31, 2004. Pricing for service provided by a provider of last resort may include a customer charge and an energy charge, which for residential and small commercial customers is adjustable based upon changes in the forward price of natural gas. For large non-residential customers, the energy charge is adjusted based upon the ERCOT market-clearing price of energy. For all customer classes, the adjustment to the energy charge is subject to a floor amount. Non-residential customers will be assessed a demand charge.

Retail Energy Supply

We continuously monitor and update our retail energy supply positions based on our retail energy demand forecasts and market conditions. We enter into bilateral contracts with third parties for electric energy, capacity and ancillary services.

Texas Genco (currently 81% owned by CenterPoint), which owns approximately 13,900 MW of aggregate net generation capacity in Texas, is our primary source of retail energy capacity.

The generating capacity of the Texas Genco facilities consists of approximately 60% of base-load, 35% of intermediate and 5% of peaking capacity, and represents approximately 20% of the total capacity in ERCOT. To

facilitate a competitive market in Texas, each power generator affiliated with a transmission and distribution utility must sell at auction 15% of the output of its installed generating capacity. These auction obligations will continue until January 2007, unless at least 40% of the electricity consumed by residential and small commercial customers in CenterPoint's service territory is being served by retail electric providers other than us. An affiliated retail electric provider may not purchase capacity sold by its affiliated power generation company in the state mandated capacity auctions. Therefore, we are prohibited from participating in the Texas Genco capacity auctions mandated by the PUCT. We may purchase capacity from non-affiliated parties, other than Texas Genco, in the capacity auctions mandated by the PUCT. Under an agreement between us and CenterPoint, Texas Genco is required to auction the remaining 85% of its capacity. We have the right to purchase 50% (but not less than 50%) of such remaining capacity at the prices established in such auctions. We also have the right to participate directly in such auctions.

We have an option to acquire CenterPoint's ownership interest in Texas Genco that is exercisable from January 10, 2004 until January 24, 2004. Texas Genco's obligation to auction its capacity and our associated rights terminate (a) if we do not exercise our option to acquire CenterPoint's ownership interest in Texas Genco by January 24, 2004 and (b) if we exercise our option to acquire CenterPoint's ownership interest in Texas Genco, on the earlier of (i) the closing of the acquisition or (ii) if the closing has not occurred, the last day of the sixteenth month after the month in which the option is exercised. For additional information regarding our option to acquire Texas Genco, see note 4(b) to our consolidated financial statements.

ERCOT

We are a member of ERCOT. The ERCOT ISO is responsible for maintaining reliable operations of the bulk electric power supply system in the ERCOT Region. Its responsibilities include ensuring that information relating to a customer's choice of retail electric provider is conveyed in a timely manner to anyone needing the information. It is also responsible for ensuring that electricity production and delivery are accurately accounted for among the generation resources and wholesale buyers and sellers in the ERCOT Region. Unlike some independent system operators in other regions of the country, the ERCOT ISO does not operate a centrally dispatched pool and does not procure energy on behalf of its members other than to maintain the reliable operation of the transmission system. Members are responsible for contracting their energy requirements bilaterally. The ERCOT ISO also serves as agent for procuring ancillary services for those who elect not to secure their own ancillary services requirement.

Members of ERCOT include retail customers, investor and municipal owned electric utilities, rural electric cooperatives, river authorities, independent generators, power marketers and retail electric providers. The ERCOT Region operates under the reliability standards set by the North American Electric Reliability Council. The PUCT has primary jurisdictional authority over the ERCOT Region to ensure the adequacy and reliability of electricity across the state's main interconnected power grid.

The ERCOT Region is divided into four congestion zones: north, south, west and Houston. While most of our retail demand and associated supply is located in the Houston congestion zone, we serve customers and acquire supply in all four congestion zones. In addition, ERCOT conducts annual and monthly auctions of transmission congestion rights which provide the entity owning transmission congestion rights the ability to financially hedge price differences between zones (basis risk). The PUCT prohibits any single ERCOT market participant from owning more than 25% of the available transmission congestion rights on any congestion path.

For information regarding our generating facilities in the ERCOT Region, see "Our Business--Wholesale Energy--ERCOT Region."

Competition

For information regarding competitive factors affecting our retail energy segment, see "Management's Discussion and Analysis of Financial Condition and Results of Operations - Risk Factors - Risks Related to Our Retail Energy Operations" in Item 7 of this Form 10-K/A.

Wholesale Energy

Our wholesale energy segment provides energy and energy services with a focus on the competitive wholesale segment of the United States energy industry. We have built a portfolio of electric power generation facilities, through a combination of acquisitions and development, that are not subject to traditional cost-based regulation; therefore, we can generally sell electricity at prices determined by the market, subject to regulatory limitations. We trade and market electricity, natural gas, natural gas transportation capacity and other energy-related commodities. We also optimize our physical assets and provide risk management services for our asset portfolio. In March 2003, we decided to exit our proprietary trading activities and liquidate, to the extent practicable, our proprietary positions. Although we are exiting the proprietary trading business, we have existing positions, which will be closed as economically feasible or in accordance with their terms. We will continue to engage in hedging activities related to our electric generating facilities, pipeline storage positions and fuel positions. For information about the risks and uncertainties relating to our wholesale energy segment, see "Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Factors--Risks Related to Our Wholesale Energy Operations " in Item 7 of this Form 10-K/A.

Overview of Wholesale Energy Market

Over the past two years, the wholesale energy markets in the United States have undergone dramatic changes. In late 2000 into early 2001, power markets across most of the United States were trading at historical highs due in large part to tight wholesale power market conditions, gas prices being at record levels because of falling supplies and strong demand from a growing economy, gas trading volumes continuing their rapid growth, and power trading and generation companies having substantial access to the debt and equity markets. However, during the summer of 2001, market conditions began to take a downward turn when the first significant wave of nearly 200,000 MW of new generating capacity commenced operations and began to ease the tight wholesale power market conditions. Also, state regulators, in concert with the FERC, began to impose price caps and other marketplace rules that resulted in power and ancillary service prices in certain markets being at or near the variable cost to provide them. Energy trading activity also saw a sharp reversal during 2001. The failure of certain energy companies damaged the reputation of the entire industry and energy trading specifically. The heightened attention on energy trading businesses and the subsequent findings and allegations of questionable business practices and transactions engaged in by a number of industry participants, including us, caused a further erosion of confidence in the industry. As a result, liquidity in the market began to decline.

The overall market conditions in the wholesale power industry continued to worsen during 2002. With the addition of still more generation capacity and heightened regulatory oversight, power prices continued their downward trend, trading at or barely above the variable cost of production in many markets. Confronted with a weaker profit outlook in both electric generation and energy trading and significant amounts of short-term debt to be refinanced, credit agencies began a series of downgrades of substantially all the industry's major market participants, leaving many with below investment grade credit ratings.

These downgrades severely curtailed the access of these companies to the debt or equity markets and triggered credit collateral requirements relating to their trading and hedging activities. Consequently, many companies were forced to significantly reduce their trading activities, which further reduced market liquidity.

During the second half of 2002 and continuing into 2003, investors and government regulators, as well as many industry participants and independent observers urged industry reforms to provide more balanced and sustainable long-term market conditions in both the power markets and the energy trading markets. The most significant of these are the FERC's efforts to implement SMD and industry efforts to develop clearing and settlement provisions at energy exchanges that would greatly reduce collateral requirements of participating companies.

Power Generation Operations

We own, own an interest in, or lease 128 operating electric power generation facilities with an aggregate net generating capacity of 19,888 MW located in six regions of the United States. The generating capacity of these

10

facilities consists of approximately 34% of base-load, 35% of intermediate and 31% of peaking capacity. We have two electric power generation facilities and three replacement or incremental electric power generation units at existing facilities, or 2,461 MW of net generating capacity, under construction.

The following table describes our electric power generation facilities and net generating capacity by region:

Region	Number of Generation Facilities (1)	Total Net Generating Capacity (MW) (2)	Dispatch Type (3)	
Mid-Atlantic				
Operating (4)..................	22	4,227	Base, Intermediate, Peak	Gas/
Under Construction (6)(7)(8)(9).	--	1,120	Base, Intermediate, Peak	Gas/
Combined.......................	22	5,347		
New York				
Operating (5)..................	77	2,952	Base, Intermediate, Peak	Gas/
Midwest				
Operating......................	10	5,052	Base, Intermediate, Peak	Gas/
Southeast				
Operating (10)(11).............	5	2,210	Base, Intermediate, Peak	Gas/
Under Construction (6)(7).......	1	800	Intermediate, Peak	Gas
Combined.......................	6	3,010		
West				
Operating (12)(13).............	7	4,642	Base, Intermediate, Peak	Gas/
Under Construction (6)..........	1	541	Base, Intermediate, Peak	Gas
Combined.......................	8	5,183		
ERCOT				
Operating......................	7	805	Base	Gas/
Total				

Operating	128	19,888
Under Construction	2	2,461
Combined	130	22,349

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(1) Unless otherwise indicated, we own a 100% interest in each facility listed.
(2) Average summer and winter net generating capacity.
(3) We use the designations "Base," "Intermediate," and "Peak" to indicate whether the facilities described are base-load, intermediate, or peaking facilities, respectively.
(4) We lease a 100%, 16.67% and 16.45% interest in three Pennsylvania facilities having 614 MW, 284 MW and 282 MW of net generating capacity, respectively, through facility lease agreements having terms of 26.5 years, 33.75 years and 33.75 years, respectively.
(5) Excludes two hydro plants with a net generating capacity of 5 MW, which are not currently operational.
(6) We consider a project to be "under construction" once we have acquired the necessary permits to begin construction, broken ground on the project site and contracted to purchase machinery for the project, including the combustion turbines.
(7) Our two construction projects in the Mid-Atlantic region and one of our projects in the Southeast region are owned by off-balance sheet special purpose entities as of December 31, 2002 and are being constructed under construction agency agreements (see note 14(b) to our consolidated financial statements).
(8) The 1,120 MW of net generating capacity under construction is based on 1,317 MW of net generating capacity currently under construction, less 197 MW of net generating capacity that will be retired upon completion of one of the projects.
(9) Our two construction projects in the Mid-Atlantic region are replacement or incremental electric power generation units at existing facilities. These units are reflected in the operating generation facilities count, but the net generating capacity of such units will be reflected in the under construction count until the units begin commercial operation.
(10) We own a 50% interest in one of these facilities having a net generating capacity of 108 MW. An independent third party owns the other 50%.
(11) We lease a 100% interest in two Florida facilities having 630 MW and 474 MW of net generating capacity, respectively, through facility lease agreements having terms of 10 years and 5 years, respectively.
(12) Beginning in January 2003, two California generation units having 264 MW of total net generating capacity were idled due to a lack of required environmental permits.
(13) We own a 50% interest in one Nevada facility having a total generating capacity of 470 MW. An independent third party owns the other 50%.

Mid-Atlantic Region

Facilities. We own, own an interest in, or lease 22 operating electric power generation facilities with an aggregate net generating capacity of 4,227 MW located in Pennsylvania, New Jersey and Maryland. The generating capacity of these facilities consists of approximately 38% of base-load, 32% of intermediate and 30% of peaking capacity.

We are constructing a 795 MW gas-fired intermediate and peaking generation unit at an existing facility located in Pennsylvania. We expect this unit will begin commercial operation in the third quarter of 2003. We are also constructing a 522 MW coal-fired base-load unit that will replace two of our generating units at an existing facility located in Pennsylvania. This new unit will add 325 MW of additional generating capacity, net of the 197 MW of generating capacity of the existing units that will be retired upon commencement of commercial operations of the new unit. We expect this unit will begin commercial operation near the end of 2004. These units are being constructed under the terms of a construction agency agreement. For additional information regarding the construction agency agreements, see notes 2(t), 14(b) and 21(a) to our consolidated financial statements. Because of lower price conditions in the PJM Market and the rising cost of operations, particularly with respect to emission costs, we retired an 82 MW coal-fired facility located in our Mid-Atlantic region in September 2002.

Market Framework. We currently sell the power generated by our Mid-Atlantic facilities in the PJM Market and occasionally to buyers in adjacent power markets, such as the ECAR Market and NY Market. We also expect to sell power in a newly created PJM West Market. Each of the PJM, the NY and the PJM West Markets operates as centralized power pools with open-access, non-discriminatory transmission systems. The PJM and PJM West Markets are administered by PJM, a FERC-approved RTO.

Although the transmission infrastructure within these markets is generally well developed and independently operated, transmission constraints exist between, and to a certain extent within, these markets. In particular, transmission of power from western Pennsylvania and upstate New York to eastern Pennsylvania, New Jersey and New York City may be constrained. Depending on the timing and nature of transmission constraints, market prices may vary from market to market, or between sub-regions of a particular market. Market prices are generally higher in New York City than in other parts of New York due to the transmission constraints.

In addition to managing the transmission system, PJM is responsible for maintaining competitive wholesale markets, operating the spot wholesale electric energy, capacity and ancillary services markets and determining the market clearing price based on bids submitted by participating generators in each market. PJM generally matches sellers with buyers within a particular market that meet specified minimum credit standards. We sell electric energy, capacity and ancillary services into the markets maintained by PJM on both a real-time basis and a forward basis for periods of up to one year. Our customers consist of the members of each market, including municipalities, electric cooperatives, integrated utilities, transmission and distribution utilities, retail electric providers and power marketers. We also sell electric energy, capacity and ancillary services to customers in our Mid-Atlantic region under negotiated bilateral contracts.

PJM has an internal market monitor. The internal market monitor reports on issues relating to the operation of the PJM Market, including the determination of transmission congestion costs or the potential of any market participation to exercise market power within the PJM Market or PJM West Market. The internal market monitor evaluates the operation of both spot and bilateral markets to detect either design or structural flaws in the PJM Market and evaluates any proposed enforcement mechanisms that are necessary to assure compliance with the PJM Protocols.

The PJM Protocols allow energy demand to respond to price changes. The lack of sufficient energy demand that may respond has been cited as the primary reason for retaining the electric energy, capacity and ancillary service market caps, which are currently set at $1,000 per MWh in the PJM Market and the energy price mitigation measures in the PJM Market.

Energy market price mitigation measures are implemented for some generating facilities when, in the opinion of PJM, transmission constraints are present. This is commonly referred to as price capping. In such instances, PJM requires, for purposes of system reliability, the dispatch of specific units. In the opinion of PJM, these units are not needed to meet energy demand and are only necessary to maintain the stability of the PJM transmission system. When price capping is imposed, the asking price submitted by these generating facilities is disregarded in setting the PJM market price and the subject units receive a mitigated price that is generally equal to incremental operating costs of the generating unit plus 10%. Historically, 11 generating facilities, representing over 250 MW, in our Mid-Atlantic region have been consistently impacted by this procedure. In addition, a few other generating facilities in our Mid-Atlantic region have experienced occasional price capping during selective hours.

PJM attempts to ensure that there is sufficient generation capacity to meet energy demand and ancillary services requirements through a capacity market. All power retailers are required to demonstrate commitments for capacity sufficient to meet their peak forecasted load plus a reserve above this level, currently set at 18%. Prices for capacity are capped by PJM at approximately $175 per MW per day.

New York Region

Facilities. We own 77 operating electric power generation facilities with an aggregate net generating capacity of 2,952 MW located in New York. Our generating facilities in the New York region consist of two distinct groups, intermediate and peaking facilities located in New York City and, with the exception of one gas-fired facility, 73 small run-of-river hydro facilities located in central and northern New York State. The overall generating capacity of these facilities consists of approximately 23% of base-load, 41% of intermediate and 36% of peaking capacity. With the exception of one facility, all of our New York facilities were acquired as a result of utility divestitures.

Market Framework. We currently sell the power generated by our New York regional facilities in the NY Market. In New York City, we sell electric energy and ancillary services into both day-ahead and real-time markets and capacity in the monthly and six month forward markets. Our customers include municipalities, electric cooperatives, integrated utilities, transmission and distribution utilities, retail electric providers and power marketers. Our hydro facilities are currently under contract to sell all electric energy, capacity and ancillary services to Niagara Mohawk under contract through September 2004.

Our sales into markets administered by NYISO are governed by the NYISO Protocols. The NYISO Protocols allow energy demand to respond to high prices in emergency and non-emergency situations. The lack of sufficient energy demand that may respond to prices has been cited as one of the primary reasons for retaining wholesale energy bid caps, which are currently set at $1,000 per MWh in the NY Market.

The NYISO Protocols established a capacity market in order to ensure that there is enough generation capacity to meet retail energy demand and ancillary services requirements. All power retailers are required to demonstrate commitments for capacity sufficient to meet their peak forecasted load plus a reserve requirement, currently set at 18%. As an additional local reliability measure, power retailers located in New York City are required to procure the majority of this capacity, currently 80% of their peak forecasted load, from generating units located in New York City. Because only a few suppliers own the existing in-city capacity, previously divested utility generation is subject to a capacity price cap. Any generation capacity added following divestiture is not subject to a capacity price cap.

NYISO has implemented a measure known as the "automated mitigation procedure" under which day-ahead energy bids will be automatically reviewed. If bids exceed certain pre-established thresholds and have a significant impact on the market-clearing price, the bids are then reduced to a pre-established market based or negotiated reference bid. NYISO has also adopted, at the FERC's direction, more stringent mitigation measures for all generating facilities in transmission-constrained New York City.

NYISO has an internal market monitoring organization. The market monitor assesses the efficiency and effectiveness of the electric energy, capacity and ancillary services. In performing these functions, the internal market monitor develops reference price levels for each generator, oversees the operation of NYISO's automatic mitigation procedure, investigates potential anti-competitive behavior by market participants, recommends changes in market Protocols and prepares periodic reports for submission to the FERC and other agencies. In addition, NYISO also has an external market advisor that works closely with the market monitor and has the independent authority to suggest changes in Protocols or recommend sanctions or penalties directly to the NYISO governing board. The NYISO market advisor issues written reports containing analyses and recommendations, which are made available to the public.

For additional information on the NY Market, see "Business--Mid-Atlantic Region--Market Framework" in Item 1 of this Form 10-K/A.

Midwest Region

Facilities. We own 10 operating electric power generation facilities with an aggregate net generating capacity of 5,052 MW located in Illinois, Ohio, Pennsylvania and West Virginia. The generating capacity of these facilities consists of approximately 57% of base-load, 6% of intermediate and 37% of peaking capacity.

Market Framework. We generally sell the electric energy, capacity and ancillary services generated and/or provided by our Midwest region portfolio into the PJM West Market, the ECAR Market and the MAIN Market. These markets include all or portions of Illinois, Wisconsin, Missouri, Indiana, Ohio, Michigan, Virginia, West Virginia, Tennessee, Maryland and Pennsylvania. The PJM West Market operates as part of the PJM centralized power pool with open-access, non-discriminatory transmission system administered by an independent system operator approved by the FERC that is responsible for, among other things, maintaining competitive wholesale markets, operating the spot wholesale energy market and determining the market clearing price. For additional information on the PJM Market and the PJM West Market, see "Business--Mid-Atlantic Region--Market Framework" in Item 1 of this Form 10-K/A.

The ECAR and MAIN Markets continue to be in a state of transition and are in the process of establishing RTOs that would define the rules and requirements around which competitive wholesale markets in the region would develop. The FERC has granted RTO status to the MISO, which administers a substantial portion of the transmission facilities in the Midwest region. The FERC has also approved the various RTO selections made by the members of the former Alliance RTO. Some of the members of this group will join the MISO and others will join PJM. The final market structure for the Midwest region remains unsettled. Some states within the ECAR and MAIN Markets have restructured their retail electric power markets to competitive markets from traditional utility monopoly markets, while others have not.

The FERC has also required MISO to engage the services of an independent market monitor. The independent market monitor's duties include monitoring the functioning of the markets run by the MISO to ensure that they are functioning efficiently. This includes identifying factors that might contribute to economic inefficiency such as design flaws, inefficient market rules and barriers to entry. The independent market monitor must also monitor the conduct of individual market participants. MISO is currently waiting on approval by the FERC for a market mitigation plan that resembles the automated mitigation procedure utilized by NYISO.

Our generating facilities located in Pennsylvania, Ohio, and West Virginia straddle the PJM West and other ECAR Markets. Currently, these generating facilities are primarily dedicated to serving the power demands of Duquesne Lighting Company in the greater Pittsburgh area under a contract through December 2004. During periods when the capacity of the generating facilities in our Midwest region exceeds the power demands of the Duquesne Lighting Company, we sell the excess power in the day-ahead markets or to municipalities, electric cooperatives, vertically integrated utilities, transmission and distribution utilities and power marketers.

We currently sell electric energy, capacity and ancillary services from our Illinois generating facilities under bilateral contracts that have terms and conditions tailored to meet the customers' requirements. Our customers include municipalities, electric cooperatives, vertically integrated utilities, transmission and distribution utilities and power marketers.

Southeast Region

Facilities. We own, own an interest in, or lease five power generation facilities with an aggregate net generating capacity of 2,210 MW located in Florida and Texas. The generating capacity of these facilities consists of approximately 2% of base-load, 27% of intermediate and 71% of peaking capacity.

We are constructing an 800 MW gas-fired intermediate and peaking facility in Mississippi. We expect this facility will begin commercial operation in the third quarter of 2003. This facility is being constructed under the terms of a construction agency agreement. For additional information regarding the construction agency agreement, see note 14(b) to our consolidated financial statements.

Market Framework. We currently conduct the majority of our Southeast regional operations in Florida. Florida, other than a portion of the western panhandle, constitutes a single reliability council and contains approximately 5% of the United States population. Although dominated by incumbent utilities, Florida is in the process of transitioning to a competitive wholesale generation market by developing rules for new capacity procurement and establishing the GridFlorida RTO. The FPSC has implemented new capacity procurement rules that require utilities to seek bids to purchase electricity from independent power producers and other utilities before embarking on self-build options for new capacity requirements. Additionally, the FPSC has approved a proposal to increase the level of planning reserve capacity from 15% to 20%. This new criterion applies to the three investor-owned utilities operating in peninsular Florida and becomes effective in the summer of 2004.

The Florida markets are expected to be administered by the GridFlorida RTO. For the past year, the Grid Florida RTO's activities have focused on concerns expressed by the FPSC. However, recent progress has been slow due to a legal challenge by the state's consumer advocate division, which is disputing the FPSC's authority to authorize the transfer of assets to an RTO. A decision on this matter may not be reached until early 2004. At this time, the GridFlorida RTO has not finalized its proposal for market monitoring, but it will be obligated to establish a market monitor.

We currently sell electric energy and capacity into the Florida market primarily under bilateral contracts that are non-standard and negotiated for terms and conditions. An OTC trading and ancillary services market has yet to fully develop. Customers who participate in power transactions in this region include municipalities, electric cooperatives and integrated utilities.

In the rest of the Southeast Region, RTO formation is occurring under the auspices of the SeTrans RTO. The SeTrans RTO will cover the area from Georgia to eastern Texas. While the FERC has currently approved the basic formation of this entity, significant details of this market will not be known until mid or late 2003. Because the SeTrans RTO is still in the formative stages of development, it has only recently begun the process of selecting the independent entity that will become its market monitor.

West Region

Facilities. We own, or own an interest in, seven electric power generation facilities with an aggregate net generating capacity of 4,642 MW located in California, Nevada and Arizona. The generating capacity of these facilities consists of approximately 18% of base-load, 75% of intermediate and 7% of peaking capacity. We are constructing a 541 MW gas-fired, base-load, intermediate and peaking generation facility in southern Nevada. We expect this facility will begin commercial operation in the fourth quarter of 2003.

15

Market Framework. Our West regional market includes the states of Arizona, California, Oregon, Nevada, New Mexico, Utah and Washington. Generally we sell the electric energy, capacity and ancillary services generated and/or provided by our California and Nevada facilities to customers located in the greater Los Angeles metropolitan area and in southern Nevada. We believe that our portfolio of intermediate and peaking facilities in southern California is important to the reliability of the California market given its production flexibility and close proximity to Los Angeles. Our customers in these states include power marketers, investor-owned utilities, electric cooperatives, municipal utilities and the Cal ISO acting on behalf of load-serving entities. We sell electric energy, capacity and ancillary services to these customers through a combination of bilateral contracts and sales made in the Cal ISO's day-ahead and hour-ahead ancillary services markets and its real-time energy market. The Cal ISO does not currently maintain a capacity market to ensure resource adequacy; however, California regulatory authorities are in the process of developing such a mechanism.

We have agreed to sell up to 100% of our 588 MW operating Arizona facility's capacity to SRP under a long-term power purchase agreement. In addition, although we do not own generation facilities in the states of Oregon, New Mexico, Utah and Washington, our trading and marketing operations have historically purchased and delivered energy commodities in these states.

Two units at our Etiwanda facility in California totaling 264 MW of intermediate capacity, under their current configuration, do not satisfy the more stringent emissions standards that went into effect in 2003. We will evaluate the California capacity market in the second quarter of 2003 and determine whether to make the investment in the necessary environmental upgrades or retire the units.

In response to California's energy crisis of 2000 and 2001, the FERC and the Cal ISO have instituted energy price caps, formerly set below $100 per MWh and currently set at $250 per MWh, and must-offer requirements affecting all merchant generators in California. Furthermore, the Western region has seen significant new generation capacity become operational as well as a return to more normal hydro and temperature conditions. The impact of these regulatory and market changes has been to significantly lower power prices and spark spreads in the West region.

The Cal ISO has a department of market analysis that acts as its internal market monitor. The department of market analysis monitors the efficiency and effectiveness of the ancillary services, congestion management and real-time energy markets. In performing these functions, the department of market analysis develops and publishes market performance indices, investigates potential anti-competitive behavior by market participants, recommends changes in market rules and protocols, and prepares periodic reports for submission to the FERC and other agencies. In addition to the department of market analysis, the Cal ISO also has a market surveillance committee that acts as its external advisor. The market surveillance committee works closely with the department of market analysis and has the independent authority to suggest changes in Cal ISO Protocols or recommend sanctions or penalties directly to the Cal ISO governing board. The market surveillance committee periodically produces written reports containing its analyses and recommendations, which are made available to the public subject to restrictions on confidential information. The Cal ISO has initiated, at the FERC's direction, automated mitigation procedures when any zonal clearing price for balancing energy exceeds $91.87 per MWh with any resulting zonal clearing price subject to the price cap of $250 per MWh. The automated mitigation procedures are only applied to bids that exceed certain reference prices and that would significantly increase the market price. However, in February 2003, the Cal ISO stated that it intends to appeal the FERC's decision regarding the application of automated mitigation procedures to local market power situations. While the FERC had adopted similar thresholds for both local and system market power, the Cal ISO is seeking to have a more restrictive procedure applied to local market power.

16

A number of initiatives currently under consideration could materially impact our California operations. These initiatives include:

- a California law directing the CPUC to seek approval from the FERC to allow the CPUC to enforce state-established maintenance and operation standards of our California plants;

- implementation of a CPUC procurement process directing California utilities to procure, on a forward basis, electricity and capacity to serve the demand on their systems;

- efforts by the Cal ISO to redesign the spot markets in California; and

- the effect of the FERC's SMD effort, including its impact on the FERC approved western RTOs.

For additional information regarding SMD, see "Business--Wholesale Energy--Regulatory" in Item 1 of this Form 10-K/A.

In Nevada and Arizona, there is presently no RTO in place to manage the transmission systems or to operate energy markets, although the utilities in both states are participating in the development of RTOs. The West Connect RTO, which includes Arizona, and the RTO West, which includes Nevada, have both been approved by the FERC and are in process of developing operating rules and tariffs. Both RTOs are expected to be operational and assume control over transmission of facilities of participating utilities within the next several years. The FERC has also approved the establishment of market monitoring organizations as part of RTO West and West Connect RTO. The FERC is encouraging the RTOs to coordinate in the development of a region-wide market monitoring function. Additionally, in Nevada and Arizona, state-level regulatory initiatives may impact competition in the electric sector. In Nevada, the state legislature has passed legislation prohibiting the state's investor-owned utilities from divesting generation. Nevada also passed legislation and adopted regulations allowing large commercial and industrial customers to seek competitive alternatives to utility generation. In Arizona, proceedings are pending before the Arizona Corporate Commission that would require the state's investor owned utilities to seek competitive supply offers to serve 2,500 to 3,200 MW of local system demand.

ERCOT Region

Facilities. We own seven power generation units at two facilities with an aggregate net generating capacity of 805 MW located in Texas. The generating capacity of these facilities consists of 100% base-load capacity.

Market Framework. For information regarding the market framework in the ERCOT region, see "Business--Retail Energy--Retail Energy Supply."

Long-term Purchase and Sale Agreements

In the ordinary course of business, and as part of our hedging strategy, we enter into long-term sales arrangements for electric energy, capacity and ancillary services, as well as long-term purchase arrangements. For information regarding our long-term fuel supply contracts, purchase power and electric capacity contracts and commitments, electric energy and electric sale contracts and tolling arrangements, see notes 14(f), 14(k) and 14(l) to our consolidated financial statements. For information regarding our hedging strategy relating to such long-term commitments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Factors--Risks Related to Our Wholesale Energy Operations" in Item 7 of this Form 10-K/A.

Commercial Operations

Strategy. Our domestic commercial business optimizes our physical asset positions consisting of our power generation asset portfolio, pipeline storage positions and fuel positions and provides risk management services for our asset positions. We perform these functions through trading, marketing and hedging activities for power, fuels and other energy related commodities. With the downturn in the industry, the decline in market liquidity, and our liquidity capital constraints, the principal function of our commercial activities has shifted to optimizing our assets. Previous large volume activities primarily involving risk management to customers, gas marketing to third parties and trading of power and gas have been significantly reduced, and in some cases eliminated. As a result, we have reduced our trading workforce from 264 to 160 as of December 31, 2002, which

include traders, originators, dispatchers and schedulers. We have also reduced support staff, including technical staff, accountants and risk control personnel, from 645 to 587 as of December 31, 2002. In addition to these staffing reductions, several unfilled positions were eliminated. In March 2003, we decided to exit our proprietary trading activities and liquidate, to the extent practicable, our proprietary positions. Although we are exiting the proprietary trading business, we have existing positions, which will be closed as economically feasible or in accordance with their terms. We will continue to engage in hedging activities related to our electric generating facilities, pipeline storage positions and fuel positions.

Asset optimization and risk management. Our domestic commercial businesses complement our merchant power generation business by providing a full range of energy management services. These services focus on two core functions, optimizing our physical asset position and providing risk management services for our portfolio. To perform these functions, we trade, market and hedge electric energy, capacity and ancillary services, as well as manage the purchase and sale of fuels and emission allowances.

Asset optimization is maximizing the financial performance of an asset position. Our commercial groups optimize our assets by employing different products (e.g., on-peak power), geographic markets (e.g., buying from and selling into adjacent markets), fuel types (e.g., burning oil rather than natural gas at our fuel switching capable plants) and transaction terms (spot to multi-year term).

Risk management services focus on managing the performance risk and price risk (of both purchases and sales) inherent in the asset position. The ultimate purpose of this activity is to identify the risks and reduce the volatility they could cause in our financial performance. Our commercial groups assist our risk control personnel and management in the identification of these risks and execute the transactions necessary to achieve this goal. As an example of this, we generally seek to sell a portion of the capacity of our domestic facilities under fixed-price sale contracts (energy or capacity) or contracts to sell energy at a predetermined multiple of fuel prices. Generally, we also seek to hedge our fuel needs associated with our forward power sale obligations. These power sales and fuel purchases provide us with certainty as to a portion of our margins. With respect to performance risk, we also take into account plant operational constraints and operating risk in making these determinations.

Physical power and services from our assets portfolios are sold in real-time, hour-ahead, day-ahead, or multi-month or multi-year term markets. For purposes of supplying our generation, we purchase fuel from a variety of suppliers under daily, monthly and term, variable-load and base-load contracts that include either market-based or fixed pricing provisions. We use derivative instruments to execute these transactions. For additional information regarding our financial exposure to derivative instruments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Factors--Risks Related to Our Businesses Generally" in Item 7 of this Form 10-K/A and "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K/A.

In addition, as part of our efforts to commercialize our asset portfolio and provide risk management services, we arrange for, schedule and balance the transportation of the natural gas from the supply receipt point to our plants. We generally obtain pipeline transportation to perform this function. Accordingly, we use a variety of transportation arrangements including short-term and long-term firm and interruptible agreements with intrastate and interstate pipelines. We also utilize brokered firm transportation agreements when dealing on the interstate pipeline system. In the normal course of business, it is common for us to hedge the risk of pipeline transportation expenses through "basis swap" transactions.

We also enter into various short-term and long-term firm and interruptible agreements for natural gas storage in order to offer peak delivery services to satisfy electric generating demands. Natural gas storage capacity allows us to better manage the unpredictable daily or seasonal imbalances between supply volumes and demand levels.

In support of our optimization and risk management effects, our power origination group, working closely with our other commercial groups, focuses on developing customized near-term products and long-term

contracts. These are designed and negotiated on a case-by-case basis to meet the specific energy requirements of our customers. The target customer group generally includes investor-owned utilities, municipalities, cooperatives and other companies that serve end users.

Risk management services to customers. In addition to optimizing our power asset portfolio, our trading and marketing businesses provide risk management services to a variety of customers, which include natural gas distribution companies, electric utilities, municipalities, cooperatives, power generators, marketers or other retail energy providers, aggregators and large volume industrial customers. Risk management services primarily focus on mitigating customers' commodity price exposure and providing firm delivery services. To provide these services to these customers, we utilize the same skills and physical and financial instruments used to optimize and manage the risks of our asset portfolio. See below for the discussion of our decision to exit proprietary trading in March 2003.

Proprietary Trading. Our commercial business obtains proprietary market knowledge and develops proprietary analysis through its efforts to manage our asset portfolio and provide risk management services to our customers. This enables our commercial groups to selectively take market positions, typically on a short-term basis, in power, fuel and other energy related commodities. Our commercial groups used derivative instruments to execute these transactions. In March 2003, we decided to exit our proprietary trading activities and liquidate, to the extent practicable, our proprietary positions. Although we are exiting the proprietary trading business, we have existing positions, which will be closed as economically feasible or in accordance with their terms. We will continue to engage in hedging activities related to our electric generating facilities, pipeline storage positions and fuel positions.

Risk Management Controls. For information regarding our risk management structure and policies relating to our trading and marketing operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations--Trading and Marketing Operations" in Item 7 of this Form 10-K/A and "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K/A.

Regulation

Electricity. The FERC has exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce by "public utilities." Public utilities that are subject to the FERC's jurisdiction must file rates with the FERC applicable to their wholesale sales or transmission of electricity in interstate commerce. All of our generation subsidiaries sell electric energy, capacity and ancillary services at wholesale and are public utilities with the exception of two facilities in Texas that are classified as qualifying facilities and not regulated as public utilities. The FERC has authorized all of our generation subsidiaries to sell electricity and related services at wholesale at market-based rates. In its orders authorizing market-based rates, the FERC also has granted these subsidiaries waivers of many of the accounting, record keeping and reporting requirements that are imposed on public utilities with cost-based rate schedules.

The FERC's orders accepting the market-based rate schedules filed by our subsidiaries or their predecessors, as is customary with such orders, reserve the right to revoke or limit our market-based rate authority if the FERC subsequently determines that any of our affiliates possess and exercise market power. If the FERC were to revoke or limit our market-based rate authority, we would have to file, and obtain the FERC's acceptance of, cost-based rate schedules for all or some of our sales. In addition, the loss of market-based rate authority could subject us to the accounting, record keeping and reporting requirements that the FERC imposes on public utilities with cost-based rate schedules.

The FERC has issued a notice of proposed rulemaking describing its intention to standardize electricity markets and eliminate continuing discrimination in transmission service, with a proposed implementation date of September 2004. The goal of SMD is to promote a more economically efficient market design that will lower delivered energy costs, maintain reliability, mitigate market power and increase customer choice options. SMD

proposes to eliminate discrimination in transmission service by requiring that all users of the grid take service pursuant to the same rates and terms and conditions of service, thus eliminating certain existing preferences enjoyed by some classes of customers. In addition, transmission-owning public utilities will be required to turn over the operation of their transmission systems to an independent transmission provider. SMD also seeks to establish day-ahead and real-time electric energy and ancillary service markets modeled after the energy markets that currently exist in the Northeast. Finally, SMD proposes to establish a capacity obligation on load serving entities and establishes nationwide price mitigation measures.

The FERC also continues to promote the formation of large RTOs and has issued numerous orders on the various RTO proposals. The FERC's goal is to promote the formation of a robust wholesale market for electricity. While RTO participation by public utilities is voluntary, the overwhelming majority of the FERC jurisdictional utilities have indicated that they will join the proposed RTO for their region. At this time there are approximately nine proposed RTOs covering the vast majority of the continental United States. In addition, large portions of the nation's transmission system are currently operated by an independent entity. The Midwest grid is operated by the MISO and the Northeast grid is operated by three separate independent entities: New England ISO, NYISO and PJM. The ERCOT ISO independently operates the Texas grid. MISO and PJM have received RTO status from the FERC.

Commercial Activities. Our domestic commercial operations are also subject to the FERC's jurisdiction. As a gas marketer, we make sales of natural gas in interstate commerce at wholesale pursuant to a blanket certificate issued by the FERC, but the FERC does not otherwise regulate the rates, terms or conditions of these gas sales.

Hydroelectric Facilities. Our hydroelectric generation facilities are subject to the FERC's exclusive authority to license non-federal hydroelectric projects located on navigable waterways and federal lands. These FERC licenses must be renewed periodically and can include conditions on operation of the project at issue.

SEC. A company engaged exclusively in the business of owning and/or operating facilities used for the generation of electric energy exclusively for sale at wholesale and selling electric energy at wholesale may be exempted from regulation under the PUHCA as an exempt wholesale generator. Our electric generation facilities have received determinations of exempt wholesale generator status from the FERC. If we lose our exempt wholesale generator status or qualifying facility status, we would have to restructure our organization or risk being subjected to further regulation by the SEC.

Competition

For a discussion of competitive factors affecting our wholesale energy segment, see "Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Factors--Risks Related to Our Wholesale Energy Operations" in Item 7 of this Form 10-K/A.

20

European Energy

In Europe, we own and operate electric generation facilities and conduct trading and origination operations. In February 2003, we agreed to sell our European energy operations. We expect to consummate the sale during the summer of 2003. For additional information regarding the disposition of our European energy operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Factors--Risks Related to the Sale of Our European Energy Operations" and note 21(b) to our consolidated financial statements.

European Power Generation and Supply

Facilities. We own five electric power generation facilities with an aggregate net generating capacity of 3,496 MW, of which 3,231 MW are operational, located in the Netherlands. These facilities consist of approximately 39% of base-load, 15% of intermediate and 46% of peaking capacity. Our facilities are grouped in three clusters adjacent to the cities of Amsterdam, Utrecht and Velsen. In 2002, our generation facilities produced 14.2 million MWh, an amount that represented approximately 13% of the electricity production of the Netherlands. In addition to electricity, our generating stations sell heated water produced as a byproduct of the generation process for use in providing heating to the cities of Amsterdam, Nieuwegein, Utrecht and Purmerend and provide ancillary services, including grid support services, to transmission system owners.

In 2002, on a volumetric basis, approximately 50% of our European generation output was natural gas-fired, 30% was coal-fired, and 20% was blast furnace gas-fired. We purchase substantially all of our European gas fuel requirements under an annual gas purchase contract with N.V. Nederlandse Gasunie, the primary supplier and transporter of natural gas in the Netherlands. The purchase price and transportation costs for natural gas under these contracts are calculated on the basis of regulated tariffs. We obtain our European coal requirements through short to medium-term forward purchase contracts on the open market through a variety of suppliers and brokers. One of our European generation stations, which has a production capacity of 144 MW, uses blast furnace gas, an industrial waste gas generated by a steel plant adjacent to the generation station, as its fuel. Two of our other European generation plants have the flexibility to operate using blast furnace gas. We purchase substantially all blast furnace gas for the 144 MW facility from the adjacent steel plant under a medium-term and a long-term contract.

Market Framework. Our European energy segment produces, buys and sells electricity, gas and other energy-related commodities primarily in the Netherlands wholesale market. Our energy trading and origination operations and activities are concentrated in Northern Europe.

The primary customers in the Netherlands are electric distribution companies, large industrial consumers and energy trading companies. We sell electricity and other energy-related commodities primarily in the form of forward purchase contracts transacted in the over-the-counter markets, on various European energy exchanges and in negotiated transactions with individual counterparties. To a lesser extent, we also engage in transactions involving financial energy-related derivative products.

The most significant factor affecting the markets in which our European energy segment operates has been the deregulation of the Dutch and certain other European wholesale energy markets, including access on a non-discriminatory basis to high voltage transmission grid systems, the establishment of new energy exchanges and other events. Notwithstanding these factors, the scope and pace of the future liberalization of the European energy markets is uncertain. In some cases, fuel suppliers continue to operate in largely regulated markets not yet open to full competition.

There are significant differences in the United States and European markets. Among other things, European energy markets involve increased currency hedging requirements (the Euro and non-Euro currencies), and more complicated cross-border tax and transmission tariff systems than in the United States. In addition, European

energy markets are significantly less mature than United States energy markets in terms of liquidity, the scope and complexity of trading and marketing products, the use of standardized market-based trading contracts and other aspects.

In addition, there exist greater uncertainties in some European jurisdictions as to the enforceability of certain contract-based mechanisms to hedge risks, such as the enforceability of automatic terminations rights and rights of set-off upon bankruptcy, limitations on liquidated damages and the rules by which European courts construct contracts. In many civil law jurisdictions, courts reserve the right to interpret contracts based upon principles of good faith and fairness as opposed to a literal construction of the contract.

European Trading and Origination

Our European trading and origination operations are currently centered in the Netherlands, with an additional office in Germany. Our European trading and origination operations will focus on hedging and optimizing our generation assets in the Netherlands. During 2002, we traded electricity and fuel products in the Netherlands, Germany, Austria, the United Kingdom and the Scandinavian countries. As of December 31, 2002, we had entered into forward purchase and sale contracts, and associated hedging transactions, covering approximately 13.6 million MWh for delivery in 2003. In September 2002, we decided to substantially exit our proprietary trading activities in Europe and, in March 2003, we decided to exit our proprietary trading activities for the company as a whole.

Regulation

Prior to the deregulation of the Dutch wholesale market in 2001, our European energy segment sold its generating output to a national production pool and, in return, received a standardized remuneration based on generation output. The remuneration included fuel cost, return of and on capital and operation and maintenance expenses. In 2001, the wholesale energy market in the Netherlands was opened to competition. We continue to be subject to regulation by national and indirectly by European regulatory agencies and operate under regulations relating to the environment, labor, tax and other matters. For example, our operations are subject to the regulation of Dutch and European Community anti-trust authorities, that have extensive authority to investigate and prosecute violations by energy companies of anti-monopolistic and price-fixing regulations. In addition, our European operations must also comply with various national technical codes and other regulations establishing access to transmission systems. Many of our significant suppliers and customers in Europe are subject to continued regulation by various national energy regulatory bodies having the authority to establish tariffs for such suppliers and customers. The impact of regulations on these entities has an indirect impact on our European operations.

Competition

For a discussion of competitive factors affecting our European energy segment, see "Management's Discussion and Analysis of Financial Condition and Operations--Risk Factors--Risks Related to Our European Energy Operations" in Item 7 of this Form 10-K/A.

Other Operations

Our other operations business segment includes the following:

- our venture capital investment portfolio; and
- unallocated corporate costs.

We are currently managing our venture capital investment portfolio and do not have plans to expand this business. As of December 31, 2002, the net book value of these investments is $44 million. See note 2(o) to our consolidated financial statements.

Environmental Matters

General

We are subject to numerous federal, state and local requirements relating to the protection of the environment and the safety and health of personnel and the public. These requirements relate to a broad range of our activities, including the discharge of pollutants into air, water, and soil, the proper handling of solid, hazardous, and toxic materials and waste, noise, and safety and health standards applicable to the workplace. In order to comply with these requirements, we will spend substantial amounts from time to time to construct, modify and retrofit equipment, acquire air emission allowances for operation of our facilities, and to clean up or decommission disposal or fuel storage areas and other locations as necessary. We anticipate spending approximately $208 million from 2003 through 2007 for environmental compliance.

If we do not comply with environmental requirements that apply to our operations, regulatory agencies could seek to impose on us civil, administrative and/or criminal liabilities as well as seek to curtail our operations. Under some statutes, private parties could also seek to impose civil fines or liabilities for property damage, personal injury and possibly other costs.

Air Quality Matters

As part of the 1990 amendments to the Federal Clean Air Act, standards for the emission of nitrogen oxide, a product of the combustion process associated with power generation, are being developed or have been finalized. The standards require reduction of emissions from our power generating facilities in the United States.

The EPA has announced its determination to regulate hazardous air pollutants, including mercury, from coal-fired and oil-fired steam electric generating facilities under Section 112 of the Clean Air Act. The EPA plans to develop maximum achievable control technology standards for these types of generating facilities as well as for turbines, engines, and industrial boilers. The rulemaking for coal and oil-fired steam electric generating facilities must be completed by December 2004. Compliance with the rules will be required within three years thereafter. The maximum achievable control technology standards that will be applicable to the generating facilities cannot be predicted at this time and may adversely impact our operations. The rulemaking for turbines is expected to be complete in August 2003, and for engines and industrial boilers in early 2004. Based on the rules currently proposed, we do not anticipate a material adverse impact on our operations.

In 1998, the United States became a signatory to the United Nations Framework Convention on Climate Change or "Kyoto Protocol." The Kyoto Protocol calls for developed nations to reduce their emissions of greenhouse gases. Carbon dioxide, which is a major byproduct of the combustion of fossil fuel, is considered to be a greenhouse gas. If the United States Senate ultimately ratifies the Kyoto Protocol, any resulting limitations on power plant carbon dioxide emissions could have a material adverse impact on all fossil fuel fired facilities, including those belonging to us.

The EPA is conducting a nationwide investigation regarding the historical compliance of coal-fueled electric generating stations with various permitting requirements of the Clean Air Act. Specifically, the EPA and the United States Department of Justice have initiated formal enforcement actions and litigation against several other utility companies that operate these stations, alleging that these companies modified their facilities without proper pre-construction permit authority. Since June 1998, six of our coal-fired facilities have received requests for information related to work activities conducted at those sites, as have two of our recently acquired Orion Power facilities. The EPA has not filed an enforcement action or initiated litigation in connection with these facilities at this time. Nevertheless, any litigation, if pursued successfully by the EPA, could accelerate the timing of emission reductions currently contemplated for the facilities and result in the imposition of penalties.

In February 2001, the United States Supreme Court upheld previously adopted EPA ambient air quality standards for fine particulate matter and ozone. While attaining these new standards may ultimately require

expenditures for air quality control system upgrades for our facilities, regulations addressing affected sources and required controls are not expected until after 2005. Consequently, it is not possible to determine the impact on our operations at this time.

In February 2002, the White House announced its "Clear Skies Initiative." The proposal is aimed at long-term reductions of multiple pollutants produced from fossil fuel-fired power plants. Reductions averaging 70% are targeted for sulfur dioxide, nitrogen oxide and mercury. If approved by the United States Congress, this program would entail a market-based approach using emission allowances; compliance with emission limits would be phased in over a period from 2008 to 2018. The Clear Skies Initiative has the potential to revise or eliminate several of the programs discussed above, including the maximum achievable control technology standards, the coal-fired utility enforcement initiative and fine particulate controls. In addition, a voluntary program for reducing greenhouse gas emissions was proposed as an alternative to the Kyoto Protocol. Fossil fuel-fired power plants in the United States would be affected by the adoption of this program, or other legislation that may be enacted by the United States Congress addressing similar issues. Such programs would require compliance to be achieved by the installation of pollution controls, the purchase of emission allowances or curtailment of operations.

Units 1 and 2 of our Etiwanda Generating Station in California are currently subject to a regulatory permit variance that requires these units to be equipped with a selective catalytic reduction system or cease operation. We must decide by June 2003 to either surrender the permits for these units or commence the installation of a selective catalytic reduction system by the end of March 2004. Each unit has a rated capacity of 132 MW. Under the regulatory permitting rules regarding peaking generation facilities, our Etiwanda Unit 5 must have the "best available control technology" installed by the end of December 2003 or cease operation. We will evaluate the California capacity market in the second quarter of 2003 and determine whether to make the investment in the necessary environmental upgrades or retire the units.

Our facilities in the Netherlands were in compliance with applicable Dutch nitrogen oxide emission standards through the year 2002. New nitrogen oxide reduction targets have recently been adopted in the Netherlands, which will require a 50% reduction in nitrogen oxide emissions from stationary sources from 2000 levels by 2010. The reductions may be achieved through the installation of emission control equipment or through the participation in a planned market-based emission trading system. Regarding present emissions, we currently believe that our European facilities will not be required to install nitrogen oxide controls or purchase emission credits before January 2006. Projected emission control costs are estimated to be approximately $45 million, although this investment may be offset to some extent or delayed if a market-based trading program develops.

The European Union, of which the Netherlands is a member, adopted the Kyoto Protocol as the goal for greenhouse gas emission targets. We believe our European energy segment will meet its current portion of target reductions because of its use of "green fuels" and efficiency improvements to its facilities. Pilot testing of a number of fuels classified as "non-fossil" was initiated in 2002.

Water Quality Matters

As a result of litigation and technological improvements, state and federal efforts toward implementing the total maximum daily load provisions of the Clean Water Act have substantially increased in recent years. The establishment of total maximum daily loads to restore water bodies currently designated as impaired may result in more stringent discharge limitations for our facilities. Compliance with such limitations may require our facilities to install additional water treatment systems, modify operational practices or implement other wastewater control measures, the costs of which cannot be estimated at this time.

In April 2002, the EPA proposed rules under Section 316(b) of the Clean Water Act relating to the design and operation of cooling water intake structures. This proposal is the second of three current phases of

rulemaking dealing with Section 316(b) and generally would affect existing facilities that use significant quantities of cooling water. Under the amended court deadline, EPA is to issue final rules for these Phase II facilities by February 2004. While the requirements of the final rule cannot be predicted at this time, there are significant potential implications under the EPA proposal for our generating facilities.

A number of efforts are under way within the EPA to evaluate water quality criteria for parameters associated with the by-products of fossil fuel combustion. These parameters include arsenic, mercury and selenium. Significant changes in these criteria could impact station discharge limits and could require our facilities to install additional water treatment equipment. The impact on us as a result of these initiatives is unknown at this time.

Liability for Preexisting Conditions and Remediations

In connection with our acquisition of facilities, we, with a few exceptions, assumed liability for preexisting conditions, including some ongoing remediations. Funds for carrying out identified remediations have been included in our planning for future funding requirements, and we are not currently aware of any environmental condition at any of our facilities that we expect to have a material adverse effect on our financial position, results of operations or cash flows.

A prior owner of one of our Northeast facilities entered into a consent order agreement with the Pennsylvania Department of Environmental Protection to remediate a coal refuse pile on the property of the facility. Under the acquisition agreements between Sithe Energies, Inc. and GPU, Inc. relating to some of our Mid-Atlantic regional facilities, GPU has agreed to retain responsibility for up to $6 million of environmental liabilities associated with the coal refuse site at this facility. We will be responsible for any amounts in excess of $6 million. We expect our remaining obligation on the coal refuse site to be $1 million. In August 2000, we signed a modified consent order agreement that committed us to complete the remediation no later than November 2004. In connection with the acquisition of some of our Mid-Atlantic facilities, we have liabilities associated with six future ash disposal site closures. We expect to pay approximately $5 million over the next five years toward closure of these facilities.

Under the New Jersey Industrial Site Recovery Act, owners and operators of industrial properties are responsible for performing all necessary remediation at a facility prior to the closing of the facility and the termination of operations, or undertake actions that ensure that the property will be remediated after the closing of the facility and the termination of operations. In connection with the acquisition of our facilities from Sithe Energies, Inc., we have agreed to take responsibility for costs relating to the four New Jersey properties we purchased from Sithe Energies, Inc. We estimate that the costs to fulfill our obligations under the act will be approximately $8 million, which we expect to pay out through 2007. However, these remedial activities are still in the early stage. Following further investigation the scope of the necessary remedial work could increase, and we could, as a result, incur greater costs.

One of our Florida generation facilities discharges wastewater to percolation ponds, which in turn, percolate into the groundwater. Elevated levels of vanadium and sodium have been detected in groundwater monitoring wells. A noncompliance letter was received in 1999 from the Florida Department of Environmental Protection. In response to that letter, a study to evaluate the cause of the elevated constituents was undertaken and operational procedures were modified. At this time, if remediation is required, the cost, if any, is not anticipated to be material.

In connection with the acquisition of 70 hydro plants in northern and central New York, three gas/oil-fired plants in New York City, and one gas/oil-fired plant in central New York, Orion Power assumed the liability for the environmental remediation at several properties. Orion Power developed remediation plans for each of the subject properties and entered into consent orders with the New York State Department of Environmental Conservation at the three New York City sites and one hydro site for releases of petroleum and other substances

by the prior owners. The remaining portion of the liability we assumed for historical releases at all of these New York plants is approximately $8 million, which we expect to pay out through 2006. The consent order related to one New York City site also contained a provision to mitigate alleged impacts on fish populations. Activity on this issue was temporarily stayed pending the outcome of potential repowering opportunities. However, should repowering be considered inappropriate for this site, best technology available upgrades to the existing water intake system will have to be negotiated with the New York State Department of Environmental Conservation.

In connection with acquisition of Midwest assets by Orion Power, Orion Power became responsible for the liability associated with the closure of three ash disposal sites in Pennsylvania. The liability we assumed and recorded for these disposal sites as of December 31, 2002 was approximately $14 million, with $1 million to be paid over the next five years.

As a result of their age, many of our facilities contain significant amounts of asbestos insulation, other asbestos containing materials, as well as lead-based paint. Existing state and federal rules require the proper management and disposal of these potentially toxic materials. We have developed a management plan that includes proper maintenance of existing non-friable asbestos installations, and removal and abatement of asbestos containing materials where necessary because of maintenance, repairs, replacement or damage to the asbestos itself. We have planned for the proper management, abatement and disposal of asbestos and lead-based paint at our facilities in our financial planning.

Under CERCLA, owners and operators of facilities from which there has been a release or threatened release of hazardous substances, together with those who have transported or arranged for the disposal of those substances, are liable for the costs of responding to that release or threatened release, and the restoration of natural resources damaged by any such release. We are not aware of any liabilities under the act that would have a material adverse effect on our results of operations, financial position or cash flows.

Other European Environmental Matters

Under Dutch environmental laws, an environmental permit is required to be maintained for each generation facility. As is customary in Dutch practice, our European energy segment has, together with other industry participants, entered into various contractual agreements with the national government on specific environmental matters, including the reduction of the use of coal by partial switch from coal to fuels such as biomass, which are termed "non-fossil fuels" for purposes of compliance under the program. The environmental laws also address public safety. Our European energy segment holds all necessary authorizations and approvals for its current operations.

Nitrogen oxide reduction targets will require a 50% reduction in nitrogen oxide emissions of stationary sources from 2000 levels by 2010. The reductions may be achieved through the installation of emission control equipment or through the participation in a planned market-based emission trading system. Our European facilities are in compliance with current and applicable Dutch nitrogen oxide emission standards. Based on current factors, we have determined that our European facilities will not be required to install nitrogen oxide controls or purchase emission credits earlier than 2006.

Our European energy operations have budgeted to spend approximately $45 million in emission control and other environmental costs associated with our European energy segment for the period 2003 through 2007. In addition, we expect to spend approximately $8 million in asbestos and other environmental remediation programs during this period.

Employees

As of December 31, 2002, we had 6,002 full-time employees. Of these employees, 1,930 are covered by collective bargaining agreements. The collective bargaining agreements expire on various dates until May 14, 2007. The following table sets forth the number of our employees by business segment as of December 31, 2002:

Segment	Number
Retail energy....	1,633
Wholesale energy.	3,143
European energy..	680
Other operations.	546
Total.....	6,002

Executive Officers

Name	Age	Present Position
R. Steve Letbetter.	55	Chairman and Chief Executive Officer
Stephen W. Naeve...	55	President and Chief Operating Officer
Robert W. Harvey...	47	Executive Vice President and Group President--Retail Business
Mark M. Jacobs.....	41	Executive Vice President and Chief Financial Officer
Hugh Rice Kelly....	60	Senior Vice President, General Counsel and Corporate Secretary
Thomas C. Livengood	47	Vice President and Chief Accounting Officer

R. Steve Letbetter is our Chairman and Chief Executive Officer. Mr.

Letbetter served as Chairman of CenterPoint from January 2000 until the Distribution and as President and Chief Executive Officer from June 1999 until the Distribution. Since 1978, he has served in various positions as an officer of CenterPoint and its corporate predecessors. Mr. Letbetter was a director of CenterPoint from 1995 until the Distribution. Mr. Letbetter resigned as Chairman, President and Chief Executive Officer of CenterPoint at the time of the Distribution.

Stephen W. Naeve is our President and Chief Operating Officer. He has served as Vice Chairman of CenterPoint from June 1999 until the Distribution and as Chief Financial Officer of CenterPoint from 1997 until the Distribution. From 1997 to 1999, Mr. Naeve held the position of Executive Vice President and Chief Financial Officer of CenterPoint. Since 1988, he served in various officer capacities with CenterPoint, including Vice President - Strategic Planning and Administration between 1993 and 1996. Mr. Naeve resigned as Vice Chairman of CenterPoint at the time of the Distribution.

Robert W. Harvey is our Executive Vice President and Group President--Retail Business. Mr. Harvey served as Vice Chairman of CenterPoint from June 1999 until the Distribution. From 1982 to 1999, Mr. Harvey was employed with the Houston office of McKinsey & Co., Inc. He was a director (senior partner) and was the leader of the firm's North American electric power and natural gas practice. Mr. Harvey resigned as Vice Chairman of CenterPoint at the time of the Distribution.

Mark M. Jacobs is our Executive Vice President and Chief Financial Officer. Mr. Jacobs served as Executive Vice President and Chief Financial Officer of CenterPoint from July 2002 until the Distribution. From 1989 to 2002, Mr. Jacobs was employed by Goldman, Sachs & Co. He was a Managing Director in the firm's Natural Resources Group. Mr. Jacobs resigned as Executive Vice President and Chief Financial Officer of CenterPoint at the time of the Distribution.

Hugh Rice Kelly is our Senior Vice President, General Counsel and Corporate Secretary. He served as Executive Vice President, General Counsel and Corporate Secretary of CenterPoint from 1997 until the Distribution. Between 1984 and 1997, he served as Senior Vice President, General Counsel and Corporate Secretary of CenterPoint. Mr. Kelly resigned as Executive Vice President, General Counsel and Corporate Secretary of CenterPoint at the time of the Distribution.

Thomas C. Livengood is our Vice President and Chief Accounting Officer. Prior to joining us in August 2002, he served as Executive Vice President and Chief Financial Officer of Carriage Services, Inc., a publicly traded consumer services company, since 1996. From 1991 to 1996, he served as Vice President and Chief Financial Officer of Tenneco Energy Company, a division of Tenneco, Inc.

ITEM 2. Properties.

Character of Ownership

Our corporate offices currently occupy approximately 500,000 square feet of leased office space in Houston, Texas, which lease expires in January 2004. During 2003, we expect to relocate our corporate offices. Upon relocation, our corporate offices will occupy approximately 520,000 square feet of leased office space in Houston, Texas. Our new lease expires in 2018, subject to two five-year renewal options.

In addition to our corporate office space, we lease or own various real property and facilities relating to our generation assets and development activities. Our principal generation facilities are generally described under "Our Business--Wholesale Energy" and "Our Business--European Energy" in Item 1 of this Form 10-K/A. We believe we have satisfactory title to our facilities in accordance with standards generally accepted in the electric power industry, subject to exceptions, which, in our opinion, would not have a material adverse effect on the use or value of the facilities.

Retail Energy

For information regarding the properties of our retail energy segment, see "Our Business--Retail Energy" in Item 1 of this Form 10-K/A.

Wholesale Energy

For information regarding the properties of our wholesale energy segment, see "Our Business--Wholesale Energy" in Item 1 of this Form 10-K/A.

European Energy

For information regarding the properties of our European energy segment, see "Our Business--European Energy" in Item 1 of this Form 10-K/A.

Other Operations

For information regarding the properties of our other operations segment, see "Our Business--Other Operations" in Item 1 of this Form 10-K/A.

ITEM 3. Legal Proceedings.

For a description of certain legal and regulatory proceedings affecting us, see note 14 to our consolidated financial statements.

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

No matters were submitted to a vote of our security holders during the fourth quarter of the fiscal year ended December 31, 2002.

PART II

ITEM 5. Market for Our Common Equity and Related Stockholder Matters.

As of March 5, 2003, our common stock was held of record by approximately 63,215 stockholders of record and approximately 132,892 beneficial owners. Our common stock is listed on the New York Stock Exchange and is traded under the symbol "RRI." The following table sets forth the high and low sales prices of our common stock on the New York Stock Exchange composite tape during the periods indicated, as reported by Bloomberg:

	Market Price	
	High	Low
2001		

Second Quarter (from May 1 through June 30)	$37.50	$23.65
Third Quarter............................	$28.60	$14.45
Fourth Quarter...........................	$19.85	$13.20
2002		
First Quarter............................	$17.45	$ 9.50
Second Quarter...........................	$17.16	$ 7.28
Third Quarter............................	$ 8.95	$ 1.66
Fourth Quarter...........................	$ 3.23	$ 0.99

The closing market price of our common stock on December 31, 2002 was $3.20 per share.

We have not paid or declared any dividends since our formation and currently intend to retain earnings for use in our business. Any future dividends will be subject to determination based upon our results of operations and financial condition, our future business prospects, any applicable contractual restrictions and other factors that our board of directors considers relevant. For a discussion of our restrictions on payment of dividends, see note 21(a) to our consolidated financial statements.

During 2001, we purchased 11 million shares of our common stock at an average price of $17.22 per share, or an aggregate purchase price of $189 million. For additional information, see note 10(b) to our consolidated ft;font-size:10pt;">

5,161

5,508

Comprehensive income attributable to Stewart
15,680

22,033

2,054

29,547

Basic average shares outstanding (000)
23,546

23,444

23,527

23,438

Basic earnings per share attributable to Stewart
0.95

0.79

0.79

0.97

Diluted average shares outstanding (000)
23,625

23,620

23,607

23,613

Diluted earnings per share attributable to Stewart
0.95

0.79

0.79

0.96

See notes to condensed consolidated financial statements.

3

CONDENSED CONSOLIDATED BALANCE SHEETS

	As of June 30, 2018 (Unaudited)	As of December 31, 2017
	($000 omitted)	
Assets		
Cash and cash equivalents	121,128	150,079
Short-term investments	23,642	24,463
Investments in debt and equity securities, at fair value	673,333	709,355
Receivables:		
Premiums from agencies	30,242	27,903
Trade and other	50,282	51,299
Income taxes	2,477	1,267
Notes	3,088	3,203
Allowance for uncollectible amounts	(4,842)	(5,156)
	81,247	78,516
Property and equipment, at cost:		
Land	3,991	3,991
Buildings	22,806	22,849
Furniture and equipment	233,154	226,461
Accumulated depreciation	(193,128)	(186,279)
	66,823	67,022
Title plants, at cost	74,237	74,237
Investments on equity method basis	8,985	9,202
Goodwill	242,736	231,428
Intangible assets, net of amortization	11,138	9,734
Deferred tax assets	4,222	4,186
Other assets	50,408	47,664
	1,357,899	1,405,886
Liabilities		
Notes payable	107,657	109,312
Accounts payable and accrued liabilities	94,057	117,740
Estimated title losses	475,460	480,990
Deferred tax liabilities	14,488	19,034
	691,662	727,076
Contingent liabilities and commitments		
Stockholders' equity		
Common Stock and additional paid-in capital	184,301	184,026
Retained earnings	499,656	491,698
Accumulated other comprehensive (loss) income:		
Net unrealized investment (losses) gains on investments available-for-sale	(6,336)	7,526
Foreign currency translation adjustments	(14,647)	(8,373)
Treasury stock – 352,161 common shares, at cost	(2,666)	(2,666)
Stockholders' equity attributable to Stewart	660,308	672,211
Noncontrolling interests	5,929	6,599
Total stockholders' equity (23,744,939 and 23,719,522 shares outstanding)	666,237	678,810
	1,357,899	1,405,886

See notes to condensed consolidated financial statements.

4

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Six Months Ended June 30,	
	2018	2017
	($000 omitted)	
Reconciliation of net income to cash provided by operating activities:		
Net income	23,759	28,165
Add (deduct):		
Depreciation and amortization	12,388	12,819
Provision for bad debt	69	634
Investment and other (gains) losses – net	(722)	389
Amortization of net premium on investments available-for-sale	3,116	3,421
Payments for title losses in excess of provisions	(1,175)	(467)
Adjustment for insurance recoveries of title losses	1,448	793
Increase in receivables – net	(4,363)	(9,792)
Increase in other assets – net	(2,626)	(6,526)
Decrease in payables and accrued liabilities – net	(26,326)	(18,868)
Change in net deferred income taxes	(457)	2,329
Net income from equity investees	(768)	(977)
Dividends received from equity investees	985	1,237
Stock-based compensation expense	1,979	3,372
Other – net	60	2
Cash provided by operating activities	7,367	16,531
Investing activities:		
Proceeds from sales of investments in securities	25,722	49,655
Proceeds from matured investments in debt securities	10,355	22,834
Purchases of investments in securities	(26,220)	(88,381)
Net sales (purchases) of short-term investments	221	(182)
Purchases of property and equipment, and real estate – net	(5,690)	(9,328)
Cash paid for acquisition of businesses	(11,978)	(18,080)
Other – net	458	410
Cash used by investing activities	(7,132)	(43,072)
Financing activities:		
Payments on notes payable	(5,993)	(17,917)
Proceeds from notes payable	26	25,897
Distributions to noncontrolling interests	(5,751)	(5,300)
Repurchases of common stock	(672)	—
Cash dividends paid	(14,127)	(14,065)
Payment of contingent consideration related to an acquisition	—	(1,298)
Purchase of remaining interest in consolidated subsidiary	(1,112)	(1,013)
Cash used by financing activities	(27,629)	(13,696)
Effects of changes in foreign currency exchange rates	(1,557)	1,670
Decrease in cash and cash equivalents	(28,951)	(38,567)
Cash and cash equivalents at beginning of period	150,079	185,772
Cash and cash equivalents at end of period	121,128	147,205

See notes to condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENT OF EQUITY (UNAUDITED)

	Common Stock ($1 par value)	Additional paid-in capital	Retained earnings	Accumulated other comprehensive loss	Treasury stock	Noncontrolling interests	Total
	($000 omitted)						
Balances at December 31, 2017	24,072	159,954	491,698	(847)	(2,666)	6,599	678,810
Cumulative effect adjustments on adoption of new accounting standards (Note 1-D)	—	—	3,592	(3,592)	—	—	—
Net income attributable to Stewart	—	—	18,598	—	—	—	18,598
Dividends on Common Stock ($0.60 per share)	—	—	(14,232)	—	—	—	(14,232)
Stock-based compensation and other	42	1,937	—	—	—	—	1,979
Stock repurchases	(17)	(655)	—	—	—	—	(672)
Purchase of remaining interest in consolidated subsidiary	—	(1,032)	—	—	—	(80)	(1,112)
Net change in unrealized gains and losses on investments, net of taxes	—	—	—	(10,434)	—	—	(10,434)
Net realized gain reclassification, net of taxes	—	—	—	(480)	—	—	(480)
Foreign currency translation adjustments, net of taxes	—	—	—	(5,630)	—	—	(5,630)
Net income attributable to noncontrolling interests	—	—	—	—	—	5,161	5,161
Distributions to noncontrolling interests	—	—	—	—	—	(5,751)	(5,751)
Balances at June 30, 2018	24,097	160,204	499,656	(20,983)	(2,666)	5,929	666,237

See notes to condensed consolidated financial statements.

6

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1

Interim financial statements. The financial information contained in this report for the three and six months ended June 30, 2018 and 2017, and as of June 30, 2018, is unaudited. This report should be read in conjunction with the Company's Annual Report on Form 10-K for the year ended December 31, 2017.

A. Management's responsibility. The accompanying interim financial statements were prepared by management, who is responsible for their integrity and objectivity. These financial statements have been prepared in conformity with U.S. generally accepted accounting principles (GAAP), including management's best judgments and estimates. In the opinion of management, all adjustments necessary for a fair presentation of this information for all interim periods, consisting only of normal recurring accruals, have been made. The Company's results of operations for interim periods are not necessarily indicative of results for a full year and actual results could differ.

B. Consolidation. The condensed consolidated financial statements include all subsidiaries in which the Company owns more than 50% voting rights in electing directors. All significant intercompany amounts and transactions have been eliminated and provisions have been made for noncontrolling interests. Unconsolidated investees, in which the Company typically owns 20% through 50% of the equity, are accounted for by the equity method.

C. Restrictions on cash and investments. The Company maintains investments in accordance with certain statutory requirements for the funding of statutory premium reserves. Statutory reserve funds, which approximated $482.4 million and $490.8 million at June 30, 2018 and December 31, 2017, respectively, are required to be fully funded and invested in high-quality securities and short-term investments. Statutory reserve funds are not available for current claim payments, which must be funded from current operating cash flow. In addition, included within cash and cash equivalents are statutory reserve funds of approximately $13.6 million and $14.2 million at June 30, 2018 and December 31, 2017, respectively. Although these cash statutory reserve funds are not restricted or segregated in depository accounts, they are required to be held pursuant to state statutes. If the Company fails to maintain minimum investments or cash and cash equivalents sufficient to meet statutory requirements, the Company may be subject to fines or other penalties, including potential revocation of its business license. These funds are not available for any other purpose. In the event that insurance regulators adjust the determination of the statutory premium reserves of the Company's title insurers, these restricted funds as well as statutory surplus would correspondingly increase or decrease.

D. Cumulative effect adjustments on adoption of new accounting standards. In February 2018, the Financial Accounting Standards Board (FASB) issued ASU 2018-02, Income Statement - Reporting Comprehensive Income, Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income, which amended its standard on comprehensive income to provide a one-time option for an entity to reclassify the stranded tax effects of the Tax Cuts and Jobs Act (the 2017 Act) that was passed in December 2017 from accumulated other comprehensive income/loss (AOCI) directly to retained earnings. The stranded tax effects result from the remeasurement of deferred tax assets and liabilities which were originally recorded in comprehensive income but whose remeasurement is reflected in the income statement. The Company adopted ASU 2018-02 effective on January 1, 2018 and reclassified $1.0 million of net tax expense from AOCI to retained earnings in the consolidated statement of equity.

In January 2016, the FASB issued ASU 2016-01, Recognition and Measurement of Financial Assets and Financial Liabilities, which, among others, (i) required equity investments, with certain exceptions, to be measured at fair value with changes in fair value recognized in net income, (ii) simplified the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment; (iii) eliminated the requirement for public business entities to disclose the methods and significant assumptions used to estimate the fair value that is required to be disclosed for financial instruments measured at amortized cost on the balance sheet;

and (iv) required separate presentation of financial assets and financial liabilities by measurement category and form of financial asset on the balance sheet or the accompanying notes to the financial statements. The Company adopted ASU 2016-01 effective on January 1, 2018, which resulted in a reclassification of the outstanding net unrealized investment gains, net of taxes, of $4.6 million relating to investments in equity securities previously carried in AOCI to retained earnings in the consolidated statement of equity.

E. Recent significant accounting pronouncement. In February 2016, the FASB issued ASU 2016-02, Leases, which updated the current guidance related to leases. The new guidance includes the requirement for the lessee to recognize in the balance sheet a liability equal to the present value of contractual lease payments with terms of more than twelve months and a right-of-use asset representing the right to use the underlying asset for the lease term. Disclosures will be required by lessees to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. This ASU is effective for annual and interim periods beginning after December 15, 2018 and early adoption is allowed. The Company expects to adopt ASU 2016-02 on January 1, 2019 using the modified retrospective method of adoption. The Company expects the adoption of ASU 2016-02 will result in material increases in the assets and liabilities reported on its consolidated balance sheets as indicated by the approximately $167.1 million of undiscounted future minimum lease payments with terms of more than twelve months as of December 31, 2017 (as disclosed in Note 16 of the Company's consolidated financial statements included in the Company's 2017 Annual Report on Form 10-K). The Company expects the new ASU will likely have an insignificant impact on its consolidated statements of operations and cash flows. The Company is currently in the process of system implementation and data migration and expects the transition to be completed during the fourth quarter 2018.

F. Merger Agreement. On March 18, 2018, the Company entered into an Agreement and Plan of Merger (the Merger Agreement) with Fidelity National Financial, Inc., a Delaware corporation (FNF), A Holdco Corp., a Delaware corporation and a wholly-owned direct subsidiary of FNF (Merger Sub I), and S Holdco LLC, a Delaware limited liability company and a wholly-owned direct subsidiary of FNF (Merger Sub II and, together with Merger Sub I, the Merger Subs). Upon the terms and subject to the conditions set forth in the Merger Agreement, at the Effective Time (as defined below), Merger Sub I will merge with and into the Company (Merger I), with the Company surviving Merger I as a direct wholly-owned subsidiary of FNF, and at the Subsequent Effective Time (as defined in the Merger Agreement), the Company will merge with and into Merger Sub II (Merger II and, together with Merger I, the Mergers), with Merger Sub II surviving Merger II as a direct wholly-owned subsidiary of FNF.

Subject to the terms and conditions of the Merger Agreement, at the effective time of Merger I (the Effective Time, each share of the Company's Common Stock outstanding immediately prior to the Effective Time (other than (i) shares owned by the Company, its subsidiaries, FNF or the Merger Subs and (ii) shares in respect of which appraisal rights have been properly exercised and perfected under Delaware law) will be converted into the right to receive cash consideration of $25.00 and 0.6425 shares of FNF common stock, par value $0.0001 per share (FNF Common Stock), subject to potential adjustment as described below. Pursuant to the terms of the Merger Agreement, the Company's stockholders have the option to elect to receive the merger consideration in all cash (the Cash Election Consideration), all FNF Common Stock (the Stock Election Consideration) or a mix of 50% cash and 50% FNF Common Stock (the Mixed Election Consideration), subject to pro-rata reductions to the extent either the election for the Cash Election Consideration or the election for the Stock Election Consideration is oversubscribed. Stockholders that elect to receive the Cash Election Consideration will receive is $50.00 per share, subject to potential adjustment as described below and proration to the extent the cash option is oversubscribed. The Stock Election Consideration and the stock portion of the Mixed Election Consideration will be calculated using a fixed exchange ratio that is based on the average of the volume weighted average prices of FNF Common Stock for each of the twenty (20) trading days prior to the signing of the Merger Agreement, or $38.91 (the Parent Share Price). The exchange ratio for the Stock Election Consideration will be equal to 1.2850 shares of FNF Common Stock per share of Common Stock (the Exchange Ratio), subject to potential adjustment described below and proration to the extent the stock option is oversubscribed.

Under the terms of the Merger Agreement, if the combined company is required to divest assets or businesses with 2017 annual revenues in excess of $75 million in order to receive required regulatory approvals (up to a cap of $225 million of 2017 annual revenues), the per share purchase price will be adjusted downwards on a sliding scale between such amounts of divestitures up to a maximum reduction of $4.50 in value in the event that businesses or assets with 2017 annual revenues of $225 million are divested, with such adjustment to consist of (i) in the case shares of Common Stock with respect to which Cash Election Consideration has been elected, a reduction of the amount of cash paid in respect of each share, (ii) in the case shares of Common Stock with respect to which Stock Election Consideration has been elected, a reduction in the Exchange Ratio based on the Parent Share Price, and (iii) in the case of shares of Common Stock with respect to which Mixed Election Consideration has been elected, a reduction in both the amount of cash and the Exchange Ratio to be paid to the holders of such shares, with 50% of the aggregate value of such reduction to consist of a reduction of the cash consideration and 50% of the aggregate value of such reduction to consist of a reduction in the Exchange Ratio based on the Parent Share Price.

The consummation of the Mergers, which is expected during the first or second quarter of 2019, is subject to the satisfaction or waiver of customary conditions, including, among other things, (i) the adoption of the Merger Agreement by the holders of a majority of the outstanding shares of Common Stock entitled to vote on the Mergers (the Company Stockholder Approval), (ii) the absence of any injunction or court or other governmental order (with respect to applicable antitrust or insurance laws, solely with respect to the Required Antitrust Regulatory Filings/Approvals and the Required Insurance Regulatory Filings/Approvals (each as defined in the Merger Agreement)) enjoining, prohibiting or rendering illegal the consummation of the Mergers, (iii) obtaining certain Required Antitrust Regulatory Filings/Approvals, (iv) obtaining certain Required Insurance Regulatory Filings/Approvals, (v) the Securities and Exchange Commission (SEC) declaring the Registration Statement (as defined in the Merger Agreement) on Form S-4 effective, (vi) the shares of FNF Common Stock to be issued in the Mergers having been approved for listing on the New York Stock Exchange, (vii) the representations and warranties made by each of the Company and FNF being true at and as of the Closing Date (as defined in the Merger Agreement), subject to the materiality standards contained in the Merger Agreement, (viii) the performance, in all material respects, by each of the Company, FNF and the Merger Subs of all of their respective obligations under the Merger Agreement and (ix) no Company Material Adverse Effect or Parent Material Adverse Effect (each as defined in the Merger Agreement) having occurred since the signing of the Merger Agreement.

The Merger Agreement contains certain customary representations, warranties and covenants made by the Company and FNF. The Merger Agreement also contains customary covenants for each of the parties, including the obligation for the parties to refrain from taking specified actions without the consent of the other party, and, in the case of the Company, conduct its business in the ordinary course and use commercially reasonable efforts to preserve intact its business organizations and relationships with third parties. Under the Merger Agreement, each of the Company and FNF has agreed to use its reasonable best efforts to take all actions and to do all things necessary or advisable under applicable law to consummate the Mergers, including preparing and filing as promptly as practicable with any governmental authority or other third party all documentation to effect all necessary filings, notices, petitions, statements, registrations, submissions of information, applications and other documents and obtaining and maintaining all approvals, consents, registrations, permits, authorizations and other confirmations required to be obtained from any governmental authority or other third party that are necessary, proper or advisable to consummate the transactions contemplated by this Agreement. Notwithstanding such obligation, in connection with obtaining any required regulatory approval, (a) FNF is not required to sell, divest, dispose of, license or hold separate (i) title plants and rights to title plants, businesses, product lines or assets to the extent that such title plants, rights to title plants, businesses, product lines or assets generated 2017 revenues in excess of $225 million in the aggregate, or (ii) any of its own brands in full and (b) FNF and its affiliates are not required to litigate in order to avoid or have terminated any legal restraint that would prevent the Mergers from being consummated.

The Merger Agreement contains certain customary termination rights in favor of either the Company or FNF, which are exercisable (i) by mutual consent, (ii) upon the failure to complete the Mergers by March 18, 2019 (the End Date), subject to certain exceptions and subject to up to two (2) extensions of up to three (3) months each upon the election of either the Company or FNF if, as of such date, all closing conditions (other than the receipt of the Required Antitrust Regulatory Filings/Approvals, the receipt of the Required Insurance Regulatory Filings/Approvals and the absence of any law or court or other governmental order relating thereto) having been met or being capable of being satisfied as of such time, (iii) in the event of a final and non-appealable law or order that prohibits the consummation of the Mergers or (iv) if the Company’s stockholders do not vote to approve the Mergers.

The Merger Agreement contains certain customary termination rights in favor of the Company, which are exercisable (i) for a breach of any representation, warranty, covenant or agreement made by FNF under the Merger Agreement that would result in failure to satisfy a closing condition (subject to certain cure periods) or (ii) if, prior to the Company Stockholder Approval being obtained, the Company’s board of directors authorizes the Company to enter into, and the Company enters into, an alternative acquisition agreement in connection with a superior proposal. Under the Merger Agreement, the Company will be obligated to pay a termination fee of $33 million to FNF if the Merger

Agreement is terminated due to the Company’s board of directors changing its recommendation or if the Company terminates the Merger Agreement to enter into an agreement for a superior proposal.

The Merger Agreement also contains certain customary termination rights in favor of FNF. If the Merger Agreement is terminated due to (i) the failure to complete the Mergers by the End Date because of a failure to obtain the Required Antitrust Regulatory Filings/Approvals or Required Insurance Regulatory Filings/Approvals, and all other closing conditions have been or are capable of being satisfied at the time of such termination, or (ii) an injunction or governmental or other court order enjoining, prohibiting or rendering illegal the consummation of the Mergers that is based on the failure to obtain the Required Antitrust Regulatory Filings/Approvals or Required Insurance Regulatory Filings/Approvals, then FNF will be obligated to pay a reverse termination fee of $50 million to the Company.

The Merger Agreement was included as Exhibit 2.1 to the Form 8-K filed with the SEC on March 19, 2018.

NOTE 2

Revenues. The Company's operating revenues, summarized by type, are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	($000 omitted)		($000 omitted)	
Title insurance premiums:				
Direct	158,947	159,488	291,708	290,489
Agency	247,257	234,407	484,111	467,756
Escrow fees	35,468	39,447	63,335	72,210
Search, abstract and valuation services	25,114	28,030	46,901	56,200
Other revenues	18,443	19,815	33,371	32,614
	485,229	481,187	919,426	919,269

Direct premiums - Premiums from title insurance policies directly issued or issued by affiliate offices are recognized at the time of the closing of the related real estate transaction.

Agency premiums - Premiums from title insurance policies written by independent agencies (agencies) are recognized when the policies are reported to the Company. In addition, where reasonable estimates can be made, the Company accrues for policies issued but not reported until after period end. The Company believes that reasonable estimates can be made when recent and consistent policy issuance information is available. Estimates are based on historical reporting patterns and other information obtained about agencies, as well as current trends in direct operations and in the title industry. In this accrual, future transactions are not being estimated. The Company is estimating revenues on policies that have already been issued by agencies but not yet reported to or received by the Company. The Company has consistently followed the same basic method of estimating unreported policy revenues for more than 10 years.

Escrow fees - An escrow is a transaction pursuant to an agreement of a buyer, seller, borrower, or lender wherein an impartial third party, such as the Company, acts in a fiduciary capacity on behalf of the parties in accordance with the terms of such agreement in order to accomplish the directions stated therein. Services provided include, among others, acting as escrow or other fiduciary agent, obtaining releases, and conducting the actual closing or settlement. Escrow fees are recognized upon closing of the escrow, which is generally at the same time of the closing of the related real estate transaction.

Search, abstract and valuation services - These services are primarily related to establishing the ownership, legal status and valuation of the property in a real estate transaction. In these cases, the Company does not issue a title insurance policy or perform duties of an escrow agent. Revenues from these services are recognized upon delivery of the service to the customer.

10

Other revenues - Other revenues consist primarily of fees related to tax-deferred property exchange services, information technology products related to real property records and closing settlement services, income from equity investees, and other services performed to facilitate the closing of real estate transactions. For those products and services that are delivered at a point in time, the related revenue is recognized upon delivery based on the unit price of the product or service. For those products and services where delivery occurs over time, the related revenue is recognized ratably over the duration of the contract.

NOTE 3

Investments in debt and equity securities. The total fair values of the Company's investments in debt and equity securities are detailed below:

	June 30, 2018	December 31, 2017
	($000 omitted)	
Investments in:		
Debt securities	637,883	671,441
Equity securities	35,450	37,914
	673,333	709,355

Investments in debt securities are classified as available-for-sale and the net unrealized gains and losses on such investments, net of applicable deferred taxes, are included as a component of AOCI within stockholders' equity. As a result of the Company's adoption of ASU 2016-01 (as discussed in Note 1-D), fair value changes relating to investments in equity securities are recognized as part of investment and other (losses) gains - net in the statement of operations beginning on January 1, 2018. Previously, the investments in equity securities, which consist of common stocks and master limited partnership interests, were accounted for similar to investments in debt securities.

As of June 30, 2018 and December 31, 2017, the net unrealized investment gains relating to investments in equity securities held were $4.9 million and $5.8 million, respectively.

The amortized costs and fair values of investments in debt securities are as follows:

	June 30, 2018		December 31, 2017	
	Amortized costs	Fair values	Amortized costs	Fair values
	($000 omitted)			
Municipal	62,837	62,831	71,581	72,669
Corporate	347,379	342,595	351,477	357,933
Foreign	222,740	219,932	229,750	228,237
U.S. Treasury Bonds	12,947	12,525	12,838	12,602
	645,903	637,883	665,646	671,441

Foreign debt securities consist of Canadian government and corporate bonds, United Kingdom treasury bonds, and Mexican government bonds.

Gross unrealized gains and losses on investments in debt securities are as follows:

	June 30, 2018		December 31, 2017	
	Gains	Losses	Gains	Losses
	($000 omitted)			
Municipal	463	469	1,263	175
Corporate	2,372	7,156	6,953	497
Foreign	1,320	4,128	1,742	3,255
U.S. Treasury Bonds	1	423	—	236
	4,156	12,176	9,958	4,163

Debt securities as of June 30, 2018 mature, according to their contractual terms, as follows (actual maturities may differ due to call or prepayment rights):

	Amortized costs	Fair values
	($000 omitted)	
In one year or less	55,856	55,917
After one year through five years	359,043	355,605
After five years through ten years	190,383	186,494
After ten years	40,621	39,867
	645,903	637,883

Gross unrealized losses on investments in debt securities and the fair values of the related securities, aggregated by investment category and length of time that individual securities have been in a continuous unrealized loss position at June 30, 2018, were:

	Less than 12 months		More than 12 months		Total	
	Losses	Fair values	Losses	Fair values	Losses	Fair values
	($000 omitted)					
Municipal	198	21,849	271	5,756	469	27,605
Corporate	6,916	268,573	240	4,755	7,156	273,328
Foreign	897	73,483	3,231	88,709	4,128	162,192
U.S. Treasury Bonds	157	5,732	266	6,686	423	12,418
	8,168	369,637	4,008	105,906	12,176	475,543

The number of specific debt investment holdings held in an unrealized loss position as of June 30, 2018 was 313. Of these securities, 64 securities were in unrealized loss positions for more than 12 months. Since the Company does not intend to sell and will more likely than not maintain each investment security until its maturity or anticipated recovery, and no significant credit risk is deemed to exist, these investments are not considered as other-than-temporarily impaired. The Company believes its investment portfolio is diversified and expects no material loss to result from the failure to perform by issuers of the debt securities it holds. Investments made by the Company are not collateralized.

Gross unrealized losses on investments in debt securities and the fair values of the related securities, aggregated by investment category and length of time that individual securities have been in a continuous unrealized loss position at December 31, 2017, were:

	Less than 12 months		More than 12 months		Total	
	Losses	Fair values	Losses	Fair values	Losses	Fair values
	($000 omitted)					
Municipal	58	17,023	117	5,784	175	22,807
Corporate	386	81,632	111	4,926	497	86,558
Foreign	1,528	116,130	1,727	39,031	3,255	155,161
U.S. Treasury Bonds	53	5,830	183	6,772	236	12,602
	2,025	220,615	2,138	56,513	4,163	277,128

NOTE 4

Fair value measurements. The Fair Value Measurements and Disclosures Topic (Topic 820) of the FASB Accounting Standards Codification (ASC) defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal, or most advantageous, market for the asset or liability in an orderly transaction between market participants at the measurement date. Topic 820 establishes a three-level fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy requires entities to maximize the use of observable inputs when possible.

The three levels of inputs used to measure fair value are as follows:

- Level 1 – quoted prices in active markets for identical assets or liabilities;
- Level 2 – observable inputs other than quoted prices included in Level 1, such as quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar assets and liabilities in markets that are not active; or other inputs that are observable or can be corroborated by observable market data; and
- Level 3 – unobservable inputs that are supported by little or no market activity and that are significant to the fair values of the assets or liabilities, including certain pricing models, discounted cash flow methodologies and similar techniques that use significant unobservable inputs.

As of June 30, 2018, financial instruments measured at fair value on a recurring basis are summarized below:

	Level 1	Level 2	Fair value measurements
	($000 omitted)		
Investments in securities:			
Debt securities:			
Municipal	—	62,831	62,831
Corporate	—	342,595	342,595
Foreign	—	219,932	219,932
U.S. Treasury Bonds	—	12,525	12,525
Equity securities	35,450	—	35,450
	35,450	637,883	673,333

As of December 31, 2017, financial instruments measured at fair value on a recurring basis are summarized below:

	Level 1	Level 2	Fair value measurements
	($000 omitted)		
Investments in securities:			
Debt securities:			
Municipal	—	72,669	72,669
Corporate	—	357,933	357,933
Foreign	—	228,237	228,237
U.S. Treasury Bonds	—	12,602	12,602
Equity securities	37,914	—	37,914
	37,914	671,441	709,355

As of June 30, 2018, Level 1 financial instruments consist of equity securities. Level 2 financial instruments consist of municipal, governmental, and corporate bonds, both U.S. and foreign. In accordance with the Company's policies and guidelines which incorporate relevant statutory requirements, the Company's third-party registered investment manager invests only in securities rated as investment grade or higher by the major rating services, where observable valuation inputs are significant. The fair value of the Company's investments in available-for-sale securities are primarily determined using a third-party pricing service provider. The third-party pricing service provider calculates the fair values using both market approach and model valuation methods, as well as pricing information obtained from brokers, dealers and custodians. Management ensures the reasonableness of the third-party service valuations by comparing them with pricing information from the Company's investment manager.

There were no transfers of investments between levels during the six months ended June 30, 2018 and 2017.

NOTE 5

Investment and other (losses) gains - net. Investments and other (losses) gains are detailed as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	($000 omitted)			
Realized gains	603	279	1,166	845
Realized losses	(38)	(955)	(68)	(1,234)
Net unrealized investment gains (losses) recognized on equity securities held	1,828	—	(376)	—
	2,393	(676)	722	(389)

Following the adoption of ASU 2016-01 discussed in Notes 1 and 3, net investment losses recognized during the three and six months ended June 30, 2018 related to investments in equity securities still held as of June 30, 2018 are calculated as follows ($000 omitted):

	June 30, 2018	
	Three Months Ended	Six Months Ended
	($000 omitted)	
Total net investment gains (losses) recognized on equity securities during the period	1,612	(614)
Less: Net realized losses on equity securities sold during the period	(216)	(238)

Net unrealized investment gains (losses) recognized on equity securities still held	1,828	(376)

14

Proceeds from sales of investments in securities are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	($000 omitted)			
Proceeds from sales of debt securities	8,003	33,776	21,149	48,826
Proceeds from sales of equity securities	2,353	36	4,573	829
Total proceeds from sales of investment in securities	10,356	33,812	25,722	49,655

NOTE 6

Goodwill and other intangibles. The summary of changes in goodwill is as follows.

	Title	Ancillary Services and Corporate	Consolidated Total
		($000 omitted)	
Balances at December 31, 2017	225,699	5,729	231,428
Acquisitions	11,308	—	11,308
Balances at June 30, 2018	237,007	5,729	242,736

During the first quarter 2018, the Company acquired certain title businesses which increased goodwill related to the title segment by a total of $11.3 million, which is substantially deductible for income tax purposes over a period of 15 years. Also, in connection with the acquisitions, the Company identified and recorded $3.6 million of other intangibles, primarily related to employment and non-compete agreements, to be amortized over 3 years from the date of acquisition.

NOTE 7

Estimated title losses. A summary of estimated title losses for the six months ended June 30 is as follows:

	2018	2017
	($000 omitted)	
Balances at January 1	480,990	462,572
Provisions:		
Current year	41,372	43,850
Previous policy years	(3,694)	1,313
Total provisions	37,678	45,163
Payments, net of recoveries:		
Current year	(5,263)	(5,966)
Previous policy years	(33,590)	(39,664)
Total payments, net of recoveries	(38,853)	(45,630)
Effects of changes in foreign currency exchange rates	(4,355)	3,189
Balances at June 30	475,460	465,294
Loss ratios as a percentage of title operating revenues:		
Current year provisions	4.6 %	4.9 %
Total provisions	4.2 %	5.1 %

During the six months ended June 30, 2018, the Company decreased its loss provisioning rate due to lower loss experience and reduced prior policy year reserves as a result of the actuarial reserve review. This resulted in a $3.7 million favorable loss development for previous policy years and decreased total title loss provisions for the six months ended June 30, 2018 compared to the same period in 2017.

NOTE 8

Share-based payments. Prior to 2018, the Company granted executives and senior management shares of restricted common stock, consisting of time-based shares, which vest on each of the first three anniversaries of the grant date, and performance-based shares, which vest upon achievement of certain financial objectives over the period of three years. Starting on January 1, 2018, the Company began granting time-based and performance-based restricted stock units, which have vesting conditions generally similar to those restricted common stock shares awarded previously. Each restricted stock unit represents a contractual right to receive a share of the Company's common stock.

The aggregate grant-date fair values of these awards during 2018 and 2017 were $4.7 million (109,000 shares with an average grant price per share of $43.39) and $4.7 million (107,000 shares with an average grant price per share of $44.21), respectively. Awards were made pursuant to the Company’s employee incentive compensation plans and the compensation expense associated with restricted stock awards is recognized over the corresponding vesting period. Additionally, during the second quarters 2018 and 2017, the Company granted its board of directors, as a component of annual director retainer compensation, 14,300 and 13,000 shares, respectively, of common stock, which vested immediately. The aggregate fair values of these director awards at the grant dates in 2018 and 2017 were both $0.6 million.

NOTE 9

Earnings per share. Basic earnings per share (EPS) attributable to Stewart is calculated by dividing net income attributable to Stewart by the weighted-average number of shares of Common Stock outstanding during the reporting periods. Outstanding shares of Common Stock granted to employees that are not yet vested (restricted shares) are excluded from the calculation of the weighted-average number of shares outstanding for calculating basic EPS. To calculate diluted EPS, the number of shares is adjusted to include the number of additional shares that would have been outstanding if the restricted shares and restricted units were vested. In periods of loss, dilutive shares are excluded from the calculation of the diluted EPS and diluted EPS is computed in the same manner as basic EPS.

The calculation of the basic and diluted EPS is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	($000 omitted, except per share)			
Numerator:				
Net income attributable to Stewart	22,377	18,568	18,598	22,657
Denominator (000):				
Basic average shares outstanding	23,546	23,444	23,527	23,438
Average number of dilutive shares relating to grants of restricted shares and units	79	176	80	175
Diluted average shares outstanding	23,625	23,620	23,607	23,613
Basic earnings per share attributable to Stewart	0.95	0.79	0.79	0.97
Diluted earnings per share attributable to Stewart	0.95	0.79	0.79	0.96

16

NOTE 10

Contingent liabilities and commitments. In the ordinary course of business, the Company guarantees the third-party indebtedness of certain of its consolidated subsidiaries. As of June 30, 2018, the maximum potential future payments on the guarantees are not more than the related notes payable recorded in the condensed consolidated balance sheets. The Company also guarantees the indebtedness related to lease obligations of certain of its consolidated subsidiaries. The maximum future obligations arising from these lease-related guarantees are not more than the Company's future minimum lease payments. As of June 30, 2018, the Company also had unused letters of credit aggregating $5.4 million related to workers' compensation and other insurance. The Company does not expect to make any payments on these guarantees.

NOTE 11

Regulatory and legal developments. The Company is subject to claims and lawsuits arising in the ordinary course of its business, most of which involve disputed policy claims. In some of these lawsuits, the plaintiff seeks exemplary or treble damages in excess of policy limits. The Company does not expect that any of these ordinary course proceedings will have a material adverse effect on its consolidated financial condition or results of operations. In addition, along with the other major title insurance companies, the Company is party to class action lawsuits concerning the title insurance industry. The Company believes that it has adequate reserves for the various litigation matters and contingencies discussed in this paragraph and that the likely resolution of these matters will not materially affect its consolidated financial condition or results of operations.

Additionally, the Company receives from time to time various other inquiries from governmental regulators concerning practices in the insurance industry. Many of these practices do not concern title insurance. To the extent the Company is in receipt of such inquiries, it believes that it has adequately reserved for these matters and does not anticipate that the outcome of these inquiries will materially affect its consolidated financial condition or results of operations.

The Company is subject to various other administrative actions and inquiries into its business conduct in certain of the states in which it operates. While the Company cannot predict the outcome of the various regulatory and administrative matters, it believes that it has adequately reserved for these matters and does not anticipate that the outcome of any of these matters will materially affect its consolidated financial condition or results of operations.

NOTE 12

Segment information. The Company reports two operating segments: title and ancillary services and corporate. The title segment provides services needed to transfer title to property in a real estate transaction and includes services such as searching, examining, closing and insuring the condition of the title to the property. In addition, the title segment includes centralized title services, home and personal insurance services and Internal Revenue Code Section 1031 tax-deferred exchanges. The ancillary services and corporate segment includes search and valuation services, which are the principal offerings of ancillary services, and expenses of the parent holding company and certain other enterprise-wide overhead costs, net of centralized administrative services costs allocated to respective operating businesses.

Selected statement of operations information related to these segments is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	($000 omitted)			
Title segment:				
Revenues	479,125	470,449	904,536	896,246
Depreciation and amortization	5,249	5,321	10,566	10,547
Income before taxes and noncontrolling interest	37,737	39,467	42,862	51,744
Ancillary services and corporate segment:				
Revenues	13,744	15,003	25,563	32,247
Depreciation and amortization	905	1,120	1,822	2,272
Loss before taxes and noncontrolling interest	(6,416)	(6,320)	(14,796)	(12,729)
Consolidated Stewart:				
Revenues	492,869	485,452	930,099	928,493
Depreciation and amortization	6,154	6,441	12,388	12,819
Income before taxes and noncontrolling interest	31,321	33,147	28,066	39,015

The Company does not provide asset information by reportable operating segment as it does not routinely evaluate the asset position by segment.

Revenues generated in the United States and all international operations are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	($000 omitted)			
United States	460,529	451,766	873,833	871,019
International	32,340	33,686	56,266	57,474
	492,869	485,452	930,099	928,493

NOTE 13

Other comprehensive (loss) income. Changes in the balances of each component of other comprehensive (loss) income and the related tax effects are as follows:

	Three Months Ended June 30, 2018			Three Months Ended June 30, 2017		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount
	($000 omitted)					
Net unrealized (losses) gains on investments:						
Change in net unrealized gains and losses on investments	(3,074)	(646)	(2,428)	548	193	355
Less: reclassification adjustment for net gains included in net income	(292)	(61)	(231)	(145)	(51)	(94)
	(3,366)	(707)	(2,659)	403	142	261
Foreign currency translation adjustments	(4,575)	(537)	(4,038)	4,334	1,130	3,204
Other comprehensive (loss) income	(7,941)	(1,244)	(6,697)	4,737	1,272	3,465

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount
	($000 omitted)					
Net unrealized (losses) gains on investments:						
Change in net unrealized gains and losses on investments	(13,208)	(2,774)	(10,434)	4,343	1,521	2,822
Less: reclassification adjustment for net gains included in net income	(607)	(127)	(480)	(710)	(249)	(461)
	(13,815)	(2,901)	(10,914)	3,633	1,272	2,361
Foreign currency translation adjustments	(6,854)	(1,224)	(5,630)	6,014	1,485	4,529
Other comprehensive (loss) income	(20,669)	(4,125)	(16,544)	9,647	2,757	6,890

19

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

MANAGEMENT'S OVERVIEW

We reported net income attributable to Stewart of $22.4 million ($0.95 per diluted share) for the second quarter 2018 compared to net income attributable to Stewart of $18.6 million ($0.79 per diluted share) for the second quarter 2017. Pretax income before noncontrolling interests for the second quarter 2018 was $31.3 million compared to a pretax income before noncontrolling interests of $33.1 million for the second quarter 2017.

On March 18, 2018, Stewart entered into an agreement and plan of merger with Fidelity National Financial, Inc. (FNF), in which the outstanding shares of Stewart will be exchanged for a combination of cash and shares of FNF, and the Company will be merged into a subsidiary of FNF (the Mergers). We announced in the first quarter 2018 that we had begun the regulatory approval process for Stewart's merger with FNF by submitting our preliminary Hart-Scott-Rodino filings to the Federal Trade Commission (FTC) and the Form A filings to the states of Texas and New York, the domiciles of Stewart's two main underwriters. During the second quarter 2018, we received an expected second request for additional information and documentary material from the FTC and are in the process of responding to this request. In addition, we have received approval from a majority of the states with which a Form E was filed and are awaiting approval from the remaining states. Subject to approval by our stockholders and regulatory authorities and the satisfaction of customary closing conditions, the Mergers are expected to close by the first or second quarter 2019.

Summary results of the title segment are as follows ($ in millions, except pretax margin):

	For the Three Months Ended June 30,		
	2018	2017	% Change
Total operating revenues	471.5	466.0	1 %
Investment income and other net gains	7.6	4.4	73 %
Pretax income	37.7	39.5	(4)%
Pretax margin	7.9 %	8.4 %	

Title operating revenues in the second quarter 2018 increased $5.5 million from the prior year quarter, driven by increased commercial and independent agency revenues, which were partially offset by lower residential direct title revenues. Pretax income declined $1.8 million in the second quarter 2018 compared to the second quarter 2017. The title segment incurred higher employee costs due to increased commissions and additional employee costs from acquisitions, which were partially offset by lower title losses and other operating expenses. Included in the segment's results were $4.0 million of net policy loss reserve reductions resulting from our midyear actuarial reserve review, partially offset by charges to policy loss expenses of $3.9 million related to two ongoing escrow litigation matters, and $1.8 million of net unrealized gains relating to changes in fair value of investments in equity securities (which were previously being recorded to other comprehensive income, but are now included in investment and other net gains due to an adoption of a new accounting standard in 2018).

Included in the non-commercial domestic revenues (as shown under the Results of Operations - Title revenues section) were revenues from purchase transactions and centralized title operations (processing primarily refinancing and default title orders) which decreased $1.9 million (1%) and $5.5 million (46%), respectively, in the second quarter 2018 compared to the prior year quarter due to lower closed orders, primarily on refinancing activities. Total commercial revenues improved 8% from the prior year quarter due to our continued focus on delivering quality service and underwriting to our domestic and international commercial customers. Total international title revenues in the second quarter 2018 decreased $1.8 million compared to the prior year quarter as a result of lower volumes, principally from our Canada operations, partially offset by the positive impact of the stronger foreign exchange rates against the U.S. dollar.

Gross revenues from independent agency operations in the second quarter 2018 increased $12.9 million compared to the second quarter 2017. The independent agency remittance rate in the second quarter 2018 remained comparable to the prior year quarter. Agency revenues, net of agency retention, improved 4% in the second quarter 2018, compared to the prior year quarter, as we maintain our focus on enhancing customer service and technology connectivity.

Summary results of the ancillary services and corporate segment are as follows ($ in millions):

	For the Three Months Ended June 30,		
	2018	2017	% Change
Total revenues	13.7	15.0	(8)%
Pretax loss	(6.4)	(6.3)	(2)%

Second quarter 2018 segment revenues declined $1.3 million compared to the prior year quarter, primarily due to a 23% revenue decrease in the valuation services business which was partially offset by a 6% increase in the search services business. The segment’s pretax results for the second quarter 2018 were comparable to the prior year quarter as a result of lower employee costs, which fully offset the revenue decline for the quarter. The segment’s results for the second quarter 2018 and 2017 included approximately $6.3 million and $5.9 million, respectively, of net expenses attributable to parent company and corporate operations

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company’s condensed consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of certain assets, liabilities, revenues, expenses and related disclosures surrounding contingencies and commitments.

Actual results can differ from our accounting estimates. While we do not anticipate significant changes in our estimates, there is a risk that such changes could have a material impact on our consolidated financial condition or results of operations for future periods. During the six months ended June 30, 2018, we made no material changes to our critical accounting estimates as previously disclosed in Management’s Discussion and Analysis in the Company’s Annual Report on Form 10-K for the year ended December 31, 2017.

Operations. Our primary business is title insurance and settlement-related services. We close transactions and issue title policies on homes, commercial and other real properties located in all 50 states, the District of Columbia and international markets through policy-issuing offices, agencies and centralized title services centers. Our ancillary services and corporate segment includes our parent holding company expenses and certain enterprise-wide overhead costs, along with our remaining ancillary services operations, principally search and valuation services.

Factors affecting revenues. The principal factors that contribute to changes in operating revenues for our title and ancillary services and corporate segments include:
- mortgage interest rates;
- availability of mortgage loans;
- number and average value of mortgage loan originations;
- ability of potential purchasers to qualify for loans;
- inventory of existing homes available for sale;
- ratio of purchase transactions compared with refinance transactions;
- ratio of closed orders to open orders;
- home prices;
- consumer confidence, including employment trends;
- demand by buyers;
- number of households;
- premium rates;
- foreign currency exchange rates;

- market share;
- ability to attract and retain highly productive sales associates;
- independent agency remittance rates;
- opening of new offices and acquisitions;
- number and value of commercial transactions, which typically yield higher premiums;
- government or regulatory initiatives, including tax incentives and the implementation of the new integrated disclosure requirements;
- acquisitions or divestitures of businesses;

21

- volume of distressed property transactions; and
- seasonality and/or weather.

Premiums are determined in part by the values of the transactions we handle. To the extent inflation or market conditions cause increases in the prices of homes and other real estate, premium revenues are also increased. Conversely, falling home prices cause premium revenues to decline. As an overall guideline, a 5% change in median home prices results in an approximate 3.7% change in title premiums. Home price changes may override the seasonal nature of the title insurance business. Historically, our first quarter is the least active in terms of title insurance revenues as home buying is generally depressed during winter months. Our second and third quarters are the most active as the summer is the traditional home buying season, and while commercial transaction closings are skewed to the end of the year, individually large commercial transactions can occur any time of year.

RESULTS OF OPERATIONS

Comparisons of our results of operations for the three and six months ended June 30, 2018 with the three and six months ended June 30, 2017 are set forth below. Factors contributing to fluctuations in the results of operations are presented in the order of their monetary significance, and we have quantified, when necessary, significant changes. Segment results are included in the discussions and, when relevant, are discussed separately.

Our statements on home sales and loan activity are based on published industry data from sources including Fannie Mae, the National Association of Realtors® (NAR), the Mortgage Bankers Association (MBA) and Freddie Mac. We also use information from our direct operations.

Operating environment. Actual existing home sales in the second quarter 2018 declined approximately 2% from the second quarter 2017. June 2018 existing home sales totaled 570,000, which was down 5% from a year ago, but up 7% from May 2018. According to NAR, the shortage of home listings in the market continues to elevate current home prices, which is pricing out would-be buyers and slowing home sales. June 2018 median and average home prices rose approximately 5% and 4%, respectively, compared to June 2017 prices. June 2018 housing starts declined 12% sequentially from May 2018 and also decreased 4% from a year ago. Newly issued building permits in June 2018 were down 2% sequentially from May 2018 and also down 3% from a year ago. According to Fannie Mae, one-to-four family residential lending declined 5% to $468 billion in the second quarter 2018 from $492 billion in the second quarter 2017, primarily driven by a 14%, or $21 billion, reduction in refinance originations. Purchase lending slightly decreased 2%, or $3 billion, in the second quarter 2018 compared to the prior year quarter. Refinance lending is forecasted to decrease $26 billion, or 20%, in the third quarter 2018 compared to the second quarter 2018. On average, refinance title premium rates are 60% of the premium rates for a similarly priced sale transaction.

Title revenues. Direct title revenue information is presented below:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	% Change	2018	2017	% Change
	($ in millions)			($ in millions)		
Non-commercial						
Domestic	145.7	153.1	(5)%	261.5	276.1	(5)%
International	22.8	27.2	(16)%	41.0	45.5	(10)%
	168.5	180.3	(7)%	302.5	321.6	(6)%
Commercial:						
Domestic	48.2	46.5	4 %	95.7	88.2	9 %

International	7.5	4.9	53 %	11.6	9.3	25 %
	55.7	51.4	8 %	107.3	97.5	10 %
Total direct title revenues	224.2	231.7	(3)%	409.8	419.1	(2)%

22

Revenues from direct title operations, which include residential, commercial, international and centralized title services transactions, decreased $7.5 million and $9.3 million in the second quarter and first six months of 2018, respectively, compared to the same periods in 2017, due to lower closed orders (primarily on refinancing activities), partially offset by improved commercial revenues. Revenues from our centralized title operations, which primarily process refinancing and default title orders, decreased $5.5 million, or 46%, and $10.9 million, or 43% in the second quarter and first six months of 2018 compared to the second quarter and first six months of 2017, respectively, primarily due to decreased refinancing orders and lower demand for default services, which are in line with industry trends. Our residential revenues, which comprise approximately 60% of our total direct revenues, slightly declined 1% ($1.9 million and $3.7 million, respectively) in the second quarter and first six months of 2018, compared to the same periods in 2017.
Our direct operations include local offices and international operations, and we generate commercial revenues both domestically and internationally. U.S. commercial revenues during the second quarter and first six months of 2018 increased $1.7 million and $7.5 million, compared to the second quarter and first six months of 2017, respectively, primarily due to our continued focus on delivering quality service and underwriting to our customers. Total international revenues in the second quarter and first six months of 2018 declined $1.8 million, or 6%, and $2.2 million, or 4%, respectively, compared to the same periods in 2017, primarily as a result of decreased transaction volume from our Canada operations, offset by increased commercial revenues and the stronger foreign currency exchange rates against the U.S. dollar. Direct revenues constituted 48% and 46% of our total title revenues in the second quarter and first six months of 2018, respectively, compared to 50% and 47%, respectively, in the same periods in 2017.

Orders information for the three and six months ended June 30 is as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2018	2017	Change	% Change	2018	2017	Change	% Change
Opened Orders:								
Commercial	8,353	10,788	(2,435)	(23)%	17,327	22,238	(4,911)	(22)%
Purchase	66,074	67,823	(1,749)	(3)%	122,565	129,065	(6,500)	(5)%
Refinance	21,615	24,183	(2,568)	(11)%	44,747	47,639	(2,892)	(6)%
Other	2,531	4,423	(1,892)	(43)%	5,544	9,019	(3,475)	(39)%
Total	98,573	107,217	(8,644)	(8)%	190,183	207,961	(17,778)	(9)%
Closed Orders:								
Commercial	6,968	8,167	(1,199)	(15)%	13,488	15,493	(2,005)	(13)%
Purchase	49,069	52,362	(3,293)	(6)%	85,750	92,564	(6,814)	(7)%
Refinance	14,582	16,298	(1,716)	(11)%	29,461	35,506	(6,045)	(17)%
Other	2,536	4,135	(1,599)	(39)%	5,651	7,333	(1,682)	(23)%
Total	73,155	80,962	(7,807)	(10)%	134,350	150,896	(16,546)	(11)%

Gross revenues from independent agency operations increased $12.9 million, or 6%, and $16.4 million, or 4% in the second quarter and first six months of 2018, respectively, compared to the same periods in 2017, primarily as a result of revenue increases in the states of New York, Texas, Pennsylvania, Arizona, Wisconsin, Ohio and Louisiana, partially offset by decreases in the states of Massachusetts, Michigan and Colorado. Agency revenues, net of retention, improved $1.6 million, or 4%, and $1.1 million, or 1%, in the second quarter and first six months of 2018, respectively, compared to the same periods in 2017, primarily due to the higher gross agency revenues and comparable average agency remittance rates. Refer further to the "Retention by agencies" discussion under Expenses below.

Ancillary services revenues. Ancillary services operating revenues decreased $1.4 million, or 9%, and $6.9 million, or 21%, in the second quarter and first six months of 2018 compared to the same periods in 2017, primarily due to lower revenues generated by the valuation services operations resulting from reduced orders from our principal customers.

Investment income. Investment income during the second quarter and first six months of 2018 was comparable to the same periods in 2017.

Investment and other gains (losses) - net. Investment and other gains - net for the second quarter and first six months of 2018 included $1.8 million of net unrealized gains and $0.4 million of net unrealized losses, respectively, related to equity securities investments (refer to Note 5 to the condensed consolidated financial statements for details), and $0.6 million of net realized gains from changes in the fair value of a contingent liability related to a prior acquisition. Investments and other losses - net for the second quarter and first six months of 2017 included $0.8 million net realized losses from changes in the fair value of a contingent liability related to a prior acquisition.

Expenses. An analysis of expenses is shown below:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	% Change	2018	2017	% Change
	($ in millions)			($ in millions)		
Amounts retained by agencies	203.8	192.6	6 %	399.0	383.7	4 %
As a % of agency revenues	82.4 %	82.1 %		82.4 %	82.0 %	
Employee costs	146.3	139.3	5 %	285.1	279.1	2 %
As a % of operating revenues	30.1 %	29.0 %		31.0 %	30.4 %	
Other operating expenses	86.0	88.8	(3)%	166.2	167.1	(1)%
As a % of operating revenues	17.7 %	18.5 %		18.1 %	18.2 %	
Title losses and related claims	18.7	24.5	(24)%	37.7	45.2	(17)%
As a % of title revenues	4.0 %	5.2 %		4.2 %	5.1 %	

Retention by agencies. Amounts retained by title agencies are based on agreements between agencies and our title underwriters. Amounts retained by independent agencies, as a percentage of revenues generated by them, averaged 82.4% and 82.1% in the second quarters 2018 and 2017, respectively, and 82.4% and 82.0% in the first six months of 2018 and 2017, respectively. The average retention percentage may vary from period to period due to the geographical mix of agency operations, the volume of title revenues and, in some states, laws or regulations. Due to the variety of such laws or regulations, as well as competitive factors, the average retention rate can differ significantly from state to state. In addition, a high proportion of our independent agencies are in states with retention rates greater than 80%. We continue to focus on increasing profit margins in every state, increasing premium revenue in states where remittance rates are above 20%, and maintaining the quality of our agency network, which we believe to be the industry's best, in order to mitigate claims risk and drive consistent future performance. While market share is important in our agency operations channel, it is not as important as margins, risk mitigation and profitability.

Employee costs. Total employee costs increased $7.0 million, or 5%, and $6.0 million, or 2%, in the second quarter and first six months of 2018, respectively, compared to the same periods in 2017, primarily due to higher commissions on increased commercial title revenues and additional employee costs attributed to previous acquisitions in the title segment, which were partially offset by decreased salaries resulting from reduced employee counts. During the second quarter and first six months of 2018, average employee counts decreased approximately 6%, primarily related to the continued volume declines in our ancillary services and centralized title operations, and staff departures in direct operations during the second quarter 2017.

Employee costs in the title segment increased $7.9 million, or 6%, and $11.4 million, or 4%, in the second quarter and first six months of 2018, compared to the second quarter and first six months of 2017, primarily due to increased commissions and additional costs from previous acquisitions. In the ancillary services and corporate segment, employee costs decreased $1.0 million, or 11%, and $5.4 million, or 26%, in the second quarter and first six months of

2018, compared to the same periods in 2017, primarily as a result of the reductions in average employee count.

Other operating expenses. Other operating expenses include costs that are fixed in nature, costs that follow, to varying degrees, changes in transaction volumes and revenues and costs that fluctuate independently of revenues. Costs that are fixed in nature include attorney and professional fees, third-party outsourcing provider fees, equipment rental, insurance, rent and other occupancy expenses, repairs and maintenance, technology costs, telephone and title plant expenses. Costs that follow, to varying degrees, changes in transaction volumes and revenues include attorney fee splits, bad debt expenses, ancillary services cost of sales expenses, copy supplies, delivery fees, outside search fees, postage, premium taxes and title plant maintenance expenses. Costs that fluctuate independently of revenues include general supplies, litigation defense, business promotion and marketing and travel.

Consolidated other operating expenses decreased $2.8 million, or 3%, and $0.9 million, or 1%, in the second quarter and first six months of 2018 compared to the same periods in 2017; while as a percentage of total operating revenues, other operating expenses were 17.7% and 18.5% in the second quarters 2018 and 2017, respectively, and 18.1% and 18.2% in the first six months of 2018 and 2017, respectively. During the first quarter 2018, we incurred $2.3 million of third-party advisory expenses recorded in the ancillary services and corporate segment relating to the strategic alternatives review. Excluding these non-operating charges, other operating expenses as a percentage of operating revenues during the first six months of 2018 were 17.8%.

Costs that follow, to varying degrees, changes in transaction volumes and revenues decreased $3.6 million, or 8%, and $5.2 million, or 7%, in the second quarter and first six months of 2018, compared to the same periods in 2017, primarily due to reduced outside title search fees and costs of services related to lower revenues from our centralized title and ancillary services operations. Costs that fluctuate independently of revenues increased $1.3 million, or 13%, and $1.8 million, or 10%, in the second quarter and first six months of 2018, compared to the same periods in 2017, primarily due to increased travel and marketing expenses. Excluding the charges mentioned above, costs that are fixed in nature decreased $1.3 million, or 4%, and $0.8 million, or 1%, in the second quarter and first six months of 2018, compared to the same periods in 2017, primarily due to reduced third-party outsourcing provider fees and professional fees.

Title losses. Provisions for title losses, as a percentage of title operating revenues, were 4.0% and 5.2% for the second quarter 2018 and 2017, respectively, and 4.2% and 5.1% for the first six months of 2018 and 2017, respectively. Title losses decreased $5.8 million, or 24%, and $7.5 million, or 17%, in the second quarter and first six months of 2018, respectively, compared to the similar periods in 2017, primarily as a result of our reduced loss provisioning rate during the first half of 2018 based on lower loss experience. During the second quarter 2018, we recorded $4.0 million of prior policy year loss reserve reductions as a result of our actuarial reserve review, while we also incurred charges of $3.9 million related to two ongoing escrow litigation matters. The title loss ratio in any given quarter can be significantly influenced by changes in new large claims incurred, escrow losses and adjustments to reserves for existing large claims. We expect our loss provisioning rate will range between 4.0% to 4.5% for the year 2018.

Cash claim payments in the second quarter and first six months of 2018, compared to the similar periods in 2017, decreased $1.2 million, or 5%, and $6.8 million, or 15%, respectively, primarily due to a reduction in payments on existing claims. We continue to manage and resolve large claims prudently and in keeping with our commitments to our policyholders.

The composition of title policy loss expense is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	($ in millions)		($ in millions)	
Provisions – known claims:				
Current year	6.0	2.1	7.5	4.2
Prior policy years	15.5	15.9	30.2	34.7
	21.5	18.0	37.7	38.9
Provisions – IBNR				
Current year	16.5	21.3	33.9	39.7
Prior policy years	(3.8)	1.1	(3.7)	1.3
	12.7	22.4	30.2	41.0
Transferred from IBNR to known claims	(15.5)	(15.9)	(30.2)	(34.7)
Total provisions	18.7	24.5	37.7	45.2

Provisions for known claims arise primarily from prior policy years as claims are not typically reported until several years after policies are issued. Provisions - Incurred But Not Reported (IBNR) are estimates of claims expected to be incurred over the next 20 years; therefore, it is not unusual or unexpected to experience changes to those estimated provisions in both current and prior policy years as additional loss experience on policy years is obtained. This loss experience may result in changes to our estimate of total ultimate losses expected (i.e., the IBNR policy loss reserve). Current year provisions - IBNR are recorded on policies issued in the current year as a percentage of premiums earned (provisioning rate). As claims become known, provisions are reclassified from IBNR to known claims. Adjustments relating to large losses (those individually in excess of $1.0 million) may impact provisions either for known claims or for IBNR.

Known claims provisions increased $3.5 million, or 19%, in the second quarter 2018 compared to the second quarter 2017 and decreased $1.2 million, or 3%, in the first six months of 2018 compared to the same period in 2017. Total provisions - IBNR decreased $9.7 million, or 43%, and $10.8 million, or 26%, in the second quarter and first six months of 2018, compared to the same periods in 2017, primarily as a result of the $4.0 million prior policy year reserve reduction recorded in the second quarter 2018, as well as a decrease in the provisioning rate related to the current year. As a percentage of title operating revenues, provisions - IBNR for the current policy year were 3.5% and 3.8% in the second quarter and first six months of 2018 compared to 4.6% and 4.5%, respectively, in the same periods in 2017.

In addition to title policy claims, we incur losses in our direct operations from escrow, closing and disbursement functions. These escrow losses typically relate to errors or other miscalculations of amounts to be paid at closing, including timing or amount of a mortgage payoff, payment of property or other taxes and payment of homeowners' association fees. Escrow losses also arise in cases of fraud, and in those cases, the title insurer incurs the loss under its obligation to ensure that an unencumbered title is conveyed. Escrow losses are recognized as expense when discovered or when contingencies associated with them (such as litigation) are resolved and are typically paid less than 12 months after the loss is recognized. During the six months ended June 30, 2018 and 2017, we recorded approximately $4.4 million and $2.1 million, respectively, of policy loss reserves relating to escrow losses arising from fraud.

Total title policy loss reserve balances are as follows:

	June 30,	December 31, 2017

	2018	
	($ in millions)	
Known claims	68.6	69.8
IBNR	406.9	411.2
Total estimated title losses	475.5	481.0

26

The amount of the reserve represents the aggregate, non-discounted future payments (net of recoveries) that we expect to incur on policy and escrow losses and in costs to settle claims. Title claims are generally incurred three to five years after policy issuance and the timing of payments on these claims can significantly impact the balance of known claims. In many cases, claims may be open for several years before the resolution and payment of the claims occur; as a result, the estimate of the ultimate amount to be paid may be modified over that time period.

Due to the inherent uncertainty in predicting future title policy losses, significant judgment is required by both our management and our third party actuaries in estimating reserves. As a consequence, our ultimate liability may be materially greater or less than current reserves and/or our third party actuary's calculated estimates.

Depreciation and amortization. Depreciation and amortization expenses during the second quarter and first six months of 2018 were comparable to the same periods in 2017.

Income taxes. Our effective tax rates, based on income before taxes and after deducting income attributable to noncontrolling interests, were 20% and 19% in the second quarter and first six months of 2018, respectively. Excluding discrete income tax benefit effects of approximately $1.5 million (primarily related to a cumulative foreign currency adjustment on deemed repatriation of foreign earnings) in both the second quarter and first six months of 2018, our effective tax rates were 25% and 26%, respectively. Our effective tax rates in the second quarter and first six months of 2017 were 37% and 32%, respectively. Excluding discrete net income tax benefit effects of $1.5 million (primarily related to previously unrecognized research and development tax credits) in the first six months of 2017, our effective tax rate was 37%. The lower effective tax rates in 2018, compared to 2017, were primarily the result of the reduced corporate tax rate of the Tax Cuts and Jobs Act that was enacted in December 2017.

LIQUIDITY AND CAPITAL RESOURCES

Our liquidity and capital resources reflect our ability to generate cash flow to meet our obligations to shareholders, customers (payments to satisfy claims on title policies), vendors, employees, lenders and others. As of June 30, 2018, our cash and investments, including amounts reserved pursuant to statutory requirements, aggregated $818.1 million ($322.2 million, net of statutory reserves on cash and investments). Of our total cash and investments at June 30, 2018, $549.1 million ($254.7 million, net of statutory reserves) was held in the United States (U.S.) and the rest internationally, principally in Canada.

Cash held at the parent company totaled $2.5 million at June 30, 2018. As a holding company, the parent company is funded principally by cash from its subsidiaries in the form of dividends, operating and other administrative expense reimbursements and pursuant to intercompany tax sharing agreements. The expense reimbursements are paid in accordance with management agreements, approved by the Texas Department of Insurance (TDI), among us and our subsidiaries. In addition to funding operating expenses, cash held at the parent company is used for dividend payments to common stockholders and for stock repurchases, if any. To the extent such uses exceed cash available, the parent company is dependent on distributions from its regulated title insurance underwriter, Stewart Title Guaranty Company (Guaranty).

A substantial majority of our consolidated cash and investments as of June 30, 2018 was held by Guaranty and its subsidiaries. The use and investment of these funds, dividends to the parent company, and cash transfers between Guaranty and its subsidiaries and the parent company are subject to certain legal and regulatory restrictions. In general, Guaranty may use its cash and investments in excess of its legally-mandated statutory premium reserve (established in accordance with requirements under Texas law) to fund its insurance operations, including claims payments. Guaranty may also, subject to certain limitations, provide funds to its subsidiaries (whose operations consist principally of field title offices and ancillary services operations) for their operating and debt service needs.

We maintain investments in accordance with certain statutory requirements in the states of domicile of our underwriters for the funding of statutory premium reserves. Statutory premium reserves, which approximated $482.4 million and $490.8 million at June 30, 2018 and December 31, 2017, respectively, are required to be fully funded and invested in high-quality securities and short-term investments. Statutory reserve funds are not available for current claim payments, which must be funded from current operating cash flow. In addition, included within cash and cash equivalents are statutory reserve funds of approximately $13.6 million and $14.2 million at June 30, 2018 and December 31, 2017, respectively. Although these cash statutory reserve funds are not restricted or segregated in depository accounts, they are required to be held pursuant to state statutes. If the Company fails to maintain minimum investments or cash and cash equivalents sufficient to meet statutory requirements, the Company may be subject to fines or other penalties, including potential revocation of its business license. As of June 30, 2018, our known claims reserve totaled $68.6 million and our estimate of claims that may be reported in the future, under generally accepted accounting principles, totaled $406.9 million. In addition to this, we had cash and investments (excluding equity method investments) of $268.4 million which are available for underwriter operations, including claims payments.

The ability of Guaranty to pay dividends to its parent is governed by Texas insurance law. The TDI must be notified of any dividend declared, and any dividend in excess of the statutory maximum of 20% of surplus (approximately $102.0 million as of December 31, 2017) would be, by regulation, considered extraordinary and subject to pre-approval by the TDI. Also, the Texas Insurance Commissioner may raise an objection to a planned distribution during the notification period. Guaranty’s actual ability or intent to pay dividends to its parent may be constrained by business and regulatory considerations, such as the impact of dividends on surplus and the liquidity ratio, which could affect its ratings and competitive position, the amount of insurance it can write and its ability to pay future dividends. As of March 31, 2018, our liquidity ratio for our principal underwriter was 109% based on its statutory balance sheet. The liquidity ratio is calculated using Guaranty's total cash and investments divided over its total liabilities. Our internal objective is to maintain a ratio of at least 100%, as we believe that ratio is crucial to our competitiveness in the market and our insurer financial strength ratings. On an ongoing basis, this ratio will largely guide our decisions as to frequency and magnitude of dividends from Guaranty to the parent company. Further, depending on business and regulatory conditions, we may in the future need to retain cash in Guaranty or even raise cash in the capital markets to contribute to it in order to maintain its ratings or statutory capital position. Such a requirement could be the result of investment losses, reserve charges, adverse economic environment operating conditions or changes in interpretation of statutory accounting requirements by regulators. No dividend was paid by Guaranty to its parent during the first six months of 2018 and 2017.

As the parent company conducts no operations apart from its wholly-owned subsidiaries, the discussion below focuses on consolidated cash flows.

	For the Six Months Ended June 30,	
	2018	2017
	($ in millions)	
Net cash provided by operating activities	7.4	16.5
Net cash used by investing activities	(7.1)	(43.1)
Net cash used by financing activities	(27.6)	(13.7)

Operating activities. Our principal sources of cash from operations are premiums on title policies and revenue from title service-related transactions, ancillary services and other operations. Our independent agencies remit cash to us net of their contractual retention. Our principal cash expenditures for operations are employee costs, operating costs and title claims payments.

Cash provided by operations decreased $9.2 million in the first six months of 2018 compared to the same period in 2017, primarily due to lower net income generated in 2018 and higher payments on accounts payable and other liabilities. Although our business is labor intensive, we are focused on a cost-effective, scalable business model which includes utilization of technology, centralized back and middle office functions and business process outsourcing. Our approach allows us to adjust more easily to seasonal and cyclical fluctuations in transaction volumes. We are continuing our emphasis on cost management, specifically focusing on lowering unit costs of production, which will result in improved margins. Our plans to improve margins also include additional automation of manual processes, and further consolidation of our various systems and production operations. We are currently investing in the technology necessary to accomplish these goals.

Investing activities. Cash used by investing activities was primarily driven by purchases of investments, capital expenditures and acquisition of subsidiaries, offset by proceeds from matured and sold investments. For the first six months of 2018 and 2017, total proceeds from securities investments sold and matured were $36.1 million and $72.5 million, respectively; while cash used for purchases of securities investments was $26.2 million and $88.4 million, respectively. The higher purchases and sale of investments in 2017, compared to 2018, was primarily due to a reallocation of cash to investments in the portfolio held by our Canadian operations, as well as overall portfolio repositioning in the first half of 2017 to prepare for a higher rate environment.

During the first six months of 2018 and 2017, we used $12.0 million and $18.1 million, respectively, of cash for acquisitions of new subsidiaries; while cash used for purchases of property and equipment were $5.7 million and $9.3 million, respectively. We maintain investment in capital expenditures at a level that enables us to implement technologies for increasing our operational and back-office efficiencies and to pursue growth in key markets.

Financing activities and capital resources. Total debt and stockholders' equity were $107.7 million and $666.2 million, respectively, as of June 30, 2018. Notes payable payments during the first six months of 2018 and 2017 of $4.1 million and $16.0 million, respectively, were related to short-term loan agreements in connection with our Section 1031 tax-deferred property exchange (Section 1031) business. During the first six months of 2017, we borrowed $16.0 million from our line of credit facility and added $9.9 million of notes payable related to our Section 1031 business. At June 30, 2018, the outstanding balance of the line of credit facility was $98.9 million, while the remaining balance of the line of credit available for use was $23.6 million, net of an unused $2.5 million letter of credit. At June 30, 2018, our debt-to-equity ratio, excluding our Section 1031 notes, was approximately 16.1%, below the 20% we have set as our unofficial internal limit on leverage.

During both the first six months of 2018 and 2017, we paid total dividends of $0.60 per common share, which aggregated $14.1 million in both periods. There were no stock repurchases during the first six months of 2018 and 2017, except for repurchases during 2018 of approximately 16,600 shares (aggregate purchase price of approximately $0.7 million) related to the statutory income tax withholding on the vesting of restricted share grants to executives and senior management.

Effect of changes in foreign currency exchange rates. The effect of changes in foreign currency exchange rates on our cash and cash equivalents on the consolidated statements of cash flows was a net decrease of $1.6 million during the first six months of 2018 and a net increase of $1.7 million during the same period in 2017. Our principal foreign operating unit is in Canada, and, on average, the value of the U.S. dollar declined relative to the Canadian dollar during the first six months of 2018, compared to its appreciation during the same period in 2017.

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We believe we have sufficient liquidity and capital resources to meet the cash needs of our ongoing operations. However, we may determine that additional debt or equity funding is warranted to provide liquidity for achievement of strategic goals or acquisitions or for unforeseen circumstances. Other than scheduled maturities of debt, operating lease payments and anticipated claims payments, we have no material contractual commitments. We expect that cash flows from operations and cash available from our underwriters, subject to regulatory restrictions, will be sufficient to fund our operations, including claims payments. However, to the extent that these funds are not sufficient, we may be required to borrow funds on terms less favorable than we currently have or seek funding from the equity market, which may not be successful or may be on terms that are dilutive to existing stockholders.

Contingent liabilities and commitments. See discussion of contingent liabilities and commitments in Note 10 to the condensed consolidated financial statements included in Item 1 of Part I of this Report.

Other comprehensive (loss) income. Unrealized gains and losses on available-for-sale securities investments and changes in foreign currency exchange rates are reported net of deferred taxes in accumulated other comprehensive (loss) income, a component of stockholders' equity, until realized. For the first six months of 2018, net unrealized investment losses of $10.4 million, net of taxes, which increased our other comprehensive loss, were primarily related to temporary decreases in the fair values over costs of our corporate bond securities available-for-sale investments, driven by increases in the overall rate environment. During the first six months of 2018, the five-year U.S. treasury yield increased approximately 50 basis points and our net unrealized investment losses were consistent with this level of interest rate increase and our average bond investments duration of slightly more than 4 years. For the first six months of 2017, net unrealized investment gains of $2.4 million, net of taxes, which increased our other comprehensive income, were primarily related to temporary increases in the fair values over costs of our corporate and municipal bond securities available-for-sale investments as a result of the slight decline in interest rates during the first six months of 2017.

Changes in foreign currency exchange rates, primarily related to our Canadian operations, increased our other comprehensive loss, net of taxes, by $5.6 million for the first six months of 2018; while they increased our other comprehensive income, net of taxes, by $4.5 million for the same period in 2017.

Off-balance sheet arrangements. We do not have any material source of liquidity or financing that involves off-balance sheet arrangements, other than our contractual obligations under operating leases. We also routinely hold funds in segregated escrow accounts pending the closing of real estate transactions and have qualified intermediaries in tax-deferred property exchanges for customers pursuant to Section 1031 of the Internal Revenue Code. The Company holds the proceeds from these transactions until a qualifying exchange can occur. In accordance with industry practice, these segregated accounts are not included on the balance sheet. See Note 17 in our Annual Report on Form 10-K for the year ended December 31, 2017.

Forward-looking statements. Certain statements in this report are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements relate to future, not past, events and often address our expected future business and financial performance. These statements often contain words such as "expect," "anticipate," "intend," "plan," "believe," "seek," "will," "foresee" or other similar words. Forward-looking statements by their nature are subject to various risks and uncertainties that could cause our actual results to be materially different than those expressed in the forward-looking statements. These risks and uncertainties include, among other things, the challenging economic conditions; adverse changes in the level of real estate activity; changes in mortgage interest rates, existing and new home sales, and availability of mortgage financing; our ability to respond to and implement technology changes, including the completion of the implementation of our enterprise systems; the impact of unanticipated title losses or the need to strengthen our policy loss reserves; any effect of title losses on our cash flows and financial condition; the ability to attract and retain highly productive sales associates; the impact of vetting our agency operations for quality and profitability; independent agency remittance rates; changes to the participants in the secondary mortgage market and the rate of refinancing that affects the demand for title insurance products; regulatory non-compliance, fraud or defalcations by our title insurance agencies or employees; our ability to timely and cost-effectively respond to significant industry changes and introduce new products and services; the outcome of pending litigation; the impact of changes in governmental and insurance regulations, including any future reductions in the pricing of title insurance products and services; our dependence on our operating subsidiaries as a source of cash flow; the continued realization of expense savings from our cost management program; our ability to successfully integrate acquired businesses; our ability to access the equity and debt financing markets when and if needed; our ability to grow our international operations; seasonality and weather; and our ability to respond to the actions of our competitors. These risks and uncertainties, as well as others, are discussed in more detail in our documents filed with the Securities and Exchange Commission, including our Annual Report on Form 10-K for the year ended December 31, 2017, and if applicable, our Quarterly Reports on Form 10-Q, and our Current Reports on Form 8-K. All forward-looking statements included in this report are expressly qualified in their entirety by such cautionary statements. We expressly disclaim any obligation to update, amend or clarify any forward-looking statements contained in this report to reflect events or circumstances that may arise after the date hereof, except as may be required by applicable law.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

There have been no material changes during the quarter ended June 30, 2018 in our investment strategies, types of financial instruments held or the risks associated with such instruments that would materially alter the market risk disclosures made in our Annual Report on Form 10-K for the year ended December 31, 2017.

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. Our principal executive officer and principal financial officer are responsible for establishing and maintaining disclosure controls and procedures. They evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of June 30, 2018, and have concluded that, as of such date, our disclosure controls and procedures are adequate and effective to ensure that information we are required to disclose in the reports that we file or submit under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms, and (ii) accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting during the quarter ended June 30, 2018, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

See discussion of legal proceedings in Note 11 to the condensed consolidated financial statements included in Item 1 of Part I of this Report, which is incorporated by reference into this Part II, Item 1, as well as Item 3. Legal Proceedings, in our Annual Report on Form 10-K for the year ended December 31, 2017.

Item 1A. Risk Factors

There are no other changes during the six months ended June 30, 2018 to our risk factors as listed in our Annual Report on Form 10-K for the year ended December 31, 2017, except for the risk factors described below relating to Stewart's merger with Fidelity National Financial (FNF) (the Mergers) as announced during the first quarter 2018.

The Mergers may present certain risks to Stewart’s business and operations prior to the closing of the Mergers, including, among other things, risks that:

FNF’s stock price may be negatively impacted by risks and conditions that apply to FNF, which are different from the risks and conditions applicable to Stewart.

Upon completion of the Mergers, our stockholders who elect to receive the Stock Election Consideration or Mixed Election Consideration will become holders of FNF Common Stock. The businesses and markets of FNF and the other companies it has acquired and may acquire in the future are different from those of Stewart. There is a risk that various factors, conditions and developments that would not affect the price of our Common Stock could negatively affect the price of FNF Common Stock.

The Mergers are subject to the receipt of consents and clearances from regulatory authorities that may impose conditions that could have an adverse effect on Stewart or that could delay or, if not obtained, could prevent completion of the Mergers.

The Mergers are subject to approvals or non-disapprovals from or notices to state insurance regulators, state financial institution regulators, state real estate regulators and various other federal and state regulatory authorities, as well as insurance authorities in Canada, Mexico and the United Kingdom. Additionally, the Mergers are subject to review by the FTC and the Antitrust Division of the DOJ under the HSR Act, and the Canada Competition Bureau under the Canadian Competition Act. Before the Mergers may be completed, applicable waiting periods must expire or terminate under antitrust laws and various approvals, consents or clearances may be required to be obtained from regulatory entities. In deciding whether to grant antitrust or other regulatory clearances, the relevant governmental entities will consider the effect of the Mergers on competition within their relevant jurisdictions. The terms and conditions of the approvals that are granted may impose requirements, limitations or costs or place restrictions on the conduct of FNF’s business following the Mergers. There can be no assurance that regulators will not impose conditions, terms, obligations or restrictions and that such conditions, terms, obligations or restrictions will not have the effect of delaying completion of the Mergers or imposing additional material costs on or materially limiting the revenues of FNF following the Mergers. In addition, neither FNF nor Stewart can provide assurance that any such conditions, terms, obligations or restrictions will not result in the delay or abandonment of the Mergers.

Our stockholders may not receive all consideration in the form they elect, and the form of consideration that they receive may have a lower value or less favorable tax consequences than the form of consideration that they elect to receive.

Our stockholders that make an election for either the Cash Election Consideration or the Stock Election Consideration will be subject to proration if holders of our Common Stock, in the aggregate, elect to receive more or less than the aggregate amount of cash consideration to be paid in the Mergers. Accordingly, some of the consideration our stockholders receive in the Mergers may differ from the type of consideration they select and such difference may be significant. This may result in, among other things, tax consequences that differ from those that would have resulted if our stockholders had received solely the form of consideration that they elected. The relative proportion of stock and cash that one of our stockholders receives may also have a value that is higher or lower than the relative proportion of stock and cash that such stockholder elected to receive.

We may have difficulty attracting, motivating and retaining executives and other employees in light of the Mergers.

Uncertainty about the effect of the Mergers on our employees may have an adverse effect on us. This uncertainty may impair our ability to attract, retain and motivate personnel until the Mergers are completed. We are dependent on the experience and industry knowledge of our officers and other key employees to execute our business plans. The combined company’s success after the Mergers will depend in part upon its ability to retain key management personnel and other key employees of FNF and Stewart. Employee retention may be particularly challenging during the pendency of the Mergers, as employees may feel uncertain about their future roles with the combined company. In addition, we may have to provide additional compensation in order to retain employees. If employees of FNF and Stewart depart because of issues relating to the uncertainty and difficulty of integration or a desire not to become employees of the combined company, the combined company’s ability to realize the anticipated benefits of the Mergers could be reduced.

We will incur substantial transaction-related costs in connection with the Mergers.

We expect to incur a number of non-recurring transaction-related costs associated with completing the Mergers, combining the operations of the two companies and achieving desired synergies. These fees and costs will be substantial. Non-recurring transaction costs include, but are not limited to, fees paid to legal, financial and accounting advisors, filing fees and printing costs. Additional unanticipated costs may be incurred in the integration of the businesses of FNF and Stewart. There can be no assurance that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction-related costs over time. Thus, any net benefit may not be achieved in the near term, the long term or at all.

The Mergers are subject to conditions, including certain conditions that may not be satisfied, and may not be completed on a timely basis, or at all. Failure to complete the Mergers could have material and adverse effects on us.

The completion of the Mergers is subject to a number of conditions, including the approval of the Merger Agreement proposal by our stockholders, which make the completion and timing of the completion of the Mergers uncertain. Also, either we or FNF may terminate the Merger Agreement if the Mergers have not been completed by March 18, 2019 (or the extended end date, if applicable), unless the failure of the Mergers to be completed by such date has resulted from the failure of the party seeking to terminate the Merger Agreement to perform its obligations.

If the Mergers are not completed on a timely basis, or at all, our ongoing businesses may be adversely affected and, without realizing any of the benefits of having completed the Mergers, we will be subject to a number of risks, including the following:

- we may be required, under certain circumstances, to pay FNF a termination fee of $33 million if the Merger Agreement is terminated under qualifying circumstances, as described in the Merger Agreement;
- we will be required to pay certain costs relating to the Mergers, whether or not the Mergers are completed, such as legal, accounting, financial advisor and printing fees;
- under the Merger Agreement, we are subject to certain restrictions on the conduct of its business prior to completing the Mergers which may adversely affect its ability to execute certain of its business strategies;
- time and resources committed by our management to matters relating to the Mergers could otherwise have been devoted to pursuing other beneficial opportunities;
- the market price of our Common Stock could decline below current market prices to the extent that such current market prices reflect a market assumption that the Mergers will be completed; and
- if the Merger Agreement is terminated and our board seeks another business combination, our stockholders cannot be certain that we will be able to find a party willing to enter into a business combination or other strategic transaction on terms equivalent to or more attractive than the terms that FNF has agreed to in the Merger Agreement.

In addition, if the Mergers are not completed, we may experience negative reactions from the financial markets and from our customers and employees. We could also be subject to litigation related to any failure to complete the Mergers or to enforcement proceedings commenced against us to perform our obligations under the Merger Agreement. If the Mergers are not completed, we cannot assure our stockholders that the risks described above will not materialize and will not adversely affect the business, financial results and stock prices of Stewart.

The Merger Agreement contains provisions that limit our ability to pursue alternatives to the Mergers, could discourage a potential competing acquirer from making a favorable alternative transaction proposal and, in specified circumstances, could require us to pay a termination fee of $33 million to FNF.

Under the Merger Agreement, we are restricted from entering into an alternative transaction. Unless and until the Merger Agreement is terminated, subject to specified exceptions, we are restricted from soliciting, initiating, knowingly facilitating, knowingly encouraging or knowingly inducing or negotiating, any inquiry, proposal or offer for a competing acquisition proposal with any person. Additionally, under the Merger Agreement, in the event of a potential change by our board of its recommendation with respect to the Mergers in light of a superior proposal, we must provide FNF with four business days' notice to allow FNF to propose an adjustment to the terms and conditions of the Merger Agreement. We may terminate the Merger Agreement and enter into an agreement with respect to a superior proposal only if specified conditions have been satisfied, including compliance with the no solicitation and termination provisions of the Merger Agreement. These provisions could discourage a third party that may have an interest in acquiring all or a significant part of Stewart from considering or proposing that acquisition, even if such third party were prepared to pay consideration with a higher per share cash or market value than the market value proposed to be received or realized in the Mergers, or might result in a potential competing acquirer proposing to pay a lower price than it would otherwise have proposed to pay because of the added expense of the termination fee that may become payable in specified circumstances.

Under the Merger Agreement, we may be required to pay to FNF a termination fee of $33 million if the Merger Agreement is terminated under specified circumstances. If such a termination fee is payable, the payment of this fee could have material and adverse consequences to our financial condition and operations.

We are subject to business uncertainties and contractual restrictions while the Mergers are pending, which could adversely affect our business and operations.

Under the terms of the Merger Agreement, we are subject to certain restrictions on the conduct of our business prior to completing the Mergers, which may adversely affect our ability to execute certain of our business strategies, including the ability in certain cases to enter into contracts or incur capital expenditures to grow our business. Such limitations could negatively affect our businesses and operations prior to the completion of the Mergers. Furthermore, the process of planning to integrate two businesses and organizations for the post-merger period can divert management attention and company resources and could ultimately have an adverse effect on us.

In connection with the pending Mergers, it is possible that some customers, suppliers and other persons with whom we have a business relationship may delay or defer certain business decisions or might decide to seek to terminate, change or renegotiate their relationships with us as a result of the proposed Mergers, which could negatively affect our revenues, earnings and cash flows, as well as the market price of shares of our Common Stock, regardless of whether the Mergers are completed.

Because the exchange ratio is fixed and because the market price of FNF Common Stock and our Common Stock will fluctuate, our stockholders receiving FNF Common Stock as part of the merger consideration cannot be sure of the market value of such merger consideration relative to the value of their shares of our Common Stock that they are exchanging.

If the Mergers are completed, each share of our Common Stock will be converted into the right to receive either $50.00 in cash, 1.2850 shares of FNF Common Stock or $25.00 in cash and 0.6425 shares of FNF Common Stock (subject to the adjustment and proration procedures set forth in the Merger Agreement). During the pendency of the Mergers, the market value of FNF Common Stock will fluctuate, and decreases in the market value of FNF Common Stock will negatively affect the value of the merger consideration that our stockholders receive. The market value of our Common Stock will also fluctuate during the pendency of the Mergers, and increases in the market value of our Common Stock may mean that the merger consideration issued to our stockholders will be worth less than the market value of the shares of our Common Stock such stockholders are exchanging. The exchange ratio was fixed at the time the Merger Agreement was executed, and the value of FNF and Stewart stock may vary significantly from their values on the date of the Merger Agreement, the date of this report, the date on which our stockholders vote on the Merger Agreement, the date on which our stockholders make their election and the date on which our stockholders receive the merger consideration. Neither Stewart nor FNF is permitted to terminate the Merger Agreement solely due to changes in the market price of either party’s common stock.

There will be a time lapse between the date on which our stockholders make an election with respect to the form of merger consideration to be received by them in exchange for their Common Stock and the date on which our stockholders actually receive FNF Common Stock, depending on their election and subject to proration. Fluctuations in the market value of FNF stock during this time period will also affect the value of the merger consideration, once it is actually received.

If any of our stockholders makes a stock election or mixed election and the market value of FNF Common Stock falls between the time of the election and the time the merger consideration is actually received, the value of the merger consideration received may be less than the value of the merger consideration such stockholder would have received under a cash election. Conversely, if any of our stockholders makes a cash election and the market value of FNF Common Stock rises between the time of the election and the time the merger consideration is actually received, the value of the merger consideration received may be less than the value of the merger consideration such stockholder would have received under a stock or mixed election. Our stockholders are urged to obtain current market quotations for FNF Common Stock when they make their elections.

If the Mergers are approved, the date that our stockholders will receive the merger consideration is uncertain and, due to potential divestitures required by regulatory authorities, the per share purchase price may be adjusted downwards.

If the proposed Mergers are approved, the date that our stockholders will receive the merger consideration depends on the completion date of the Mergers, which is uncertain. Additionally, under the terms of the Merger Agreement, if the combined company is required to divest assets or businesses with 2017 annual revenues in excess of $75 million in order to receive required regulatory approvals (up to a cap of $225 million of 2017 annual revenues), the per share purchase price will be adjusted downwards on a sliding scale between such amounts of divestitures up to a maximum reduction of $4.50 in value in the event that businesses or assets with 2017 annual revenues of $225 million are divested.

There can be no assurance that a divestiture or divestitures of businesses and assets in excess of $75 million in 2017 annual revenues will not occur, and accordingly there can be no assurance that holders of our Common Stock will receive (i) for those who make an election for the Cash Election Consideration, $50.00 per share in cash instead of an amount less than $50.00 per share in cash (but in any case, no less than $45.50 per share in cash), (ii) for those who make an election for the Stock Election Consideration, an amount of FNF Common Stock equal to 1.2850 shares of FNF Common Stock per share of our Common Stock instead of an amount of FNF Common Stock less than 1.2850 shares of FNF common stock per share of our common stock calculated based on a reduced exchange ratio for the number of shares of FNF Common Stock per share of our Common Stock or (iii) for those who make an election for the Mixed Election Consideration, $25.00 per share in cash and an amount of FNF Common Stock equal to 0.6425 shares of FNF Common Stock per share of our Common Stock instead of an amount less than $25.00 per share in cash and an amount of FNF Common Stock less than 0.6425 shares of FNF Common Stock per share of our Common Stock calculated based on a reduced exchange ratio for the number of shares of FNF Common Stock per share of our Common Stock, as applicable.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

There were no repurchases of our Common Stock during the six months ended June 30, 2018, except for repurchases related to the statutory income tax withholding on the vesting of restricted share grants to executives and senior management.

Item 5. Other Information

Our book value per share was $28.06 and $28.62 as of June 30, 2018 and December 31, 2017, respectively. As of June 30, 2018, our book value per share was based on approximately $666.2 million in stockholders' equity and 23,744,939 shares of Common Stock outstanding. As of December 31, 2017, our book value per share was based on approximately $678.8 million in stockholders' equity and 23,719,522 shares of Common Stock outstanding.

Item 6. Exhibits
Exhibit

2.1 - Agreement and Plan of Merger, dated as of March 18, 2018, among the Registrant, Fidelity National Financial, Inc., A Holdco Corp. and S Holdco LLC. (incorporated by reference in this report from Exhibit 2.1 of the Current Report on Form 8-K filed on March 19, 2018)

3.1 - Restated Certificate of Incorporation of the Registrant, dated April 28, 2016 (incorporated by reference in this report from Exhibit 3.1 of the Current Report on Form 8-K filed April 29, 2016)

3.2 - Third Amended and Restated By-Laws of the Registrant, as of April 27, 2016 (incorporated by reference in this report from Exhibit 3.2 of the Current Report on Form 8-K filed April 28, 2016)

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

32.1* - Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

32.2* - Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

36

101.INS* - XBRL Instance Document

101.SCH* - XBRL Taxonomy Extension Schema Document

101.CAL* - XBRL Taxonomy Extension Calculation Linkbase Document

101.DEF* - XBRL Taxonomy Extension Definition Linkbase Document

101.LAB* - XBRL Taxonomy Extension Label Linkbase Document

101.PRE* - XBRL Taxonomy Extension Presentation Linkbase Document
* Filed herewith
† Management contract or compensatory plan

SIGNATURE
Pursuant to the requirements of the Securities and Exchange Act of 1934, the registrant has caused this report to be signed on its behalf by the undersigned thereunto duly authorized.
August 6, 2018
Date
Stewart Information Services Corporation
Registrant

By: /s/ David C. Hisey
David C. Hisey, Chief Financial Officer, Secretary and Treasurer