SL GREEN REALTY CORP
Form DEF 14A
April 30, 2009

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

SCHEDULE 14A

Proxy Statement Pursuant to Section 14(a) of
the Securities Exchange Act of 1934 (Amendment No.)

Filed by the Registrant ý

Filed by a Party other than the Registrant o

Check the appropriate box:

o Preliminary Proxy Statement

o **Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e)(2))**

ý Definitive Proxy Statement

o Definitive Additional Materials

o Soliciting Material Pursuant to §240.14a-12

SL GREEN REALTY CORP.

(Name of Registrant as Specified In Its Charter)

(Name of Person(s) Filing Proxy Statement, if other than the Registrant)

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(3) Filing Party:

(4) Date Filed:

SL GREEN REALTY CORP.
420 Lexington Avenue
New York, New York 10170-1881

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS
to be held on June 11, 2009

Dear Stockholder:

You are invited to attend the 2009 annual meeting of stockholders of SL Green Realty Corp., a Maryland corporation, which will be held on Thursday, June 11, 2009 at 10:00 a.m., local time, at the Grand Hyatt New York Hotel, Park Avenue at Grand Central Terminal, 109 East 42nd Street, New York, New York. At the annual meeting, stockholders will be asked to consider and vote upon the following proposals:

1. To elect two Class III directors to serve on our Board of Directors for a three-year term; and

2. To ratify the appointment of Ernst & Young LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2009.

In addition, stockholders may be asked to consider and vote upon any other matters that may properly be brought before the annual meeting and at any adjournments or postponements thereof.

Any action may be taken on the foregoing matters at the annual meeting on the date specified above, or on any date or dates to which the annual meeting may be adjourned, or to which the annual meeting may be postponed.

Our Board of Directors has fixed the close of business on March 30, 2009 as the record date for determining the stockholders entitled to notice of, and to vote at, the annual meeting and at any adjournments or postponements thereof.

The Securities and Exchange Commission recently adopted rules that allow us to make proxy materials available to our stockholders on the Internet. You can now access proxy materials and authorize your proxy at http://www.proxyvote.com. You may also authorize your proxy via the Internet or by telephone by following the instructions on that website. In order to authorize your proxy via the Internet or by telephone you must have a stockholder identification number which is being mailed to you on a Notice of Internet Availability of Proxy Materials. You may also request a paper or an e-mail copy of our proxy materials and a paper proxy card by following the instructions included in the Notice of Internet Availability of Proxy Materials.

By Order of our Board of Directors

Andrew S. Levine
Secretary

Important Notice Regarding the Availability of Proxy Materials for the Stockholder Meeting to be Held on June 11, 2009.

This proxy statement and our 2008 Annual Report to Stockholders are available at http://www.proxyvote.com

New York, New York
April 30, 2009

Whether or not you plan to attend the annual meeting, please carefully read the proxy statement and other proxy materials and complete a proxy for your shares as soon as possible. You may authorize your proxy via the Internet or by telephone by following the instructions on the website indicated in the Notice of Internet Availability of Proxy Materials that you received in the mail. You may also request a paper or an e-mail copy of our proxy materials and a paper proxy card at any time. If you attend the annual meeting, you may vote in person if you wish, even if you have previously submitted your proxy. Please note, however, that if your shares are held of record by a bank, broker or other nominee and you wish to vote in person at the annual meeting, you must obtain a proxy issued in your name from such bank, broker or other nominee.

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420 Lexington Avenue
New York, New York 10170-1881

PROXY STATEMENT

FOR OUR 2009 ANNUAL MEETING OF STOCKHOLDERS

to be held on June 11, 2009

These proxy materials are being made available in connection with the solicitation of proxies by the Board of Directors, or the Board, of SL Green Realty Corp., a Maryland corporation, for use at the 2009 annual meeting of stockholders to be held on Thursday, June 11, 2009 at 10:00 a.m., local time, at the Grand Hyatt New York Hotel, Park Avenue at Grand Central Terminal, 109 East 42nd Street, New York, New York, or at any postponement or adjournment of the annual meeting. References in this proxy statement to "we," "us," "our," "ours," and the "Company" refer to SL Green Realty Corp., unless the context otherwise requires. This proxy statement and a form of proxy have been made available to our stockholders on the Internet, and the Notice of Internet Availability of Proxy Materials has been mailed, on or about April 30, 2009.

QUESTIONS AND ANSWERS ABOUT THE ANNUAL MEETING

What is the Notice of Internet Availability of Proxy Materials that I received in the mail this year instead of a full set of proxy materials?

In accordance with rules recently adopted by the Securities and Exchange Commission, or the SEC, we may furnish proxy materials, including this proxy statement and the Company's 2008 annual report to stockholders, by providing access to these documents on the Internet instead of mailing a printed copy of our proxy materials to our stockholders. In accordance with such rules, most of our stockholders have already received a Notice of Internet Availability of Proxy Materials, or the Notice, which provides a website address with instructions for accessing our proxy materials, including this proxy statement, and for requesting printed copies of the proxy materials by mail or electronically by e-mail.

If you would like to receive a paper or an e-mail copy of our proxy materials for the 2009 annual meeting or for all future annual meetings, you should follow the instructions for requesting such materials included in the Notice. We believe the delivery option that we have chosen this year will allow us to provide our stockholders with the proxy materials they need, while lowering the cost of delivery of the materials and reducing the environmental impact of printing and mailing printed copies.

Who is entitled to vote at the annual meeting?

Holders of record of our common stock, $0.01 par value per share, at the close of business on March 30, 2009, the record date for the annual meeting, are entitled to receive notice of the annual meeting and to vote at the annual meeting. If you are a holder of record of our common stock as of the record date, you may vote the shares that you held on the record date even if you sell such shares after the record date. Each outstanding share as of the record date entitles its holder to cast one vote for each matter to be voted upon and, with respect to the election of directors, one vote for each director to be elected. Stockholders do not have the right to cumulate voting for the election of directors.

What is the purpose of the annual meeting?

At the annual meeting, you will be asked to vote on the following proposals:

Proposal 1: the election of two Class III directors to serve on our Board of Directors for a three-year term; and

Proposal 2: the ratification of the appointment of Ernst & Young LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2009.

You may also be asked to consider and act upon any other matters that may properly be brought before the annual meeting and at any adjournments or postponements thereof.

What constitutes a quorum?

The presence, in person or by proxy, of holders of a majority of the total number of outstanding shares entitled to vote at the annual meeting is necessary to constitute a quorum for the transaction of any business at the annual meeting. As of the record date, there were 57,258,756 shares outstanding and entitled to vote at the annual meeting.

What vote is required to approve each proposal?

A plurality of all of the votes cast at the annual meeting at which a quorum is present is required for the election of directors. A majority of all of the votes cast at the annual meeting at which a quorum is present is required for the ratification of the appointment of Ernst & Young LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2009. We will treat abstentions as shares that are present and entitled to vote for purposes of determining the presence or absence of a quorum. Abstentions do not constitute a vote "for," "withheld" or "against" and will not be counted as "votes cast." Therefore, abstentions will have no effect on either Proposal 1 or Proposal 2.

Can I change my vote after I submit my proxy card?

If you cast a vote by proxy, you may revoke it at any time before it is voted by:

- filing a written notice revoking the proxy with our Secretary at our address;
- properly signing and forwarding to us a proxy with a later date; or
- appearing in person and voting by ballot at the annual meeting.

If you attend the annual meeting, you may vote in person whether or not you have previously given a proxy, but your presence (without further action) at the annual meeting will not constitute revocation of a previously given proxy. Unless you have received a legal proxy to vote the shares, if you hold your shares through a bank, broker or other nominee, that is, in "street name," only that bank, broker or other nominee can revoke your proxy on your behalf.

You may revoke a proxy for shares held by a bank, broker or other nominee by submitting new voting instructions to the bank, broker or other nominee or, if you have obtained a legal proxy from the bank, broker or other nominee giving you the right to vote the shares at the annual meeting, by attending the annual meeting and voting in person.

How do I vote?

Voting in Person at the Annual Meeting. If you hold your shares in your own name as a holder of record with our transfer agent, The Bank of New York Mellon Corporation, and attend the annual meeting, you may vote in person at the annual meeting. If your shares are held by a bank, broker or other nominee, that is, in "street name," and you wish to vote in person at the annual meeting, you will need to obtain a "legal proxy" from the bank, broker or other nominee that holds your shares of record.

Voting by Proxy. You should submit your proxy or voting instructions as soon as possible.

If you received a paper copy of this Proxy Statement. You can vote by valid proxy received by telephone, electronically via the Internet or by mail. The deadline for voting by telephone or electronically via the Internet is 11:59 p.m., Eastern Time, on June 10, 2009. If voting by mail, you must:

- indicate your instructions on the proxy;
- date and sign the proxy;
- mail the proxy promptly in the enclosed envelope; and
- allow sufficient time for the proxy to be received before the date of the annual meeting.

If your shares are held in "street name" such as in a stock brokerage account, by a bank or other nominee, please follow the instructions you received from your broker or with respect to the voting of your shares.

If you received a Notice of Internet availability or e-mail copy of this Proxy Statement. Please submit your proxy via the internet using the instructions included in the Notice. The deadline for voting electronically via the Internet is 11:59 p.m., Eastern Time, on June 10, 2009.

If you have any questions regarding how to authorize your proxy by telephone or via the Internet, please call MacKenzie Partners, Inc., toll-free at (800) 322-2885 or collect at (212) 929-5500.

Even if you plan to attend the annual meeting, we recommend that you submit a proxy to vote your shares in advance so that your vote will be counted if you later are unable to attend the annual meeting.

How is my vote counted?

If you authorize your proxy to vote your shares electronically via the Internet or by telephone, or, if you received a proxy card by mail and you properly marked, signed, dated and returned it, the shares that the proxy represents will be voted in the manner specified on the proxy. If no specification is made, your shares will be voted "for" the election of the nominees for the Class III directors named in this proxy statement, and "for" ratification of the appointment of Ernst & Young LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2009. It is not anticipated that any matters other than those set forth in this proxy statement will be presented at the annual meeting. If other matters are presented, proxies will be voted in accordance with the discretion of the proxy holders. In addition, since no stockholder proposals or nominations were received on a timely basis, no such matters will be brought to a vote at the annual meeting.

How does the Board recommend that I vote on each of the proposals?

The Board recommends that you vote:

- FOR *Proposal 1*: the election of Stephen L. Green and John H. Alschuler, Jr. to serve on our Board of Directors for a three-year term, as Class III directors; and
- FOR *Proposal 2*: the ratification of the appointment of Ernst & Young LLP as our independent registered public accounting firm for the fiscal year ending on December 31, 2009.

What other information should I review before voting?

Our 2008 annual report, including financial statements for the fiscal year ended December 31, 2008, is being made available to you along with this proxy statement. You may obtain, free of charge, copies of our 2008 annual report and our Annual Report on Form 10-K for the fiscal year ended December 31, 2008, which contains additional information about the Company, on our website at *http://www.slgreen.com* or by directing your request in writing to SL Green Realty Corp., 420 Lexington Avenue, New York, New York 10170-1881, Attention: Investor

Relations. The 2008 annual report and the Annual Report on Form 10-K, however, are not part of the proxy solicitation materials, and the information found on, or accessible through, our website is not incorporated into, and does not form a part of, this proxy statement or any other report or document we file with or furnish to the SEC.

Who is soliciting my proxy?

This solicitation of proxies is made by and on behalf of the Board. We will pay the cost of the solicitation of proxies. We have retained MacKenzie Partners, Inc. at an aggregate estimated cost of $7,500, plus out-of-pocket expenses, to assist in the solicitation of proxies. In addition to the solicitation of proxies by mail, our directors, officers and employees may solicit proxies personally or by telephone.

How do I change how I receive proxy materials in the future?

Instead of receiving a Notice of Internet Availability of Proxy Materials in the mail for future meetings, stockholders may elect to receive links to proxy materials by e-mail or to receive a paper copy of the proxy materials and a paper proxy card by mail. If you elect to receive proxy materials by e-mail, you will not receive a Notice of Internet Availability of Proxy Materials in the mail. Instead, you will receive an e-mail with links to proxy materials and online voting. In addition, if you elect to receive a paper copy of the proxy materials, or if applicable rules or regulations require delivery of the proxy materials, you will not receive a Notice of Internet Availability of Proxy Materials in the mail. If you received a paper copy of the proxy materials or the Notice of Internet Availability of Proxy Materials in the mail, you can eliminate all such paper mailings in the future by electing to receive an e-mail that will provide Internet links to these documents. Opting to receive all future proxy materials online will save us the cost of producing and mailing documents to you and help us conserve natural resources. You can change your election by directing your request in writing to SL Green Realty Corp., 420 Lexington Avenue, New York, New York 10170-1881, Attention: Investor Relations, by sending a blank e-mail with the 12-digit control number on your Notice of Internet Availability to sendmaterial@proxyvote.com, via the internet at *http://www.proxyvote.com* or by telephone at (800) 579-7639. Your election will remain in effect until you change it.

What should I do if I received more than one Notice of Internet Availability of Proxy Materials?

There are circumstances under which you may receive more than one Notice of Internet Availability of Proxy Materials. For example, if you hold your shares in more than one brokerage account, you may receive a separate voting instruction card for each such brokerage account. In addition, if you are a stockholder of record and your shares are registered in more than one name, you will receive more than one Notice of Internet Availability of Proxy Materials. Please authorize your proxy in accordance with the instructions of each Notice of Internet Availability of Proxy Materials separately, since each one represents different shares that you own.

No person is authorized on our behalf to give any information or to make any representations with respect to the proposals other than the information and the representations contained in this proxy statement, and, if given or made, such information and/or representations must not be relied upon as having been authorized.

PROPOSAL 1: ELECTION OF DIRECTORS

The Board of Directors, or the Board, of SL Green Realty Corp., or the Company, currently consists of five members and is divided into three classes. Directors in each class serve for a term of three years or until their successors are duly elected and qualify. The term of directors of one class expires at each annual meeting of stockholders.

At the annual meeting, two directors will be elected to serve until the 2012 annual meeting or until their successors are duly elected and qualify. The Board, upon the recommendation of the Nominating and Corporate Governance Committee, has nominated Stephen L. Green and John H. Alschuler, Jr. for election to serve as Class III directors. Each of the nominees is currently serving as a Class III director. Each of the nominees has consented to being named in this proxy statement and to serve as a director if elected. However, if either nominee is unable to accept election, proxies voted in favor of such nominee will be voted for the election of such other person or persons as the Board elects to nominate.

A plurality of all of the votes cast at the annual meeting at which a quorum is present in person or by proxy is required for the election of directors. We will treat abstentions as shares that are present and entitled to vote for purposes of determining the presence or absence of a quorum. Abstentions do not constitute a vote "for," "against" or "withheld" and will not be counted as "votes cast". Therefore, abstentions will have no effect on this proposal, assuming a quorum is present.

The Board unanimously recommends a vote "FOR" the election of each of Mr. Green and Mr. Alschuler.

Information Regarding the Nominees and the Continuing Directors

The following table and biographical descriptions set forth certain information with respect to each nominee for election as a Class III director at the 2009 annual meeting and the continuing Class I and Class II directors whose terms expire at the annual meetings of stockholders in 2010 and 2011, respectively, based upon information furnished by each director.

Name	Age	Director Since
Class III Nominees (terms will expire in 2012)		
John H. Alschuler, Jr.	61	1997
Stephen L. Green	71	1997
Class I Continuing Director (term will expire in 2010)		
Edward Thomas Burton, III	66	1997
Class II Continuing Directors (terms will expire in 2011)		
Marc Holliday	42	2001
John S. Levy	73	1997

Class III Nominees Terms Will Expire in 2012

John H. Alschuler, Jr. has served as one of our directors since 1997 and serves as Chairman of our Compensation Committee and as a member of our Audit, Executive and Nominating and Corporate Governance Committees. Since 2008, Mr. Alschuler has been the Chairman of HR&A Advisors Inc., an economic development, real-estate and public policy consulting organization. Mr. Alschuler is also an Adjunct Associate Professor at Columbia University, where he teaches real estate development at the Graduate School of Architecture, Planning & Preservation. Mr. Alschuler currently serves as a member of the Board of Directors of Friends of the High Line Inc., a Section 501(c)(3) tax-exempt organization. Mr. Alschuler received a B.A. degree from Wesleyan University and an Ed.D. degree from the University of Massachusetts at Amherst. Mr. Alschuler is 61 years old.

Stephen L. Green has served as our Chairman and a member of the Board since 1997 and serves as the Chairman of our Executive Committee. Mr. Green serves as an executive officer, working in conjunction with our Chief Executive Officer, overseeing our long-term strategic direction. In January 2004, Mr. Green stepped down from his position as our Chief Executive Officer following the promotion of Mr. Holliday to that position. Mr. Green founded our predecessor, S.L. Green Properties, Inc., in 1980. Prior to our initial public offering in 1997, Mr. Green had been involved in the acquisition of over 50 Manhattan office buildings containing in excess of 4.0 million square feet. Mr. Green has also served as Chairman of the Board of Gramercy Capital Corp., or Gramercy, since August 2004. Mr. Green is an at-large member of the Executive Committee of the Board of Governors of the Real Estate Board of New York and has previously served as Chairman of the Real Estate Board of New York's Tax Committee. Mr. Green has also served as a member of the Board of Directors of Stemedica Cell Technologies, Inc. since 2007. Mr. Green currently serves as a member of the Board of Directors of Streetsquash, Inc., a Section 501(c)(3) tax-exempt organization. Mr. Green also serves as a member of the board of trustees of the NYU Langone Medical Center. Mr. Green received a B.A. degree from Hartwick College and a J.D. degree from Boston College Law School. Mr. Green is 71 years old.

Class I Continuing Director Term Will Expire in 2010

Edwin Thomas Burton, III has served as one of our directors since 1997 and serves as Chairman of our Audit Committee and as a member of our Compensation and Nominating and Corporate Governance Committees. Mr. Burton is a Professor of Economics at the University of Virginia, has held various teaching positions at York College, Rice University and Cornell University, and has written and lectured extensively in the field of economics. Mr. Burton also serves as a member of the Board of Trustees of the Investment Advisory Committee of the Virginia Retirement System for state and local employees of the Commonwealth of Virginia, and served as its Chairman from 1997 until March 2001. Mr. Burton also serves as a consultant to numerous companies on investment strategy and investment banking. From 1994 until 1995, Mr. Burton served as Senior Vice President, Managing Director and director of Interstate Johnson Lane, Incorporated, an investment banking firm, where he was in charge of the Corporate Finance and Public Finance Divisions. From 1987 to 1994, Mr. Burton served as President of Rothschild Financial Services, Incorporated (a subsidiary of Rothschild, Inc. of North America), an investment banking company headquartered in New York City that is involved in proprietary trading, securities lending and other investment activities. Mr. Burton has also served as a member of the Board of Capstar Hotel Company, a publicly-traded hotel company, and SNL Securities, a private securities data company. Mr. Burton received a B.A. degree and an M.A. degree in Economics from Rice University and a Ph.D. degree in Economics from Northwestern University. Mr. Burton is 66 years old.

Class II Continuing Directors Terms Will Expire in 2011

Marc Holliday has served as our Chief Executive Officer since January 2004 and as one of our directors since December 2001. He also serves as a member of our Executive Committee. Mr. Holliday stepped down as our President in April 2007, when Andrew Mathias, our current President, was promoted to that position. Mr. Holliday joined the Company as Chief Investment Officer in July 1998. Mr. Holliday also serves as a director of Gramercy, and has served in such capacity since 2004. In October 2008, Mr. Holliday stepped down from his positions of President and Chief Executive Officer of Gramercy, positions he had held since August 2004. Prior to joining the Company, Mr. Holliday was Managing Director and Head of Direct Originations for New York-based Capital Trust, a mezzanine finance company, where he was in charge of originating direct principal investments for the firm, consisting of mezzanine debt, preferred equity and first mortgages. From 1991 to 1997, Mr. Holliday served in various management positions, including Senior Vice President at Capital Trust's predecessor, Victor Capital Group, a private real estate investment bank specializing in advisory services, investment management and debt and equity placements. Mr. Holliday received a B.S. degree in Business and

Finance from Lehigh University in 1988 and an M.S. degree in Real Estate Development from Columbia University in 1990. Mr. Holliday is 42 years old.

John S. Levy has served as one of our directors since 1997 and serves as Chairman of our Nominating and Corporate Governance Committee and as a member of our Audit and Compensation Committees. Mr. Levy retired from Lehman Brothers Inc. in 1995. From 1983 until 1995, at Lehman Brothers (or its predecessors), he served as Managing Director and Chief Administrative Officer of the Financial Services Division, Senior Executive Vice President and Co-Director of the International Division and Managing Partner of the Equity Securities Division. Mr. Levy was associated with A.G. Becker Incorporated (or its predecessors) from 1960 until 1983, where he served as Managing Director of the Execution Services Division, Vice President-Manager of Institutional and Retail Sales, Manager of the Institutional Sales Division, Manager of the New York Retail Office and a Registered Representative. Mr. Levy received a B.A. degree from Dartmouth College. Mr. Levy is 73 years old.

Biographical Information Regarding Executive Officers Who Are Not Directors

Gregory F. Hughes has served as our Chief Operating Officer since April 2007 and has served as our Chief Financial Officer since February 2004. Mr. Hughes also served as Chief Credit Officer of Gramercy from August 2004 to October 2008. Prior to joining the Company, from 2002 to 2003, Mr. Hughes was Managing Director and Chief Financial Officer of the real estate private equity group at JP Morgan Partners. From 1999 to 2002, Mr. Hughes was a partner and served as Chief Financial Officer of Fortress Investment Group LLC. Mr. Hughes also served as Chief Financial Officer of Wellsford Residential Property Trust and Wellsford Real Properties. From 1985 to 1992, Mr. Hughes worked at Kenneth Leventhal & Co., a public accounting firm specializing in real estate and financial services. Mr. Hughes received a B.S. degree in Accounting from the University of Maryland and is a Certified Public Accountant. Mr. Hughes is 46 years old.

Andrew S. Levine has served as our Chief Legal Officer since April 2007 and as our General Counsel, Executive Vice President and Secretary since November 2000. Prior to joining the Company, Mr. Levine was a partner in the REIT and Real Estate Transactions and Business groups at the law firm of Pryor, Cashman, Sherman & Flynn, LLP. Prior to joining Pryor, Cashman, Sherman & Flynn, LLP, Mr. Levine was a partner at the law firm of Dreyer & Traub. Mr. Levine received a B.A. degree from the University of Vermont and a J.D. degree from Rutgers School of Law, where Mr. Levine was an Editor of the Law Review. Mr. Levine is 50 years old.

Andrew Mathias has served as our President since April 2007 and as our Chief Investment Officer since January 2004. Mr. Mathias is in charge of the firm's equity and structured finance investments, overseeing our acquisitions and dispositions and our joint venture program. Mr. Mathias joined the Company in March 1999 as Vice President and was promoted to Director of Investments in 2002, a position he held until his promotion to Chief Investment Officer. In October 2008, Mr. Mathias stepped down from his position as Chief Investment Officer of Gramercy, a position he had held since August 2004. Prior to joining the Company, Mr. Mathias worked at Capital Trust and its predecessor, Victor Capital Group. Mr. Mathias also worked on the high yield and restructuring desk at Bear Stearns and Co. Mr. Mathias received a B.S. degree in Economics from the Wharton School at the University of Pennsylvania. Mr. Mathias is 35 years old.

The Board and its Committees

The Board held ten meetings during fiscal year 2008. Each of the directors attended at least 75% of the total number of Board meetings held during 2008 and Messrs. Holliday and Green attended our 2008 annual meeting.

The Board of Directors has four standing committees: an Audit Committee, a Compensation Committee, a Nominating and Corporate Governance Committee and an Executive Committee. The current charters for each of the Audit Committee, Compensation Committee and Nominating and

Corporate Governance Committee are available on our corporate website at *www.slgreen.com* under the "Investors Corporate Governance" section. Further, we will provide a copy of these charters without charge to each stockholder upon written request. Requests for copies should be addressed to Andrew S. Levine, Secretary, at SL Green Realty Corp., 420 Lexington Avenue, New York, New York 10170-1881. From time to time, the Board may also create additional committees for such purposes as the Board may determine.

Audit Committee. Our Audit Committee consists of John H. Alschuler, Jr., Edwin Thomas Burton, III (Chairman) and John S. Levy, each of whom is "independent" within the meaning of the rules of the NYSE and the SEC and each of whom meets the financial literacy standard required by the rules of the NYSE. The Board has determined that Mr. Burton is an "audit committee financial expert" as defined in the rules promulgated by the SEC under the Sarbanes-Oxley Act of 2002, as amended. Our Audit Committee's primary purpose is to assist the Board in its oversight of the integrity of the Company's financial statements; the Company's compliance with legal and regulatory requirements; the qualifications and independence of the registered public accounting firm employed by the Company for the audit of the Company's financial statements; the performance of the people responsible for the Company's internal audit function; and the performance of the Company's independent registered public accounting firm. Our Audit Committee also prepares the report that the rules of the SEC require be included in this proxy statement and provides an open avenue of communication among the Company's independent registered public accounting firm, its internal auditors, its management and the Board. Our management is responsible for the preparation, presentation and integrity of our financial statements and for the effectiveness of internal control over financial reporting. Management is responsible for maintaining appropriate accounting and financial reporting principles and policies and internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Our independent registered public accounting firm is responsible for planning and carrying out a proper audit of our annual financial statements, reviewing our quarterly financial statements prior to the filing of each Quarterly Report on Form 10-Q, and annually auditing the effectiveness of our internal control over financial reporting and other procedures. Our Audit Committee held nine meetings during fiscal year 2008. Each of the committee members attended at least 75% of the total number of meetings of our Audit Committee held during fiscal year 2008. Additional information regarding the functions performed by our Audit Committee is set forth in the "Audit Committee Report" included in this annual proxy statement.

Compensation Committee. Our Compensation Committee consists of John H. Alschuler, Jr. (Chairman), Edwin Thomas Burton, III and John S. Levy, each of whom is "independent" within the meaning of the rules of the NYSE. Each member of our Compensation Committee is also a "non-employee director," as defined in Section 16 of the Securities Exchange Act of 1934, as amended. Our Compensation Committee's primary purposes are to determine how the Company's Chief Executive Officer should be compensated; to administer the Company's employee benefit plans and executive compensation programs; to set policies and review management decisions regarding compensation of the Company's senior executives other than its Chief Executive Officer; and to produce the report on executive compensation required to be included in this proxy statement. With respect to the compensation of our executive officers, our Compensation Committee solicits recommendations from our Chief Executive Officer regarding total compensation for all executive officers other than the Chief Executive Officer and reviews his recommendations in terms of total compensation and the allocation of such compensation among base salary, annual bonus amounts and other long-term incentive compensation as well as the allocation of such items among cash and equity compensation. Our Compensation Committee has retained Gressle & McGinley LLC as its independent outside compensation consulting firm and has engaged Gressle & McGinley to provide the Compensation Committee with relevant data concerning the marketplace, our peer group and its own independent analysis and recommendation concerning executive compensation. Gressle & McGinley regularly participates in Compensation Committee meetings. See "Executive Compensation Compensation Discussion and Analysis." Our Compensation Committee held five meetings during fiscal year 2008. Each of the committee members attended at least 75% of the total number Compensation Committee meetings held during fiscal year 2008.

Nominating and Corporate Governance Committee. Our Nominating and Corporate Governance Committee consists of John H. Alschuler, Jr., Edwin Thomas Burton, III and John S. Levy (Chairman), each of whom is "independent" within the meaning of the rules of the NYSE. Our Nominating and Corporate Governance Committee's primary purposes are to identify individuals qualified to fill vacancies or newly created positions on the Board; to recommend to the Board the persons it should nominate for election as directors at annual meetings of the Company's stockholders; to recommend directors to serve on all committees of the Board; and to develop and recommend to the Board corporate governance guidelines applicable to the Company. During fiscal year 2008, our Nominating and Corporate Governance Committee nominated two Class II directors who were elected at our 2008 annual meeting of stockholders and held two meetings during fiscal year 2008. All of the committee members attended each of the Nominating and Corporate Governance Committee meetings held during fiscal year 2008.

Executive Committee. Subject to the supervision and oversight of the Board, our Executive Committee, which consists of Stephen L. Green (Chairman), Marc Holliday and John H. Alschuler, Jr., is responsible for, among other things, the approval of the acquisition, disposition and financing of investments by us; the authorization of the execution of certain contracts and agreements, including those relating to the borrowing of money by us; and the exercise, in general, of all other powers of the Board, except for such powers which require action by all directors or the independent directors under our articles of incorporation or bylaws or under applicable law.

Special Committee Gramercy Internalization. In 2008, our board formed a special committee, consisting of John H. Alschuler (Chairman), Jr., Edwin Thomas Burton, III and John S. Levy, to consider the internalization by Gramercy of its management functions and related actions.

Director Compensation

Directors of the Company who are also employees receive no additional compensation for their services as directors. The following table* sets forth information regarding the compensation paid to, and the compensation expense we recognized with respect to, our non-employee directors during the fiscal year ended December 31, 2008.

Name	Fees Earned or Paid in Cash(1) ($)	Stock Awards(2) ($)	Option Awards(3) ($)	All Other Compensation(4) ($)	Total ($)
Edwin T. Burton, III	$ 127,500	$ 100,800	$ 45,371	$ 23,008	$296,679
John H. Alschuler, Jr.	$ 143,000	$ 100,800	$ 45,371	$ 14,360	$303,531
John S. Levy	$ 119,500	$ 100,800	$ 45,371	$ 22,311	$287,982

* The columns for "Non-Equity Incentive Plan Compensation" and "Change in Pension Value and Nonqualified Deferred Compensation Earnings" have been omitted because they are not applicable.

(1) Each of Mr. Burton and Mr. Levy deferred all of their 2008 cash compensation and Mr. Alschuler deferred $25,000 of his 2008 cash compensation pursuant to our Independent Directors' Deferral Program. Deferred compensation included annual fees, chairman fees and board and committee meeting fees and is credited in the form of phantom stock units. Messrs. Burton, Levy and Alschuler received 2,156 units, 1,973 units and 350 units, respectively, in connection with 2008 cash compensation they elected to defer.

(2) Amounts shown do not reflect compensation actually received by the non-employee director. Instead, the amounts shown are the compensation costs recognized by the Company in fiscal year 2008 for stock awards as determined pursuant to Statement of Financial Accounting Standards No. 123R, or SFAS 123R. The assumptions used to calculate the value of stock awards are set forth under Note 2 of the Notes to Consolidated Financial Statements included in our Annual Report on Form 10-K for the year ended December 31, 2008, which was filed with the SEC on February 27, 2009. At December 31, 2008, the aggregate number of stock awards, including phantom stock units, outstanding was as follows: Mr. Burton 22,832; Mr. Alschuler 7,155; and Mr. Levy 29,387.

(3)

Amounts shown do not reflect compensation actually received by the non-employee director. Instead, the amounts shown are the compensation costs recognized by the Company in fiscal year 2008 for option awards as determined pursuant to SFAS 123R. The assumptions used to calculate the value of option awards are set forth under Note 2 of the Notes to Consolidated Financial Statements included in our Annual Report on Form 10-K for the year ended December 31, 2008, which was filed with the SEC on February 27, 2009. The full grant date fair value of the awards to each non-employee director calculated in accordance with SFAS 123R is $45,371. At December 31, 2008, the aggregate number of option awards outstanding was as follows: Mr. Burton 12,000; Mr. Alschuler 30,000; and Mr. Levy 60,000.

(4)

Represents the value of dividends paid in 2008 on the phantom stock units held by each non-employee director.

During the fiscal year ended December 31, 2008, each non-employee director received an annual fee of $50,000. Each non-employee director also received $1,500 for each meeting of the Board or a committee of the Board that he attended. The annual fee payable to our non-employee directors is payable quarterly, half in restricted stock and half in cash, unless a non-employee director elects to have the director fee paid 100% in stock or elects to defer all or part of the annual fee pursuant to our Independent Directors' Deferral Program as described below. The meeting fees are paid in cash unless a non-employee director elects to defer all or part of the meeting fees pursuant to our Independent Directors' Deferral Program. One of our non-employee directors who resides outside of New York is reimbursed for expenses of attending Board and committee meetings.

The Chairman of our Audit Committee, the Chairman of our Compensation Committee, and the Chairman of our Nominating and Corporate Governance Committee received additional annual fees of $10,000, $7,500 and $5,000, respectively, which are payable in cash unless such chairman elects to defer all or part of such fee pursuant to our Independent Directors' Deferral Program. In addition, each member of our Audit Committee was entitled to receive a fee of $4,000 per meeting for any special meetings of the Audit Committee held independently of Board meetings. No such meetings were held in 2008. The special meeting fees are paid in cash unless a director elects to defer all or part of the meeting fees pursuant to our Deferral Program. Under our Amended and Restated 2005 Stock Option and Incentive Plan, each non-employee director is entitled to an annual grant of options to purchase 6,000 shares, which are priced at the close of business on the first business day in the year of grant, all of which vest on the date of grant. In 2008, each non-employee director received a grant of 1,000 shares of restricted stock pursuant to our Amended and Restated 2005 Stock Option and Incentive Plan. In 2009, each non-employee director received a grant of 4,023 shares of restricted stock, which, at the closing price of our common stock on the grant date of January 2, 2009, had a fair market value of $100,000. A third of the shares from each such restricted stock grant vest on each of the first three anniversaries of the grant date, subject to the non-employee director remaining a member of the Board on the vesting date. A non-employee director may elect to defer all or part of the annual stock grant pursuant to our Deferral Program. In 2008, each non-employee director received a one-time fee of $15,000 in connection with such director's service on our special committee considering the internalization by Gramercy of its management functions. Additionally, the chairman of this special committee received an additional fee of $7,500, and each member of the committee is entitled to a fee of $1,500 per meeting. All fees in connection with this special internalization committee are paid in cash unless a director elects to defer all or part of the meeting fees pursuant to our Deferral Program.

Under our Deferral Program, our non-employee directors may elect to defer up to 100% of their annual fee, chairman fees, meeting fees and annual stock grant. Unless otherwise elected by a participant, fees deferred under the program will be credited in the form of phantom stock units. The phantom stock units are convertible into an equal number of shares of our common stock upon such director's termination of service from the Board or a change in control of the Company, as defined by the program. Phantom stock units are credited quarterly to each non-employee director using the closing price of our common stock on the first trading day of the respective quarter. In lieu of paying cash dividends on phantom stock units held by participating non-employee directors, each such director's account is credited for an amount of phantom stock units with a value equal to the dividend otherwise payable in respect of each quarter. The grant relating to any portion of director compensation that is paid in stock is made under our Amended and Restated 2005 Stock Option and Incentive Plan.

PROPOSAL 2: RATIFICATION OF APPOINTMENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Audit Committee of the Board has appointed the accounting firm of Ernst & Young LLP to serve as our independent registered public accounting firm for the fiscal year ending December 31, 2009, subject to ratification by our stockholders. Stockholder ratification of the appointment of Ernst & Young LLP is not required by law, the New York Stock Exchange or the Company's organizational documents. However, as a matter of good corporate governance, the Board has elected to submit the appointment of Ernst & Young LLP to the stockholders for ratification at the 2009 annual meeting. If the stockholders fail to ratify the appointment of Ernst & Young LLP, the Audit Committee will reconsider the matter, taking into consideration the stockholder vote on the ratification and the advisability of appointing a new independent registered public accounting firm prior to the completion of the 2009 audit and may decide to retain Ernst & Young LLP notwithstanding the vote. Ernst & Young LLP has served as our independent registered public accounting firm since our formation in June 1997 and is considered by our management to be well-qualified. Ernst & Young LLP has advised us that neither it nor any member thereof has any financial interest, direct or indirect, in the Company or any of our subsidiaries in any capacity.

A representative of Ernst & Young LLP will be present at the annual meeting, will be given the opportunity to make a statement at the annual meeting if he or she so desires and will be available to respond to appropriate questions.

A majority of all of the votes cast at the annual meeting at which a quorum is present is required for the ratification of the appointment of Ernst & Young LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2009. We will treat abstentions as shares that are present and entitled to vote for purposes of determining the presence or absence of a quorum. Abstentions do not constitute a vote "for," "against" or "withheld" and will not be counted as "votes cast". Therefore, abstentions will have no effect on this proposal, assuming a quorum is present.

Fee Disclosure

Audit Fees

Fees, including out-of-pocket expenses, for audit services totaled approximately $2,622,400 in fiscal year 2008 and $3,021,000 in fiscal year 2007. Audit fees include fees associated with our annual audit and the reviews of our quarterly reports on Form 10-Q. In addition, audit fees include Sarbanes-Oxley Section 404 planning and testing, fees for public filings in connection with various property acquisitions, joint venture audits, and services relating to public filings in connection with our preferred and common stock offerings and certain other transactions. Our joint venture partners paid approximately half of the joint venture audit fees. Audit fees also include fees for accounting research and consultations.

Audit-Related Fees

Fees for audit-related services totaled approximately $71,900 in 2008 and $52,000 in 2007. The audit-related services principally include fees for operating expense and tax certiorari audits. In addition, the audit-related services include fees for agreed-upon procedures projects and acquisition due diligence.

Tax Fees

No fees were incurred for tax services, including tax compliance, tax advice and tax planning in 2008 or in 2007.

All Other Fees

No fees were incurred for all other services not included above in 2008 or in 2007.

Our Audit Committee considers whether the provision by Ernst & Young LLP of any services that would be required to be described under "All Other Fees" would be compatible with maintaining Ernst & Young LLP's independence from both management and the Company.

Pre-Approval Policies and Procedures of our Audit Committee

Our Audit Committee must pre-approve all audit services and permissible non-audit services provided by our independent registered public accounting firm, except for any *de minimis* non-audit services. Non-audit services are considered *de minimis* if: (1) the aggregate amount of all such non-audit services constitutes less than five percent of the total amount of revenues we paid to our independent registered public accounting firm during the fiscal year in which they are provided; (2) we did not recognize such services at the time of the engagement to be non-audit services; and (3) such services are promptly brought to our Audit Committee's or any of its members' attention and approved by our Audit Committee or any of its members who has authority to give such approval prior to the completion of the audit. None of the fees reflected above were approved by our Audit Committee pursuant to this *de minimis* exception. All services provided by Ernst & Young LLP in 2008 were pre-approved by our Audit Committee. Our Audit Committee may delegate to one or more of its members who is an independent director the authority to grant pre-approvals.

The Board unanimously recommends a vote "FOR" the ratification of the appointment of Ernst & Young LLP as our independent registered public accounting firm.

AUDIT COMMITTEE REPORT

The following report of the Audit Committee of the Board of Directors of SL Green Realty Corp. regarding the responsibilities and functions of our Audit Committee will not be deemed to be incorporated by reference in any previous or future documents filed by us with the Securities and Exchange Commission under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate this report by reference in any such document.

Our Audit Committee oversees our financial reporting process on behalf of the Board, in accordance with our Audit Committee Charter. Management has the primary responsibility for the preparation, presentation and integrity of our financial statements, accounting and financial reporting principles, internal controls, and procedures designed to ensure compliance with accounting standards, applicable laws and regulations. In fulfilling its oversight responsibilities, our Audit Committee reviewed and discussed the audited financial statements in the Annual Report on Form 10-K for the year ended December 31, 2008 with management, including a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant judgments and the clarity of disclosures in the financial statements.

Our Audit Committee reviewed and discussed with Ernst & Young LLP, our independent registered public accounting firm, who is responsible for auditing our financial statements and for expressing an opinion on the conformity of those audited financial statements with accounting principles generally accepted in the United States, their judgments as to the quality, not just the acceptability, of our accounting principles and such other matters as are required to be discussed with the Audit Committee under Statement on Auditing Standards No. 61, as currently in effect. Our Audit Committee received from Ernst & Young LLP the written disclosures and the letter required by the applicable requirements of the Public Company Accounting Oversight Board regarding communications with the Audit Committee concerning independence, discussed with Ernst & Young LLP their independence from both management and the Company and considered the compatibility of Ernst & Young LLP's provision of non-audit services to the Company with their independence.

Our Audit Committee discussed with Ernst & Young LLP the overall scope and plans for their audit. Our Audit Committee met with Ernst & Young LLP, with and without management present, to discuss the results of their examinations, their evaluations of our internal controls and the overall quality of our financial reporting, including off-balance sheet investments and our compliance with Section 404 of the Sarbanes-Oxley Act of 2002.

In reliance on the reviews and discussions referred to above, but subject to the limitations on the role and responsibilities of our Audit Committee referred in the Report, our Audit Committee recommended to the Board (and the Board has approved) that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2008 for filing with the Securities and Exchange Commission.

The Board has determined that each member of our Audit Committee is financially literate and has accounting or related financial management expertise, as such qualifications are defined under the rules of the New York Stock Exchange. The Board has also determined that our Audit Committee has at least one "audit committee financial expert," as defined in Item 401(h) of SEC Regulation S-K, such expert being Mr. Edwin Thomas Burton, III, and that he is "independent," as that term is used in Item 7(d)(3)(iv) of Schedule 14A under the Securities Exchange Act of 1934, as amended.

Our Audit Committee held nine meetings during fiscal year 2008 (including sessions with only non-management directors attending after certain of these meetings). The members of our Audit Committee are not professionally engaged in the practice of auditing or accounting. Committee members rely, without independent investigation or verification, on the information provided to them and on the representations made by management and our independent registered public accounting firm. Accordingly, our Audit Committee's oversight does not provide an independent basis to determine that management has maintained appropriate accounting and financial reporting principles or appropriate internal controls and procedures designed to assure compliance with accounting standards and applicable laws and regulations. Furthermore, our Audit Committee's considerations and discussions referred to above do not assure that the audit of our financial statements has been carried out in accordance with the standards of the Public Company Accounting Oversight Board (United States), that the financial statements are presented in accordance with accounting principles generally accepted in the United States or that our registered public accounting firm is in fact "independent."

Submitted by our Audit Committee
Edwin Thomas Burton, III (Chairman)
John H. Alschuler, Jr.
John S. Levy

CORPORATE GOVERNANCE MATTERS

We are committed to operating our business under strong and accountable corporate governance practices. You are encouraged to visit the "Investors Corporate Governance" section of our corporate website at *http://www.slgreen.com* to view or to obtain copies of our committee charters, Code of Ethics, Corporate Governance Guidelines and director independence standards. The information found on, or accessible through, our website is not incorporated into, and does not form a part of, this proxy statement or any other report or document we file with or furnish to the SEC. You may also obtain, free of charge, a copy of the respective charters of our committees, code of ethics, corporate governance principles and director independence standards by directing your request in writing to SL Green Realty Corp., 420 Lexington Avenue, New York, New York 10170-1881, Attention: Investor Relations. Additional information relating to the corporate governance of the Company is also included in other sections of this proxy statement.

Corporate Governance Guidelines

The Board has adopted Corporate Governance Guidelines that address significant issues of corporate governance and set forth procedures by which the Board carries out its responsibilities. Among the areas addressed by the Corporate Governance Guidelines are categorical director qualification standards, director responsibilities, director access to management and independent advisors, director compensation, director orientation and continuing education, management succession, annual performance evaluation of the Board and management responsibilities. Our Nominating and Corporate Governance Committee is responsible, among other things, for assessing and periodically reviewing the adequacy of the Corporate Governance Guidelines and will recommend, as appropriate, proposed changes to the Board.

Director Independence

Our Corporate Governance Guidelines provide that a majority of our directors serving on the Board must be independent as required by the listing standards of the NYSE and the applicable rules promulgated by the SEC. In addition, the Board has adopted categorical director independence standards which assist the Board in making its determinations with respect to the independence of directors. These standards are included in this proxy statement as Appendix A. The Board has affirmatively determined, based upon its review of all relevant facts and circumstances and after considering all applicable relationships, of which the Board had knowledge, between or among the directors and the Company or our management (some of such relationships are described in the section of this proxy statement entitled "Certain Relationships and Related Transactions"), that each of the following directors and director nominees has no direct or indirect material relationship with us and is independent under the listing standards of the NYSE, the applicable rules promulgated by the SEC and our director independence standards: Messrs. Edwin T. Burton, III, John H. Alschuler, Jr. and John S. Levy. The Board has determined that Messrs. Green and Holliday, our two other directors, are not independent because they are also executive officers of the Company.

Code of Ethics

The Board has adopted a Code of Ethics that applies to our directors, executive officers and employees. The Code of Ethics is designed to assist our directors, executive officers and employees in complying with law, in resolving moral and ethical issues that may arise and in complying with our policies and procedures. Among the areas addressed by the Code of Ethics are compliance with applicable laws, conflicts of interest, use and protection of the Company's assets, confidentiality, communications with the public, accounting matters, records retention, fair dealing, discrimination and harassment and health and safety.

Audit Committee Financial Expert

The Board has determined that Edwin T. Burton, III is our "audit committee financial expert," as defined in Item 401(h) of SEC Regulation S-K, and that he is "independent," as that term is used in Item 7(d)(3)(iv) of Schedule 14A under the Securities Exchange Act of 1934, as amended. Mr. Burton has agreed to serve as our audit committee financial expert.

Communications with the Board

We have a process by which stockholders and/or other parties may communicate with the Board, individual directors (including the independent directors) or independent directors as a group. Any such communications may be sent to the Board or any named individual director (including the independent directors), by U.S. mail or overnight delivery and should be directed to Andrew S. Levine, Secretary, at SL Green Realty Corp., 420 Lexington Avenue, New York, New York 10170-1881. Mr. Levine forwards all such communications to the intended recipient or recipients. Any such communications may be made anonymously.

Whistleblowing and Whistleblower Protection Policy

Our Audit Committee has established procedures for (1) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls or auditing matters, and (2) the confidential and anonymous submission by our employees of concerns regarding questionable accounting or auditing matters. If you wish to contact our Audit Committee to report complaints or concerns relating to the financial reporting of the Company, you may do so in writing to the Chairman of our Audit Committee, c/o Andrew S. Levine, Secretary, SL Green Realty Corp., 420 Lexington Avenue, New York, New York 10170-1881. Any such communications may be made anonymously.

Director Attendance at Annual Meetings

We encourage each member of the Board to attend each annual meeting of stockholders. Messrs. Holliday and Green attended the annual meeting of stockholders held on June 25, 2008.

Identification of Director Candidates

Our Nominating and Corporate Governance Committee assists the Board in identifying and reviewing director candidates to determine whether they qualify for membership on the Board and recommends director nominees to the Board to be considered for election at our annual meeting of stockholders.

Each director candidate must have (1) education and experience that provides knowledge of business, financial, governmental or legal matters that are relevant to the Company's business or to its status as a publicly owned company, (2) an unblemished reputation for integrity, (3) a reputation for exercising good business judgment and (4) sufficient available time to be able to fulfill his or her responsibilities as a member of the Board and of any committees to which he or she may be appointed.

In making recommendations to the Board, our Nominating and Corporate Governance Committee considers such factors as it deems appropriate. These factors may include judgment, skill, diversity, experience with businesses and other organizations comparable to the Company, the interplay of the candidate's experience with the experience of other Board members, the candidate's industry knowledge and experience, the ability of a nominee to devote sufficient time to the affairs of the Company, any actual or potential conflicts of interest and the extent to which the candidate generally would be a desirable addition to the Board and any committees of the Board.

Our Nominating and Corporate Governance Committee may solicit and consider suggestions of our directors or management regarding possible nominees. Our Nominating and Corporate Governance Committee may also procure the services of outside sources or third parties to assist in the identification of director candidates.

Our Nominating and Corporate Governance Committee may consider director candidates recommended by our stockholders. Our Nominating and Corporate Governance Committee will apply the same standards in considering candidates submitted by stockholders as it does in evaluating candidates submitted by members of the Board. Any recommendations by stockholders should follow the procedures outlined under "Stockholder Proposals" in this proxy statement and should also provide the reasons supporting a candidate's recommendation, the candidate's qualifications and the candidate's written consent to being considered as a director nominee. No director candidates were recommended by our stockholders for election at the 2009 annual meeting.

Executive Sessions of Non-Management Directors

In accordance with the Corporate Governance Guidelines, the non-management directors serving on the Board generally meet in an executive session after each regularly scheduled meeting of the Audit Committee without the presence of any directors or other persons who are part of our management. The executive sessions are regularly chaired by the chair of the Board committee (other than the Executive Committee) having jurisdiction over the particular subject matter to be discussed at the particular session or portion of a session.

Disclosure Committee

We maintain a Disclosure Committee consisting of members of our executive management and senior employees. Our Disclosure Committee meets at least quarterly. The purpose of our Disclosure Committee is to bring together representatives from our core business lines and employees involved in the preparation of our financial statements so that the group can discuss any issues or matters of which the members are aware that should be considered for disclosure in our public SEC filings. Our Disclosure Committee reports to our Chief Executive Officer and Chief Financial Officer.

EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Overview

This section of our proxy statement discusses the principles underlying our executive compensation policies and decisions and the most important factors relevant to an analysis of these policies and decisions. It provides qualitative information regarding the manner and context in which compensation is awarded to, and earned by, our named executive officers and places in perspective the data presented in the tables and narrative that follow.

Throughout this proxy statement, the individuals who served as our Chief Executive Officer and Chief Financial Officer during our 2008 fiscal year, as well as the other individuals included in the "Summary Compensation Table" on page 32, are referred to as the "named executive officers," or our "executives."

Executive Summary

The REIT industry, especially in the New York City metropolitan area, was negatively affected by the downturn in market conditions, increased layoffs in the financial services industry, freezing of the debt markets, and lowered demand for office space. Consequently, our stock price suffered a decline of over 70% in 2008. Notwithstanding these difficult economic conditions, we achieved several important goals in 2008 including (i) annual funds from operations (or FFO)(1) growth of approximately 7.5% (which is in the upper quartile of our peer group), (ii) significant leasing activity across our property portfolio, including the renewal of our lease with Viacom, Inc., for approximately 1.3 million square feet, (iii) a portfolio-wide occupancy rate as of December 31, 2008 of 96.7%, (iv) implementation of a prudent risk and debt management strategy that included the repurchase of outstanding convertible bonds that resulted in a gain to stockholders on the early extinguishment of debt and (v) "same store" net operating income growth of approximately 8%. In keeping with our strong pay-for-performance policy, the following actions were taken during 2008:

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(1) Funds from operations, or FFO is a widely recognized measure of REIT performance. We compute FFO in accordance with standards established by the National Association of Real Estate Investment Trusts, or NAREIT. NAREIT currently defines FFO as net income (loss) (computed in accordance with GAAP), excluding gains (or losses) from debt restructuring and sales of properties, plus real estate related depreciation and amortization and after adjustments for unconsolidated partnerships and joint ventures. See "Other Matters Funds from Operations (FFO)" for the statement of usefulness.

- We generally reduced 2008 cash bonuses to our named executive officers by approximately 37% and overall annual bonus compensation by approximately 57%, which the Compensation Committee felt was appropriate given the decline in stock price yet adequate to reward management for industry-leading fundamental performance;

- We generally reduced 2008 total direct compensation to our named executive officers between 45% to 54%;

- As part of our Compensation Committee's monitoring and review of evolving "best practices," in mid-2008, we eliminated, on a prospective basis, the practice of awarding income tax gross-up payments upon the vesting of restricted stock (including performance-based awards), and in early 2009, we eliminated, on a prospective basis, the practice of paying dividends on performance shares prior to satisfying performance-based criteria; and

- Our named executive officers agreed to the cancellation of (i) all outstanding stock options with exercise prices in excess of $75 per share, and (ii) awards under our 2006 Outperformance Plan, which led to a non-cash compensation charge in the fourth quarter of 2008, but will, on a going-forward basis, materially reduce future income statement equity compensation costs related to the voluntarily forfeited awards.

Objectives of Our Compensation Program

Our Compensation Committee has adopted an executive compensation philosophy designed to achieve the following objectives:

- To provide performance-based incentives that create a strong alignment of management and stockholder interests; and

- To attract and retain leadership talent in a market that remains highly competitive for New York City commercial real estate management talent.

In order to reach these goals, our Compensation Committee, in consultation with our Chief Executive Officer and external compensation consultants, has adopted executive compensation practices which follow a pay-for-performance philosophy. Our primary business objective of maximizing Total Return to Stockholders, or TRS, through growth in FFO while seeking appreciation in the value of our investment properties demands a longer-term focus. Our executive compensation programs, therefore, both currently and historically, have been based heavily on the achievement of both annual and multi-year performance measures.

A substantial portion of the named executive officers' compensation has been provided in the form of equity subject to significant back-ended vesting requirements. These equity incentives were designed in order to (i) ensure that management maintains a long-term focus that serves the best interests of stockholders, and (ii) attract, retain, and motivate an experienced and talented executive management team in the intensely competitive New York City commercial real estate market.

How We Determine Executive Compensation

Our Compensation Committee determines compensation for our named executive officers and is comprised of our three independent directors, John H. Alschuler, Jr. (Chairman), Edwin Thomas Burton, III and John S. Levy. Our Compensation Committee exercises independent discretion in respect of executive compensation matters and administers our equity incentive plan, including reviewing and approving equity grants to our executives pursuant to this plan. Our Compensation Committee operates under a written charter adopted by the Board, a copy of which is available on our website at *http://www.slgreen.com*.

Our Compensation Committee has retained Gressle & McGinley LLC as its independent outside compensation consulting firm and has engaged Gressle & McGinley to provide the Compensation Committee with relevant data concerning the marketplace, our peer group and its own independent analysis and recommendation concerning executive compensation. Gressle & McGinley regularly participates in Compensation Committee meetings. Our Compensation Committee has the authority to replace Gressle & McGinley as its independent outside compensation consultant or hire additional consultants at any time. Gressle & McGinley does not provide any additional services either to our Compensation Committee or otherwise to the Company.

The Company has separately retained The Schonbraun McCann Group, a real estate advisory practice of FTI Consulting, Inc., or the SM Group, to provide the Company and our Chief Executive Officer with market and industry data. The market and industry data provided by the SM Group, which is incorporated as a component of the materials and data reviewed by our Compensation Committee, Gressle & McGinley and the Company during the compensation-setting process, is separate and apart from the independent analyses and reports prepared by Gressle & McGinley. The SM Group has participated in Compensation Committee meetings and meetings with management. The SM Group also provides additional professional services to the Company.

With respect to the compensation of our named executive officers, our Compensation Committee solicits recommendations from our Chief Executive Officer regarding total compensation for the other named executive officers and reviews his recommendations regarding total compensation, the allocation of this compensation among base salary, annual bonus amounts and other long-term incentive compensation, as well as the portion of overall compensation to be provided in cash and equity. Our Chairman also advises our Compensation Committee on these matters as they pertain to the compensation of our Chief Executive Officer. The other named executive officers do not play a role in determining their own compensation, other than discussing their performance with our Chief Executive Officer. We do not have a pre-established policy for the allocation between cash and non-cash compensation or between annual and long-term incentive compensation, but our Compensation Committee has generally sought to have a majority of the overall compensation opportunity for named executive officers represented by long-term equity-based incentives. In making compensation decisions, our Compensation Committee also considers the after-tax impact of stock that vested during the fiscal year. For a discussion of our long-term incentive compensation arrangements, including our Outperformance Plans, see "Long-Term Incentives." This has resulted in a substantial portion of our named executive officer's total compensation consisting of equity of the Company. Our Compensation Committee also reviews materials and data provided by Gressle & McGinley and the SM Group in analyzing these recommendations. The ultimate determination of total compensation and the elements that comprise that total compensation is made solely by our Compensation Committee.

Our Compensation Committee meets regularly during the year (five meetings in 2008) to evaluate executive performance, to monitor market conditions in light of our goals and objectives, to solicit input from the compensation consultants on market practices, including peer group pay practices, and new developments and to review our executive compensation practices. As part of these meetings, in formulation of its executive compensation policies and practices for 2008, the Compensation Committee reviewed then existing policies of the RiskMetrics Group and other governance groups. The Compensation Committee periodically reviews our executive compensation policies and practices to insure that such policies are in line with current market practices. Our Compensation Committee makes regular reports to the Board.

Our named executive officers' compensation and performance for 2008 was evaluated on both an absolute basis and by reference to a "peer group" that was selected based upon the following characteristics: (i) industry sector/business model, (ii) equity market capitalization, (iii) peer group continuity from year to year, (iv) peer group utilized for performance review, and (v) geographic location. However, peer groups are used only as a point of reference; our Compensation Committee does not specifically target a percentile or range of percentiles when determining executive compensation. Depending upon the Company's business and individual performance results, a named executive officer's total direct compensation may be within, below or above the market range for that position. The peer group for named executive officer compensation consisted of the following 15 REITs: Alexandria Real Estate Equities, Inc., AMB Property Corporation, Boston Properties, Inc., Brandywine Realty Trust, Corporate Office Properties Trust Inc., Douglas Emmett, Inc., Duke Realty Corporation, First Industrial Realty Trust, Inc., iStar Financial Inc., Kilroy Realty Corporation, Lexington Realty Trust, Liberty Property Trust, Mack-Cali Realty Corporation, ProLogis Trust and Vornado Realty Trust. During 2008, the composition of the peer group that we used in 2007 was re-evaluated, and, as a result, Digital Realty Trust, Inc. was removed due to its focus on the technology industry and technology-related real estate and was replaced for 2008 by Lexington Realty Trust, a New York City-based REIT with a sizable office portfolio.

Additionally, in order to be more exhaustive and evaluate a broader scope of information in determining executive compensation, a selective chief executive officer peer group was utilized by our

Compensation Committee for 2008 that consisted of the following 11 companies: Annaly Mortgage Management, Inc., CapitalSource, Inc., Douglas Emmett, Inc., iStar Financial Inc., Kilroy Realty Corporation, Marriott International, Inc., MGM Mirage Incorporated, NorthStar Realty Finance Corporation, Ventas, Inc., Vornado Realty Trust, and Wynn Resorts, Limited. During 2008, the composition of the selective chief executive officer peer group was re-evaluated and Alexandria Real Estate Equities, Inc., Healthcare Property Investors, Inc., Hilton Hotels Corporation and Starwood Hotel & Resorts Worldwide, companies that formed part of the 2007 peer group, were removed and were replaced for 2008 with Douglas Emmett, Inc., Ventas, Inc. and Wynn Resorts Limited.

Further, our Compensation Committee recognized that our primary peer group contained an insufficient number of executive chairman and therefore a selective chairman peer group was utilized for 2008 that was comprised of executives who function exclusively as chairperson and not as chief executive officer. For 2008, the selective chairman peer group consisted of the following 10 companies: Ashford Hospital Trust, Inc., Boston Properties, Inc., Digital Realty Trust, Inc., Douglas Emmett, Inc., Hersha Hospitality Trust, Host Hotels & Resorts, Inc., Lexington Realty Trust, W.P. Carey & Co. LLC, Washington Real Estate Investment Trust, and Weingarten Realty Investors. During 2008, in order to ensure that this peer group continues to consist of companies with executives who function exclusively as chairperson and not as chief executive officer, the peer group was re-evaluated and, as a result, Equity One, Inc., Felcor Lodging Trust Incorporated, Health Care REIT and Spirit Finance Corporation, which formed part of the 2007 peer group, were removed and were replaced for 2008 by Hersha Hospitality Trust, Host Hotels & Resorts, Inc. and Washington Real Estate Investment Trust.

What Our Compensation Program is Designed to Reward

As noted above, our Compensation Committee has designed our executive compensation program to achieve the following objectives: (i) to provide performance based incentives to align management and stockholder interests and (ii) to attract and retain leadership talent in a market that remains highly competitive for New York City real estate management talent. Our compensation program rewards the achievement of annual, long-term and strategic goals of both the Company and the individual executive. Our Compensation Committee evaluates performance on an absolute basis against financial and other measures, as well as on a relative basis by comparing the Company's performance against other office REITs and against the REIT industry generally. Comparative performance is an important metric since market conditions may affect the ability to meet specific performance criteria. Historically, our Compensation Committee has structured our compensation program so that half or more of total compensation to our named executive officers has been provided in the form of equity incentive compensation based on the superior long-term performance of the Company. This has taken the form of our Outperformance Plans and our restricted stock and option grants. The remainder of the incentive award is paid in cash. To address our retention objective, a substantial portion of long-term performance-based awards have time-based vesting requirements with significant back-end vesting after the award has been earned.

Elements of Our Compensation Program

Our named executive officers' compensation currently has three primary components:

- annual base salary;
- annual incentive awards, which include cash and equity bonuses; and
- long-term equity incentives, which include restricted stock awards, stock options or performance awards made pursuant to a named executive officer's employment agreement, our 2005 Stock Option and Incentive Plan, or our 2005 Plan, or pursuant to our Outperformance Plans, as applicable.

The overall levels of compensation as well as the allocation between these elements are determined by our Compensation Committee based upon analysis of the Company's performance during the year. Historically, our compensation has been divided between base salary, restricted stock grants, multi-year awards under our Outperformance Plans and cash bonus payments. Restricted share grants and awards under our Outperformance Plans are designed to align management's focus and stockholder interest and to provide incentives for each executive to successfully implement our long-term strategic goals. Our named executive officers have historically received a substantial portion of their compensation in the form of equity of the Company.

Why We Chose Each Element and How Each Element Fits into Our Overall Compensation Objectives

We view the various components of compensation as related but distinct. Our Compensation Committee designs total executive compensation packages that it believes will best create retention incentives, link compensation to performance and align the interests of our named executive officers and our stockholders. Each of our named executive officers has an employment agreement with us, which is described under "Potential Payments Upon Termination or Change of Control."

Annual Base Salary. Our Compensation Committee pays our named executive officers' annual base salaries to compensate them for services rendered during the fiscal year. The base salaries for our named executive officers have historically been near or below the median of those in the peer group. We intentionally structure an executive's annual base salary to be a relatively low percentage of total compensation. In 2008, Mr. Holliday was the only named executive officer to receive an increase in his base salary, as his employment agreement contains a provision that provides for bi-annual cost-of-living salary increases. Mr. Holliday's salary level had not been adjusted since his employment agreement was executed in January 2004. In order to remain in compliance with the mandated bi-annual cost-of-living salary increases as specified in the employment agreement, in 2008 the Compensation Committee increased Mr. Holliday's base salary from $600,000 to $688,490. Additionally, we made a payment in 2008 to him of $135,956, which represents a catch-up payment in lieu of previous contractual salary increases to which Mr. Holliday was entitled. In the future, the Compensation Committee does not expect to enter into employment agreements with our named executive officers that contain automatic salary increases.

Annual Incentive Awards. Annual incentive awards are provided in the form of cash and equity bonuses designed to focus a named executive officer on achieving key corporate financial objectives (both individually and Company-based), to motivate certain desired individual behaviors and to reward substantial achievement of these objectives and individual goals. While the Compensation Committee does not set specific fixed targets that entitle the executive officers to formulaic bonuses, the named executive officers are made aware, at the beginning of the year, of the business objectives and goals the Committee will consider when evaluating corporate and individual performance and determining annual incentive awards. For 2008, the Compensation Committee considered the following performance criteria, among others, in its determination of annual incentive awards:

- Growth in funds from operations, both on an absolute basis and relative to the performance of the peer group companies;
- Growth in "same store" net operating income;
- Leasing performance and occupancy levels;
- Capital markets performance and maintenance of a strong balance sheet;
- Implementation and achievement of strategic goals, including expense control and adherence to annual budget;

Total return to shareholders, both on an absolute basis and relative to the peer group and REIT industry; and

Tenant satisfaction performance relative to local and national markets.

The evaluation of 2008 performance and determination of 2008 annual incentive awards is consistent with the Committee's historical practice of linking pay to performance in a non-formulaic manner, thereby providing the Committee the discretion it feels is necessary in order to take into account changing market conditions. For a discussion of 2008 annual incentive payments, see "Measuring 2008 Performance."

Long-Term Equity Incentives. Long-term equity incentives have been provided to our named executive officers through the grant of restricted stock awards, stock options or performance awards pursuant to our 2005 Plan, and our 2006 Outperformance Plan, our 2005 Outperformance Plan and our 2003 Outperformance Plan, or collectively, our Outperformance Plans. Several of our named executive officers previously received awards of interests in GKK Manager LLC, or the Manager Interests, and awards of Class B limited partner interests in GKK Capital L.P., or the Class B Interests. For a discussion of such awards, see "Other Equity Incentive Awards."

The grant of equity awards links a named executive officer's compensation and net worth directly to the performance of our stock price. This encourages our named executive officers to make decisions with an ownership mentality. The vesting provisions of these equity awards (generally two to four years) are designed to act as a retention device and provide a strong incentive to the executives to increase stockholder value long after they performed the services in the year for which the equity awards were granted. The awards also contain forfeiture provisions, with a significant portion of the vesting back-ended, and therefore subject to forfeiture if the executive voluntarily leaves or is terminated with cause. For a discussion of these awards, see "Employment and Noncompetition Agreements." As discussed below, under "Tax Payments Made Upon the Vesting of Equity Awards," during 2008, we discontinued, on a prospective basis, our practice of making income tax gross-up payments to our named executive officers to cover a portion of their income tax liability incurred upon the vesting of their restricted stock awards.

Our performance based equity awards have historically provided for dividend payments prior to vesting. During early 2009, in connection with its periodic review of our executive compensation practices, the Compensation Committee has determined to discontinue its practice, on a going forward basis, of paying dividends on performance-based shares prior to achieving the performance criteria. These dividends will be accumulated and paid to the executives if and when the performance metrics are met.

Equity awards under our Outperformance Plans are designed to compensate our named executive officers upon the attainment of certain goals with respect to total return to stockholders and to provide an incentive for executives to remain with the Company and focus on long-term growth in our stock price and dividends. Under our Outperformance Plans, the executives may earn restricted stock, LTIP Units or other equity-based awards contingent upon the extent, if any, our TRS exceeds a threshold of 10% per annum over a three- or four-year performance period (or earlier upon achieving performance levels that trigger certain acceleration provisions). Upon the achievement of the designated performance thresholds, awards that may be earned under our Outperformance Plans are subject to an overall cap and further include time-based vesting requirements following the achievement of the performance thresholds. This creates, in the aggregate, up to a seven-year period (with most of the awards vesting in the final two years) that the executive needs to stay at the Company in order to realize a significant majority of the value of these awards. Even after achieving the performance thresholds, during the remaining three or four years until full vesting, the named executive officers bear the same share price and total return risk as our stockholders. TRS goals have been attained under our 2003 and 2005 Outperformance Plans and awards earned under the plans are currently subject to such additional time-based vesting requirements.

The awards made to our named executive officers under the 2005 Outperformance Plan provide a useful illustration of the Compensation Committee's philosophy of aligning the interests of management with those of our stockholders and the effect of the back-ended vesting requirements included in the various long-term equity awards. In June 2006, as a result of industry-leading TRS, the performance thresholds under the 2005 Outperformance Plan were achieved and surpassed at a time when our stock price was $100.30 per share. The underlying awards, however, remained subject to a vesting schedule with the first tranche of 129,984 units vesting on November 30, 2008, when our stock price was $18.96 per share, a decrease of approximately 81% from the price at which such awards were earned. The remaining 259,966 unvested units awarded to our named executive officers under the 2005 Outperformance Plan are scheduled to vest ratably on November 30, 2009 and November 30, 2010, and the ultimate value realized by our named executive officers will depend on the price of our stock on these dates (see "LTIP Units" below for a discussion of the features of this separate class of units of limited partnership interest in our operating partnership).

The structure of our Outperformance Plans ties a large portion of a named executive officer's compensation to creation of stockholder value on a long-term basis. As discussed above with respect to the 2005 Outperformance Plan, even after reaching TRS targets, the back-ended vesting feature of the awards creates a strong shoulder-to-shoulder alignment between management and stockholders and provides our executives with a very strong economic incentive to continue their employment with the Company and maximize our stock price.

With respect to the 2006 Outperformance Plan, in December 2008, our named executive officers rescinded their interests in the plan. This rescission, which led to a non-cash compensation charge in the fourth quarter of 2008, will on a going-forward basis materially reduce future equity compensation charges on our income statement related to the 2006 Outperformance Plan.

All stock options are priced in accordance with the terms of our 2005 Plan and are based on the price of our common stock at the close of business on the day prior to the date of grant. In December 2008, our named executive officers agreed to the cancellation of all of their stock options with exercise prices above $75.00 per share. This cancellation, which led to a non-cash compensation charge in the fourth quarter of 2008, will on a going-forward basis eliminate future equity compensation charges on our income statement related to such options.

Tax Payments Made Upon the Vesting of Equity Awards. The Company has historically provided, pursuant to employment agreements with our named executive officers, income tax gross-up payments relating to restricted stock awards and certain other equity awards. These tax payments were primarily awarded in connection with the vesting of restricted stock (generally equal to 40% of the value of the shares on the vesting date) in order to avoid requiring the named executive officers to sell shares of our common stock to satisfy tax obligations. The Compensation Committee took into consideration the value of these tax gross-ups when determining the level of compensation paid to our named executive officers. As noted above, in mid-2008, in connection with its ongoing monitoring and review of "best practices" relating to executive compensation, including policies announced by RiskMetrics Group and other governance groups, our Compensation Committee decided to discontinue the use of these tax gross-up payments on a prospective basis. This discontinuation does not apply to previously awarded restricted stock grants, including awards made in the beginning months of 2008, under which we are contractually obligated to make such income tax gross-up payments.

Pay-for-Performance

As evidenced by examining our executive compensation programs over the past several years, the executive compensation philosophy adopted by us and our Compensation Committee demonstrates the implementation of a pay-for-performance culture that ensures the alignment of management and stockholder interests. Our named executive officers were paid well relative to their peers during times of industry-leading performance (e.g., 2007 and 2006), yet during more challenging times, (e.g., 2008), they received substantial decreases in compensation amounts and what our Compensation Committee believed was a comparatively larger decrease in compensation relative to our peer group.

For example, while the amount of compensation provided to our executives in 2007 and 2006 were in the upper quartile of our peer group, these amounts were directly linked to exceptional corporate performance. In addition to achieving year-over-year FFO growth in excess of 20% and 10%, respectively, in 2007 and 2006, representing fundamental performance at the 93rd and 73rd percentile, respectively, of our peer group, our multi-year TRS through the periods ended December 31, 2007 and 2006, respectively, was at or near the top of our peer group and significantly outperformed the broader REIT industry. Specifically, we outperformed the MSCI US REIT Index by 40.71% and 124.24%, respectively, for the three- and five-year periods ended December 31, 2007, and we outperformed the MSCI US REIT Index by 155.80% and 245.84%, respectively, for the three- and five-year periods ending December 31, 2006.

As further discussed below, our overall performance for 2008 resulted in a substantial decrease in the overall 2008 compensation for our executives. In addition, as noted above, the back-ended, retention-based vesting provisions contained in equity awards for which performance thresholds had previously been achieved, in conjunction with the decline in our stock price, has resulted in substantial loss to the executives in the value of these awards, thus additionally demonstrating the shoulder-to-shoulder alignment between management and stockholders.

Measuring 2008 Performance

A further illustration of our strong pay-for-performance philosophy is evidenced in the manner in which 2008 performance bonuses were determined and the ultimate amounts of these bonuses. While 2008 was a challenging year for companies in all industries, with the combined impact of frozen credit markets and a modern-day "run on banks" that led to trillions of dollars of lost investor value in both the debt and equity markets, the REIT industry was particularly negatively impacted. The downturn in global macroeconomic conditions affected REITs by both shutting down access to the credit markets and by decreasing demand for commercial real estate space. Companies such as ours with exposure to the New York City metropolitan area were heavily impacted as they had to contend with increased unemployment caused by the collapse of institutions such as Lehman Brothers and Bear Stearns and widespread layoffs throughout the financial services industry that has historically served as the backbone of the New York City economy. Consequently, our stock price suffered a decline of over 70% in 2008. In addition, TRS was -71%, -63% and -25% during the respective 1-year, 3-year and 5-year periods ending December 31, 2008, which placed it approximately 33% below the MSCI US REIT Index for the 1-year and 3-year periods, and 29% below the Index for the 5-year period.

Notwithstanding the downturn in market conditions which affected our stock price performance, we managed to attain significant operational achievements despite these economic conditions. Specifically, we achieved the following select milestones in 2008:

- Annual FFO growth of approximately 7.5%, placing us at the upper quartile of our peer group;

- Significant strength in leasing across our property portfolio, including the renewal and extension of our lease with one of our largest tenants, Viacom, Inc., covering approximately 1.3 million square feet, or approximately 5% of our total rentable square footage as of year-end 2008. Occupancy as of December 31, 2008 was 96.7%;

- Implementation and execution of a prudent risk and debt management strategy to address current economic conditions, which included the repurchase of approximately $348.6 million of convertible bonds that resulted in a gain on the early extinguishment of debt aggregating approximately $117.9 million;

Achieved "same store" net operating income growth of approximately 8%; and

Attained a tenant satisfaction rating in our core New York City property portfolio of 85%, or approximately 500 basis points above the Kingsley Index[SM], a leading survey-based performance benchmarking tool in the commercial real estate industry.

As 2008 year-end bonus decisions were being contemplated, our Compensation Committee sought to find a balance between (i) acknowledging the significant operational achievements attained by our named executive officers during the year, as highlighted above, (ii) ensuring that bonus and total compensation amounts were in line with the prevailing market and adequate to address retention needs in the competitive New York City commercial real estate markets and (iii) recognizing the global economic conditions and the Company's material decline in stock price. In light of the aforementioned considerations, our Compensation Committee approved the following aggregate 2008 cash bonuses for the named executive officers:

Executive	2008 Cash Bonus
Marc Holliday	$ 4,750,000
Stephen Green	$ 2,659,000
Andrew Mathias	$ 3,562,500
Gregory Hughes	$ 2,375,000
Andrew Levine	$ 593,750

Comparison of 2007 and 2008 Cash Bonuses

The following Table illustrates the percentage changes in 2008 cash bonuses as compared with cash bonuses for 2007:

	2008 Cash Bonus	2007 Cash Bonus	% Change
Marc Holliday	**$ 4,750,000**	**$ 7,500,000**	**-37%**
Stephen Green(1)	**$ 2,659,000**	**$ 2,500,000**	**+6%**
Andrew Mathias	**$ 3,562,500**	**$ 5,625,000**	**-37%**
Gregory Hughes	**$ 2,375,000**	**$ 3,750,000**	**-37%**
Andrew Levine	**$ 593,750**	**$ 937,500**	**-37%**

(1) Mr. Green elected to receive his 2007 cash bonus in the form of restricted stock.

As illustrated above, 2008 cash bonus levels for our named executive officers were generally approximately 37% below 2007 levels. Preliminary market indications at the time 2008 bonus amounts were being determined suggested that 2008 compensation levels among equity REITs and specifically among our peer group constituents were going to be approximately 25% below 2007 levels, and accordingly our Compensation Committee determined that it was prudent to generally decrease our named executive officers' compensation by a greater percentage.

Comparison of 2007 and 2008 Total Bonuses

The Table and discussion above was limited to a comparison of cash bonuses for 2008 versus 2007. As indicated in the Table below, when the year-over-year comparison is expanded to take into account the award of stock bonuses (including the income tax gross-up amount associated with those stock bonuses in 2007), the percentage decrease in aggregate 2008 bonuses is even larger. After the Compensation Committee decided to significantly reduce 2008 incentive compensation, it decided that the reduced 2008 bonus awards would be paid in cash and therefore it did not award any stock bonuses to our named executive officers for 2008. As a result, aggregate 2008 bonus amounts were decreased for each of our executives and generally represented a decrease of approximately 57% when compared to aggregate cash and stock bonuses for 2007, as reflected below:

	2008 Bonus	2007 Cash and Stock Bonus(1)	% Change
Marc Holliday	**$ 4,750,000**	**$ 11,000,000**	**-57%**
Stephen Green	**$ 2,659,000**	**$ 3,500,000**	**-24%**
Andrew Mathias	**$ 3,562,500**	**$ 8,250,000**	**-57%**
Gregory Hughes	**$ 2,375,000**	**$ 5,500,000**	**-57%**
Andrew Levine	**$ 593,750**	**$ 1,375,000**	**-57%**

(1) 2007 stock bonuses represent grant date fair values and include an additional 40% of such values, representing the amounts of the related income tax gross-up payments.

Comparison of 2008 and 2007 Total Direct Compensation

In order to provide our stockholders with an analysis of compensation directly attributable to a calendar year, and thus enabling a more meaningful year-over-year compensation comparison, we are including below a Total Direct Compensation Table. The Total Direct Compensation Table consists solely of (1) the actual salary paid for the year, (2) the annual cash bonus and grant date fair value of any stock bonus earned for the year irrespective of when such amounts were ultimately paid and/or vested, as well as (3) any income tax gross-ups associated with the vesting of any shares referenced in (2) above, based upon the grant date fair value of the stock bonus (as noted above, in mid-2008, the Company discontinued the use of income tax gross-ups on a prospective basis). This Table illustrates one of the analyses undertaken by our Compensation Committee in determining each element of our named executive officers' compensation for the particular year in light of such executive's performance during the year, and it further demonstrates the correlation between the executive's pay and overall company performance.

The principal differences between the Total Direct Compensation Table and the Summary Compensation Table, presented on page 32, are that (1) the full value of equity awards is shown in the year of their grant rather than being expensed over several years as required under SFAS No. 123R and reflected in the Summary Compensation Table, and (2) the amount of the related income tax gross-up is based upon the grant date value of the equity award, rather than on the value of the shares at the date of vesting.

Name	Year	Salary	Cash Bonus	Grant Date Fair Value of Stock Bonus	Gross-up on Stock Bonus(1)	Total Direct Compensation(2)	Change from Prior Year
Marc Holliday	2008	$824,446(3)	$4,750,000	$ 0	$ 0	$ 5,574,446	-52%
	2007	$600,000	$7,500,000	$2,500,000	$ 1,000,000	$ 11,600,000	
Stephen Green	2008	$600,000	$2,659,000	$ 0	$ 0	$ 3,259,000	-21%
	2007	$600,000	$ 0	$2,500,000	$ 1,000,000	$ 4,100,000	
Andrew Mathias	2008	$500,000	$3,562,500	$ 0	$ 0	$ 4,062,500	-54%
	2007	$500,000	$5,625,000	$1,875,000	$ 750,000	$ 8,750,000	
Gregory Hughes	2008	$500,000	$2,375,000	$ 0	$ 0	$ 2,875,000	-52%
	2007	$500,000	$3,750,000	$1,250,000	$ 500,000	$ 6,000,000	
Andrew Levine	2008	$350,000	$ 593,750	$ 0	$ 0	$ 943,750	-45%
	2007	$350,000	$ 937,500	$ 312,500	$ 125,000	$ 1,725,000	

(1) The gross-up is taken into account in determining the value of the stock bonus that is granted to the named executive officer. As noted above, in mid-2008, the Company prospectively eliminated the practice of providing income tax gross-up payments on equity grants.

(2) Does not include the value of perquisites, including automobile benefits provided to Mr. Green.

(3) Includes $135,956, which represents a catch-up payment in lieu of previous contractual salary increases to which Mr. Holliday was entitled.

As noted from this Table, aggregate total direct compensation decreased for each of our named executive officers and generally decreased between 45% and 54% in 2008 as compared with 2007 compensation, consistent with our overall pay-for-performance philosophy.

Employee Benefits

We have a 401(k) Savings/Retirement Plan, or our 401(k) Plan, to cover eligible employees of ours and of any designated affiliate. Our 401(k) Plan permits eligible employees to defer up to 15% of their annual compensation, subject to certain limitations imposed by the IRC. The employees' elective deferrals are immediately vested and non-forfeitable upon contribution to the 401(k) Plan. We do not provide our named executive officers with a supplemental pension or any other retirement benefits that are in addition to the 401(k) benefits provided generally to our employees.

Perquisites and Other Personal Benefits

We do not provide significant perquisites or personal benefits to our named executive officers, except that we reimburse our Chief Executive Officer and our Chairman for costs associated with automobiles they lease for personal use. Additionally, we provide our Chairman with a full-time driver and our Chief Executive Officer receives certain insurance benefits. The costs of these benefits constitute only a small percentage of any applicable executive's compensation.

Other Matters

Tax Treatment. Our Compensation Committee reviews and considers the tax efficiency of executive compensation as part of its decision making process. Section 162(m) of the Internal Revenue Code of 1986, as amended, or the IRC, generally limits the deductibility of compensation over $1 million to a corporation's named executive officers. The Company is a real estate investment trust and therefore generally does not pay income taxes. In addition, our named executive officers provide most of their services to our operating partnership. We have received a private letter ruling from the

Internal Revenue Service to the effect that the deduction limitation of Section 162(m) does not apply with respect to compensation to our named executive officers for services rendered to this partnership.

Tax Gross-up Payments. As discussed above, see "Long Term Incentives," we have discontinued the use, on a prospective basis, of income tax gross-up payments made on the vesting of restricted stock and other equity grants.

LTIP Units. In both our 2005 Outperformance Plan and our 2006 Outperformance Plan, in lieu of issuing shares of restricted stock, we issued a separate class of units of limited partnership interest in our operating partnership, which we refer to as LTIP units. LTIP units are similar to common units in our operating partnership, which generally are economically equivalent to shares of our common stock, except that the LTIP units are structured as "profits interests" for U.S. federal income tax purposes. As profits interests, LTIP units generally only have value, other than with respect to the right to receive distributions, if the value of the assets of our operating partnership increases between the issuance of LTIP units and the date of a book-up event for partnership tax purposes. LTIP units granted under our 2005 Outperformance Plan and our 2006 Outperformance Plan were not entitled to receive distributions prior to the LTIPs being earned based on the performance-based hurdles contained in these plans being achieved. Once earned, these LTIP units, whether vested or unvested, entitle the holder to receive distributions per unit from our operating partnership that are equivalent to the dividends paid per share on our common stock. Our named executive officers agreed to the cancellation of their awards under our 2006 Outperformance Plan.

LTIP units are intended to offer executives substantially the same long-term incentive as shares of restricted stock, with more favorable U.S. federal income tax treatment available for "profits interests." More specifically, one key disadvantage of restricted stock is that executives are generally taxed on the full market value of a grant at the time of vesting, even if they choose to hold the stock.

Conversely, under current federal income tax law, an executive would generally not be subject to tax at the time of issuance or vesting but only when he or she chooses to liquidate his or her LTIP units. Therefore, an executive who wishes to hold his or her equity awards for the long term can generally do so in a more tax-efficient manner with LTIP units. In light of the trade-offs between increased tax efficiency and incremental economic risk involved in LTIP units as compared to restricted stock, we chose to use LTIP units for our 2005 Outperformance Plan and our 2006 Outperformance Plan. We believe that the use of LTIP units in these plans has (1) enhanced our equity-based compensation package overall, (2) advanced the goal of promoting long-term equity ownership by executives, (3) not adversely impacted dilution as compared to restricted stock, and (4) further aligned the interests of our executives with the interests of our stockholders. We also believe that these benefits outweigh the loss of the U.S. federal income tax business-expense deduction from the issuance of LTIP units, as compared to restricted stock. Although we have chosen to use LTIP units for our 2005 Outperformance Plan and our 2006 Outperformance Plan, we have not chosen to utilize LTIP units for our other equity awards primarily because we have not viewed the additional economic risk associated with LTIP units as appropriate for our other equity awards, which do not include performance-based vesting hurdles based solely on our total return to stockholders.

Other Equity Incentive Awards. In May 2005, the Compensation Committee approved long-term incentive performance awards pursuant to which certain of our employees, including certain of our named executive officers, were awarded a portion of the interests previously held by us in GKK Manager LLC, or the Manager, as well as in the Class B Interests in Gramercy's operating partnership. After giving effect to these awards, we owned 65.83 units of the Class B limited partner interests and 65.83% of the Manager as of December 31, 2007. As of that date, the officers and employees who received these awards owned 15.6 units of the Class B limited partner interests and 15.6% of the Manager. These awards provided for three-year cliff vesting based on continued employment and achievement of performance hurdles. The performance hurdles were to be measured over the period beginning May 19, 2005 and ending on the earlier of (i) May 18, 2008, (ii) a Change of Control, or (iii) a "Sale Event" of Gramercy (as defined in the operating agreement of the Manager). The performance hurdles would be met if as a result of one of the three described triggering events, we achieved (i) a rate of return on our weighted average cash investment in Gramercy during this measurement period (inclusive of cash and stock dividends, stock appreciation, income of the Manager and all other income earned by us as a result of our investment in Gramercy) equal to or greater than 36% over the three-year period, as adjusted under certain circumstances; and (ii) we achieved either (a) a total return to stockholders equal to or greater than 30% over the three-year period, as adjusted under certain circumstances, (b) funds from operations growth equal to or greater than 21% over the three-year period, as adjusted under certain circumstances, or (c) average total return to stockholders in the top 25% of an identified peer group. In May, 2008, the Compensation Committee determined that these performance hurdles were met because we achieved a rate of return on our weighted average cash investment in Gramercy during that period (inclusive of cash and stock dividends, stock appreciation, income of the Manager and all other income earned by us as a result of our investment in Gramercy) in excess of the 36% hurdle. In addition, we achieved a total return to stockholders which exceeded the 30% hurdle. During this period we held all cash or other distributions payable on these awards which were released to the grantees after the Compensation Committee determined that these performance hurdles were met. In December of 2008, our named executive officers who held awards in the Manager and the Class B limited partner interests agreed to relinquish these awards to the Company.

Gramercy Capital Corp. Equity Awards. Until October 27, 2008, certain of our named executive officers also served as executive officers of Gramercy. The Compensation Committee of the board of directors of Gramercy has granted equity awards, including restricted stock awards, stock options and performance awards, to these executive officers under Gramercy's equity incentive plan and Outperformance plan, as applicable. For a discussion of these awards, please refer to Gramercy's proxy statement that has been filed with the SEC in connection with its 2009 annual meeting of stockholders.

Accounting Treatment. Beginning on January 1, 2003, we began accounting for stock-based payments through our equity incentive plans, including our Outperformance Plans, in accordance with the requirements of SFAS No. 123R. We recorded approximately $12.2 million of compensation expense during the year ended December 31, 2008 in connection with our 2006 Outperformance Plan. During the fourth quarter of 2008, we and certain of our employees, including each of our named executive officers, mutually agreed to cancel the awards granted to such employees under the 2006 Outperformance Plan.

Funds from Operations (FFO). We compute FFO in accordance with standards established by the National Association of Real Estate Investment Trusts, or NAREIT, which may not be comparable to FFO reported by other REITs that do not compute FFO in accordance with the NAREIT definition, or that interpret the NAREIT definition differently than we do. The revised White Paper on FFO approved by the Board of Governors of NAREIT in April 2002 defines FFO as net income (loss) (computed in accordance with GAAP), excluding gains (or losses) from debt restructuring and sales of properties, plus real estate related depreciation and amortization and after adjustments for unconsolidated partnerships and joint ventures. We present FFO because we consider it an important supplemental measure of our operating performance and believe that it is frequently used by securities analysts, investors and other interested parties in the evaluation of REITS. We also use FFO as one of several criteria to determine performance-based bonuses for members of our senior management. FFO is intended to exclude GAAP historical cost depreciation and amortization of real estate and related assets, which assumes that the value of real estate assets diminishes ratably over time. Historically, however, real estate values have risen or fallen with market conditions. Because FFO excludes depreciation and amortization unique to real estate, gains and losses from property dispositions and extraordinary items, it provides a performance measure that, when compared year over year, reflects the impact to operations from trends in occupancy rates, rental rates, operating costs and interest costs, providing perspective not immediately apparent from net income. FFO does not represent cash generated from operating activities in accordance with GAAP and should not be considered as an alternative to net income (determined in accordance with GAAP), as an indication of our financial performance or to cash flow from operating activities (determined in accordance with GAAP) as a measure of our liquidity, nor is it indicative of funds available to fund our cash needs, including our ability to make cash distributions.

Compensation Committee Report

The Compensation Committee of the Board of Directors of SL Green Realty Corp. has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, our Compensation Committee recommended to the Board that the Compensation Discussion and Analysis be included in this annual proxy statement and incorporated by reference in the Company's Annual Report on Form 10-K for the year ended December 31, 2008.

Submitted by our Compensation Committee
John H. Alschuler, Jr. (Chairman)
Edwin Thomas Burton, III
John S. Levy

Summary Compensation Table

The following table* sets forth information regarding the compensation paid to, and the compensation expense we recognized with respect to, our Chief Executive Officer, our Chief Financial Officer and each of our three most highly compensated executive officers, other than our Chief Executive Officer and Chief Financial Officer, whose total compensation exceeded $100,000 during the fiscal year ended December 31, 2008, or collectively, the "named executive officers".

Name And Principal Position	Year	**4,024.9**		
Investments in consolidated subsidiaries	—	1,621.9	(1,621.9)	—
Notes receivable from consolidated subsidiaries	—	945.4	(945.4)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	22.1	0.4	—	22.5
Nonutility plant - net	1.7	163.5	—	165.2
Goodwill - net	205.0	—	—	205.0
Regulatory assets	206.2	16.0	—	222.2
Other assets	53.1	4.0	(8.9)	48.2
TOTAL ASSETS	$ 4,872.1	$2,868.3	$ (2,719.9)	$ 5,020.5
LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary	Parent	Eliminations &	
	Guarantors	Company	Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$ 134.8	$5.5	$ —	$ 140.3
Intercompany payables	18.9	—	(18.9)	—
Payables to other Vectren companies	22.7	—	—	22.7
Accrued liabilities	149.1	20.2	(2.8)	166.5
Short-term borrowings	—	101.4	—	101.4
Intercompany short-term borrowings	91.1	30.9	(122.0)	—
Current maturities of long-term debt	49.1	—	—	49.1
Total current liabilities	465.7	158.0	(143.7)	480.0
Long-Term Debt				
Long-term debt	335.4	995.8	—	1,331.2
Long-term debt due to VUHI	945.4	—	(945.4)	—
Total long-term debt - net	1,280.8	995.8	(945.4)	1,331.2

Deferred Credits & Other Liabilities				
Deferred income taxes	878.7	3.2	—	881.9
Regulatory liabilities	460.8	1.2	—	462.0
Deferred credits & other liabilities	164.2	9.2	(8.9)	164.5
Total deferred credits & other liabilities	1,503.7	13.6	(8.9)	1,508.4
Common Shareholder's Equity				
Common stock (no par value)	845.9	872.7	(845.9)	872.7
Retained earnings	776.0	828.2	(776.0)	828.2
Total common shareholder's equity	1,621.9	1,700.9	(1,621.9)	1,700.9
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$ 4,872.1	$ 2,868.3	$ (2,719.9)	$ 5,020.5

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Condensed Consolidating Balance Sheet as of December 31, 2016 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$ 7.6	$ 1.8	$ —	$ 9.4
Accounts receivable - less reserves	102.4	0.2	—	102.6
Intercompany receivables	17.5	157.1	(174.6)	—
Accrued unbilled revenues	112.0	—	—	112.0
Inventories	119.0	—	—	119.0
Recoverable fuel & natural gas costs	29.9	—	—	29.9
Prepayments & other current assets	36.5	4.4	(2.3)	38.6
Total current assets	424.9	163.5	(176.9)	411.5
Utility Plant				
Original cost	6,545.4	—	—	6,545.4
Less: accumulated depreciation & amortization	2,562.5	—	—	2,562.5
Net utility plant	3,982.9	—	—	3,982.9
Investments in consolidated subsidiaries	—	1,577.2	(1,577.2)	—
Notes receivable from consolidated subsidiaries	—	945.4	(945.4)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	20.9	0.4	—	21.3
Nonutility plant - net	1.7	163.1	—	164.8
Goodwill - net	205.0	—	—	205.0
Regulatory assets	190.0	16.2	—	206.2
Other assets	53.9	3.7	(8.6)	49.0
TOTAL ASSETS	$ 4,879.5	$ 2,869.5	$ (2,708.1)	$ 5,040.9

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$ 194.6	$ 10.8	$ —	$ 205.4
Intercompany payables	14.8	—	(14.8)	—
Payables to other Vectren companies	25.4	—	—	25.4
Accrued liabilities	126.0	16.4	(2.3)	140.1
Short-term borrowings	—	194.4	—	194.4
Intercompany short-term borrowings	142.3	17.5	(159.8)	—
Current maturities of long-term debt	49.1	—	—	49.1
Total current liabilities	552.2	239.1	(176.9)	614.4
Long-Term Debt				
Long-term debt - net of current maturities & debt subject to tender	335.2	995.8	—	1,331.0
Long-term debt due to VUHI	945.4	—	(945.4)	—
Total long-term debt - net	1,280.6	995.8	(945.4)	1,331.0
Deferred Credits & Other Liabilities				
Deferred income taxes	855.4	(0.9)	—	854.5
Regulatory liabilities	452.4	1.3	—	453.7
Deferred credits & other liabilities	161.7	10.2	(8.6)	163.3
Total deferred credits & other liabilities	1,469.5	10.6	(8.6)	1,471.5

Common Shareholder's Equity				
Common stock (no par value)	844.4	831.2	(844.4)	831.2
Retained earnings	732.8	792.8	(732.8)	792.8
Total common shareholder's equity	1,577.2	1,624.0	(1,577.2)	1,624.0
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$ 4,879.5	$ 2,869.5	$ (2,708.1)	$ 5,040.9

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Condensed Consolidating Statement of Income for the three months ended March 31, 2017 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$ 292.8	$ —	$ —	$ 292.8
Electric utility	132.1	—	—	132.1
Other	—	11.4	(11.3)	0.1
Total operating revenues	424.9	11.4	(11.3)	425.0
OPERATING EXPENSES				
Cost of gas sold	112.9	—	—	112.9
Cost of fuel & purchased power	41.2	—	—	41.2
Other operating	96.7	—	(11.1)	85.6
Depreciation & amortization	51.1	6.3	—	57.4
Taxes other than income taxes	13.9	0.5	—	14.4
Total operating expenses	315.8	6.8	(11.1)	311.5
OPERATING INCOME	109.1	4.6	(0.2)	113.5
Other income - net	6.7	12.2	(11.9)	7.0
Interest expense	16.9	12.8	(12.1)	17.6
INCOME BEFORE INCOME TAXES	98.9	4.0	—	102.9
Income taxes	37.4	(0.4)	—	37.0
Equity in earnings of consolidated companies, net of tax	—	61.5	(61.5)	—
NET INCOME	$ 61.5	$ 65.9	$ (61.5)	$ 65.9

Condensed Consolidating Statement of Income for the three months ended March 31, 2016 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$ 281.2	$ —	$ —	$ 281.2
Electric utility	142.1	—	—	142.1
Other	—	10.6	(10.5)	0.1
Total operating revenues	423.3	10.6	(10.5)	423.4
OPERATING EXPENSES				
Cost of gas sold	111.6	—	—	111.6
Cost of fuel & purchased power	44.2	—	—	44.2
Other operating	99.4	—	(10.0)	89.4
Depreciation & amortization	47.6	6.0	—	53.6
Taxes other than income taxes	16.6	0.5	—	17.1
Total operating expenses	319.4	6.5	(10.0)	315.9
OPERATING INCOME	103.9	4.1	(0.5)	107.5
Other income - net	4.6	12.3	(11.3)	5.6
Interest expense	16.9	12.4	(11.8)	17.5
INCOME BEFORE INCOME TAXES	91.6	4.0	—	95.6
Income taxes	34.6	(0.1)	—	34.5
Equity in earnings of consolidated companies, net of tax	—	57.0	(57.0)	—

NET INCOME	$ 57.0	$ 61.1	$ (57.0)	$ 61.1

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Condensed Consolidating Statement of Cash Flows for the three months ended March 31, 2017 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 176.0	$ 11.0	$ —	$ 187.0
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from				
Additional capital contribution from parent	1.5	41.5	(1.5)	41.5
Requirements for:				
Dividends to parent	(18.3)	(30.5)	18.3	(30.5)
Net change in intercompany short-term borrowings	(51.2)	13.4	37.8	—
Net change in short-term borrowings	—	(93.0)	—	(93.0)
Net cash used in financing activities	(68.0)	(68.6)	54.6	(82.0)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	18.3	(18.3)	—
Requirements for:				
Capital expenditures, excluding AFUDC equity	(96.6)	(11.9)	—	(108.5)
Consolidated subsidiary investments	—	(1.5)	1.5	—
Changes in restricted cash	0.9	—	—	0.9
Net change in short-term intercompany notes receivable	(13.4)	51.2	(37.8)	—
Net cash used in investing activities	(109.1)	56.1	(54.6)	(107.6)
Net change in cash & cash equivalents	(1.1)	(1.5)	—	(2.6)
Cash & cash equivalents at beginning of period	7.6	1.8	—	9.4
Cash & cash equivalents at end of period	$ 6.5	$ 0.3	$ —	$ 6.8

Condensed Consolidating Statement of Cash Flows for the three months ended March 31, 2016 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 134.8	$ 11.9	$ —	$ 146.7
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Long-term debt, net of issuance costs	109.4	—	(109.4)	—
Additional capital contribution from parent	26.5	26.5	(26.5)	26.5
Requirements for:				
Dividends to parent	(27.2)	(29.0)	27.2	(29.0)
Net change in intercompany short-term borrowings	(126.8)	26.7	100.1	—
Net change in short-term borrowings	—	(14.5)	—	(14.5)
Net cash used in financing activities	(18.1)	9.7	(8.6)	(17.0)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	27.2	(27.2)	—
Requirements for:				
Capital expenditures, excluding AFUDC equity	(81.7)	(6.7)	—	(88.4)
Consolidated subsidiary investments	—	(26.5)	26.5	—
Net change in long-term intercompany notes receivable	—	(109.4)	109.4	—
Net change in short-term intercompany notes receivable	(26.7)	126.8	(100.1)	—

Net cash used in investing activities	(108.4)	11.4	8.6	(88.4)
Net change in cash & cash equivalents	8.3	33.0	—	41.3
Cash & cash equivalents at beginning of period	5.5	0.7	—	6.2
Cash & cash equivalents at end of period	$ 13.8	$ 33.7	$ —	$ 47.5

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4. Excise and Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes billed to customers, which totaled $9.4 million in each of the three months ended March 31, 2017 and 2016, as a component of operating revenues. Expenses associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

5. Supplemental Cash Flow Information

As of March 31, 2017 and December 31, 2016, the Company had accruals related to utility and nonutility plant purchases totaling approximately $19.1 million and $27.4 million, respectively.

6. Transactions with Other Vectren Companies and Affiliates

Vectren Infrastructure Services Corporation (VISCO)
VISCO, a wholly owned subsidiary of the Company's parent, provides underground pipeline construction and repair services. VISCO's customers include the Company's utilities and fees incurred by the Company totaled $25.8 million and $19.6 million for the three months ended March 31, 2017 and 2016, respectively. Amounts owed to VISCO at March 31, 2017 and December 31, 2016 are included in Payables to other Vectren companies in the Condensed Consolidated Balance Sheets.

Support Services & Purchases
The Company's parent provides corporate and general and administrative services to the Company and allocates certain costs to the Company, including costs for share-based compensation and for pension and other postretirement benefits that are not directly charged to subsidiaries. These costs are allocated using various allocators, including number of employees, number of customers and/or the level of payroll, revenue contribution and capital expenditures. Allocations are at cost. For the three months ended March 31, 2017 and 2016, the Company received corporate allocations totaling $16.9 million and $17.3 million, respectively.

The Company does not have share-based compensation plans and pension or other postretirement plans separate from the Company's parent and allocated costs include participation in the plans of the Company's parent. The allocation methodology for retirement costs is consistent with FASB guidance related to “multiemployer” benefit accounting.

7. Commitments & Contingencies

Commitments
The Company's regulated utilities have both firm and non-firm commitments, some of which are between five and twenty year agreements to purchase natural gas, electricity, and coal, as well as certain transportation and storage rights. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

Legal & Regulatory Proceedings
The Company is party to various legal proceedings, audits, and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company that are likely to have a material adverse effect on its financial condition, results of operations or cash flows.

8. Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement
The Company monitors and maintains its natural gas distribution system to ensure natural gas is delivered in a safe and efficient manner. The Company's natural gas utilities are currently engaged in programs to replace bare steel and cast iron infrastructure and other activities in both Indiana and Ohio to mitigate risk, improve the system, and comply with applicable regulations, many of which are the result of federal pipeline safety requirements. Laws passed in both Indiana and Ohio provide utilities the

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opportunity to timely recover costs of federally mandated projects and other infrastructure improvement projects outside of a base rate proceeding.

Indiana Senate Bill 251 (Senate Bill 251) provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, based on the overall rate of return most recently approved by the IURC, along with recovery of depreciation and other operating costs associated with these mandates. The remaining 20 percent of those costs is deferred for future recovery in the utility's next general rate case.

Indiana Senate Bill 560 (Senate Bill 560) supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs are deferred and recovered in the utility’s next general rate case, which must be filed before the expiration of the seven-year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

Ohio House Bill 95 (House Bill 95) permits a natural gas utility to apply for recovery of much of its capital expenditure program. This legislation also allows for the deferral of costs, such as depreciation, property taxes, and debt-related post-in-service carrying costs until recovery is approved by the PUCO.

Indiana Recovery and Deferral Mechanisms
The Company's Indiana natural gas utilities received Orders in 2008 and 2007 associated with the most recent base rate cases. These Orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The Orders provide for the deferral of depreciation and post-in-service carrying costs on qualifying projects totaling $20 million annually at Indiana Gas and $3 million annually at SIGECO. The debt-related post-in-service carrying costs are currently recognized in the Consolidated Statements of Income. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At March 31, 2017 and December 31, 2016, the Company has regulatory assets totaling $22.3 million and $21.9 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company’s seven-year capital investment plan discussed below.

Requests for Recovery under Indiana Regulatory Mechanisms
In August 2014, the IURC issued an Order approving the Company’s seven-year capital infrastructure replacement and improvement plan (the Plan), beginning in 2014, and the proposed accounting authority and recovery. Compliance projects and other infrastructure improvement projects were approved pursuant to Senate Bill 251 and 560, respectively. As provided in the two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs, including a return, recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company’s next base rate proceeding. In addition, the Order established guidelines to annually update the seven-year capital investment plan. Finally, the Order approved the Company’s proposal to recover eligible costs

assigned to the residential customer class via a fixed monthly charge per residential customer.

In March 2016, the IURC issued an Order re-approving approximately $890 million of the Company’s gas infrastructure modernization projects requested in the third update of the Plan, and approving the inclusion in rates of actual investments made through June 30, 2015. While most of the proposed capital spend has been approved as proposed, approximately $80 million of projects were not approved for recovery through the mechanisms pursuant to these filings. Specifically, the Company proposed to add a new project to its Plan pursuant to Senate Bill 560 totaling approximately $65 million. The project, which consists of a 20-mile transmission line and other related investments required to support industrial customer growth and ongoing

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system reliability in the Lafayette, Indiana area, as well as allows the Company to further diversify its gas supply portfolio via access to shale gas in the Marcellus and Utica reserves, was excluded for recovery under the Plan. The IURC stated because the project was not in the original plan filed in 2013, it does not qualify for cost recovery under Senate Bill 560. In the Order, the IURC did pre-approve the project for rate base inclusion upon the filing of the next base rate case. The Company believes such plan updates should be expected to accommodate new projects that emerge during the term of the plan as ongoing risk assessments determine new projects are required. The Company filed an appeal of the March 2016 Order on April 29, 2016 to challenge the IURC's finding which limits the scope of the Plan updates. On April 27, 2017, the Indiana Court of Appeals denied the Company's appeal of the Order. The Company is evaluating its options related to the Plan update issue, but as noted herein the project at issue was previously approved by the IURC for recovery in the Company's next general base rate case. Further, the Company does not expect similar issues related to updating future plan filings as the project inclusion process is now better understood by all parties.

Subsequent to the March 2016 Order, the Company has received two additional Orders approving plan investments. On June 29, 2016, the IURC issued an Order approving the inclusion in rates of investments made from July 2015 to December 2015. On January 25, 2017 the IURC issued an Order (January 2017 Order) approving the inclusion in rates of investments made from January 2016 to June 2016. Through the January 2017 Order, approximately $338 million of the approved capital investment plan has been incurred and included for recovery. The January 2017 Order also approved the Company's plan update, which is now $950 million through 2020. The plan increase of $60 million is due to additional investment related to pipeline safety and compliance requirements under Senate Bill 251.

At March 31, 2017 and December 31, 2016, the Company has regulatory assets related to the Plan totaling $54.9 million and $51.1 million, respectively.

On April 3, 2017, the Company submitted its sixth semi-annual filing, seeking approval for recovery of an additional $69.1 million of capital investments made through December 31, 2016. An evidentiary hearing has been scheduled for June 22, 2017, and the Company expects an order later in 2017.

Ohio Recovery and Deferral Mechanisms

The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines, as well as certain other infrastructure investments. This rider is updated annually for qualifying capital expenditures and allows for a return on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of certain other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels through 2017. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. In the event the Company exceeds these caps, amounts in excess can be deferred for future recovery. The Order also approved the Company's commitment that the DRR can only be further extended as part of a base rate case. In total, the Company has made capital investments on projects that are now in-service under the DRR totaling $269.7 million as of March 31, 2017, of which $204.0 million has been approved for recovery under the DRR through December 31, 2015. On May 1, 2017, the Company submitted its annual request for an adjustment in the DRR rates to recover an additional $57.1 million of capital investments made through December 31, 2016. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $25.9 million and $24.4 million at March 31, 2017 and December 31, 2016, respectively.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. At March 31, 2017 and December 31, 2016, the

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Company has regulatory assets totaling $46.7 million and $41.9 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. As of March 31, 2017, the Company's deferrals have not reached this bill impact cap. On May 1, 2017, the Company submitted its most recent annual report required under its House Bill 95 Order. This report covers the Company's capital expenditure program through calendar year 2017.

Given the extension of the DRR through 2017, as discussed above, and the continued ability to defer other capital expenses under House Bill 95, it is anticipated that the Company will file a general rate case for the inclusion in rate base of the above costs in early 2018.

Pipeline and Hazardous Materials Safety Administration (PHMSA)
In March 2016, PHMSA published a notice of proposed rulemaking (NPRM) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a particular focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. The Company is evaluating the impact these proposed rules will have on its integrity management programs and transmission and distribution systems. Progress on finalizing the rule continues to work through the administrative process. It is expected the rule will be finalized in 2018 and the Company believes the costs to comply with the new rules would be considered federally mandated and therefore should be recoverable.

In December 2016, PHMSA issued final rules related to integrity management for storage operations. Efforts are underway to implement the new requirements. Further, the Company reviewed the Underground Natural Gas Storage Safety Recommendations from a joint Department of Energy and PHMSA led task force. These rules could increase the potential for capital expenditures and increase operating and maintenance expenses. The Company believes the cost to comply with these new rules would be considered federally mandated and therefore should be recoverable using various regulatory recovery mechanisms.

Additionally, PHMSA finalized a rule on excess flow valves, which went into effect in April 2017. At the customer's request, excess flow valves will be installed at the customer's cost.

9. Electric Rate & Regulatory Matters

Regulatory Treatment of Investments in Electric Infrastructure
On February 23, 2017, the Company filed for authority to recover costs related to its electric system modernization plan, using the mechanism allowed under Senate Bill 560. The electric system modernization plan includes investments to upgrade portions of the Company’s network of substations, transmission and distribution systems, to enhance reliability and allow the grid to accept advanced technology to improve the information and service provided to customers. The filing requests the recovery of associated capital expenditures estimated to be approximately $500 million over the seven-year period beginning in 2017. A field hearing in this proceeding was held on May 2, 2017. Testimony from the public provided during this hearing will be considered by the IURC in this case. Filed testimony of intervening parties was required by May 4, 2017. An evidentiary hearing has been scheduled for June 26, 2017. Under the timeline provided by Senate Bill 560, the Company expects an order in September 2017.

Renewable Generation Resources
On February 22, 2017, the Company also filed for authority to recover costs related to the construction of three solar projects, using the mechanism allowed under Senate Bill 29, which allows for timely recovery of costs and expenses incurred during the construction and operation of clean energy projects. These investments, presented as part of the Company’s Integrated Resource Plan (IRP) submitted in December 2016, allow the Company to add approximately 4

MW of universal solar generation, rooftop solar generation, and 1 MW of battery storage resources to its portfolio. See more information on the IRP below in Environmental & Sustainability Matters. The cost of the projects is estimated to be approximately $15 million. Filed testimony of intervening parties was required by May 11, 2017. An evidentiary hearing has been scheduled for June 15, 2017, and the Company expects an order by the end of 2017.

SIGECO Electric Environmental Compliance Filing
On January 28, 2015, the IURC issued an Order approving the Company’s request for approval of capital investments in its coal-fired generation units to comply with new EPA mandates related to mercury and air toxic standards (MATS) effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA pertaining to its A.B. Brown generating station sulfur trioxide emissions. The MATS rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants.

As of March 31, 2017, $30 million has been spent on equipment to control mercury in both air and water emissions, and $40 million to address the issues raised in the NOV. The Order approved the Company’s request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. These costs will be included for recovery no later than the next rate case. The initial phase of the projects went into service in 2014, with the remaining investment going into service in 2016. As of March 31, 2017, the Company has approximately $9.0 million deferred related to depreciation and operating expense, and $3.3 million deferred related to post-in-service carrying costs. MATS compliance was required beginning April 16, 2015, and the Company continues to operate in full compliance with the MATS rule.

In June 2015, Joint Appellants’ Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) challenged the IURC's January 2015 Order. On October 29, 2015, the Indiana Court of Appeals issued an opinion that affirmed the IURC’s findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules but remanded the case to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV. On June 22, 2016, the IURC issued an Order granting the Company a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. On February 14, 2017, the Court affirmed the IURC's June 22, 2016 Order.

SIGECO Electric Demand Side Management (DSM) Program Filing
On August 31, 2011, the IURC issued an Order approving an initial three-year DSM plan in the Company's electric service territory that complied with the IURC’s energy saving targets. Consistent with the Company’s proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; and 3) lost margin recovery associated with the implementation of DSM programs for large customers. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. For the three months ended March 31, 2017 and 2016, the Company recognized electric utility revenue of $3.0 million and $2.6 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. The legislation allows for industrial customers to opt out of participating in energy efficiency programs and as a result of this legislation, most of the Company’s eligible industrial customers have since opted out of participation in the applicable energy efficiency programs.

Indiana Senate Bill 412 (Senate Bill 412) requires electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also requires the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years 2016 and 2017. On March 23, 2016, the IURC issued an Order approving the Company's 2016-2017 energy efficiency plan. The Order provides for cost recovery of program and administrative expenses and includes performance incentives for reaching energy savings goals. The Order also included a lost margin recovery mechanism that now limits that recovery related to new programs to the shorter of four years or the life of the installed energy efficiency measure. Prior electric energy efficiency orders did not limit lost margin recovery in this manner. This ruling follows other recent IURC decisions implementing the same lost margin recovery limitation with respect to other electric utilities in Indiana. The Company appealed this lost margin recovery restriction based on the Company's commitment to promote and drive participation in its energy efficiency programs.

On March 7, 2017, the Court of Appeals reversed the IURC finding on the Company's 2016-2017 energy efficiency plan that the four year cap on lost margin recovery was arbitrary and the IURC failed to properly interpret the governing statute requiring it to review the utility's originally submitted DSM proposal and either approve or reject it as a whole, including the proposed lost margin recovery. The case has been remanded back to the Commission for further proceedings to determine the reasonableness of the Company's entire energy efficiency plan.

On April 10, 2017, the Company submitted its request for approval of its Energy Efficiency Plan for calendar years 2018 through 2020. Consistent with prior filings, this filing included a request for continued cost recovery of program and administrative expenses, including performance incentives for reaching energy savings goals and continued recovery of lost margins over the life of the installed energy efficiency measure. Filed testimony of intervening parties is required by July 14, 2017. An evidentiary hearing has been scheduled for August 31, 2017, and the Company expects an order by the end of 2017.

FERC Return on Equity (ROE) Complaints

On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against the MISO and various MISO transmission owners, including SIGECO (first complaint case). The joint parties sought to reduce the 12.38 percent ROE used in the MISO transmission owners' rates, including SIGECO's formula transmission rates, to 9.15 percent covering the refund period from November 12, 2013 through February 11, 2015 (first refund period). On September 28, 2016, the FERC issued a final order authorizing a 10.32 percent base ROE for the first refund period and prospectively through the date of the order in a second complaint case as detailed below.

A second customer complaint case was filed on February 11, 2015 covering the refund period from February 12, 2015 through May 11, 2016 (second refund period). An initial decision from the FERC administrative law judge on June 30, 2016, authorized a base ROE of 9.70 percent for the second refund period. The FERC is expected to rule on the proposed order in the second complaint case in 2017, which will authorize a base ROE for this period and prospectively from the date of the order.

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as the MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The FERC deferred the implementation of this adder until the pending complaint is resolved. The adder will be applied retroactively from January 6, 2015 through May 11, 2016 and prospectively from the September 28, 2016 order in the first complaint case.

The Company has reflected these results in its financial statements. As of March 31, 2017, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $136.0 million at March 31, 2017.

On April 14, 2017, the U.S. Court of Appeals for the District of Columbia circuit vacated the FERC Opinion in a prior case that established a new methodology for calculating ROE. This methodology was utilized in the final order in the Company's first complaint case, and the initial decision in the Company's second complaint case. The Appeals Court stated that FERC did not prove the existing ROE was not just and reasonable and also failed to provide any reasoned basis for their selected ROE. The Company will continue to monitor this proceeding and evaluate any potential impacts on the Company's complaint cases but would not expect them to be material.

10. Environmental & Sustainability Matters

The Company initiated a corporate sustainability program in 2012 with the publication of the initial corporate sustainability report of the Company's parent. Since that time the Company continues to develop strategies that focus on those environmental, social and governance (ESG) factors that contribute to the long-term growth of a sustainable business model. As detailed further below and in the upcoming corporate sustainability report for 2016, the Company continues to set out its plans, among other things, to upgrade and diversify its generation portfolio. The sustainability policies and efforts, and in particular its policies and procedures designed to ensure compliance with applicable laws and regulations, are directly overseen by Vectren's Corporate Responsibility and Sustainability Committee, as well as vetted with Vectren's full Board of Directors. Further discussion of key goals, strategies, and governance practices can be found in the Company’s latest sustainability report, which received core level certification from the Global Reporting Initiative.

The Company is subject to extensive environmental regulation pursuant to a variety of federal, state, and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities including particulate matter, sulfur dioxide (SO2), nitrogen oxide (NOx), and mercury, among others. Environmental legislation and regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO's electric operations.

Integrated Resource Planning Process

As required by the state of Indiana, the Company completed its 2016 Integrated Resource Plan (IRP) and submitted to the IURC on December 16, 2016. The state requires each electric utility to perform and submit an IRP that uses economic modeling to consider the costs and risks associated with available resource options to provide reliable electric service for the next twenty year period. During 2016, the Company held three public stakeholder meetings to gather input and feedback as well as communicate results of the IRP process as it progressed. In developing its IRP, the Company considered both the cost to continue operating its existing generation units in a manner that complies with current and anticipated future environmental requirements, as well as various resource alternatives, such as the use of energy efficiency programs and renewable resources as part of its overall generation portfolio. After submission, parties to the IRP provide comments on the plan. While the IURC does not approve or reject the IRP, comments received are taken into consideration, ultimately resulting in a report issued by the IURC, likely in the summer of 2017.

Currently, the Company operates approximately 1,000 MW of coal-fired generation, 245 MW of natural gas peaking units, and 3 MW via a landfill-gas-to-electricity facility. The Company also has 80 MW of wind power through two long-term power purchase agreements and 32 MW of coal generation through its ownership in OVEC. The Company’s 2016 IRP preferred portfolio illustrates a future less reliant on coal. The twenty year plan reflects the retirement of a portion of the Company’s current coal-fired fleet, transitions a significant portion of generation to natural gas and includes new renewable energy sources, specifically universal solar. The detailed plan would introduce approximately 54 MW of universal solar installed by 2019. The plan suggests the Company will exit its joint operations of Warrick Unit 4, a 300 MW unit shared with Alcoa, by 2020. The Company would complete upgrades to its existing coal-fired F.B. Culley Unit 3, a 270-megawatt unit, to comply with federal water regulations specific to the Effluent Limitations Guidelines (ELG) around 2023 in order to keep the unit in operation. As discussed in more detail in the ELG section below, the EPA has administratively stayed the compliance deadlines in the ELG rule pending reconsideration. In 2024, the IRP points to the retirement of coal-fired A.B. Brown plant Units 1 & 2 along with F.B. Culley Unit 2, collectively representing 580 MW. This generation would be replaced by a newly constructed combined cycle natural gas plant, with the capability of producing approximately 890 MW by 2024. In addition, the Company intends to continue to offer energy efficiency programs annually. Similarly, as discussed in more detail below, the short-term uncertainties related to ELG implementation are not expected to have a significant impact on the Company’s long term preferred generation plan.

The Company’s IRP considered a broad range of potential resources and variables and is focused on ensuring it offers a reliable, reasonably priced generation portfolio as well as a balanced energy mix. The Company plans to finalize this generation portfolio transition plan and submit a regulatory filing, including construction timelines and costs of new generation resources, as well as necessary unit retrofits, to the IURC in late 2017 to begin the generation transition process. The Company will seek approval of its generation plan, including timely recovery of all federally mandated compliance costs, as well as the authority to defer the cost of new generation until the time of a rate case.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule

In December 2014, the EPA released its final Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. The final rule allows beneficial reuse of ash and the majority of the ash generated by the

Company's generating plants will continue to be reused. As it relates to the CCR rule, legislation was passed in December 2016 by Congress that would provide for enforcement of the federal program by states rather than through citizen suits. Additionally, the CCR rule is currently being challenged by multiple parties in judicial review proceedings.

Under the final CCR rule, the Company is required to complete a series of integrity assessments, including seismic modeling given the Company's facilities are located within two seismic zones, and groundwater monitoring studies to determine the remaining service life of the ponds and whether a pond must be retrofitted with liners or closed in place, with bottom ash handling conversions completed. In late 2015, using general utility industry data, the Company prepared cost estimates for the retirement of the ash ponds at the end of their useful lives, based on its interpretation of the closure alternatives contemplated in the final rule. The resulting estimates ranged from approximately $35 million to $80 million. These estimates contemplated final capping and monitoring costs of the ponds at both F.B. Culley and A.B. Brown generating stations. These rules are not applicable to the Company's Warrick generating unit, as this unit has historically been part of a larger generating station that predominantly serves an adjacent industrial facility.

Throughout 2016, the Company has continued to refine site specific estimates and now estimates the costs to be in the range of $45 million to $100 million. Significant factors impacting the resulting cost estimates include the closure time frame and the method of closure. Current estimates contemplate additional beneficial reuse of the ash, as well as implications of the Company's preferred IRP. Ongoing analysis, the continued refinement of assumptions, or the inability to beneficially reuse the ash may result in estimated costs in excess of the current range.

As of December 31, 2016, the Company had recorded an approximate $40 million asset retirement obligation (ARO). The recorded ARO reflects the present value of the approximate $45 million in estimated costs in the range above. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO.

In order to maintain current operations of the ponds, the Company has spent approximately $17 million on the reinforcement of the ash pond dams and other operational changes in 2016 to meet the more stringent 2,500 year seismic event structural and safety standard in the CCR rule.

Effluent Limitation Guidelines (ELGs)
Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing electric generation facilities. On September 30, 2015, the EPA released final revisions to the existing steam electric ELGs setting stringent technology-based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELGs will be implemented when existing water discharge permits for the plants are renewed, with compliance activities expected to commence where operations continue, within the 2018-2023 time frame. The ELGs work in tandem with the aforementioned CCR requirements, effectively prohibiting the use of less costly lined sediment basin options for disposal of coal combustion residuals, and virtually mandate conversions to dry bottom ash handling.

The current wastewater discharge permit for the A.B. Brown power plant had an expiration date of October 2016 and, for the F.B. Culley plant, a date of December 2016, and final renewals were issued by the state environmental agency in February 2017 and March 2017, respectively. As part of the permit renewals, the Company requested alternate compliance dates for ELGs. Compliance with the ELGs will not be required prior to November 2018, but no later than December 31, 2023. For plants identified in the Company's preferred IRP to be retired prior to December 31, 2023, the

Company has requested those plants would not require new treatment technology, which was approved by the state agency provided that the Company notifies the state within one year of issuance of the renewal of its intent to retire the unit. For the F.B. Culley plant, the Company has proposed a 2020 compliance date for dry bottom ash and 2023 compliance date for flue gas desulfurization wastewater, which was approved by the state and finalized in the permit renewal.

On April 13, 2017, as part of the Administration's regulatory reform initiative, which is focused on the number and nature of regulations, the EPA granted petitions to reconsider the ELG rule, and indicated it would stay the current implementation deadlines in the rule during the pendency of the reconsideration. With publication in the federal register, the EPA will be seeking public comment on the stay of the ELG implementation deadlines. The EPA has also indicated it intends to seek a stay of the current judicial review litigation in federal district court. As the Company does not currently have short-term ELG implementation deadlines in its recently renewed wastewater discharge permits, the Company does not currently anticipate immediate impacts from the EPA's administrative stay of implementation deadlines due to the longer compliance time frames granted by the state, and will continue to work with the state agency to evaluate further implementation plans. The Company believes the stay of the ELG implementation deadlines do not impact its preferred generation plan as modeled in the IRP due to comparable ash handling restrictions required by the CCR rule which is not subject to an administrative stay, and other projected operational expenditures; however, on May 3, 2017, a coalition of environmental organizations filed a challenge to the stay of the ELG rule in the U.S. District Court for the District of Columbia.

Cooling Water Intake Structures
Section 316(b) of the Clean Water Act requires generating facilities use the "best technology available" (BTA) to minimize adverse environmental impacts on a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a state level case-by-case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company's facilities. The Company is currently undertaking the required ecological studies and anticipates timely compliance in 2021-2022. To comply, the Company believes capital investments will likely be in the range of $4 million to $8 million.

Air Quality

Ozone NAAQS
On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level within the range of 65 to 70 ppb. On October 1, 2015, the EPA finalized a new NAAQS for ozone at the high end of the range, or 70 ppb. On September 16, 2016, Indiana submitted its initial determination to the EPA recommending that counties in southwest Indiana, specifically Vanderburgh, Posey and Warrick, be declared in attainment of the new more stringent ozone standard based upon air monitoring data from 2014-2016. The EPA was expected to make final determinations as to whether a region is in attainment for the new NAAQS in 2017; however, in a March filing challenging the new standard, the EPA filed a request to stay the litigation pending a potential review of the ozone standard by the agency. While the future of the current ozone standard is not certain, it is possible counties in southwest Indiana could be declared in non-attainment with the current ozone standard, and thus could have an effect on future economic development activities in the Company's service territory. The Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units. In September 2016, the EPA finalized a supplement to the Cross State Air Pollution Rule (CSAPR) that requires further NOx reductions during the ozone season (May - September). The Company is positioned to comply with these NOx reduction requirements through its current investment in SCR technology.

One Hour SO2 NAAQS
On February 16, 2016, the EPA notified states of the commencement of a 120 day consultation period between the state and the EPA with respect to the EPA's recommendations for new non-attainment designations for the 2010 One Hour SO2 NAAQS. Identified on the list was Posey County, Indiana, where the Company's A.B. Brown Generating Station is located. While the Company is in compliance with all applicable SO2 limits in its permits, the Company reached an agreement with the state of Indiana on voluntary measures that the Company was able to implement

without significant incremental costs to ensure that Posey County remains in attainment with the 2010 One Hour SO_2 NAAQS. The Company's coal-fired generating fleet is 100 percent scrubbed for SO_2 and 90 percent controlled for NO_x.

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Climate Change

On August 3, 2015, the EPA released its final CPP rule which requires a 32 percent reduction in carbon emissions from 2005 levels. This results in a final emission rate goal for Indiana of 1,242 lb CO_2/MWh to be achieved by 2030. The new rule gives states the option of seeking a two-year extension from the initial deadline of September 2016 to submit a final state implementation plan (SIP). In March 2017, the EPA withdrew a Federal Implementation Plan (FIP) as a compliance option. Under the CPP, states have the flexibility to include energy efficiency and other measures should they choose to implement a SIP as provided in the final rule. While states are given an interim goal (1,451 lb CO_2/MWh for Indiana), the final rule gives states the flexibility to shape their own emissions reduction over the 2022-2029 time period. The final rule was published in the Federal Register on October 23, 2015, and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January 2016, the reviewing court denied the states' and other parties requests to stay the implementation of the CPP pending completion of judicial review. On January 26, 2016, 29 states and state agencies, including the 24 state coalition referenced above, filed a request for immediate stay of implementation of the rule with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted the stay request to delay the implementation of the regulation while being challenged in court. Extensive oral argument was held in September 2016. The stay will remain in place while the lower court concludes its review. Among other things, the stay delays the requirement to submit a final SIP by the original September 2016 deadline and could extend implementation to 2024. In March 2017, as part of the ongoing regulatory reform efforts of the Administration, the EPA has filed a motion with the U.S. Court of Appeals for the District of Columbia circuit to suspend litigation pending the EPA's reconsideration of the CPP rule, which was granted on April 28, 2017.

At the time of release of the CPP, Indiana was the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. The Company's share of total tons of CO_2 generated by Indiana's electric utilities has historically been less than 6 percent. Since 2005 through 2015, the Company has achieved a reduction in emissions of CO_2 of 31 percent (on a tonnage basis) through the retirement of F.B. Culley Unit 1, expiration of municipal wholesale power contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology. Since emissions are further impacted by coal burn reductions and energy efficiency programs, the Company's emissions of CO_2 can vary year to year. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by energy sources other than coal and natural gas, due to the long-term wind contracts and a landfill gas investment. With respect to the CO_2 emission rate, since 2005 through 2015, the Company has lowered its CO_2 emission rate (as measured in lbs CO_2/MWh) from 1,967 lbs CO_2/MWh to 1,922 lbs CO_2/MWh, for a reduction of 3 percent. The Company's CO_2 emission rate of 1,922 lbs CO_2/MWh is basically the same as Indiana's average CO_2 emission rate of 1,923 lbs CO_2/MWh. The Company plans to consider these reductions in CO_2 emissions and renewable generation in future discussions with the state to develop a possible state implementation plan.

Impact of Legislative Actions & Other Initiatives is Unknown

At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions. However, these compliance cost estimates were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. The Company is undertaking a detailed review of the requirements of the CPP and a review of potential compliance options. The Company will also continue to remain engaged with the Indiana legislators and regulators to assess the final rule and to develop a plan that is the least cost to its customers.

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28 percent GHG emission reduction from 2005 levels by 2025. The Administration has not indicated yet whether it intends to remain in the Agreement or withdraw its participation. As previously noted, since 2005 through 2015, the Company has achieved reduced emissions of CO2 by 31 percent (on a tonnage basis). While the litigation and reconsideration of the CPP rules remains uncertain, the Company will continue to monitor regulatory activity regarding GHG emission standards that may affect its electric generating units.

Manufactured Gas Plants

In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/ feasibility study (RI/FS) was completed at one of the sites under an agreed upon order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO’s service territory, all of which are currently enrolled in the IDEM’s VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $44.2 million ($23.9 million at Indiana Gas and $20.3 million at SIGECO). The estimated accrued costs are limited to the Company’s share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received approximately $15.4 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company’s utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of both March 31, 2017 and December 31, 2016, approximately $2.9 million of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

11. Fair Value Measurements

The carrying values and estimated fair values using primarily Level 2 assumptions of the Company's other financial instruments follow:

	March 31, 2017		December 31, 2016	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,380.3	$1,487.7	$1,380.1	$1,495.3
Short-term borrowings	101.4	101.4	194.4	194.4
Cash & cash equivalents	6.8	6.8	9.4	9.4
Restricted Cash	—	—	0.9	0.9

For the balance sheet dates presented in these financial statements, the Company had no material assets or liabilities recorded at fair value outstanding, and no material assets or liabilities valued using Level 3 inputs.

Certain methods and assumptions must be used to estimate the fair value of financial instruments. The fair value of the Company's long-term debt was estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Company for instruments with similar characteristics. Because of the maturity dates and variable interest rates of short-term borrowings and cash & cash equivalents, those carrying amounts approximate fair value. Because of the inherent difficulty of estimating interest rate and other market risks, the methods used to estimate fair value may not always be indicative of actual realizable value, and different methodologies could produce different fair value estimates at the reporting date.

Under current regulatory treatment, call premiums on reacquisition of utility-related long-term debt are generally recovered in customer rates over the life of the refunding issue. Accordingly, any reacquisition of this debt would not be expected to have a material effect on the Company's results of operations.

12. Impact of Recently Issued Accounting Principles
Revenue Recognition Guidance
In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). While the Company continues to assess the standard and initial conclusions could change based on completion of that assessment, the Company preliminarily plans to adopt the guidance under the modified retrospective method.

In July 2015, the FASB approved a one year deferral that became effective through an ASU in August and changed the effective date to annual reporting periods beginning after December 15, 2017, including interim periods, with early adoption permitted, but not before the original effective date of December 15, 2016.

The Company is currently assessing the impacts this guidance may have on the Consolidated Balance Sheets, Consolidated Statements of Operations, and disclosures including the ability to recognize revenue for certain contracts, and its accounting for contributions in aid of construction (CIAC). While management will continue to analyze the impact of this new standard and the related ASUs that clarify guidance in the standard, at this time, management does not believe adoption of the standard will have a significant impact on the Company's pattern of revenue recognition. The Company plans to adopt the guidance effective January 1, 2018.

Leases
In February 2016, the FASB issued new accounting guidance for the recognition, measurement, presentation and disclosure of leasing arrangements. This ASU requires the recognition of lease assets and liabilities for those leases currently classified as operating leases while also refining the definition of a lease. In addition, lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. This ASU is effective for the interim and annual reporting periods beginning January 1, 2019, although it can be early adopted, with a modified retrospective approach for leases that commenced prior to the date of adoption. The Company is currently evaluating the standard to determine the impact it will have on the financial statements.

Stock Compensation
In March 2016, the FASB issued new accounting guidance which is intended to simplify several aspects of accounting for share-based payment transactions, including the income tax consequences. This ASU is effective for annual periods beginning after December 15, 2016, and interim periods therein. The Company does not have share-based compensation plans separate from the Company's parent; the Company is however allocated costs associated with the plans of the Company's parent. Pursuant to these plans, share based awards are settled via cash payments and are

therefore not impacted by this standard. The Company's adoption of this standard did not have a material impact on the financial statements.

Presentation of Net Periodic Pension and Postretirement Benefit Costs

In March 2017, the FASB issued new accounting guidance to improve the presentation of net periodic pension and postretirement benefit costs. This ASU is effective for annual periods beginning after December 15, 2017, and relevant interim periods. Early adoption is permitted. This ASU requires that the service cost component is reported in the same line items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside of income from operations. The Company does not have pension and postretirement plans separate from the Company's parent. However, the Company's parent allocates the periodic cost of its retirement plans to the Company's subsidiaries. The Company is currently evaluating the standard to determine the impact it will have on the financial statements, however, does not anticipate its adoption to have a significant impact on the financial statements. The Company plans to adopt the guidance effective January 1, 2018.

Other Recently Issued Standards
Management believes other recently issued standards, which are not yet effective, will not have a material impact on the Company's financial condition, results of operations, or cash flows upon adoption.

13. Segment Reporting

The Company’s operations consist of regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment. The Gas Utility Services segment provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west-central Ohio. The Electric Utility Services segment provides electric distribution services primarily to southwestern Indiana, and includes the Company’s power generating and wholesale power operations. Regulated operations supply natural gas and/or electricity to over one million customers. In total, the Company is comprised of three operating segments: Gas Utility Services, Electric Utility Services, and Other Operations. Net income is the measure of profitability used by management for all operations.

Information related to the Company’s business segments is summarized below:

	Three Months Ended March 31,	
(In millions)	2017	2016
Revenues		
Gas Utility Services	$292.8	$281.2
Electric Utility Services	132.1	142.1
Other Operations	11.4	10.6
Eliminations	(11.3)	(10.5)
Total Revenues	$425.0	$423.4
Profitability Measure - Net Income (Loss)		
Gas Utility Services	$47.9	$40.4
Electric Utility Services	13.7	16.6
Other Operations	4.3	4.1
Total Net Income	$65.9	$61.1

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

Description of the Business

Vectren Utility Holdings, Inc. (the Company, Utility Holdings, or VUHI), an Indiana corporation, was formed on March 31, 2000 to serve as the intermediate holding company for Vectren Corporation’s (Vectren or the Company's parent) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Herein, 'the Company' may also refer to Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Inc. and/or Vectren Energy Delivery of Ohio, Inc. The Company also has other assets that provide information technology and other services to the three utilities. Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana and was organized on June 10, 1999. Both Vectren and the Company are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to approximately 597,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 145,000 electric customers and approximately 112,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 320,000 natural gas customers located near Dayton in west-central Ohio. The Company segregates its regulatory utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment.

The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto as well as the Company’s 2016 annual report filed on Form 10-K.

Executive Summary of Consolidated Results of Operations

In the first quarter of 2017, the Company's earnings were $65.9 million, compared to $61.1 million in 2016. The improved 2017 results in the quarter were primarily driven by returns earned on the Indiana and Ohio gas infrastructure investment programs and increased large gas customer margin. These increases were partially offset by the impact of warmer weather on residential and commercial electric customer usage and a reduction in electric large customer usage as a large customer completed its transition to a co-generation facility.

Results of Operations

Margin

Throughout this discussion, the terms Gas utility margin and Electric utility margin are used. Gas utility margin is calculated as Gas utility revenues less the Cost of gas sold. Electric utility margin is calculated as Electric utility revenues less Cost of fuel & purchased power. The Company believes Gas utility and Electric utility margins are better indicators of relative contribution than revenues since gas prices and fuel and purchased power costs can be volatile and are generally collected on a dollar-for-dollar basis from customers.

In addition, the Company separately reflects regulatory expense recovery mechanisms within Gas utility margin and Electric utility margin. These amounts represent dollar-for-dollar recovery of operating expenses. The Company utilizes these approved regulatory mechanisms to recover variations in operating expenses from the amounts reflected in base rates and are generally expenses that are subject to volatility. Following is a discussion and analysis of margin generated from regulated utility operations.

Gas Utility Margin (Gas utility revenues less Cost of gas sold)
Gas Utility margin and throughput by customer type follows:

	Three Months Ended March 31,	
(In millions)	2017	2016
Gas utility revenues	$292.8	$281.2
Cost of gas sold	112.9	111.6
Total gas utility margin	$179.9	$169.6
Margin attributed to:		
Residential & commercial customers	$139.4	$130.0
Industrial customers	21.1	19.0
Other	2.7	2.9
Regulatory expense recovery mechanisms	16.7	17.7
Total gas utility margin	$179.9	$169.6
Sold & transported volumes in MMDth attributed to:		
Residential & commercial customers	42.9	47.0
Industrial customers	34.9	35.9
Total sold & transported volumes	77.8	82.9

Gas utility margins were $179.9 million for the three months ended March 31, 2017, and compared to 2016, increased $10.3 million in the quarter. Gas utility margins increased $11.3 million in the quarter when excluding margin from regulatory expense recovery mechanisms, which decreased $1.0 million. Gas margin was favorably impacted by increased returns on infrastructure investment programs in Indiana and Ohio of $9.4 million in the first quarter of 2017 compared to 2016, and also reflects increases in large customer margin of $1.3 million primarily due to a new customer that came online in the second half of 2016. With rate designs that substantially limit the impact of weather on small customer margin, the warmer than normal weather in the first quarter of 2017 did decrease sold and transported volumes, but had only a slight unfavorable impact on small customer margin compared to 2016. Heating degree days were 92 percent of normal in Ohio and 85 percent of normal in Indiana in the first quarter of 2017, compared to 97 percent of normal in Ohio and 92 percent of normal in Indiana in the same period in 2016.

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Electric Utility Margin (Electric utility revenues less Cost of fuel & purchased power
Electric Utility margin and volumes sold by customer type follows:

	Three Months Ended March 31,	
(In millions)	2017	2016
Electric utility revenues	$132.1	$142.1
Cost of fuel & purchased power	41.2	44.2
Total electric utility margin	$90.9	$97.9
Margin attributed to:		
Residential & commercial customers	$57.6	$60.0
Industrial customers	23.0	26.0
Other	0.9	1.3
Regulatory expense recovery mechanisms	2.4	4.0
Subtotal: retail	$83.9	$91.3
Wholesale power & transmission system margin	7.0	6.6
Total electric utility margin	$90.9	$97.9
Electric volumes sold in GWh attributed to:		
Residential & commercial customers	601.1	639.8
Industrial customers	491.4	654.2
Other customers	6.0	6.1
Total retail volumes sold	1,098.5	1,300.1

Retail
Electric retail utility margins were $83.9 million for the three months ended March 31, 2017, and compared to 2016, decreased by $7.4 million in the quarter. Electric margin, which is not protected by weather normalizing mechanisms, reflects a $2.1 million decrease in customer margin in the quarter related to weather as annualized heating degree days in the first quarter of 2017 were 85 percent of normal compared to 92 percent of normal in 2016. Additionally, results reflect a decrease in large customer usage of $3.1 million. This decrease in margin is due to the completion by a large customer of its transition to a co-generation (cogen) facility resulting in lower usage of approximately 170 GWh when compared to the same period in the prior year. Margin from regulatory expense recovery mechanisms decreased $1.6 million in the first quarter of 2017 compared to the first quarter of 2016.

As previously discussed, SABIC Innovative Plastics (SABIC), a large industrial utility customer of the Company, announced on December 3, 2013, its plan to build a cogen facility in order to generate power to meet a significant portion of its ongoing power needs. Electric service was provided to SABIC by the Company under a long-term contract that expired on May 2, 2016. At that date, SABIC became a tariff customer. The cogen facility was operational as of January 1, 2017 and is expected to provide approximately 85 MW of capacity. The Company will continue to provide all of SABIC's power requirements above the approximate 85 MW capacity of the cogen, as well as backup power under approved tariff rates.

Margin from Wholesale Electric Activities
The Company earns a return on electric transmission projects constructed by the Company in its service territory that meet the criteria of MISO's regional transmission expansion plans and also markets and sells its generating and transmission capacity to optimize the return on its owned assets. Substantially all off-system sales are generated in the MISO Day Ahead and Real Time markets when sales into the MISO in a given hour are greater than amounts purchased for native load. Further detail of MISO off-system margin and transmission system margin follows:

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(In millions)	Three Months Ended March 31, 2017	2016
MISO Transmission system margin	$5.8	$5.6
MISO Off-system margin	1.2	1.0
Total wholesale margin	$7.0	$6.6

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms and other transmission system operations, totaled $5.8 million and $5.6 million during the three months ended March 31, 2017 and 2016, respectively. The Company had invested $157.7 million in qualifying projects. The net plant balance for these projects totaled $136 million at March 31, 2017. These projects include an interstate 345 kV transmission line that connects the Company’s A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. These projects earn a FERC approved equity rate of return on the net plant balance and recover operating expenses. In September 2016, the FERC issued a final order authorizing the transmission owners to receive a 10.32 percent base ROE plus, a separately approved 50 basis point adder compared to the previously authorized 12.38 percent. The Company has reflected these outcomes in its financial statements. The 345 kV project is the largest of these qualifying projects, with a cost of $106.8 million that earned the FERC approved equity rate of return, including while under construction.

For the three months ended March 31, 2017, margin from off-system sales were $1.2 million compared to $1.0 million in 2016. The base rate changes implemented in May 2011 require that wholesale margin from off-system sales earned above or below $7.5 million per year is shared equally with customers. Results for the periods presented reflect lower market pricing due primarily to low natural gas prices.

Other Operating
During the first quarter of 2017, other operating expenses were $85.6 million, and decreased $3.8 million compared to the first quarter of 2016. Excluding costs recovered directly in margin, other operating expenses decreased $0.9 million quarter over quarter when compared to 2016. The reduction in the quarter was primarily impacted by changes in performance-based compensation driven by movements in the stock price of the Company's parent.

Depreciation & Amortization
In the first quarter of 2017, depreciation and amortization expense was $57.4 million, compared to $53.6 million in 2016. The increase reflects increased plant placed in service, which is largely driven by increased gas utility plant as a result of the Indiana and Ohio infrastructure programs.

Taxes Other Than Income Taxes
Taxes other than income taxes were $14.4 million for the first quarter of 2017, a decrease of $2.7 million, compared to 2016. The reduction in taxes other than income taxes in the first quarter of 2017 compared to 2016 was primarily related to lower property taxes.

Other Income - Net

Other income-net reflects income of $7.0 million for the first quarter of 2017, an increase of $1.4 million, compared to 2016. The increases are primarily due to increased allowance for funds used during construction (AFUDC) driven by increased capital expenditures related to gas utility infrastructure replacement investments.

Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement
The Company monitors and maintains its natural gas distribution system to ensure natural gas is delivered in a safe and efficient manner. The Company's natural gas utilities are currently engaged in programs to replace bare steel and cast iron infrastructure and other activities in both Indiana and Ohio to mitigate risk, improve the system, and comply with applicable regulations, many of which are the result of federal pipeline safety requirements. Laws passed in both Indiana and Ohio provide utilities the opportunity to timely recover costs of federally mandated projects and other infrastructure improvement projects outside of a base rate proceeding.

Indiana Senate Bill 251 (Senate Bill 251) provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, based on the overall rate of return most recently approved by the IURC, along with recovery of depreciation and other operating costs associated with these mandates. The remaining 20 percent of those costs is deferred for future recovery in the utility's next general rate case.

Indiana Senate Bill 560 (Senate Bill 560) supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs are deferred and recovered in the utility’s next general rate case, which must be filed before the expiration of the seven-year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

Ohio House Bill 95 (House Bill 95) permits a natural gas utility to apply for recovery of much of its capital expenditure program. This legislation also allows for the deferral of costs, such as depreciation, property taxes, and debt-related post-in-service carrying costs until recovery is approved by the PUCO.

Indiana Recovery and Deferral Mechanisms
The Company's Indiana natural gas utilities received Orders in 2008 and 2007 associated with the most recent base rate cases. These Orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The Orders provide for the deferral of depreciation and post-in-service carrying costs on qualifying projects totaling $20 million annually at Indiana Gas and $3 million annually at SIGECO. The debt-related post-in-service carrying costs are currently recognized in the Consolidated Statements of Income. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At March 31, 2017 and December 31, 2016, the Company has regulatory assets totaling $22.3 million and $21.9 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company’s seven-year capital investment plan discussed below.

Requests for Recovery under Indiana Regulatory Mechanisms

In August 2014, the IURC issued an Order approving the Company's seven-year capital infrastructure replacement and improvement plan (the Plan), beginning in 2014, and the proposed accounting authority and recovery. Compliance projects and other infrastructure improvement projects were approved pursuant to Senate Bill 251 and 560, respectively. As provided in the two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs, including a return, recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company's next base rate proceeding. In addition, the Order established guidelines to annually update the seven-year capital investment plan. Finally, the Order approved the Company’s proposal to recover eligible costs assigned to the residential customer class via a fixed monthly charge per residential customer.

In March 2016, the IURC issued an Order re-approving approximately $890 million of the Company’s gas infrastructure modernization projects requested in the third update of the Plan, and approving the inclusion in rates of actual investments made through June 30, 2015. While most of the proposed capital spend has been approved as proposed, approximately $80 million of projects were not approved for recovery through the mechanisms pursuant to these filings. Specifically, the Company proposed to add a new project to its Plan pursuant to Senate Bill 560 totaling approximately $65 million. The project, which consists of a 20-mile transmission line and other related investments required to support industrial customer growth and ongoing system reliability in the Lafayette, Indiana area, as well as allows the Company to further diversify its gas supply portfolio via access to shale gas in the Marcellus and Utica reserves, was excluded for recovery under the Plan. The IURC stated because the project was not in the original plan filed in 2013, it does not qualify for cost recovery under Senate Bill 560. In the Order, the IURC did pre-approve the project for rate base inclusion upon the filing of the next base rate case. The Company believes such plan updates should be expected to accommodate new projects that emerge during the term of the plan as ongoing risk assessments determine new projects are required. The Company filed an appeal of the March 2016 Order on April 29, 2016 to challenge the IURC's finding which limits the scope of the Plan updates. On April 27, 2017, the Indiana Court of Appeals denied the Company's appeal of the Order. The Company is evaluating its options related to the Plan update issue, but as noted herein the project at issue was previously approved by the IURC for recovery in the Company's next general base rate case. Further, the Company does not expect similar issues related to updating future plan filings as the project inclusion process is now better understood by all parties.

Subsequent to the March 2016 Order, the Company has received two additional Orders approving plan investments. On June 29, 2016, the IURC issued an Order approving the inclusion in rates of investments made from July 2015 to December 2015. On January 25, 2017 the IURC issued an Order (January 2017 Order) approving the inclusion in rates of investments made from January 2016 to June 2016. Through the January 2017 Order, approximately $338 million of the approved capital investment plan has been incurred and included for recovery. The January 2017 Order also approved the Company's plan update, which is now $950 million through 2020. The plan increase of $60 million is due to additional investment related to pipeline safety and compliance requirements under Senate Bill 251.

At March 31, 2017 and December 31, 2016, the Company has regulatory assets related to the Plan totaling $54.9 million and $51.1 million, respectively.

On April 3, 2017, the Company submitted its sixth semi-annual filing, seeking approval for recovery of an additional $69.1 million of capital investments made through December 31, 2016. An evidentiary hearing has been scheduled for June 22, 2017, and the Company expects an order later in 2017.

Ohio Recovery and Deferral Mechanisms
The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines, as well as certain other infrastructure investments. This rider is updated annually for qualifying capital expenditures and allows for a return on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of certain other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels through 2017. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. In the event the Company exceeds these caps, amounts in excess can be deferred for future recovery. The Order also approved the Company's commitment that the DRR can only be further extended as part of a base rate case. In total, the Company has made capital investments on projects that are now in-service under the DRR totaling $269.7 million as of March 31, 2017, of which $204.0 million has been approved for recovery under the DRR through December 31, 2015. On May 1, 2017, the Company submitted its annual request for an adjustment in the DRR rates to recover an additional $57.1 million of capital investments made through December 31, 2016. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $25.9 million and $24.4 million at March 31, 2017 and December 31, 2016, respectively.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. At March 31, 2017 and December 31, 2016, the Company has regulatory assets totaling $46.7 million and $41.9 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. As of March 31, 2017, the Company's deferrals have not reached this bill impact cap. On May 1, 2017, the Company submitted its most recent annual report required under its House Bill 95 Order. This report covers the Company's capital expenditure program through calendar year 2017.

Given the extension of the DRR through 2017, as discussed above, and the continued ability to defer other capital expenses under House Bill 95, it is anticipated that the Company will file a general rate case for the inclusion in rate base of the above costs in early 2018.

Pipeline and Hazardous Materials Safety Administration (PHMSA)
In March 2016, PHMSA published a notice of proposed rulemaking (NPRM) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a particular focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. The Company is evaluating the impact these proposed rules will have on its integrity management programs and transmission and distribution systems. Progress on finalizing the rule continues to work through the administrative process. It is expected the rule will be finalized in 2018 and the Company believes the costs to comply with the new rules would be considered federally mandated and therefore should be recoverable.

In December 2016, PHMSA issued final rules related to integrity management for storage operations. Efforts are underway to implement the new requirements. Further, the Company reviewed the Underground Natural Gas Storage Safety Recommendations from a joint Department of Energy and PHMSA led task force. These rules could increase the potential for capital expenditures and increase operating and maintenance expenses. The Company believes the cost to comply with these new rules would be considered federally mandated and therefore should be recoverable using various regulatory recovery mechanisms.

Additionally, PHMSA finalized a rule on excess flow valves, which went into effect in April 2017. At the customer's request, excess flow valves will be installed at the customer's cost.

Electric Rate & Regulatory Matters

Regulatory Treatment of Investments in Electric Infrastructure
On February 23, 2017, the Company filed for authority to recover costs related to its electric system modernization plan, using the mechanism allowed under Senate Bill 560. The electric system modernization plan includes investments to upgrade portions of the Company’s network of substations, transmission and distribution systems, to enhance reliability and allow the grid to accept advanced technology to improve the information and service provided to customers. The filing requests the recovery of associated capital expenditures estimated to be approximately $500 million over the seven-year period beginning in 2017. A field hearing in this proceeding was held on May 2, 2017. Testimony from the public provided during this hearing will be considered by the IURC in this case. Filed testimony of intervening parties was required by May 4, 2017. An evidentiary hearing has been scheduled for June 26, 2017. Under the timeline provided by Senate Bill 560, the Company expects an order in September 2017.

Renewable Generation Resources
On February 22, 2017, the Company also filed for authority to recover costs related to the construction of three solar projects, using the mechanism allowed under Senate Bill 29, which allows for timely recovery of costs and expenses incurred during the construction and operation of clean energy projects. These investments, presented as part of the Company’s Integrated Resource Plan (IRP) submitted in December 2016, allow the Company to add approximately 4 MW of universal solar generation, rooftop solar generation, and 1 MW of battery storage resources to its portfolio. See more information on the IRP below in Environmental & Sustainability Matters. The cost of the projects is estimated to be approximately $15 million. Filed testimony of intervening parties was required by May 11, 2017. An evidentiary hearing has been scheduled for June 15, 2017, and the Company expects an order by the end of 2017.

SIGECO Electric Environmental Compliance Filing
On January 28, 2015, the IURC issued an Order approving the Company’s request for approval of capital investments in its coal-fired generation units to comply with new EPA mandates related to mercury and air toxic standards (MATS) effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA pertaining to its A.B. Brown generating station sulfur trioxide emissions. The MATS rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants.

As of March 31, 2017, $30 million has been spent on equipment to control mercury in both air and water emissions, and $40 million to address the issues raised in the NOV. The Order approved the Company’s request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. These costs will be included for recovery no later than the next rate case. The initial phase of the projects went into service in 2014, with the remaining investment going into service in 2016. As of March 31, 2017, the Company has approximately $9.0 million deferred related to depreciation and operating expense, and $3.3 million deferred related to post-in-service carrying costs. MATS compliance was required beginning April 16, 2015, and the Company continues to operate in full compliance with the MATS rule.

In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) challenged the IURC's January 2015 Order. On October 29, 2015, the Indiana Court of Appeals issued an opinion that affirmed the IURC's findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules but remanded the case to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV. On June 22, 2016, the IURC issued an Order granting the Company a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. On February 14, 2017, the Court affirmed the IURC's June 22, 2016 Order.

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SIGECO Electric Demand Side Management (DSM) Program Filing
On August 31, 2011, the IURC issued an Order approving an initial three-year DSM plan in the Company's electric service territory that complied with the IURC's energy saving targets. Consistent with the Company's proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; and 3) lost margin recovery associated with the implementation of DSM programs for large customers. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. For the three months ended March 31, 2017 and 2016, the Company recognized electric utility revenue of $3.0 million and $2.6 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. The legislation allows for industrial customers to opt out of participating in energy efficiency programs and as a result of this legislation, most of the Company's eligible industrial customers have since opted out of participation in the applicable energy efficiency programs.

Indiana Senate Bill 412 (Senate Bill 412) requires electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also requires the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years 2016 and 2017. On March 23, 2016, the IURC issued an Order approving the Company's 2016-2017 energy efficiency plan. The Order provides for cost recovery of program and administrative expenses and includes performance incentives for reaching energy savings goals. The Order also included a lost margin recovery mechanism that now limits that recovery related to new programs to the shorter of four years or the life of the installed energy efficiency measure. Prior electric energy efficiency orders did not limit lost margin recovery in this manner. This ruling follows other recent IURC decisions implementing the same lost margin recovery limitation with respect to other electric utilities in Indiana. The Company appealed this lost margin recovery restriction based on the Company's commitment to promote and drive participation in its energy efficiency programs.

On March 7, 2017, the Court of Appeals reversed the IURC finding on the Company's 2016-2017 energy efficiency plan that the four year cap on lost margin recovery was arbitrary and the IURC failed to properly interpret the governing statute requiring it to review the utility's originally submitted DSM proposal and either approve or reject it as a whole, including the proposed lost margin recovery. The case has been remanded back to the Commission for further proceedings to determine the reasonableness of the Company's entire energy efficiency plan.

On April 10, 2017, the Company submitted its request for approval of its Energy Efficiency Plan for calendar years 2018 through 2020. Consistent with prior filings, this filing included a request for continued cost recovery of program and administrative expenses, including performance incentives for reaching energy savings goals and continued recovery of lost margins over the life of the installed energy efficiency measure. Filed testimony of intervening parties is required by July 14, 2017. An evidentiary hearing has been scheduled for August 31, 2017, and the Company expects an order by the end of 2017.

FERC Return on Equity (ROE) Complaints
On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against the MISO and various MISO transmission owners, including SIGECO (first complaint case). The joint parties sought to reduce the 12.38 percent ROE used in the MISO transmission owners' rates, including SIGECO's formula transmission rates, to 9.15 percent covering the refund period from November 12, 2013 through February 11, 2015 (first refund period). On September 28, 2016, the FERC issued a

final order authorizing a 10.32 percent base ROE for the first refund period and prospectively through the date of the order in a second complaint case as detailed below.

A second customer complaint case was filed on February 11, 2015 covering the refund period from February 12, 2015 through May 11, 2016 (second refund period). An initial decision from the FERC administrative law judge on June 30, 2016, authorized a base ROE of 9.70 percent for the second refund period. The FERC is expected to rule on the proposed order in the second complaint case in 2017, which will authorize a base ROE for this period and prospectively from the date of the order.

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as the MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The FERC deferred the implementation of this adder until the pending complaint is resolved. The adder will be applied retroactively from January 6, 2015 through May 11, 2016 and prospectively from the September 28, 2016 order in the first complaint case.
The Company has reflected these results in its financial statements. As of March 31, 2017, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $136.0 million at March 31, 2017.

On April 14, 2017, the U.S. Court of Appeals for the District of Columbia circuit vacated the FERC Opinion in a prior case that established a new methodology for calculating ROE. This methodology was utilized in the final order in the Company's first complaint case, and the initial decision in the Company's second complaint case. The Appeals Court stated that FERC did not prove the existing ROE was not just and reasonable and also failed to provide any reasoned basis for their selected ROE. The Company will continue to monitor this proceeding and evaluate any potential impacts on the Company's complaint cases but would not expect them to be material.

Environmental & Sustainability Matters

The Company initiated a corporate sustainability program in 2012 with the publication of the initial corporate sustainability report of the Company's parent. Since that time the Company continues to develop strategies that focus on those environmental, social and governance (ESG) factors that contribute to the long-term growth of a sustainable business model. As detailed further below and in the upcoming corporate sustainability report for 2016, the Company continues to set out its plans, among other things, to upgrade and diversify its generation portfolio. The sustainability policies and efforts, and in particular its policies and procedures designed to ensure compliance with applicable laws and regulations, are directly overseen by Vectren's Corporate Responsibility and Sustainability Committee, as well as vetted with Vectren's full Board of Directors. Further discussion of key goals, strategies, and governance practices can be found in the Company’s latest sustainability report at www.vectren.com/sustainability, which received core level certification from the Global Reporting Initiative.

The Company is subject to extensive environmental regulation pursuant to a variety of federal, state, and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities including particulate matter, sulfur dioxide (SO2), nitrogen oxide (NOx), and mercury, among others. Environmental legislation and regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO's electric operations.

Integrated Resource Planning Process

As required by the state of Indiana, the Company completed its 2016 Integrated Resource Plan (IRP) and submitted to the IURC on December 16, 2016. The state requires each electric utility to perform and submit an IRP that uses economic modeling to consider the costs and risks associated with available resource options to provide reliable electric service for the next twenty year period. During 2016, the Company held three public stakeholder meetings to gather input and feedback as well as communicate results of the IRP process as it progressed. In developing its IRP, the Company considered both the cost to continue operating its existing generation units in a manner that complies with current and anticipated future environmental requirements, as well as various resource alternatives, such as the use of energy efficiency programs and renewable resources as part of its overall generation portfolio. After submission, parties to the IRP provide comments on the plan. While the IURC does not approve or reject the IRP, comments received are taken into consideration, ultimately resulting in a report issued by the IURC, likely in the summer of 2017.

Currently, the Company operates approximately 1,000 MW of coal-fired generation, 245 MW of natural gas peaking units, and 3 MW via a landfill-gas-to-electricity facility. The Company also has 80 MW of wind power through two long-term power purchase agreements and 32 MW of coal generation through its ownership in OVEC. The Company’s 2016 IRP preferred portfolio illustrates a future less reliant on coal. The twenty year plan reflects the retirement of a portion of the Company’s current coal-fired fleet, transitions a significant portion of generation to natural gas and includes new renewable energy sources, specifically universal solar. The detailed plan would introduce approximately 54 MW of universal solar installed by 2019. The plan suggests the Company will exit its joint operations of Warrick Unit 4, a 300 MW unit shared with Alcoa, by 2020. The Company would complete upgrades to its existing coal-fired F.B. Culley Unit 3, a 270-megawatt unit, to comply with federal water regulations specific to the Effluent Limitations Guidelines (ELG) around 2023 in order to keep the unit in operation. As discussed in more detail in the ELG section below, the EPA has administratively stayed the compliance deadlines in the ELG rule pending reconsideration. In 2024, the IRP points to the retirement of coal-fired A.B. Brown plant Units 1 & 2 along with F.B. Culley Unit 2, collectively representing 580 MW. This generation would be replaced by a newly constructed combined cycle natural gas plant, with the capability of producing approximately 890 MW by 2024. In addition, the Company intends to continue to offer energy efficiency programs annually. Similarly, as discussed in more detail below, the short-term uncertainties related to ELG implementation are not expected to have a significant impact on the Company’s long term preferred generation plan.

The Company’s IRP considered a broad range of potential resources and variables and is focused on ensuring it offers a reliable, reasonably priced generation portfolio as well as a balanced energy mix. The Company plans to finalize this generation portfolio transition plan and submit a regulatory filing, including construction timelines and costs of new generation resources, as well as necessary unit retrofits, to the IURC in late 2017 to begin the generation transition process. The Company will seek approval of its generation plan, including timely recovery of all federally mandated compliance costs, as well as the authority to defer the cost of new generation until the time of a rate case.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule
In December 2014, the EPA released its final Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. The final rule allows beneficial reuse of ash and the majority of the ash generated by the Company’s generating plants will continue to be reused. As it relates to the CCR rule, legislation was passed in December 2016 by Congress that would provide for enforcement of the federal program by states rather than through citizen suits. Additionally, the CCR rule is currently being challenged by multiple parties in judicial review proceedings.

Under the final CCR rule, the Company is required to complete a series of integrity assessments, including seismic modeling given the Company’s facilities are located within two seismic zones, and groundwater monitoring studies to determine the remaining service life of the ponds and whether a pond must be retrofitted with liners or closed in place, with bottom ash handling conversions completed. In late 2015, using general utility industry data, the Company prepared cost estimates for the retirement of the ash ponds at the end of their useful lives, based on its interpretation of the closure alternatives contemplated in the final rule. The resulting estimates ranged from approximately $35 million to $80 million. These estimates contemplated final capping and monitoring costs of the ponds at both F.B. Culley and A.B. Brown generating stations. These rules are not applicable to the Company's Warrick generating unit, as this unit has historically been part of a larger generating station that predominantly serves an adjacent industrial facility.

Throughout 2016, the Company has continued to refine site specific estimates and now estimates the costs to be in the range of $45 million to $100 million. Significant factors impacting the resulting cost estimates include the closure time frame and the method of closure. Current estimates contemplate additional beneficial reuse of the ash, as well as implications of the Company's preferred IRP. Ongoing analysis, the continued refinement of assumptions, or the inability to beneficially reuse the ash may result in estimated costs in excess of the current range.

As of December 31, 2016, the Company had recorded an approximate $40 million asset retirement obligation (ARO). The recorded ARO reflects the present value of the approximate $45 million in estimated costs in the range above. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO.

In order to maintain current operations of the ponds, the Company has spent approximately $17 million on the reinforcement of the ash pond dams and other operational changes in 2016 to meet the more stringent 2,500 year seismic event structural and safety standard in the CCR rule.

Effluent Limitation Guidelines (ELGs)
Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing electric generation facilities. On September 30, 2015, the EPA released final revisions to the existing steam electric ELGs setting stringent technology-based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELGs will be implemented when existing water discharge permits for the plants are renewed, with compliance activities expected to commence where operations continue, within the 2018-2023 time frame. The ELGs work in tandem with the aforementioned CCR requirements, effectively prohibiting the use of less costly lined sediment basin options for disposal of coal combustion residuals, and virtually mandate conversions to dry bottom ash handling.

The current wastewater discharge permit for the A.B. Brown power plant had an expiration date of October 2016 and, for the F.B. Culley plant, a date of December 2016, and final renewals were issued by the state environmental agency in February 2017 and March 2017, respectively. As part of the permit renewals, the Company requested alternate compliance dates for ELGs. Compliance with the ELGs will not be required prior to November 2018, but no later than December 31, 2023. For plants identified in the Company’s preferred IRP to be retired prior to December 31, 2023, the Company has requested those plants would not require new treatment technology, which was approved by the state agency provided that the Company notifies the state within one year of issuance of the renewal of its intent to retire the unit. For the F.B. Culley plant, the Company has proposed a 2020 compliance date for dry bottom ash and 2023 compliance date for flue gas desulfurization wastewater, which was approved by the state and finalized in the permit renewal.

On April 13, 2017, as part of the Administration's regulatory reform initiative, which is focused on the number and nature of regulations, the EPA granted petitions to reconsider the ELG rule, and indicated it would stay the current implementation deadlines in the rule during the pendency of the reconsideration. With publication in the federal register, the EPA will be seeking public comment on the stay of the ELG implementation deadlines. The EPA has also indicated it intends to seek a stay of the current judicial review litigation in federal district court. As the Company does not currently have short-term ELG implementation deadlines in its recently renewed wastewater discharge permits, the Company does not currently anticipate immediate impacts from the EPA’s administrative stay of implementation deadlines due to the longer compliance time frames granted by the state, and will continue to work with the state agency to evaluate further implementation plans. The Company believes the stay of the ELG implementation deadlines do not impact its preferred generation plan as modeled in the IRP due to comparable ash handling restrictions required by the CCR rule which is not subject to an administrative stay, and other projected operational expenditures; however, on May 3, 2017, a coalition of environmental organizations filed a challenge to the stay of the ELG rule in the U.S. District Court for the District of Columbia.

Cooling Water Intake Structures
Section 316(b) of the Clean Water Act requires generating facilities use the “best technology available” (BTA) to minimize adverse environmental impacts on a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a state level case-by-case assessment of BTA for each facility. The final rule lists

seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company’s facilities. The Company is currently undertaking the required ecological studies and anticipates timely compliance in 2021-2022. To comply, the Company believes capital investments will likely be in the range of $4 million to $8 million.

Air Quality

Ozone NAAQS
On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level within the range of 65 to 70 ppb. On October 1, 2015, the EPA finalized a new NAAQS for ozone at the high end of the range, or 70 ppb. On September 16, 2016, Indiana submitted its initial determination to the EPA recommending that counties in southwest Indiana, specifically Vanderburgh, Posey and Warrick, be declared in attainment of the new more stringent ozone standard based upon air monitoring data from 2014-2016. The EPA was expected to make final determinations as to whether a region is in attainment for the new NAAQS in 2017; however, in a March filing challenging the new standard, the EPA filed a request to stay the litigation pending a potential review of the ozone standard by the agency. While the future of the current ozone standard is not certain, it is possible counties in southwest Indiana could be declared in non-attainment with the current ozone standard, and thus could have an effect on future economic development activities in the Company's service territory. The Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units. In September 2016, the EPA finalized a supplement to the Cross State Air Pollution Rule (CSAPR) that requires further NOx reductions during the ozone season (May - September). The Company is positioned to comply with these NOx reduction requirements through its current investment in SCR technology.

One Hour SO2 NAAQS
On February 16, 2016, the EPA notified states of the commencement of a 120 day consultation period between the state and the EPA with respect to the EPA's recommendations for new non-attainment designations for the 2010 One Hour SO2 NAAQS. Identified on the list was Posey County, Indiana, where the Company's A.B. Brown Generating Station is located. While the Company is in compliance with all applicable SO2 limits in its permits, the Company reached an agreement with the state of Indiana on voluntary measures that the Company was able to implement without significant incremental costs to ensure that Posey County remains in attainment with the 2010 One Hour SO2 NAAQS. The Company's coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx.

Climate Change

The Company, along with the Company's parent, remains committed to responsible environmental stewardship and conservation efforts. The preferred IRP, as submitted to the IURC in December 2016, is a balanced approach toward environmental stewardship and conservation goals, supplying service at a reasonable cost, and operating in compliance with water, air and solid waste regulations. The preferred IRP would result in a 60 percent reduction in carbon emissions from 2005 to 2024 and assumed the CPP, as described below, was in place beginning in 2024. While the ultimate fate of the CPP regulation is unknown given the legal challenges it faces and recent statements from the Administration, the Company has prepared the IRP as a long-term plan that performs well in both high and low regulatory environments.

Ultimately if a national climate change policy is implemented, the Company believes it should have the following elements:

- An inclusive scope that involves all sectors of the economy and sources of greenhouse gases, and recognizes early actions and investments made to mitigate greenhouse gas emissions;
- Provisions for enhanced use of renewable energy sources as a supplement to baseload generation including effective energy conservation, demand side management, and generation efficiency measures;

- Inclusion of incentives for research and development and investment in advanced clean coal technology; and
- A strategy supporting alternative energy technologies and biofuels and continued increase in the domestic supply of natural gas and oil to reduce dependence on foreign oil.

Based on data made available through the Electronic Greenhouse Gas Reporting Tool (e-GRRT) maintained by the EPA, the Company's direct CO2 emissions from its fossil fuel electric generation that report under the Acid Rain Program were less than one half of one percent of all emissions in the United States from similar sources. Emissions from other Company operations, including those from its natural gas distribution operations and the greenhouse gas emissions the Company is required to report on behalf of its end use customers, are similarly available through the EPA's e-GRRT database and reporting tool.

Current Initiatives to Increase Conservation & Reduce Emissions

The Company is committed to a policy that reduces greenhouse gas emissions and conserves energy usage. Evidence of this commitment includes:

- Since 2005 and through 2015, the Company has achieved a reduction in emissions of CO_2 of 31 percent (on a tonnage basis) through the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology.
- Focusing the mission statement and purpose of the Company's parent on corporate sustainability and the need to help customers conserve and manage energy costs. The annual sustainability report received Core level certification by the Global Reporting Initiative and demonstrates commitment to sustainability and transparency in operations. The latest sustainability report can be found at www.vectren.com/sustainability;
- Implementing home and business energy efficiency initiatives in the Company’s Indiana and Ohio gas utility service territories such as offering rebates on high efficiency furnaces, programmable thermostats, and insulation and duct sealing;
- Implementing home and business energy efficiency initiatives in the electric service territory such as rebate programs on central air conditioning units, LED lighting, home weatherization and energy audits;
- Building a renewable energy portfolio to complement base load generation in advance of mandated renewable energy portfolio standards;
- Evaluating potential carbon requirements with regard to new generation, other fuel supply sources, and future environmental compliance plans;
- Further reducing the Company’s carbon footprint by building a more sustainable vehicle fleet with lower overall fuel consumption; and
- Reducing methane emissions through becoming a founding partner in the EPA Natural Gas STAR Methane Challenge Program. The Company's primary method for reducing methane emissions is through continued replacement of bare steel and cast iron gas distribution pipeline assets.

On August 3, 2015, the EPA released its final CPP rule which requires a 32 percent reduction in carbon emissions from 2005 levels. This results in a final emission rate goal for Indiana of 1,242 lb CO_2/MWh to be achieved by 2030. The new rule gives states the option of seeking a two-year extension from the initial deadline of September 2016 to submit a final state implementation plan (SIP). In March 2017, the EPA withdrew a Federal Implementation Plan (FIP) as a compliance option. Under the CPP, states have the flexibility to include energy efficiency and other measures should they choose to implement a SIP as provided in the final rule. While states are given an interim goal (1,451 lb CO_2/MWh for Indiana), the final rule gives states the flexibility to shape their own emissions reduction over the 2022-2029 time period. The final rule was published in the Federal Register on October 23, 2015, and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January 2016, the reviewing court denied the states’ and other parties requests to stay the implementation of the CPP pending completion of judicial review. On January 26, 2016, 29 states and state agencies, including the 24 state coalition referenced above, filed a request for immediate stay of implementation of the rule with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted the stay request to delay the implementation of the regulation while being challenged in court. Extensive oral argument was held in September 2016. The stay will remain in place while the lower court concludes its review. Among other things, the stay delays the requirement to submit a final SIP by the original September 2016 deadline and could extend implementation to 2024. In March 2017, as part of the ongoing regulatory reform efforts of the Administration, the EPA has filed a motion with the U.S. Court of Appeals for the District of Columbia circuit to suspend litigation pending the EPA’s reconsideration of the CPP rule, which was granted on April 28, 2017.

At the time of release of the CPP, Indiana was the 5th largest carbon emitter in the nation in tons of CO2 produced from electric generation. The Company’s share of total tons of CO2 generated by Indiana's electric utilities has historically been less than 6 percent. Since 2005 through 2015, the Company has achieved a reduction in emissions of CO2 of 31 percent (on a tonnage basis) through the retirement of F.B. Culley Unit 1, expiration of municipal wholesale power contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology. Since emissions are further impacted by coal burn reductions and energy efficiency programs, the Company's emissions of CO2 can vary year to year. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments

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for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by energy sources other than coal and natural gas, due to the long-term wind contracts and a landfill gas investment. With respect to the CO2 emission rate, since 2005 through 2015, the Company has lowered its CO2 emission rate (as measured in lbs CO2/MWh) from 1,967 lbs CO2/MWh to 1,922 lbs CO2/MWh, for a reduction of 3 percent. The Company's CO2 emission rate of 1,922 lbs CO2/MWh is basically the same as Indiana's average CO2 emission rate of 1,923 lbs CO2/MWh. The Company plans to consider these reductions in CO2 emissions and renewable generation in future discussions with the state to develop a possible state implementation plan.

Impact of Legislative Actions & Other Initiatives is Unknown
At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions. However, these compliance cost estimates were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. The Company is undertaking a detailed review of the requirements of the CPP and a review of potential compliance options. The Company will also continue to remain engaged with the Indiana legislators and regulators to assess the final rule and to develop a plan that is the least cost to its customers.

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28 percent GHG emission reduction from 2005 levels by 2025. The Administration has not indicated yet whether it intends to remain in the Agreement or withdraw its participation. As previously noted, since 2005 through 2015, the Company has achieved reduced emissions of CO2 by 31 percent (on a tonnage basis). While the litigation and reconsideration of the CPP rules remains uncertain, the Company will continue to monitor regulatory activity regarding GHG emission standards that may affect its electric generating units.

Manufactured Gas Plants

In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/ feasibility study (RI/FS) was completed at one of the sites under an agreed upon order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO's service territory, all of which are currently enrolled in the IDEM's VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $44.2 million ($23.9 million at Indiana Gas and $20.3 million at SIGECO). The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received approximately $15.4 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of both March 31, 2017 and December 31, 2016, approximately $2.9 million of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Impact of Recently Issued Accounting Guidance

Revenue Recognition Guidance
In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). While the Company continues to assess the standard and initial conclusions could change based on completion of that assessment, the Company preliminarily plans to adopt the guidance under the modified retrospective method.

In July 2015, the FASB approved a one year deferral that became effective through an ASU in August and changed the effective date to annual reporting periods beginning after December 15, 2017, including interim periods, with early adoption permitted, but not before the original effective date of December 15, 2016.

The Company is currently assessing the impacts this guidance may have on the Consolidated Balance Sheets, Consolidated Statements of Operations, and disclosures including the ability to recognize revenue for certain contracts, and its accounting for contributions in aid of construction (CIAC). While management will continue to analyze the impact of this new standard and the related ASUs that clarify guidance in the standard, at this time, management does not believe adoption of the standard will have a significant impact on the Company's pattern of revenue recognition. The Company plans to adopt the guidance effective January 1, 2018.

Leases
In February 2016, the FASB issued new accounting guidance for the recognition, measurement, presentation and disclosure of leasing arrangements. This ASU requires the recognition of lease assets and liabilities for those leases currently classified as operating leases while also refining the definition of a lease. In addition, lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. This ASU is effective for the interim and annual reporting periods beginning January 1, 2019, although it can be early adopted, with a modified retrospective approach for leases that commenced prior to the date of adoption. The Company is currently evaluating the standard to determine the impact it will have on the financial statements.

Stock Compensation
In March 2016, the FASB issued new accounting guidance which is intended to simplify several aspects of accounting for share-based payment transactions, including the income tax consequences. This ASU is effective for annual periods beginning after December 15, 2016, and interim periods therein. The Company does not have share-based compensation plans separate from the Company's parent; the Company is however allocated costs associated with the plans of the Company's parent. Pursuant to these plans, share based awards are settled via cash payments and are therefore not impacted by this standard. The Company's adoption of this standard did not have a material impact on

the financial statements.

Presentation of Net Periodic Pension and Postretirement Benefit Costs

In March 2017, the FASB issued new accounting guidance to improve the presentation of net periodic pension and postretirement benefit costs. This ASU is effective for annual periods beginning after December 15, 2017, and relevant interim periods. Early adoption is permitted. This ASU requires that the service cost component is reported in the same line items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside of income from operations. The Company does not have pension and postretirement plans separate from the

Company's parent. However, the Company's parent allocates the periodic cost of its retirement plans to the Company's subsidiaries. The Company is currently evaluating the standard to determine the impact it will have on the financial statements, however, does not anticipate its adoption to have a significant impact on the financial statements. The Company plans to adopt the guidance effective January 1, 2018.

Other Recently Issued Standards
Management believes other recently issued standards, which are not yet effective, will not have a material impact on the Company's financial condition, results of operations, or cash flows upon adoption.

Financial Condition

The Company funds the short-term and long-term financing needs of its utility subsidiary operations. The Company's parent does not guarantee the Company's debt. Outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. The guarantees are full and unconditional and joint and several, and the Company has no subsidiaries other than the subsidiary guarantors. Information about the subsidiary guarantors as a group is included in Note 3 to the condensed consolidated financial statements. Long-term debt and short-term obligations outstanding at March 31, 2017 approximated $996 million and $101 million, respectively. Additionally, prior to the Company's formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue new tax exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at March 31, 2017 was approximately $384 million.

The Company’s operations have historically been the primary source for Vectren’s common stock dividends.

The credit ratings of the senior unsecured debt of the Company, SIGECO and Indiana Gas, at March 31, 2017, were A-/A2, as rated by Standard and Poor's Ratings Services (Standard and Poor’s) and Moody’s Investor Services (Moody’s), respectively. The credit ratings on SIGECO's secured debt were A/Aa3. The Company's commercial paper had a credit rating of A-2/P-1. The current outlook of both Moody’s and Standard and Poor’s is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor’s and Moody’s lowest level investment grade rating is BBB- and Baa3, respectively.

The Company’s consolidated equity capitalization objective is 50-60 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company’s operations. The Company’s equity to long-term capitalization ratio was 55 percent and 54 percent as of March 31, 2017 and December 31, 2016, respectively. Long-term capitalization includes long-term debt, including current maturities, as well as common shareholder’s equity.

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of March 31, 2017, the Company was in compliance with all debt covenants.

Available Liquidity

The Company's A-/A2 investment grade credit ratings have allowed it to access the capital markets as needed, and as evidenced by past financing transactions, the Company believes it will have the ability to continue to do so. The Company anticipates funding future capital expenditures and dividends principally through internally generated funds, supplemented with incremental external debt financing. However, the resources required for capital investment remain uncertain for a variety of factors including, but not limited to, expanded environmental regulations on power generation and regulatory initiatives involving gas pipeline infrastructure replacement. These regulations may result in the need to raise additional capital in the coming years.

The Company routinely seeks approval at the IURC and the PUCO for long-term financing authority at the individual utility level. This authority allows for the flexibility for each utility to issue debt and equity securities to third parties or to issue debt and equity securities to the Company and thus receive some of the proceeds from various Company issuances to third parties on the same terms as those obtained by the Company. The majority of the long-term debt needs of the utilities is expected to be met through these debt issuances, some or all of which are then reloaned to the individual utilities. On June 15, 2016 an Order for long-term financing authority of $70 million of long-term debt and $75 million of equity financing was received from the PUCO for VEDO and expires in June 2017. On February 22, 2017, orders for long-term financing authority of $160 million and $200 million of long-term debt, and $120 million and $180 million of equity financing, were received from the IURC for SIGECO and Indiana Gas, respectively. These orders expire in March 2019.

Consolidated Short-Term Borrowing Arrangements

At March 31, 2017, the Company had $350 million of short-term borrowing capacity. As reduced by borrowings currently outstanding, approximately $249 million was available. This short-term credit facility is available through October 31, 2019 and is used to supplement working capital needs and also to fund capital investments and debt redemptions.

The Company has historically funded its short-term borrowing needs through the commercial paper market but maintains the ability to use the short-term borrowing facility when necessary. Following is certain information regarding these short-term borrowing arrangements.

(In millions)	2017	2016
As of March 31		
Balance Outstanding	$101.4	$—
Weighted Average Interest Rate	1.14%	N/A
Quarterly Average - March 31		
Balance Outstanding	$152.6	$3.0
Weighted Average Interest Rate	0.96%	0.56%
Maximum Month End Balance Outstanding	$186.0	$10.8

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. The PATH Act allows for 50 percent bonus depreciation for property placed in service in 2015 - 2017; 40 percent in 2018; and 30 percent in 2019. Including the impact of alternative minimum tax credits that will be utilized in future periods, the extension of 50 percent bonus depreciation is expected to result in an approximate $55 million positive impact to cash flows for the 2017 tax year.

Potential Uses of Liquidity

Pension Funding Obligations

Currently, the Company's parent does not anticipate making contributions to its qualified pension plans in 2017.

Planned Capital Expenditures

Capital expenditures are estimated at approximately $480 million for the remainder of 2017.

Contractual Obligations

The Company’s contractual obligations primarily consist of debt issued by the Company and its subsidiaries as well as certain plant and nonutility plant purchase commitments. For the three months ended March 31, 2017, there were no significant changes to the Company’s contractual obligations from those identified in the Company’s Annual Report on Form 10-K for the year ended December 31, 2016, other than those which occur in the normal and ordinary course of business and those mentioned below.

The Company's regulated utilities have both firm and non-firm commitments, some of which are between five and twenty year agreements to purchase natural gas, electricity, and coal, as well as certain transportation and storage rights. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

Comparison of Historical Sources & Uses of Liquidity

Operating Cash Flow
The Company's primary source of liquidity to fund working capital requirements has been cash generated from operations, which totaled $187.0 million and $146.7 million for the three months ended March 31, 2017 and 2016, respectively. The increase in operating cash flow in the first quarter of 2017 compared to 2016 is driven primarily by increased cash flow from certain weather related working capital changes. Additionally, there were no contributions made to qualified pension plans in the first quarter of 2017, compared to a $15 million contribution in the first quarter of 2016.

Financing Cash Flow
Net cash flow required for financing activities was $82.0 million and $17.0 million during the three months ended March 31, 2017 and 2016, respectively. The decrease in cash flows required for financing activities is due primarily to a greater payoff of short term borrowings in the first quarter of 2017 compared to the first quarter of 2016. This decrease is partially offset by additional capital received from the nonutility operations of the Company's parent. Financing activity in both periods reflects the payment of dividends.

Investing Cash Flow
Cash flow required for investing activities was $107.6 million and $88.4 million during the three months ended March 31, 2017 and 2016, respectively. The primary use of cash in both periods reflects expenditures for utility capital expenditures.

Forward-Looking Information

A “safe harbor” for forward-looking statements is provided by the Private Securities Litigation Reform Act of 1995 (Reform Act of 1995). The Reform Act of 1995 was adopted to encourage such forward-looking statements without the threat of litigation, provided those statements are identified as forward-looking and are accompanied by meaningful cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Certain matters described in Management’s Discussion and Analysis of Results of Operations and Financial Condition are forward-looking statements. Such statements are based on management’s beliefs, as well as assumptions made by and information currently available to management. When used in this filing, the words “believe”, “anticipate”, “endeavor”, “estimate”, “expect”, “objective”, “projection”, “forecast”, “goal”, “likely”, and expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company’s actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Factors affecting utility operations such as unfavorable or unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to coal and natural gas costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.
- New legislation, litigation and government regulation or other actions, such as changes in or additions to tax laws or rates, pipeline safety regulation and environmental laws, including laws governing air emissions, carbon, waste water discharges and the handling and disposal of coal combustion residuals that could impact the continued operation, and/or cost recovery of generation plants and related assets. These compliance costs could substantially change the

nature of the Company's generation fleet.

- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, physical attacks, cyber attacks, or other similar occurrences could adversely affect the Company's facilities, operations, financial condition, results of operations, and reputation.
- Increased competition in the energy industry, including the effects of industry restructuring, unbundling, and other sources of energy.
- Regulatory factors such as uncertainty surrounding the composition of state regulatory commissions, adverse regulatory changes, unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under

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regulation, interpretation of regulatory-related legislation by the IURC and/or PUCO and appellate courts that review decisions issued by the agencies, and the frequency and timing of rate increases.

- Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.
- Economic conditions including the effects of inflation, commodity prices, and monetary fluctuations.
- Economic conditions surrounding the current economic uncertainty, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas, electricity; economic impacts of changes in business strategy on both gas and electric large customers; lower residential and commercial customer counts; variance from normal population growth and changes in customer mix; and higher operating expenses.
- Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.
- Volatile oil prices and the potential impact on customer consumption and price of other fuel commodities.
- Direct or indirect effects on the Company’s business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.
- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Risks associated with material business transactions such as acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.
- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with federal and state laws and interpretations of these laws.
- The performance of projects undertaken by Vectren's nonutility businesses, specifically Vectren's infrastructure services businesses.

The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of changes in actual results, changes in assumptions, or other factors affecting such statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to various business risks associated with commodity prices, interest rates, and counter-party credit. These financial exposures are monitored and managed by the Company as an integral part of its overall risk management program. The Company’s risk management program includes, among other things, the occasional use of derivatives. The Company will, from time to time, execute derivative contracts in the normal course of operations while buying and selling commodities and when managing interest rate risk.

The Company's parent has a risk management committee that consists of senior management as well as financial and operational management. The committee is actively involved in identifying risks as well as reviewing and authorizing risk mitigation strategies.

These risks are not significantly different from the information set forth in Item 7A Quantitative and Qualitative Disclosures About Market Risk included in the Company's 2016 Form 10-K and is therefore not presented herein.

ITEM 4. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended March 31, 2017, there have been no changes to the Company’s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of March 31, 2017, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of March 31, 2017, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:

1) recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and
2) accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The Company is party to various legal proceedings and audits and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company that are likely to have a material adverse effect on its financial position, results of operations, or cash flows. See the notes to the consolidated financial statements regarding commitments and contingencies, environmental matters, and rate and regulatory matters. The condensed consolidated financial statements are included in Part 1 Item 1.

During the third quarter of 2014, the Company was notified of claims by a group of current and former SIGECO employees (“claimants”) who participated in the Pension Plan for Salaried Employees of SIGECO (“SIGECO Salaried Plan”). That plan was merged into the Vectren Corporation Combined Non-Bargaining Retirement Plan (“Vectren Combined Plan”) effective July 1, 2000. The claims related to the claimants’ election for benefits to be calculated under the Vectren Combined Plan’s cash-balance formula rather than the SIGECO Salaried Plan formula. On March 12, 2015, certain claimants filed a Class Action Complaint against the Vectren Combined Plan (Plan) and the Company. The Company denied the allegations set forth in the Complaint and moved to dismiss the case. In April 2016, the court dismissed part of the complaint but allowed the remaining claims to proceed. On February 6, 2017, the parties reached a settlement in principle to resolve the matter. The terms of the settlement in principle are not expected to have a material impact on the Plan or the Company.

ITEM 1A. RISK FACTORS

Investors should consider carefully factors that may impact the Company’s operating results and financial condition, causing them to be materially adversely affected. The Company’s risk factors have not materially changed from the information set forth in Item 1A Risk Factors included in the Company's 2016 Form 10-K and are therefore not presented herein.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Not Applicable

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not Applicable

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

Not Applicable

ITEM 6. EXHIBITS

Exhibits and Certifications

31.1	Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Executive Officer
31.2	Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Financial Officer
32	Certification Pursuant To Section 906 of The Sarbanes-Oxley Act Of 2002
101	Interactive Data File.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	VECTREN UTILITY HOLDINGS, INC. Registrant
May 15, 2017	/s/M. Susan Hardwick M. Susan Hardwick Executive Vice President and Chief Financial Officer (Signing on behalf of the registrant and as Principal Accounting & Financial Officer)

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