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

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2013

Commission File Number 1-7850

SOUTHWEST GAS CORPORATION
(Exact name of registrant as specified in its charter)

California (State or other jurisdiction of incorporation or organization)	**88-0085720** (I.R.S. Employer Identification No.)
5241 Spring Mountain Road **Post Office Box 98510** **Las Vegas, Nevada** (Address of principal executive offices)	**89193-8510** (Zip Code)

Registrant's telephone number, including area code: (702) 876-7237

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

Title of each class	Name of each exchange on which registered
Common Stock, $1 par value	**New York Stock Exchange, Inc.**

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. **Yes** ☐ **No** ☑

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). **Yes** ☑ **No** ☐

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

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

Large accelerated filer	☑	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐

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

Aggregate market value of the voting and non-voting common stock held by nonaffiliates of the registrant:
$2,168,003,842 as of June 28, 2013

The number of shares outstanding of common stock:
Common Stock, $1 Par Value, 46,494,781 shares as of February 18, 2014

DOCUMENTS INCORPORATED BY REFERENCE

Description	Part Into Which Incorporated
Annual Report to Shareholders for the Year Ended December 31, 2013	Parts I, II, and IV
2014 Proxy Statement	Part III

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PART I

Item 1. BUSINESS

Southwest Gas Corporation (the "Company") was incorporated in March 1931 under the laws of the state of California. The Company is composed of two business segments: natural gas operations ("Southwest" or the "natural gas operations" segment) and construction services.

Southwest is engaged in the business of purchasing, distributing, and transporting natural gas for customers in portions of Arizona, Nevada, and California. Southwest is the largest distributor of natural gas in Arizona, selling and transporting natural gas in most of central and southern Arizona, including the Phoenix and Tucson metropolitan areas. Southwest is also the largest distributor of natural gas in Nevada, serving the Las Vegas metropolitan area and northern Nevada. In addition, Southwest distributes and transports natural gas for customers in portions of California, including the Lake Tahoe area and the high desert and mountain areas in San Bernardino County.

NPL Construction Co. ("NPL" or the "construction services" segment), a wholly owned subsidiary, is a full-service underground piping contractor that primarily provides utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems.

Financial information concerning the Company's business segments is included in Note 13 of the Notes to Consolidated Financial Statements, which is included in the 2013 Annual Report to Shareholders and is incorporated herein by reference.

The Company maintains a website (www.swgas.com) for the benefit of shareholders, investors, customers, and other interested parties. The Company makes its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports available, free of charge, through its website as soon as reasonably practicable after such material is electronically filed with, or furnished to, the Securities and Exchange Commission ("SEC"). The Company's Corporate Governance Guidelines, Code of Business Conduct and Ethics, and charters of the nominating and corporate governance, audit, and compensation committees of the board of directors are also available on the Company's website. Print versions of these documents are available to shareholders upon request directed to the Corporate Secretary, Southwest Gas Corporation, 5241 Spring Mountain Road, Las Vegas, NV 89150.

NATURAL GAS OPERATIONS

General Description

Southwest is subject to regulation by the Arizona Corporation Commission ("ACC"), the Public Utilities Commission of Nevada ("PUCN"), and the California Public Utilities Commission ("CPUC"). These commissions regulate public utility rates, practices, facilities, and service territories in their respective states. The CPUC also regulates the issuance of all securities by the Company, with the exception of short-term borrowings. Certain accounting practices, transmission facilities, and rates are subject to regulation by the Federal Energy Regulatory Commission ("FERC"). NPL is not regulated by the state utilities commissions in any of its operating areas.

As of December 31, 2013, Southwest purchased and distributed or transported natural gas to 1,904,000 residential, commercial, and industrial customers in geographically diverse portions of Arizona, Nevada, and California. Southwest added 28,000 net new customers during 2013. Southwest expects similar customer growth in 2014.

The table below lists the percentage of operating margin (operating revenues less net cost of gas) by major customer class for the years indicated:

	Distribution		
For the Year Ended	**Residential and Small Commercial**	**Other Sales Customers**	**Transportation**
December 31, 2013	85%	4%	11%
December 31, 2012	85%	4%	11%
December 31, 2011	86%	4%	10%

Southwest is not dependent on any one or a few customers such that the loss of any one or several would have a significant adverse impact on earnings or cash flows.

Transportation of customer-secured gas to end-users accounted for 47% of total system throughput in 2013. Customers who utilized this service transported 104 million dekatherms in 2013, 100 million dekatherms in 2012, and 94 million dekatherms in 2011. Although these volumes are significant, these customers provided a much smaller proportionate share of operating margin.

The demand for natural gas is seasonal, with greater demand in the colder winter months and decreased demand in the warmer summer months. It is the opinion of management that comparisons of earnings for interim periods do not reliably reflect overall trends and changes in operations. The decoupled rate mechanisms in place in the three-state service territory are structured with seasonal variations. Also, earnings for interim periods can be significantly affected by the timing of general rate relief.

Rates and Regulation

Rates that Southwest is authorized to charge its distribution system customers are determined by the ACC, PUCN, and CPUC in general rate cases and are derived using rate base, cost of service, and cost of capital experienced in an historical test year, as adjusted in Arizona and Nevada, and projected for a future test year in California. The FERC regulates the northern Nevada transmission and liquefied natural gas ("LNG") storage facilities of Paiute Pipeline Company ("Paiute"), a wholly owned subsidiary, and the rates it charges for transportation of gas directly to certain end-users and to various local distribution companies ("LDCs"). The LDCs transporting on the Paiute system are: NV Energy (serving Reno and Sparks, Nevada) and Southwest (serving Truckee, South and North Lake Tahoe in California and various locations throughout northern Nevada).

Rates charged to customers vary according to customer class and rate jurisdiction and are set at levels that are intended to allow for the recovery of all prudently incurred costs, including a return on rate base sufficient to pay interest on debt as well as a reasonable return on common equity. Rate base consists generally of the original cost of utility plant in service, plus certain other assets such as working capital and inventories, less accumulated depreciation on utility plant in service, net deferred income tax liabilities, and certain other deductions.

Rate structures in all service territories allow Southwest to separate or "decouple" the recovery of operating margin from natural gas consumption, though decoupled structures vary by state. In California, authorized operating margin levels vary by month. In Nevada, a decoupled rate structure applies to most customer classes providing stability in annual operating margin. In Arizona, a full revenue decoupling mechanism with a winter-period monthly weather adjuster is in place, for most customer classes.

Rate schedules in all service areas contain deferred energy or purchased gas adjustment provisions, which allow Southwest to file for rate adjustments as the cost of purchased gas changes. Deferred energy and purchased gas adjustment (collectively "PGA") rate changes affect cash flows, but have no direct impact on profit margin. Filings to change rates in accordance with PGA clauses are subject to audit by the appropriate state regulatory commission staff.

Information with respect to recent general rate cases and PGA filings is included in the Rates and Regulatory Proceedings section of Management's Discussion and Analysis ("MD&A") in the 2013 Annual Report to Shareholders.

The table below lists recent docketed general rate filings and the status of such filing within each ratemaking area:

Ratemaking Area	Type of Filing	Month Filed	Month Final Rates Effective
Arizona:	General rate case	November 2010	January 2012
California:			
Northern and Southern	Annual attrition	October 2012	January 2013
Northern and Southern	General rate case	December 2012	Pending
Nevada:			
Northern and Southern	General rate case	April 2012	November 2012
FERC:			
Paiute	General rate case	February 2009	April 2010
Paiute	General rate case	February 2014	Pending

While Southwest is subject to regulatory rules and oversight with regard to rates and operating requirements under its various state tariffs (and federal tariff, in the case of Paiute Pipeline), it is also subject to regulation with regard to the safety and integrity of its pipeline systems. The Department of Transportation ("DOT") administers pipeline regulations through the Office of Pipeline Safety, within the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). In recent years, various pieces of legislation have been passed in the areas of distribution integrity, control room management, and pipeline safety. The Pipeline Inspection, Protection, Enforcement, and Safety ("PIPES") Act of 2006 mandated, among other things, a graduated implementation program for control room management, a requirement to install excess flow valves on single-family residential customer locations, and a Distribution Integrity Management Program ("DIMP"), required to be in place by August 2011, that includes evaluation and mitigation of risks, as well as certain reporting requirements. Additionally, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("the Bill"), effective January 2012, which increased/strengthened previously existing safety requirements, including damage prevention programs, penalty provisions, and requirements related to automatic and remote-controlled shut-off valves, public awareness programs, incident notification, and maximum allowable operating pressure for certain facilities. The Bill required the DOT to conduct further study of existing programs and future requirements. The Company continues to monitor changing pipeline safety legislation and participates to the extent possible in crafting associated mandates and reporting. As rules are developed, they could impact the Company's expenses and the timing and amount of capital expenditures.

Demand for Natural Gas

Deliveries of natural gas by Southwest are made under a priority system established by state regulatory commissions. The priority system is intended to ensure that the gas requirements of higher-priority customers, primarily residential customers and other customers who use 500 therms or less of gas per day, are fully satisfied on a daily basis before lower-priority customers, primarily electric utility and large industrial customers able to use alternative fuels, are provided any quantity of gas or capacity.

Demand for natural gas is greatly affected by temperature. On cold days, use of gas by residential and commercial customers can be seven times greater than on warm days because of increased use of gas for space heating. To fully satisfy this increased high-priority demand, gas is withdrawn from storage in certain service areas, or peaking supplies are purchased from suppliers. If necessary, service to interruptible lower-priority customers may be curtailed to provide the needed delivery system capacity. Southwest maintains no significant backlog on its orders for gas service.

Natural Gas Supply

Southwest is responsible for acquiring and arranging delivery of natural gas to its system in sufficient quantities to meet its sales customers' needs. Southwest's primary natural gas acquisition objective is to ensure that adequate supplies of natural gas are available at the best cost. Southwest acquires natural gas from a wide variety of sources and a mix of purchase provisions, which includes spot market and firm supplies. The purchases may have terms from one day to several years and utilize both fixed and indexed pricing. During 2013, Southwest acquired natural gas from 44 suppliers. Southwest regularly monitors the number of suppliers, their performance, and their relative contribution to the overall customer supply portfolio. New suppliers are contracted when possible, and solicitations for supplies are extended to the largest practicable list of suppliers, taking into account each supplier's creditworthiness. Competitive pricing, flexibility in meeting Southwest's requirements, and aggressive participation by suppliers who have demonstrated reliability of service are instrumental to any one supplier's inclusion in Southwest's portfolio. The goal of this practice is to mitigate the risk of nonperformance by any one supplier and ensure competitive prices.

Balancing reliability with supply cost results in a continually changing mix of purchase provisions within the supply portfolios. To address the unique requirements of its various market areas, Southwest assembles and administers a separate natural gas supply portfolio for each of its jurisdictional areas. Southwest facilitates most natural gas purchases through competitive bid processes.

To mitigate customer exposure to short-term market price volatility, Southwest seeks to fix the price on a portion (for the 2013/2014 heating season, currently ranging from 25% to 35%, depending on the jurisdiction) of its forecasted annual normal-weather volume requirement, primarily using firm, fixed-price purchasing arrangements that are secured periodically throughout the year. Southwest's price volatility mitigation program includes the use of financial derivatives, in the form of fixed-for-floating-index-price swaps combined with indexed-price physical purchases, to secure a portion of the fixed-price portfolio for the Arizona and Nevada jurisdictional areas. The combination of fixed-price contracts and financial derivatives is designed to increase flexibility for Southwest and increase supplier diversification. The cost of such financial derivatives combined with the associated indexed-price physical purchases is recovered from customers through PGA mechanisms in the respective jurisdictional area.

As part of the most recent Annual Rate Adjustment filing in Nevada, and the associated stipulation, the Company agreed to suspend further swaps and fixed-price purchases pursuant to the Volatility Mitigation Program ("VMP") for its Nevada territories. The suspension is forward looking and does not impact prior VMP purchase transactions. The Company will continue to evaluate the suspension of these VMP purchases in light of prevailing market fundamentals and regulatory conditions. Any future decision concerning VMP purchases will be documented and retained to facilitate regulatory review in accordance with the stipulation. The Company plans to schedule quarterly meetings with the PUCN Staff and the Bureau of Consumer Protection to discuss market fundamentals, along with any decision by the Company concerning VMP purchases for the Nevada service territories.

For the 2013/2014 heating season, fixed-price purchases approximated $4 per dekatherm. Southwest makes non-fixed-price natural gas purchases under variable-price contracts with firm quantities or on the spot market. Prices for these contracts are not known until the month or day of purchase.

The firm natural gas supply arrangements are structured such that a stated volume of natural gas is required to be nominated by Southwest and delivered by the supplier. Contracts provide for fixed or market-based penalties to be paid by the non-performing party.

Storage availability can influence the average annual price of natural gas, as storage allows a company to purchase natural gas quantities during the off-peak season and store it for use in high demand periods when prices may be greater or supplies/capacity tighter. Southwest currently has no storage availability in its southern Nevada rate jurisdiction. Limited storage availability exists in southern and northern California and northern Nevada, and effective July 2013, the Arizona rate jurisdiction.

Southwest has a contract with Southern California Gas Company that is intended for delivery only within Southwest's southern California rate jurisdiction. In addition, contracts with Paiute for its LNG facility allow for peaking capability only in northern Nevada and northern California. For all storage options, Southwest purchases natural gas for injection during the off-peak period for use in the high demand months, but these supplies have a limited impact on the overall price.

Southwest also has interruptible storage contracts with Northwest Pipeline Corporation ("NWPL") for the northern Nevada and northern California rate jurisdictions. NWPL has the discretion to limit Southwest's ability to inject or withdraw from this interruptible storage, which consequently limits Southwest's use of this interruptible storage capacity. As such, this storage provides limited operational flexibility to adjust daily flowing supplies to meet demand, and has limited impact on the overall price of natural gas supplies.

In 2013, Southwest entered into a contract for its Arizona rate jurisdiction with Enstor Grama Ridge Storage and Transportation, LLC ("Enstor") which provides for a maximum quantity of 600,000 dekatherms of natural gas underground storage in New Mexico that is deliverable on the El Paso system.

Natural gas supplies for Southwest's southern system (Arizona, southern Nevada, and southern California properties) are primarily obtained from producing regions in Colorado and New Mexico (San Juan basin), Texas (Permian basin), and Rocky Mountain areas. For its northern system (northern Nevada and northern California properties), Southwest primarily obtains natural gas from Rocky Mountain producing areas and from Canada.

The landscape for national natural gas supply has changed dramatically during recent years. Advanced drilling techniques have provided access to abundant and sustainable natural gas supplies. The natural gas market has responded with reductions to both price volatility and the total price of the commodity. An ample and diverse natural gas supply is available to Southwest's customers at a highly competitive price when compared with competing forms of energy.

Southwest arranges for transportation of natural gas to its Arizona, Nevada, and California service territories through the pipeline systems of El Paso Natural Gas Company ("El Paso"), Kern River Gas Transmission Company ("Kern River"), Transwestern Pipeline Company ("Transwestern"), NWPL, Tuscarora Gas Pipeline Company ("Tuscarora"), Southern California Gas Company, and Paiute. Southwest regularly monitors short- and long-term supply and pipeline capacity availability to ensure the reliability of service to its customers. Southwest currently receives firm transportation service, both on a short- and long-term basis, for all of its service territories on the pipeline systems noted above. Southwest also contracts for firm natural gas supplies that are delivered to Southwest's city gates to supplement its firm capacity on the interstate pipelines and to meet projected peak-day demands. Southwest could also utilize its interruptible contracts on the interstate pipelines for the transportation of additional natural gas supplies.

Southwest believes that the current levels of contracted firm interstate capacity and delivered purchases are sufficient to serve each of its service territories' forecasted peak-day requirements. As the need arises to acquire additional capacity on one of the interstate pipeline transmission systems, primarily due to customer growth, Southwest will continue to consider available options to obtain that capacity, either through the use of firm contracts with a pipeline company, by purchasing capacity on the open market, or through the purchase of firm delivered natural gas supplies.

Competition

Electric utilities are the principal competitors of Southwest for the residential and small commercial markets throughout its service areas. Competition for space heating, general household, and small commercial energy needs generally occurs at the initial installation phase when the customer/builder typically makes the decision as to which type of equipment to install and operate. The customer will generally continue to use the chosen energy source for the life of the equipment. Southwest interfaces directly with the various home builders and commercial property developers in its service territories to ensure that natural gas appliances are considered in new developments and commercial centers. As a result of its efforts, Southwest has continued to experience growth in the new construction market among residential and small commercial customer classes.

Unlike residential and small commercial customers, certain large commercial, industrial, and electric generation customers have the capability to switch to alternative energy sources. To date, Southwest has been successful in retaining most of these customers by setting rates at levels competitive with commercially available alternative energy sources such as electricity, fuel oils, and coal. However, high natural gas prices can impact Southwest's ability to retain some of these customers. Overall, management does not anticipate any material adverse impact on operating margin from fuel switching by these large customers.

Southwest competes with interstate transmission pipeline companies, such as El Paso, Kern River, Transwestern and Tuscarora, to provide service to certain large end-users. End-use customers located in proximity to these interstate pipelines pose a potential bypass threat. Southwest attempts to closely monitor each customer situation and provide competitive service in order to retain the customer. Southwest has remained competitive through the use of negotiated transportation contract rates, special long-term contracts with electric generation and cogeneration customers, and other tariff programs. These competitive response initiatives have mitigated the loss of margin earned from large customers.

Environmental Matters

Federal, state, and local laws and regulations governing the discharge of materials into the environment have a direct impact upon Southwest. Environmental efforts, with respect to matters such as storm water management, emissions of air pollutants, hazardous material management, protection of endangered species and archeological resources, directly impact the complexity and time required to obtain pipeline rights-of-way and construction permits. However, increased environmental legislation and regulation can also be beneficial to the natural gas industry. Natural gas is one of the most environmentally-friendly fossil fuels currently available and its use can help energy users to comply with stricter environmental air quality standards.

The United States Environmental Protection Agency ("EPA") and the State of California Environmental Protection Agency ("Cal/EPA") have issued regulations that require the reporting of greenhouse gas emissions ("GHG") from large sources and suppliers in order to facilitate the development of policies and programs to reduce GHGs. The Company reports required information to EPA and Cal/EPA under each respective Mandatory Reporting Rule ("MRR") including the volumes of natural gas that it receives for distribution to LDC customers (EPA and Cal/EPA MRR Subpart NN), and the "fugitive" GHG emissions that result from the operation of its LDC pipelines (EPA MRR Subpart W). While some parts of the MRRs do not apply to Southwest, other required information is already being reported to the Department of Energy, the Department of Transportation, or is available in existing Company databases. The Company also monitors the development of climate legislation (including the State of California Global Warming Solutions Act), which could result in additional requirements or have financial implications.

Employees

At December 31, 2013, the natural gas operations segment had 2,220 regular full-time equivalent employees. Southwest believes it has a good relationship with its employees and that compensation, benefits, and working conditions afforded its employees are comparable to those generally found in the utility industry. No employees are represented by a union.

CONSTRUCTION SERVICES

NPL is a full-service contractor whose customers are primarily energy services utilities. NPL derives revenue from installation, replacement, repair, and maintenance of energy distribution systems. NPL contracts primarily with LDCs to install, repair, and maintain energy distribution systems from the town border station to the end-user. The primary focus of NPL operations is distribution pipe and service hook-up replacements as well as line installations for new business development. Construction work varies from relatively small projects to the piping of entire communities. Construction activity is seasonal in most areas. Peak construction periods are the summer and fall months in colder climate areas, such as the Midwest. In the warmer climate areas, such as the southwestern United States, construction continues year round.

During the past few years, several factors have impacted the nation’s natural gas distribution system and resulted in an increase in large multi-year distribution pipe replacement projects. The Department of Transportation’s Pipeline and Hazardous Materials Safety Administration instituted DIMP which required operators of gas distribution pipelines to develop and implement integrity management programs to enhance safety by identifying and reducing pipeline integrity risks. Also contributing to the increase in replacement projects were bonus depreciation tax deduction incentives provided for by the Small Jobs Act of 2010 and the Tax Relief Unemployment Insurance Reauthorization and Job Creation Act of 2010. The American Tax Payer Relief Act of 2012 extended 50% bonus depreciation deduction tax incentives for 2013, but such incentives were not extended for years after 2013. Finally, funding for customers’ planned replacement projects improved due to greater access to the national credit markets.

In connection with the increased construction activity, several large multi-year distribution pipe replacement projects were awarded to NPL. NPL was selected as the sole contractor on certain of these projects, or one of several contractors to work on others. NPL continues to bid on pipe replacement projects throughout the country and has made structural and transitional changes to match the increased size and complexity of the business. The amount of work completed by NPL on these multi-year contracts will vary from year to year.

NPL business activities are often concentrated in utility service territories where existing energy lines are scheduled for replacement. An LDC will typically contract with NPL to provide pipe replacement services and new line installations. Contract terms generally specify unit-price or fixed-price arrangements. Unit-price contracts establish prices for all of the various services to be performed during the contract period. These contracts often have annual pricing reviews. During 2013, approximately 85% of revenue was earned under unit-price contracts. As of December 31, 2013, a backlog of approximately $27 million existed with respect to outstanding fixed-priced construction contracts.

Materials used by NPL in its construction activities are typically specified, purchased, and supplied by NPL’s customers. Construction contracts also contain provisions which make customers generally liable for remediating environmental hazards encountered during the construction process. Such hazards might include digging in an area that was contaminated prior to construction, finding endangered animals, digging in historically significant sites, etc. Otherwise, NPL’s operations have minimal environmental impact (dust control, normal waste disposal, handling harmful materials, etc.)

Competition within the industry has traditionally been limited to several regional and numerous local competitors in what has been a largely fragmented industry. Some national competitors also exist within the industry. NPL currently operates in 20 major markets nationwide. Its customers are primarily the principal LDCs in those markets. During 2013, NPL served 72 customers, with Southwest accounting for approximately 14% of NPL revenues. Additionally, two customers accounted for approximately 25% of total revenue, while four other customers individually accounted for 5% or more of NPL revenues.

Employment fluctuates between seasonal construction periods, which are normally heaviest in the summer and fall months. At December 31, 2013, NPL had 3,760 regular full-time equivalent employees. Employment peaked in August 2013 when there were 4,158 employees. Most employees are represented by unions and are covered by collective bargaining agreements, which is typical of the utility construction industry.

Operations are conducted from 23 field locations with corporate headquarters located in Phoenix, Arizona. Buildings and equipment storage yards are normally leased from third parties. The lease terms are typically five years or less.

NPL is not directly affected by regulations promulgated by the ACC, PUCN, CPUC, or FERC in its construction services. NPL is an unregulated energy services subsidiary of Southwest Gas Corporation. However, because NPL performs work for the regulated natural gas segment of the Company, its construction costs are subject indirectly to “prudency reviews” just as any other capital work that is performed by third parties or directly by Southwest. However, such “prudency reviews” would not bring NPL under the regulatory jurisdiction of any of the commissions noted above.

NPL has a 65% interest in IntelliChoice Energy, LLC (“ICE”) and consolidates ICE as a majority owned subsidiary. ICE was established in 2009 and markets natural gas engine-driven heating, ventilating, and air conditioning (“HVAC”) technology and products. To date, ICE has not been a significant component of NPL operating results.

Item 1A. RISK FACTORS

*Described below (and in **Item 7A. Quantitative and Qualitative Disclosures about Market Risk** of this report) are risk factors that we have identified that may have a negative impact on our future financial performance or affect whether we achieve the goals or expectations expressed or implied in any forward-looking statements contained herein. Unless indicated otherwise, references below to “we,” “us,” and “our” should be read to refer to Southwest Gas Corporation and its subsidiaries.*

Governmental policies and regulatory actions can reduce our earnings.

Regulatory commissions set our rates and determine what we can charge for our rate-regulated services. Our ability to obtain timely future rate increases depends on regulatory discretion. Governmental policies and regulatory actions, including those of the Arizona Corporation Commission, the California Public Utilities Commission, the Federal Energy Regulatory Commission, and the Public Utilities Commission of Nevada relating to allowed rates of return, rate structure, purchased gas and investment recovery, operation and construction of facilities, present or prospective wholesale and retail competition, changes in tax laws and policies, and changes in and compliance with environmental and safety laws such as the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and policies, can reduce our earnings. Risks and uncertainties relating to delays in obtaining, or failure to obtain, regulatory approvals, conditions imposed in regulatory approvals, and determinations in regulatory investigations can also impact financial performance. In particular, the timing and amount of rate relief can materially impact results of operations.

We are unable to predict what types of conditions might be imposed on Southwest or what types of determinations might be made in pending or future regulatory proceedings or investigations. We nevertheless believe that it is not uncommon for conditions to be imposed in regulatory proceedings, for Southwest to agree to conditions as part of a settlement of a regulatory proceeding, or for determinations to be made in regulatory investigations that reduce our earnings and liquidity. For example, we may request recovery of a particular operating expense in a general rate case filing that a regulator disallows, negatively impacting our earnings if the expense continues to be incurred. We received regulatory approval of a settlement in our most recent Arizona general rate case filing in which we agreed to not file a general rate case in Arizona until April 30, 2016. This could result in gradual earnings deterioration as costs increase during the stay-out period. If, despite rate establishment surrounding the decoupling mechanism, approval of the mechanism is rescinded by Arizona regulators, the prohibition against the filing of general rate cases during the stay-out period will be eliminated.

We may be subject to disallowances, penalties or fines related to the operation of natural gas pipelines under recent regulations concerning natural gas pipeline safety, which could have an adverse effect on our results of operations, financial condition, and/or cash flows.

We are committed to consistently monitoring and maintaining our distribution system and storage operations to ensure that natural gas is acquired, stored and delivered safely, reliably and efficiently. Given recent high-profile natural gas accidents in the U.S., we anticipate that the natural gas industry could be the subject of increased federal, state, and local regulatory oversight over time. We intend to work diligently with industry associations and federal, state, and local regulators to ensure compliance with any new laws, such as the "Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011." We expect there to be increased costs associated with compliance (and potential penalties for any non-compliance) with this and similar laws. If these costs are not recoverable in our customer rates, or if there are delays in recoverability due to regulatory lag, they could have a negative impact on our operating costs and financial results.

Our operating results may be adversely impacted by a prolonged economic downturn.

The economic slowdown in the United States, and particularly in our service areas, resulted in a marked decline in the new housing market and an increase in the inventory of idle/vacant homes. Commercial entities (including restaurants and other service establishments) were also impacted, resulting in reductions in operations or closures. If the recovery process regresses (or if another economic slowdown occurs), our financial condition, results of operations, and cash flows could be adversely affected. Fluctuations and uncertainties in the economy make it challenging for us to accurately forecast and plan future business activities and to identify risks that may affect our business, financial condition, and operating results. We cannot predict the timing, strength, or duration of the recovery, or any future economic slowdowns. If the economy or the markets in which we operate worsen from present levels, it may have an adverse effect on our business, financial condition, and results of operations.

We rely on having access to interstate pipelines' transportation capacity. If these pipelines were not available, it could impact our ability to meet our customers' full requirements.

We must acquire both sufficient natural gas supplies and interstate pipeline capacity to meet customer requirements. We must contract for reliable and adequate delivery capacity for our distribution system, while considering the dynamics of the interstate pipeline capacity market, our own in-system resources, as well as the characteristics of our customer base. Interruptions to or reductions of interstate pipeline service caused by physical constraints, excessive customer usage, or other force majeure could reduce our normal supply of gas. A prolonged interruption or reduction of interstate pipeline service in any of our jurisdictions, particularly during the winter heating season, would reduce cash flow and earnings.

Our earnings may be materially impacted due to volatility in the cash surrender value of our company-owned life insurance policies during periods in which stock market changes are significant.

We have life insurance policies with a net death benefit value at December 31, 2013 of approximately $238 million on members of management and other key employees to indemnify ourselves against the loss of talent, expertise, and knowledge, as well as to provide indirect funding for certain nonqualified benefit plans. The net cash surrender value of these policies (which is the cash amount we would receive if we voluntarily terminated the policies) is approximately $93 million at December 31, 2013 and is included in the caption "Other property and investments" on the balance sheet. Cash surrender values are directly influenced by the investment portfolio underlying the insurance policies. This portfolio includes both equity and fixed income (mutual fund) investments. As a result, the cash surrender value (but not the net death benefits) moves up and down consistent with the movements in the broader stock and bond markets. During 2013, Southwest recognized $12.4 million in Other income (deductions) due to increases in the cash surrender values of its company-owned life insurance policies and net death benefits recognized (compared to an increase of $6.6 million due to increases in cash surrender values in 2012). We are considering making changes in the underlying investment portfolio to help mitigate future volatility in company-owned life insurance policies cash surrender values. Current tax regulations provide for tax-free treatment of life insurance (death benefit) proceeds. Therefore, changes in the cash surrender value components of company-owned life insurance policies, as they progress towards the ultimate death benefits, are also recorded without tax consequences. Currently, we intend to hold the company-owned life insurance policies for their duration and purchase additional policies as necessary. Changes in the cash surrender value of company-owned life insurance policies, except as related to the purchase of additional policies, affect our earnings but not our cash flows.

The cost of providing pension and postretirement benefits is subject to changes in pension asset values, changing demographics, and actuarial assumptions which may have an adverse effect on our financial results.

We provide pension and postretirement benefits to eligible employees. Our costs of providing such benefits are subject to changes in the market value of our pension fund assets, changing demographics, life expectancies of beneficiaries, current and future legislative changes, and various actuarial calculations and assumptions. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, withdrawal rates, interest rates, and other factors. These differences may result in a significant impact on the amount of pension expense or other postretirement benefit costs recorded in future periods. For example, lower than assumed returns on investments and/or reductions in bond yields would result in increased contributions and higher pension expense which would have a negative impact on our cash flows and results of operations.

Our liquidity, and in certain circumstances our earnings, may be reduced during periods in which natural gas prices are rising significantly or are more volatile.

Increases in the cost of natural gas may arise from a variety of factors, including weather, changes in demand, the level of production and availability of natural gas, transportation constraints, transportation capacity cost increases, federal and state energy and environmental regulation and legislation, the degree of market liquidity, natural disasters, wars and other catastrophic events, national and worldwide economic and political conditions, the price and availability of alternative fuels, and the success of our strategies in managing price risk.

Rate schedules in each of our service territories contain purchased gas adjustment clauses which permit us to file for rate adjustments to recover increases in the cost of purchased gas. Increases in the cost of purchased gas have no direct impact on our profit margins, but do affect cash flows and can therefore impact the amount of our capital resources. We have used short-term borrowings in the past to temporarily finance increases in purchased gas costs, and we expect to do so during 2014, if the need again arises.

We may file requests for rate increases to cover the rise in the cost of purchased gas. Due to the nature of the regulatory process, there is a risk of disallowance of full recovery of these costs during any period in which there has been a substantial run-up of these costs or our costs are more volatile. Any disallowance of purchased gas costs would reduce cash flow and earnings.

The nature of our operations presents inherent risks of loss that could adversely affect our results of operations.

Our operations are subject to inherent hazards and risks such as gas leaks, fires, natural disasters, catastrophic accidents, explosions, pipeline ruptures, and other hazards and risks that may cause unforeseen interruptions, personal injury, or property damage. Additionally, our facilities, machinery, and equipment, including our pipelines, are subject to third party damage from construction activities, vandalism, or acts of terrorism. Such incidents could result in severe business disruptions, significant decreases in revenues, and/or significant additional costs to us. Any such incident could have an adverse effect on our financial condition, earnings and cash flows. In addition, any of these or similar events could cause environmental pollution, personal injury or death claims, damage to our properties or the properties of others, or loss of revenue by us or others.

We maintain liability insurance for some, but not all, risks associated with the operation of our natural gas pipelines and facilities. In connection with these liability insurance policies, we are responsible for an initial deductible or self-insured retention amount per incident, after which the insurance carriers would be responsible for amounts up to the policy limits. These liability insurance policies require us to be responsible for the first $1 million dollars (self-insured retention) of each incident plus the first $4 million in total claims above our self-insured retention in the policy year. We cannot predict the likelihood that any future event will occur which will result in a claim exceeding $1 million; however, a large claim for which we were deemed liable would reduce our earnings up to and including these self-insurance maximums.

Fixed-price contracts at NPL are subject to potential losses that could adversely affect results of operations.

NPL enters into a variety of types of contracts customary in the underground utility construction industry. These contracts include unit-priced contracts, unit-priced contracts with revenue caps, and fixed-price (lump sum) contracts. Contracts with caps and fixed-price arrangements can be susceptible to constrained profits, or even losses, especially those contracts that cover an extended-duration performance period. This is due, in part, to the necessity of estimating costs far in advance of the completion date (at bid inception). Unforeseen inflation, or other costs unanticipated at inception, can detrimentally impact profitability for these types of contracts.

A significant reduction in our credit ratings could materially and adversely affect our business, financial condition, and results of operations.

We cannot be certain that any of our current credit ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Our credit ratings are subject to change at any time in the discretion of the applicable ratings agencies. Numerous factors, including many which are not within our control, are considered by the ratings agencies in connection with assigning credit ratings.

Any future downgrade could increase our borrowing costs, which would diminish our financial results. We would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease. A downgrade could require additional support in the form of letters of credit or cash or other collateral and otherwise adversely affect our business, financial condition and results of operations.

Uncertain economic conditions may affect our ability to finance capital expenditures.

Our ability to finance capital expenditures and other matters will depend upon general economic conditions in the capital markets. Declining interest rates are generally believed to be favorable to utilities while rising interest rates are believed to be unfavorable because of the high capital costs of utilities. In addition, our authorized rate of return is based upon certain assumptions regarding interest rates. If interest rates are lower than assumed rates, our authorized rate of return in the future could be reduced. If interest rates are higher than assumed rates, it will be more difficult for us to earn our currently authorized rate of return.

We require numerous permits and other approvals from various federal, state, and local governmental agencies to operate our business; any failure to obtain or maintain required permits or approvals could negatively affect our business and results of operations.

All of our existing and planned development projects require multiple permits. The acquisition, ownership and operation of natural gas pipelines and storage facilities require numerous permits, approvals and certificates from federal, state, and local governmental agencies. Once received, approvals may be subject to litigation, and projects may be delayed or approvals reversed in litigation. If there is a delay in obtaining any required regulatory approvals or if we fail to obtain or maintain any required approvals or to comply with any applicable laws or regulations, we may not be able to construct or operate our facilities, or we may be forced to incur additional costs.

Use of technologies presents a risk for attacks on our information systems and the stability of our operations.

Over the last several years we have undertaken a variety of initiatives to integrate, standardize, centralize and streamline our operations. These efforts have resulted in greater reliance on technological tools. The failure of any of these technologies, or our inability to have technologies supported, updated, expanded or integrated into other technologies, could adversely impact our operations. Additionally, we could experience breaches of security pertaining to sensitive customer, employee and vendor information maintained by us in the normal course of business, which could adversely affect the utility's reputation, diminish customer confidence, disrupt operations, and subject us to possible financial liability or increased regulation or litigation, any of which could adversely affect our financial condition and results of operations.

Furthermore, we rely on information technology systems in our natural gas operations segment for our distribution and storage operations. There are various risks associated with these systems, including, hardware and software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other inadvertent errors or deliberate human acts. In particular, cyber security attacks, terrorism or other malicious acts could damage, destroy or disrupt our business systems. Any failure of information technology systems could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. As these potential cyber security attacks become more common and sophisticated, we could be required to incur costs to strengthen our systems or obtain specific insurance coverage against potential losses.

Disruptions in labor relations with NPL's employees could adversely affect results of operations.

The majority of NPL's labor force is covered by collective bargaining agreements with labor unions which is typical of the utility construction industry. Labor disruptions, boycotts, strikes, or significant negotiated wage and benefit increases at NPL, whether due to employee turnover or otherwise, could have a material adverse effect on NPL's business and our results of operations and cash flows.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 2. PROPERTIES

The plant investment of Southwest consists primarily of transmission and distribution mains, compressor stations, peak shaving/storage plants, service lines, meters, and regulators, which comprise the pipeline systems and facilities located in and around the communities served. Southwest also includes other properties such as land, buildings, furnishings, work equipment, vehicles, and software systems in plant investment. The northern Nevada and northern California properties of Southwest are referred to as the northern system; the Arizona, southern Nevada, and southern California properties are referred to as the southern system. Several properties are leased by Southwest, including a portion of the corporate headquarters office complex located in Las Vegas, Nevada. Total gas plant, exclusive of leased property, at December 31, 2013 was $5.4 billion, including construction work in progress. It is the opinion of management that the properties of Southwest are suitable and adequate for its purposes.

Substantially all gas main and service lines are constructed across property owned by others under right-of-way grants obtained from the record owners thereof, on the streets and grounds of municipalities under authority conferred by franchises or otherwise, or on public highways or public lands under authority of various federal and state statutes. None of the numerous county and municipal franchises are exclusive, and some are of limited duration. These franchises are renewed regularly as they expire, and Southwest anticipates no serious difficulties in obtaining future renewals.

With respect to the right-of-way grants, Southwest has had continuous and uninterrupted possession and use of all such rights-of-way, and the associated gas mains and service lines, commencing with the initial stages of construction of such facilities. Permits have been obtained from public authorities and other governmental entities in certain instances to cross or to lay facilities along roads and highways. These permits typically are revocable at the election of the grantor and Southwest occasionally must relocate its facilities when requested to do so by the grantor. Permits have also been obtained from railroad companies to cross over or under railroad lands or rights-of-way, which in some instances require annual or other periodic payments and are revocable at the election of the grantors.

Southwest operates two primary pipeline transmission systems:

- a system (including an LNG storage facility) owned by Paiute extending from the Idaho-Nevada border to the Reno, Sparks, and Carson City areas and communities in the Lake Tahoe area in both California and Nevada and other communities in northern and western Nevada; and
- a system extending from the Colorado River at the southern tip of Nevada to the Las Vegas distribution area.

Southwest provides natural gas service in parts of Arizona, Nevada, and California. Service areas in Arizona include most of the central and southern areas of the state including Phoenix, Tucson, Yuma, and surrounding communities. Service areas in northern Nevada include Carson City, Yerington, Fallon, Lovelock, Winnemucca, and Elko. Service areas in southern Nevada include the Las Vegas valley (including Henderson and Boulder City) and Laughlin. Service areas in southern California include Barstow, Big Bear, Needles, and Victorville. Service areas in northern California include the Lake Tahoe area and Truckee.

Information on properties of NPL can be found in this Form 10-K under Construction Services.

Item 3. LEGAL PROCEEDINGS

The Company is named as a defendant in various legal proceedings. The ultimate dispositions of these proceedings are not presently determinable; however, it is the opinion of management that none of this litigation individually or in the aggregate will have a material adverse impact on the Company’s financial position or results of operations.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Item 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

The listing of the executive officers of the Company is set forth under **Part III Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE**, which by this reference is incorporated herein.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The principal market on which the common stock of the Company is traded is the New York Stock Exchange. At February 18, 2014, there were 15,314 holders of record of common stock, and the market price of the common stock was $54.35. The quarterly market price of, and dividends on, Company common stock required by this item are included in the 2013 Annual Report to Shareholders filed as an exhibit hereto and incorporated herein by reference.

In February 2014, the Board of Directors ("Board") increased the quarterly dividend payout to 36.5 cents per share, effective with the June 2014 payment. This marks the eighth consecutive year in which the dividend was increased. Over time, the Board intends to increase the dividend such that the payout ratio approaches a local distribution company peer group average, while maintaining the Company's stable and strong credit ratings and the ability to effectively fund future rate base growth. The timing and amount of any future increases will be based upon the Board's continued review of the Company's dividend rate in the context of the performance of the Company's two operating segments and their future growth prospects. The quarterly common stock dividend declared was 26.5 cents per share throughout 2011, 29.5 cents per share throughout 2012, and 33 cents per share throughout 2013.

Item 6. SELECTED FINANCIAL DATA

Information required by this item is included in the 2013 Annual Report to Shareholders and is incorporated herein by reference.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Information required by this item is included in the 2013 Annual Report to Shareholders and is incorporated herein by reference.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to various forms of market risk, including commodity price risk, weather risk, and interest rate risk. The following describes the Company's exposure to these risks.

Commodity Price Risk

In managing its natural gas supply portfolios, Southwest has historically entered into short duration (generally one year or less) fixed-price contracts and variable-price contracts (firm and spot). Southwest has experienced price volatility over the past several years and such volatility is expected to continue into 2014 and beyond.

Southwest is protected financially from commodity price risk by deferred energy or purchased gas adjustment (collectively "PGA") mechanisms in each of its jurisdictions. These mechanisms generally allow Southwest to defer over- or under-collections of gas costs to PGA balancing accounts. With regulatory approval, Southwest can either refund amounts over-collected or recoup amounts under-collected in future periods. In addition to the PGA mechanism, Southwest utilizes volatility mitigation programs to attempt to further reduce price volatility for customers. Under these programs, Southwest fixes the price of a portion (for the 2013/2014 heating season, currently ranging from 25% to 35%, depending on the jurisdiction) of its natural gas portfolio using fixed-price contracts and/or derivative instruments (fixed-for-floating swaps), and where available, natural gas storage.

As part of the most recent Nevada Annual Rate Adjustment Application and associated stipulation, the Company has agreed to suspend further swaps and fixed-price purchases pursuant to the Volatility Mitigation Program for its Nevada service territories. The decision will not impact previously executed purchase arrangements. The Company along with its regulators will continue to evaluate this strategy in light of prevailing or anticipated changing market conditions.

Southwest's natural gas purchasing practices are subject to prudence review by the various regulatory bodies in each jurisdiction. PGA changes affect cash flows and potentially short-term borrowing requirements, but do not directly impact profit margin.

Weather Risk

Rate design is the primary mechanism available to Southwest to mitigate weather risk. All of Southwest's service territories have decoupled rate structures which mitigate weather risk. In California, CPUC regulations allow Southwest to decouple operating margin from usage and offset weather risk. In Nevada, a decoupled rate structure applies to most customer classes providing stability in annual operating margin by insulating the Company from the effects of lower usage (including volumes associated with unusual weather). In Arizona, a full revenue decoupling mechanism, which includes a winter-period monthly weather adjuster, is in place for most customer classes. With decoupled rate structures, Southwest's operating margin is limited during unusually cold weather. However, Southwest is not assured that decoupled rate structures will continue to be supported in future rate cases.

Interest Rate Risk

Interest rate risk is the risk that changes in interest rates could adversely affect earnings or cash flows. The primary interest rate risk for the Company is the risk of increasing interest rates on variable-rate obligations. Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. In Nevada, fluctuations in interest rates on $150 million of variable-rate Industrial Development Revenue Bonds ("IDRBs") are tracked and recovered from ratepayers through an interest balancing account, which mitigates risk to earnings and cash flows from interest rate fluctuations on these IDRBs between general rate cases. As of December 31, 2013 and 2012, Southwest had $60 million and $161 million, respectively, in variable-rate debt outstanding, excluding the IDRBs noted above. Assuming a constant outstanding balance in variable-rate debt for the next twelve months, a hypothetical 1% change in interest rates would increase or decrease interest expense for the next twelve months by approximately $600,000.

Other risk information is included in **Item 1A. Risk Factors** of this report.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Consolidated Financial Statements of Southwest Gas Corporation and Notes thereto, together with the report of PricewaterhouseCoopers LLP, are included in the 2013 Annual Report to Shareholders and are incorporated herein by reference.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

The Company has established disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed in reports filed or submitted under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and to provide reasonable assurance that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and benefits of controls must be considered relative to their costs. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or management override of the control. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and may not be detected.

Based on the most recent evaluation, as of December 31, 2013, management of the Company, including the Chief Executive Officer and Chief Financial Officer, believe the Company's disclosure controls and procedures are effective at attaining the level of reasonable assurance noted above.

Internal Control Over Financial Reporting

The report of management of the Company required to be reported herein is incorporated by reference to the information reported in the 2013 Annual Report to Shareholders under the caption “Management’s Report on Internal Control Over Financial Reporting” on page 78.

The Attestation Report of the Independent Registered Public Accounting Firm required to be reported herein is incorporated by reference to the information reported in the 2013 Annual Report to Shareholders under the caption “Report of Independent Registered Public Accounting Firm” on page 79.

There have been no changes in the Company’s internal controls over financial reporting that occurred during the most recent fiscal quarter that have materially affected or that are reasonably likely to materially affect the Company’s internal control over financial reporting.

Item 9B. OTHER INFORMATION

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

(a) *Identification of Directors.* Information with respect to Directors is set forth under the heading “Election of Directors” in the definitive 2014 Proxy Statement, which by this reference is incorporated herein.

(b) *Identification of Executive Officers.* The name, age, position, and period position held during the last five years for each of the Executive Officers of the Company as of December 31, 2013 are as follows:

Name	Age	Position	Period Position Held
Jeffrey W. Shaw	55	President and Chief Executive Officer	2012-Present
		Chief Executive Officer	2009-2012
John P. Hester	51	Executive Vice President	2013-Present
		Senior Vice President/Regulatory Affairs & Energy Resources	2009-2013
William N. Moody	57	Executive Vice President	2013-Present
		Senior Vice President/Staff Operations & Technology	2012-2013
		Vice President/Gas Resources	2009-2012
Roy R. Centrella	56	Senior Vice President/Chief Financial Officer	2010-Present
		Vice President/Controller and Chief Accounting Officer	2009-2010
Eric DeBonis	46	Senior Vice President/Operations	2012-Present
		Senior Vice President/Staff Operations & Technology	2011-2012
		Vice President/Special Projects	2010-2011
		Vice President/Central Arizona Division	2009-2010
Karen S. Haller	50	Senior Vice President/General Counsel and Corporate Secretary	2012-Present
		Vice President/General Counsel, Compliance Officer, and Corporate Secretary Vice	2010-2012
		President/General Counsel and Compliance Officer	2009-2010
Laura Lopez Hobbs	54	Senior Vice President/Human Resources and Administration	2012-Present
		Vice President/Administration	2010-2012
		Vice President/Human Resources	2009-2010
Edward A. Janov	59	Senior Vice President/Corporate Development	2010-Present
		Senior Vice President/Finance	2009-2010
Anita M. Romero	51	Senior Vice President/Staff Operations & Technology	2013-Present
		Vice President/Information Services	2012-2013
		Vice President/Special Projects	2011-2012
		Vice President/Southern Nevada Division	2009-2011
Kenneth J. Kenny	51	Vice President/Finance/Treasurer	2010-Present
		Vice President/Treasurer	2009-2010
Gregory J. Peterson	54	Vice President/Controller and Chief Accounting Officer	2010-Present
		Assistant Controller	2009-2010

(c) *Identification of Certain Significant Employees*. None.

(d) *Family Relationships.* No Directors or Executive Officers are related either by blood, marriage, or adoption.

(e) *Business Experience.* Information with respect to Directors is set forth under the heading “Election of Directors” in the definitive 2014 Proxy Statement, which by this reference is incorporated herein. All Executive Officers have held responsible positions with the Company for at least five years as described in (b) above.

(f) *Involvement in Certain Legal Proceedings*. None.

(g) *Promoters and Control Persons*. None.

(h) *Audit Committee Financial Expert.* Information with respect to the financial expert of the Board of Directors’ audit committee is set forth under the heading “Committees of the Board” in the definitive 2014 Proxy Statement, which by this reference is incorporated herein.

(i) *Identification of the Audit Committee.* Information with respect to the composition of the Board of Directors’ audit committee is set forth under the heading “Committees of the Board” in the definitive 2014 Proxy Statement, which by this reference is incorporated herein.

(j) *Material Changes in Director Nomination Procedures for Security Holders*. None.

Section 16(a) Beneficial Ownership Reporting Compliance. The Company has adopted procedures to assist its directors and executive officers in complying with Section 16(a) of the Exchange Act which includes assisting in the preparation of forms for filing. Based upon a review of filings with the SEC and written representations that no other reports were required, the Company believes that all of its directors and executive officers complied during 2013 with the reporting requirements of Section 16(a) of the Exchange Act, except for the following Form 4:

The exercise of 3,000 options of Company common stock by director Anne L. Mariucci on April 3, 2013 was reported on April 9, 2013.

Code of Business Conduct and Ethics. The Company has adopted a code of business conduct and ethics for its employees, including its chief executive officer, chief financial officer, chief accounting officer, and non-employee directors. A code of ethics is defined as written standards that are reasonably designed to deter wrongdoing and to promote: 1) honest and ethical conduct; 2) full, fair, accurate, timely, and understandable disclosure in reports and documents that a registrant files; 3) compliance with applicable governmental laws, rules, and regulations; 4) the prompt internal reporting of violations of the code to an appropriate person or persons identified in the code; and 5) accountability for adherence to the code. The Company's Code of Business Conduct & Ethics can be viewed on the Company's website (www.swgas.com). If any substantive amendments to the Code of Business Conduct & Ethics are made or any waivers are granted, including any implicit waiver, from a provision of the Code of Business Conduct & Ethics, to the Company's chief executive officer, chief financial officer and chief accounting officer, the Company will disclose the nature of such amendment or waiver on the Company's website, www.swgas.com.

Item 11. EXECUTIVE COMPENSATION

Information with respect to executive compensation is set forth under the heading "Executive Compensation" in the definitive 2014 Proxy Statement, which by this reference is incorporated herein.

(a) *Compensation Committee Interlocks and Insider Participation.* Information with respect to Compensation Committee interlocks and insider participation is set forth under the heading "Governance of the Company" in the definitive 2014 Proxy Statement, which by this reference is incorporated herein.

(b) *Compensation Committee Report.* Information with respect to the Compensation Committee Report is set forth under the heading "Compensation Committee Report" in the definitive 2014 Proxy Statement, which by this reference is incorporated herein.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

(a) *Security Ownership of Certain Beneficial Owners.* Information with respect to security ownership of certain beneficial owners is set forth under the heading "Securities Ownership by Directors, Director Nominees, Executive Officers, and Certain Beneficial Owners" in the definitive 2014 Proxy Statement, which by this reference is incorporated herein.

(b) *Security Ownership of Management.* Information with respect to security ownership of management is set forth under the heading "Securities Ownership by Directors, Director Nominees, Executive Officers, and Certain Beneficial Owners" in the definitive 2014 Proxy Statement, which by this reference is incorporated herein.

(c) *Changes in Control*. None.

(d) *Securities Authorized for Issuance Under Equity Compensation Plans*.

At December 31, 2013, the Company had three stock-based compensation plans. With respect to the first plan, the Company previously granted options to purchase shares of common stock to key employees and outside directors. The option grants in 2006 consumed the remaining options that could be issued under the option plan and no future grants are anticipated.

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Equity Compensation Plan Information

Plan category (Thousands of shares)	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance (excluding securities reflected in column a) (c)
Equity compensation plans approved by security holders	52	$ 27.57	—
Equity compensation plans not approved by security holders	—	—	—
Total	52	$ 27.57	—

Pursuant to the terms of the management incentive plan, the Company may issue performance shares to encourage key employees to remain in its employment to achieve short-term and long-term performance goals.

Plan category (Thousands of shares)	Number of securities to be issued upon vesting of performance shares (a)	Weighted-average grant date fair value of award (b)	Number of securities remaining available for future issuance (excluding securities reflected in column a) (c)
Equity compensation plans approved by security holders	323	$ 39.16	172
Equity compensation plans not approved by security holders	—	—	—
Total	323	$ 39.16	172

Pursuant to the terms of the restricted stock/unit plan, the Company may award restricted stock and restricted stock units to attract, motivate, retain and reward key employees with incentives for high levels of individual performance and improved financial performance of the Company and to attract, motivate, and retain experienced and knowledgeable independent directors.

Plan category (Thousands of shares)	Number of securities to be issued upon vesting of restricted stock units (a)	Weighted-average grant date fair value of award (b)	Number of securities remaining available for future issuance (excluding securities reflected in column a) (c)
Equity compensation plans approved by security holders	245	$ 38.00	150
Equity compensation plans not approved by security holders	—	—	—
Total	245	$ 38.00	150

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Additional information regarding the three equity compensation plans is included in Note 10 of the Notes to Consolidated Financial Statements in the 2013 Annual Report to Shareholders.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information with respect to certain relationships and related transactions, and director independence is set forth under the heading “Governance of the Company” in the definitive 2014 Proxy Statement, which by this reference is incorporated herein.

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information with respect to accounting fees and services associated with PricewaterhouseCoopers LLP is set forth under the heading “Selection of Independent Registered Public Accounting Firm” in the definitive 2014 Proxy Statement, which by this reference is incorporated herein.

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report on Form 10-K:

(1) The Consolidated Financial Statements of the Company (including the Report of Independent Registered Public Accounting Firm) required to be reported herein are incorporated by reference to the information reported in the 2013 Annual Report to Shareholders under the following captions:

(2) All schedules have been omitted because the required information is either inapplicable or included in the Notes to Consolidated Financial Statements.

(3) **See LIST OF EXHIBITS**.

(b) **See LIST OF EXHIBITS**.

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LIST OF EXHIBITS

Exhibit Number	Description of Document
3(i)	Restated Articles of Incorporation, as amended. Incorporated herein by reference to Exhibit 3(i) to Form 10–Q for the quarter ended September 30, 2007, File No. 1-07850.
3(ii)	Amended Bylaws of Southwest Gas Corporation. Incorporated herein by reference to Exhibit 3(ii) to Form 8–K dated July 31, 2012, File No. 1-07850.
4.01	Indenture between City of Big Bear Lake, California, and Harris Trust and Savings Bank as Trustee, dated December 1, 1993, with respect to the issuance of $50,000,000 Industrial Development Revenue Bonds (Southwest Gas Corporation Project), 1993 Series A, due 2028. Incorporated herein by reference to Exhibit 4.11 to Form 10-K for the year ended December 31, 1993, File No. 1-07850.
4.02	Indenture between the Company and Harris Trust and Savings Bank dated July 15, 1996, with respect to Debt Securities. Incorporated herein by reference to Exhibit 4.04 to Form 8-K dated July 26, 1996, File No. 1–07850.
4.03	First Supplemental Indenture of the Company to Harris Trust and Savings Bank dated August 1, 1996, supplementing and amending the Indenture dated as of July 15, 1996, with respect to 7 1/2% and 8% Debentures, due 2006 and 2026, respectively. Incorporated herein by reference to Exhibit 4.11 to Form 8-K dated July 31, 1996, File No. 1-07850.
4.04	Second Supplemental Indenture of the Company to Harris Trust and Savings Bank dated December 30, 1996, supplementing and amending the Indenture dated as of July 15, 1996, with respect to Medium-Term Notes. Incorporated herein by reference to Exhibit 4.04 to Form 8-K dated December 30, 1996, File No. 1–07850.
4.05	Indenture between Clark County, Nevada, and Harris Trust and Savings Bank as Trustee, dated as of October 1, 1999, with respect to the issuance of $35,000,000 Industrial Development Revenue Bonds (Southwest Gas Corporation), Series 1999A and Taxable Series 1999B or convertibles of Series B (Series C and D), due 2038. Incorporated herein by reference to Exhibit 4.20 to Form 10-K for the year ended December 31, 1999, File No. 1-07850.
4.06	Certificate of Trust of Southwest Gas Capital III. Incorporated herein by reference to Exhibit 4.04 to Form S–3 dated August 7, 2003, File No. 333-106419.
4.07	Certificate of Trust of Southwest Gas Capital IV. Incorporated herein by reference to Exhibit 4.05 to Form S–3 dated August 7, 2003, File No. 333-106419.
4.08	Trust Agreement of Southwest Gas Capital III. Incorporated herein by reference to Exhibit 4.07 to Form S-3 dated August 7, 2003, File No. 333-106419.
4.09	Trust Agreement of Southwest Gas Capital IV. Incorporated herein by reference to Exhibit 4.08 to Form S-3 dated August 7, 2003, File No. 333-106419.
4.10	Form of Common Stock Certificate. Incorporated herein by reference to Exhibit 4 to Form 8-K dated July 22, 2003, File No. 1-07850.
4.11	Indenture between Clark County, Nevada, and BNY Midwest Trust Company as Trustee, dated as of July 1, 2004, with respect to the issuance of $65,000,000 Industrial Development Revenue Bonds (Southwest Gas Corporation), Series 2004A, due 2034. Incorporated herein by reference to Exhibit 4 to Form 10-Q for the quarter ended September 30, 2004, File No. 1-07850.
4.12	Indenture between Clark County, Nevada, and BNY Midwest Trust Company as Trustee, dated as of October 1, 2004, with respect to the issuance of $75,000,000 Industrial Development Refunding Revenue Bonds (Southwest Gas Corporation), Series 2004B, due 2033. Incorporated herein by reference to Exhibit 4.01 to Form 10-K for the year ended December 31, 2004, File No. 1-07850.

Exhibit Number	Description of Document
4.13	Indenture of Trust between Clark County, Nevada, and the Bank of New York Trust Company, N.A. as Trustee, dated as of October 1, 2005, relating to Clark County, Nevada Industrial Development Revenue Bonds Series 2005A. Incorporated herein by reference to Exhibit 4.1 to Form 10-Q for the quarter ended September 30, 2005, File No. 1-07850.
4.14	Indenture of Trust between Clark County, Nevada, and the Bank of New York Trust Company, N.A. as Trustee, dated as of September 1, 2006, relating to Clark County, Nevada Industrial Development Revenue Bonds Series 2006A. Incorporated herein by reference to Exhibit 4.01 to Form 10-Q for the quarter ended September 30, 2006, File No. 1-07850.
4.15	Indenture of Trust between Clark County, Nevada, and the BNY Midwest Trust Company, as Trustee, dated as of March 1, 2003, relating to Clark County, Nevada Industrial Development Revenue Bonds Series 2003. Incorporated herein by reference to Exhibit 10.01 to Form 10-Q for the quarter ended September 30, 2008, File No. 1-07850.
4.16	Indenture of Trust between Clark County, Nevada and The Bank of New York Mellon Trust Company, N.A., as Trustee, dated as of September 1, 2008, relating to Clark County, Nevada Industrial Development Revenue Bonds Series 2008A. Incorporated herein by reference to Exhibit 10.02 to Form 10-Q for the quarter ended September 30, 2008, File No. 1-07850.
4.17	Indenture of Trust between Clark County, Nevada and The Bank of New York Mellon Trust Company, N.A., as Trustee, dated December 1, 2009, relating to Clark County, Nevada Industrial Development Revenue Bonds Series 2009A. Incorporated herein by reference to Exhibit 4.27 to Form 10-K for the year ended December 31, 2009, File No. 1-07850.
4.18	Note Purchase Agreement, dated November 18, 2010, by and between the Company and Metropolitan Life Insurance Company, John Hancock Life Insurance Company (U.S.A.), certain of their respective affiliates, and Union Fidelity Life Insurance Company. Incorporated herein by reference to Exhibit 4.1 to Form 8-K dated November 18, 2010, File No. 1-07850.
4.19	Form of 6.1% Senior Note due 2041. Incorporated herein by reference to Exhibit 4.2 to Form 8-K dated November 18, 2010, File No. 1-07850.
4.20	Indenture, dated December 7, 2010, by and between Southwest Gas Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee. Incorporated herein by reference to Exhibit 4.1 to Form 8-K dated December 7, 2010, File No. 1-07850.
4.21	First Supplemental Indenture, dated as of December 10, 2010, supplementing and amending the indenture dated as of December 7, 2010, by and between Southwest Gas Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee (including the Form of 4.45% Senior Notes due 2020). Incorporated herein by reference to Exhibit 4.1 to Form 8-K dated December 10, 2010, File No. 1-07850.
4.22	Indenture, dated March 23, 2012, by and between Southwest Gas Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee. Incorporated herein by reference to Exhibit 4.1 to Form 8-K dated March 20, 2012, File No. 1-07850.
4.23	Indenture, dated as of October 4, 2013, by and between Southwest Gas Corporation and the Bank of New York Mellon Trust Company, N.A., as Trustee. Incorporated herein by reference to Exhibit 4.1 to Form 8-K dated October 1, 2013. File No. 1-07850.
4.24	The Company hereby agrees to furnish to the SEC, upon request, a copy of any instruments defining the rights of holders of long-term debt issued by Southwest Gas Corporation or its subsidiaries; the total amount of securities authorized thereunder does not exceed 10% of the consolidated total assets of Southwest Gas Corporation and its subsidiaries.

Exhibit Number	Description of Document
10.01	Project Agreement between the Company and City of Big Bear Lake, California, dated as of December 1, 1993. Incorporated herein by reference to Exhibit 10.05 to Form 10-K for the year ended December 31, 1993, File No. 1-07850.
10.02	Amended and Restated Lease Agreement between the Company and Spring Mountain Road Associates, dated as of July 1, 1996. Incorporated herein by reference to Exhibit 10 to Form 10-Q for the quarter ended September 30, 1996, File No. 1-07850.
10.03 *	Southwest Gas Corporation Supplemental Retirement Plan, amended and restated as of January 1, 2005. Incorporated herein by reference to Exhibit 10.03 to Form 10-K for the year ended December 31, 2007, File No. 1–07850.
10.04 *	Southwest Gas Corporation Board of Directors Retirement Plan, amended and restated as of January 1, 2005. Incorporated herein by reference to Exhibit 10.04 to Form 10-K for the year ended December 31, 2007, File No. 1-07850.
10.05 *	Form of Change in Control Agreement with Company Officers. Incorporated herein by reference to Exhibit 10.1 to Form 8-K dated November 14, 2013, File No. 1-07850.
10.06 *	Southwest Gas Corporation Management Incentive Plan, amended and restated effective January 20, 2009. Incorporated herein by reference to Appendix A to the Proxy Statement dated March 18, 2009, File No. 1–07850.
10.07 *	Southwest Gas Corporation 2002 Stock Incentive Plan. Incorporated herein by reference to the Proxy Statement dated April 2, 2002, File No. 1-07850. Southwest Gas Corporation 1996 Stock Incentive Plan. Incorporated herein by reference to Appendix C to the Proxy Statement dated May 30, 1996, File No. 1–07850.
10.08 *	Southwest Gas Corporation Executive Deferral Plan, amended and restated March 1, 2008, effective January 1, 2005. Southwest Gas Corporation Executive Deferral Plan, amended and restated effective January 1, 2009. Incorporated herein by reference to Exhibit 10.10 to Form 10-K for the year ended December 31, 2008, File No. 1-07850.
10.09 *	Southwest Gas Corporation Directors Deferral Plan, amended and restated effective January 1, 2009. Incorporated herein by reference to Exhibit 10.11 to Form 10-K for the year ended December 31, 2008, File No. 1-07850.
10.10	Financing agreement dated as of March 1, 2003 by and between Clark County, Nevada, and Southwest Gas Corporation relating to Clark County, Nevada Industrial Development Revenue Bonds Series 2003A, Series 2003B, Series 2003C, Series 2003D and Series 2003E. Incorporated herein by reference to Exhibit 10 to Form 10-Q for the quarter ended September 30, 2003, File No. 1-07850.
10.11 *	Form of Executive Option Grant under 2002 Stock Incentive Plan. Incorporated herein by reference to Exhibit 10 to Form 10-Q for the quarter ended September 30, 2004, File No. 1-07850.
10.12	Financing Agreement dated as of October 1, 2004 by and between the Company and Clark County, Nevada, relating to Clark County, Nevada Industrial Development Revenue Bonds Series 2004B. Incorporated herein by reference to Exhibit 10.01 to Form 10-K for the year ended December 31, 2004, File No. 1-07850.
10.13	First Amendment to Financing Agreement by and between Clark County, Nevada, and Southwest Gas Corporation dated as of July 1, 2005, amending the Financing Agreement dated as of March 1, 2003, with respect to Clark County, Nevada Industrial Development Revenue Bonds Series 2003A, Series 2003B, Series 2003C, Series 2003D, and Series 2003E. Incorporated herein by reference to Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2005, File No. 1-07850.
10.14	Financing Agreement dated as of October 1, 2005 by and between Clark County, Nevada, and Southwest Gas Corporation relating to Clark County, Nevada Industrial Development Revenue Bonds Series 2005A. Incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2005, File No. 1-07850.

Exhibit Number	Description of Document
10.15	Financing Agreement dated as of September 1, 2006 by and between Clark County, Nevada, and Southwest Gas Corporation relating to Clark County, Nevada Industrial Development Revenue Bonds Series 2006A. Incorporated herein by reference to Exhibit 10.01 to Form 10-Q for the quarter ended September 30, 2006, File No. 1-07850.
10.16	Financing Agreement between Clark County, Nevada, and Southwest Gas Corporation, dated as of September 1, 2008, relating to Clark County, Nevada Industrial Development Revenue Bonds Series 2008A. Incorporated herein by reference to Exhibit 10.03 to Form 10-Q for the quarter ended September 30, 2008, File No. 1-07850.
10.17	Financing Agreement between Clark County, Nevada and Southwest Gas Corporation, dated December 1, 2009, relating to Clark County, Nevada Industrial Development Revenue Bonds Series 2009A. Incorporated herein by reference to Exhibit 10.21 to Form 10-K for the year ended December 31, 2009, File No. 1-07850.
10.18	$300 million Credit Facility. Incorporated herein by reference to Exhibit 10.1 to Form 8-K dated March 15, 2012, File No. 1-07850.
10.19 *	Southwest Gas Corporation 2006 Restricted Stock/Unit Plan, as amended and restated. Incorporated herein by reference to Appendix A to the Proxy Statement dated March 28, 2012, File No. 1-07850.
99.01	NPL Credit Facility Agreement. Incorporated herein by reference to Exhibit 99.01 to Form 10-Q for the quarter ended June 30, 2012, File No. 1-07850.
99.02	NPL Credit Facility Agreement – First Amendment. Incorporated herein by reference to Exhibit 99.01 to Form 10-Q for the quarter ended September 30, 2012, File No. 1-07850.
99.03	NPL Credit Facility Agreement – Second Amendment. Incorporated herein by reference to Exhibit 99.02 to Form 10-Q for the quarter ended September 30, 2012, File No. 1-07850.
12.01	Computation of Ratios of Earnings to Fixed Charges of Southwest Gas Corporation.
13.01	Portions of 2013 Annual Report to Shareholders incorporated by reference to the Form 10-K.
21.01	List of subsidiaries of Southwest Gas Corporation.
23.01	Consent of PricewaterhouseCoopers LLP, an independent registered public accounting firm.
31.01	Section 302 Certifications.
32.01	Section 906 Certifications.
101.01	The following materials from the Company's Annual Report on Form 10-K for the year ended December 31, 2013, formatted in Extensible Business Reporting Language ("XBRL"): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Income, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Cash Flows, (v) the Consolidated Statements of Equity, and (vi) the Notes to the Consolidated Financial Statements.

* Management Contracts or Compensation Plans

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

SOUTHWEST GAS CORPORATION

Date: February 27, 2014

By /s/ JEFFREY W. SHAW
Jeffrey W. Shaw
President and Chief Executive Officer

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SIGNATURES

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

Signature	Title	Date
/S/ ROBERT L. BOUGHNER (Robert L. Boughner)	Director	February 27, 2014
/S/ JOSÉ A. CÁRDENAS (José A. Cárdenas)	Director	February 27, 2014
/S/ THOMAS E. CHESTNUT (Thomas E. Chestnut)	Director	February 27, 2014
/S/ STEPHEN C. COMER (Stephen C. Comer)	Director	February 27, 2014
/S/ LEROY C. HANNEMAN, JR. (LeRoy C. Hanneman, Jr.)	Director	February 27, 2014
/S/ MICHAEL O. MAFFIE (Michael O. Maffie)	Director	February 27, 2014
/S/ ANNE L. MARIUCCI (Anne L. Mariucci)	Director	February 27, 2014
/S/ MICHAEL J. MELARKEY (Michael J. Melarkey)	Chairman of the Board of Directors	February 27, 2014
/S/ JEFFREY W. SHAW (Jeffrey W. Shaw)	Director, President and Chief Executive Officer	February 27, 2014
/S/ A. RANDALL THOMAN (A. Randall Thoman)	Director	February 27, 2014
/S/ THOMAS A. THOMAS (Thomas A. Thomas)	Director	February 27, 2014
/S/ TERRENCE L. WRIGHT (Terrence L. Wright)	Director	February 27, 2014
/S/ ROY R. CENTRELLA (Roy R. Centrella)	Senior Vice President/ Chief Financial Officer	February 27, 2014
/S/ GREGORY J. PETERSON (Gregory J. Peterson)	Vice President, Controller, and Chief Accounting Officer	February 27, 2014

Exhibit 12.01

SOUTHWEST GAS CORPORATION
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
(Thousands of dollars)

	December 31,				
	2013	**2012**	**2011**	**2010**	**2009**
1. Fixed charges:					
A) Interest expense	$ 62,958	$ 67,148	$ 68,183	$ 75,481	$ 81,861
B) Amortization	2,002	2,001	2,137	2,620	2,097
C) Interest portion of rentals	11,809	10,605	8,943	6,455	6,644
Total fixed charges	$ 76,769	$ 79,754	$ 79,263	$ 84,556	$ 90,602
2. Earnings (as defined):					
D) Pretax income from continuing operations	$222,815	$207,915	$175,066	$158,378	$132,035
Fixed Charges (1. above)	76,769	79,754	79,263	84,556	90,602
Total earnings as defined	$299,584	$287,669	$254,329	$242,934	$222,637
	3.90	3.61	3.21	2.87	2.46

Consolidated Selected Financial Statistics

Year Ended December 31, (Thousands of dollars, except per share amounts)	2013	2012	2011	2010	2009
Operating revenues	$1,950,782	$1,927,778	$1,887,188	$1,830,371	$1,893,824
Operating expenses	1,676,567	1,656,254	1,637,108	1,598,254	1,685,433
Operating income	$ 274,215	$ 271,524	$ 250,080	$ 232,117	$ 208,391
Net income	$ 145,320	$ 133,331	$ 112,287	$ 103,877	$ 87,482
Total assets at year end	$4,565,174	$4,488,057	$4,276,007	$3,984,193	$3,906,292
Capitalization at year end					
Total equity	$1,412,395	$1,308,498	$1,225,031	$1,166,996	$1,102,086
Subordinated debentures	—	—	—	—	100,000
Long-term debt, excluding current maturities	1,381,327	1,268,373	930,858	1,124,681	1,169,357
	$2,793,722	$2,576,871	$2,155,889	$2,291,677	$2,371,443
Current maturities of long-term debt	$ 11,105	$ 50,137	$ 322,618	$ 75,080	$ 1,327
Common stock data					
Common equity percentage of capitalization	50.6%	50.8%	56.8%	50.9%	46.5%
Return on average common equity	10.6%	10.4%	9.3%	9.1%	8.1%
Basic earnings per share	$ 3.14	$ 2.89	$ 2.45	$ 2.29	$ 1.95
Diluted earnings per share	$ 3.11	$ 2.86	$ 2.43	$ 2.27	$ 1.94
Dividends declared per share	$ 1.32	$ 1.18	$ 1.06	$ 1.00	$ 0.95
Payout ratio	42%	41%	43%	44%	49%
Book value per share at year end	$ 30.51	$ 28.39	$ 26.68	$ 25.60	$ 24.44
Market value per share at year end	$ 55.91	$ 42.41	$ 42.49	$ 36.67	$ 28.53
Market value per share to book value per share	183%	149%	159%	143%	117%
Common shares outstanding at year end (000)	46,356	46,148	45,956	45,599	45,092
Number of common shareholders at year end	15,359	16,028	16,834	17,821	20,489
Ratio of earnings to fixed charges	3.90	3.61	3.21	2.87	2.46

Natural Gas Operations

Year Ended December 31,	2013	2012	2011	2010	2009
(Thousands of dollars)					
Sales	$1,212,293	$1,238,513	$1,329,512	$1,438,809	$1,547,081
Transportation	87,861	83,215	73,854	73,098	67,762
Operating revenue	1,300,154	1,321,728	1,403,366	1,511,907	1,614,843
Net cost of gas sold	436,001	479,602	613,489	736,175	866,630
Operating margin	864,153	842,126	789,877	775,732	748,213
Expenses					
Operations and maintenance	384,914	369,979	358,498	354,943	348,942
Depreciation and amortization	193,848	186,035	175,253	170,456	166,850
Taxes other than income taxes	45,551	41,728	40,949	38,869	37,318
Operating income	$ 239,840	$ 244,384	$ 215,177	$ 211,464	$ 195,103
Contribution to consolidated net income	$ 124,169	$ 116,619	$ 91,420	$ 91,382	$ 79,420
Total assets at year end	$4,272,029	$4,204,948	$4,048,613	$3,845,111	$3,782,913
Net gas plant at year end	$3,486,108	$3,343,794	$3,218,944	$3,072,436	$3,034,503
Construction expenditures and property additions	$ 314,578	$ 308,951	$ 305,542	$ 188,379	$ 212,919
Cash flow, net					
From operating activities	$ 265,290	$ 344,441	$ 216,745	$ 342,522	$ 371,416
From (used in) investing activities	(304,189)	(296,886)	(289,234)	(178,685)	(265,850)
From (used in) financing activities	44,947	(43,453)	(2,327)	(107,779)	(81,744)
Net change in cash	$ 6,048	$ 4,102	$ (74,816)	$ 56,058	$ 23,822
Total throughput (thousands of therms)					
Residential	741,327	655,046	718,765	704,693	669,736
Small commercial	298,045	270,665	303,923	300,940	294,225
Large commercial	102,761	116,582	112,256	111,833	117,241
Industrial/Other	50,210	47,830	50,208	58,922	72,623
Transportation	1,037,916	998,095	941,544	998,600	1,043,894
Total throughput	2,230,259	2,088,218	2,126,696	2,174,988	2,197,719
Weighted average cost of gas purchased ($/therm)	$ 0.42	$ 0.42	$ 0.58	$ 0.62	$ 0.71
Customers at year end	1,904,000	1,876,000	1,859,000	1,837,000	1,824,000
Employees at year end	2,220	2,245	2,298	2,349	2,423
Customer to employee ratio	858	836	809	782	753
Degree days – actual	1,918	1,740	2,002	1,998	1,824
Degree days – ten-year average	1,876	1,866	1,888	1,876	1,882

About Southwest Gas Corporation

Southwest Gas Corporation and its subsidiaries (the "Company") consist of two business segments: natural gas operations ("Southwest" or the "natural gas operations" segment) and construction services.

Southwest is engaged in the business of purchasing, distributing, and transporting natural gas for customers in portions of Arizona, Nevada, and California. Southwest is the largest distributor of natural gas in Arizona, selling and transporting natural gas in most of central and southern Arizona, including the Phoenix and Tucson metropolitan areas. Southwest is also the largest distributor of natural gas in Nevada, serving the Las Vegas metropolitan area and northern Nevada. In addition, Southwest distributes and transports natural gas for customers in portions of California, including the Lake Tahoe area and the high desert and mountain areas in San Bernardino County.

As of December 31, 2013, Southwest had 1,904,000 residential, commercial, industrial, and other natural gas customers, of which 1,022,000 customers were located in Arizona, 695,000 in Nevada, and 187,000 in California. Residential and commercial customers represented over 99% of the total customer base. During 2013, 56% of operating margin was earned in Arizona, 34% in Nevada, and 10% in California. During this same period, Southwest earned 85% of its operating margin from residential and small commercial customers, 4% from other sales customers, and 11% from transportation customers. These general patterns are expected to remain materially consistent for the foreseeable future.

Southwest recognizes operating revenues from the distribution and transportation of natural gas (and related services) to customers. Operating margin is the measure of gas operating revenues less the net cost of gas sold. Management uses operating margin as a main benchmark in comparing operating results from period to period. The principal factors affecting changes in operating margin are general rate relief and customer growth. All of Southwest's service territories have decoupled rate structures, which are designed to eliminate the direct link between volumetric sales and revenue, thereby mitigating the impacts of weather variability and conservation on margin, allowing the Company to aggressively pursue energy efficiency initiatives.

NPL Construction Co. ("NPL" or the "construction services" segment), a wholly owned subsidiary, is a full-service underground piping contractor that primarily provides utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems. NPL operates in 20 major markets nationwide. Construction activity is cyclical and can be significantly impacted by changes in weather, general and local economic conditions (including the housing market), interest rates, employment levels, job growth, the equipment resale market, pipe replacement programs of utilities, and local and federal regulation (including tax rates and incentives). During the past few years, utilities have implemented or modified pipeline integrity management programs to enhance safety pursuant to federal and state mandates. These programs, coupled with bonus depreciation tax deduction incentives, have resulted in a significant increase in multi-year pipeline replacement projects throughout the country. Generally, revenues are lowest during the first quarter of the year due to less favorable winter weather conditions. Revenues typically improve as more favorable weather conditions occur during the summer and fall months. In certain circumstances, such as with large, longer duration bid contracts, or unit-price contracts with revenue caps, results may be impacted by differences between costs incurred and those anticipated when the work was originally bid.

Executive Summary

The items discussed in this Executive Summary are intended to provide an overview of the results of the Company's operations and are covered in greater detail in later sections of management's discussion and analysis. As reflected in the table below, the natural gas operations segment accounted for an average of 85% of consolidated net income over the past three years. As such, management's discussion and analysis is primarily focused on that segment.

Summary Operating Results

Year ended December 31,	2013	2012	2011
(In thousands, except per share amounts)			
Contribution to net income			
Natural gas operations	$124,169	$116,619	$ 91,420
Construction services	21,151	16,712	20,867
Consolidated	$145,320	$133,331	$112,287
Average number of common shares outstanding	46,318	46,115	45,858
Basic earnings per share			
Consolidated	$ 3.14	$ 2.89	$ 2.45
Natural Gas Operations			
Operating margin	$864,153	$842,126	$789,877

2013 Overview

Consolidated results for 2013 increased compared to 2012 due to improved results from both business segments. Basic earnings per share were $3.14 in 2013 compared to basic earnings per share of $2.89 in 2012.

Natural gas operations highlights include the following:

- Operating margin increased $22 million, or 3%, compared to the prior year
- Operating expenses increased $27 million, or 4%, between years
- Net financing costs decreased $4 million between 2013 and 2012
- Other income increased $8 million between years
- Redemption at par of $30 million of 5.45% IDRBs and $15 million of 5.80% IDRBs in March 2013 and $8.27 million of 5.55% IDRBs in September 2013 (all originally due in 2038)
- Issued $250 million of 4.875% 30-year senior notes in October 2013
- The Company's credit rating was upgraded from BBB+ to A- by Standard & Poor's, from A- to A by Fitch, and from Baa1 to A3 by Moody's Investors Service in March 2013, May 2013, and January 2014, respectively

Construction services highlights include the following:

- Revenues in 2013 increased $45 million, or 7%, compared to 2012
- Construction expenses increased $32 million or 6%, compared to 2012
- Contribution to net income increased $4 million compared to 2012

Customer Growth. Southwest completed 21,000 first-time meter sets, but realized 28,000 net new customers over the last twelve months. The incremental additions reflect a return to service of customer meters on previously vacant homes.

Southwest estimates the remaining number of excess inactive meters is approximately 26,000 at December 31, 2013 and anticipates a continued gradual return of customers associated with previously vacant homes. Southwest projects customer growth of about 1.5% for 2014.

Company-Owned Life Insurance ("COLI"). Southwest has life insurance policies on members of management and other key employees to indemnify itself against the loss of talent, expertise, and knowledge, as well as to provide indirect funding for certain nonqualified benefit plans. The COLI policies have a combined net death benefit value of approximately $238 million at December 31, 2013. The net cash surrender value of these policies (which is the cash amount that would be received if Southwest voluntarily terminated the policies) is approximately $93 million at December 31, 2013 and is included in the caption "Other property and investments" on the balance sheet. The Company currently intends to hold the COLI policies for their duration and purchase additional policies as necessary. Current tax regulations provide for tax-free treatment of life insurance (death benefit) proceeds. Therefore, the changes in the cash surrender value components of COLI policies as they progress toward the ultimate death benefits are also recorded without tax consequences. Cash surrender values are directly influenced by the investment portfolio underlying the insurance policies. This portfolio includes both equity and fixed income (mutual fund) investments. As a result, generally the cash surrender value (but not the net death benefit) moves up and down consistent with the movements in the broader stock and bond markets. The Company is considering shifting the investment mix of the underlying investment portfolio more toward fixed income to help mitigate future cash surrender value volatility in COLI policies. As indicated in Note 1 of the Notes to Consolidated Financial Statements, cash surrender values of COLI policies increased $12.4 million (including $1.4 million of incremental death benefits) in 2013 and $6.6 million in 2012. Management currently expects average returns of $3 million to $5 million annually on the COLI policies, excluding any net death benefits recognized.

Issuance and Redemption of Debt. In March 2013, the Company redeemed at par the 5.45% Series 2003C and the 5.80% Series 2003E IDRBs originally due in 2038. In September 2013, the Company redeemed at par the $8.27 million 5.55% 1999 Series D IDRBs originally due in 2038. The Company facilitated these redemptions primarily from borrowings under its $300 million credit facility. In October 2013, the Company issued $250 million of 4.875% senior notes at a 0.078% discount. The notes will mature in October 2043. A portion of the net proceeds were used to temporarily pay down amounts outstanding under the credit facility. The remaining net proceeds were used for general corporate purposes.

Liquidity. Southwest believes its liquidity position is solid. Southwest has a $300 million credit facility maturing in March 2017. The facility is provided through a consortium of eight major banking institutions. Historically, facility borrowings have been low and concentrated in the first half of the winter heating period when gas purchases require temporary financing. During 2013, credit facility usage was impacted by a $111 million reduction in deferred purchased gas cost liabilities and the extinguishment of $53 million in Clark County, Nevada IDRBs. The maximum amount outstanding on the credit facility (including a commercial paper program) during 2013 was $195 million (prior to the paydown from the senior notes). At December 31, 2013, $10 million was outstanding on the long-term portion of the credit facility (all of which was under the commercial paper program), and no borrowings were outstanding on the short-term portion of the credit facility. Southwest has no significant debt maturities prior to 2017.

Construction Services. NPL's contribution to net income for 2013 was $21.2 million, a $4.4 million increase over the results for 2012. The prior year included recognition of a $15 million pretax loss on a large fixed-price contract, partially offset by $8 million in gains on sale of equipment. The current year includes higher general and administrative expenses due to structural and transitional changes associated with NPL's increased size and business complexity and additional legal-related expenses.

Results of Natural Gas Operations

Year Ended December 31,	2013	2012	2011
(Thousands of dollars)			
Gas operating revenues	$1,300,154	$1,321,728	$1,403,366
Net cost of gas sold	436,001	479,602	613,489
Operating margin	864,153	842,126	789,877
Operations and maintenance expense	384,914	369,979	358,498
Depreciation and amortization	193,848	186,035	175,253
Taxes other than income taxes	45,551	41,728	40,949
Operating income	239,840	244,384	215,177
Other income (deductions)	12,261	4,165	(5,404)
Net interest deductions	62,555	66,957	68,777
Income before income taxes	189,546	181,592	140,996
Income tax expense	65,377	64,973	49,576
Contribution to consolidated net income	$ 124,169	$ 116,619	$ 91,420

2013 vs. 2012

Contribution to consolidated net income from natural gas operations increased by $8 million between 2013 and 2012. The improvement was primarily due to increases in operating margin and other income and a decrease in net interest deductions, partially offset by higher operating expenses.

Operating margin increased $22 million between years. Rate relief provided $8 million of the increase in operating margin (including general rate relief in Nevada and net attrition amounts in California). New customers contributed $7 million of the increase during 2013 as approximately 28,000 net new customers were added during the last twelve months. Incremental margin from customers outside the decoupling mechanisms and other miscellaneous revenues (including amounts associated with recoveries of Arizona regulatory assets) contributed the remainder of the increase.

Operations and maintenance expense increased $14.9 million, or 4%, between years primarily due to higher general costs, employee-related costs (including a majority of the $6.4 million increase in pension costs), uncollectible expense, and pipeline integrity management programs, partially offset by lower legal claims and expenses.

Depreciation and amortization expense increased $7.8 million, or 4%. Average gas plant in service for the current year increased $230 million, or 5%, as compared to the prior year. This was attributable to pipeline capacity reinforcement work, franchise requirements, scheduled and accelerated pipe replacement activities, and new business. Increases in depreciation from these plant additions were partially offset by lower depreciation rates in Nevada (effective November 2012). Amortization associated with the recovery of Arizona regulatory assets, new conservation and energy efficiency programs in Nevada, and other amortization collectively increased $6.2 million.

Taxes other than income taxes increased $3.8 million between periods due to higher property taxes in Arizona and changes resulting from the last Nevada general rate case, whereby modified business and mill taxes became components of operating expenses.

Other income, which principally includes returns on COLI policies (including recognized net death benefits) and non-utility expenses, increased $8.1 million between 2013 and 2012. The current year reflects $12.4 million of COLI policy cash surrender value increases including net death benefits recognized, while the prior year included $6.6 million of COLI-related income. In addition, Arizona non-recoverable pipe replacement costs were $2.5 million lower in 2013 as compared to 2012 because this pipe replacement activity was substantially completed in 2012.

Net interest deductions decreased $4.4 million between 2013 and 2012 primarily due to cost savings from debt refinancing, redemptions, and lower interest expense associated with deferred PGA balances payable. The decrease was partially offset by the October 2013 issuance of $250 million of 4.875% senior notes. The prior year included a temporary increase in debt outstanding for approximately two months associated with debt refinancing that occurred in the first half of 2012.

2012 vs. 2011

Contribution to consolidated net income from natural gas operations increased by $25 million between 2012 and 2011. The improvement was primarily due to increases in operating margin and other income, partially offset by higher operating expenses.

Operating margin increased $52 million between years. Rate relief in Arizona ($45 million) and Nevada ($2 million) provided $47 million of the increase in operating margin. New customers contributed the remaining $5 million increase in operating margin during 2012. A $4 million increase between years, due to an adjustment (related to a regulatory deferral mechanism) that decreased operating margin in 2011, was offset by a reduction of $4 million in operating margin between years, primarily due to moderately cold weather experienced in Arizona in the first half of 2011. With a new rate decoupling mechanism in Arizona, effective January 2012, weather is no longer a significant factor in operating margin overall.

Operations and maintenance expense increased $11.5 million, or 3%, between years primarily due to higher general costs and employee-related costs including approximately $6 million of net pension expense, and to approximately $1 million in leak survey costs associated with a special Arizona program (see *Customer-Owned Yardline ("COYL") Program* in the **Rates and Regulatory Proceedings** section).

Depreciation expense increased $10.8 million, or 6%, as a result of additional plant in service. Average gas plant in service for 2012 increased $247 million, or 5%, compared to 2011. This was attributable to pipeline capacity reinforcement work, franchise requirements, scheduled and accelerated pipe replacement activities, and to a lesser degree, new business. The increase was partially offset by approximately $1 million due to a reduction in depreciation rates in Nevada, which became effective in November 2012.

Other income increased $9.6 million between 2012 and 2011. Cash surrender values of COLI policies increased $6.6 million in 2012, while COLI-related income (resulting from recognized death benefits net of decreases in cash surrender values) was $700,000 in the prior year. COLI income in 2012 was especially high due to strong equity-market returns on investments underlying the policies. In addition, Arizona non-recoverable pipe replacement and other non-utility costs were lower in 2012, especially during the fourth quarter, as compared to 2011. The non-recoverable portion of this pipe replacement activity was substantially completed in 2012.

Net interest deductions decreased $1.8 million between 2012 and 2011 primarily due to cost savings from refinancing, partially offset by a temporary increase in debt outstanding for approximately two months associated with the issuance of $250 million of 3.875% senior notes in March 2012 to repay $200 million of 7.625% senior notes that matured in May 2012, and by additional interest on variable-rate IDRBs.

Outlook for 2014

Operating margin for 2014 is expected to be favorably influenced by customer growth similar to 2013, as well as incremental margin associated with an expected California rate case decision (see **Rates and Regulatory Proceedings**).

Operating expenses for 2014 compared to 2013 will continue to be impacted by inflation, general cost increases, and depreciation expense on plant additions. Incremental costs, including higher property and general taxes, offset by a $9 million decrease in pension costs (approximately $7 million to be reflected in operations and maintenance expense), are expected to result in an overall operating expense increase of approximately 2% to 3%.

COLI-related income of $12.4 million in 2013 is significantly in excess of expected average returns and is not sustainable at these levels. Southwest expects longer term normal changes in COLI cash surrender values to range from $3 million to $5 million on an annual basis. However, individual quarterly and annual periods will continue to be subject to volatility.

Southwest anticipates an approximate $5 million to $6 million increase in net interest deductions in 2014 compared to 2013 primarily due to the October 2013 issuance of $250 million of 4.875% senior notes, partially offset by interest savings associated with the redemptions that occurred during 2013.

Infrastructure tracker mechanisms in Nevada and Arizona will contribute modestly to 2014 operating results and trend upward over the next several years.

Results of Construction Services

Year Ended December 31,	2013	2012	2011
(Thousands of dollars)			
Construction revenues	$650,628	$606,050	$483,822
Operating expenses:			
Construction expenses	573,284	541,523	423,703
Depreciation and amortization	42,969	37,387	25,216
Operating income	34,375	27,140	34,903
Other income (deductions)	39	246	(8)
Net interest deductions	1,145	1,063	825
Income before income taxes	33,269	26,323	34,070
Income tax expense	12,565	10,303	13,727
Net income	20,704	16,020	20,343
Net income (loss) attributable to noncontrolling interest	(447)	(692)	(524)
Contribution to consolidated net income attributable to NPL	$ 21,151	$ 16,712	$ 20,867

2013 vs. 2012

Contribution to consolidated net income from construction services for 2013 increased $4.4 million compared to 2012. The increase was primarily due to a $15 million pretax loss recognized on a large fixed-price contract in 2012, partially offset by lower gains on the sale of equipment and higher general and administrative expenses (included in Construction expenses) in 2013.

Revenues increased $44.6 million, or 7%, when compared to 2012 due primarily to an increase in utility customer contracts for pipe replacement work, partially offset by the winding down of a portion of work related to the large fixed-price contract noted above. Construction revenues include NPL contracts with Southwest totaling $88.2 million in 2013 and $83.4 million in 2012. NPL accounts for services provided to Southwest at contractual (market) prices at contract inception.

Construction expenses increased $31.8 million, or 6%, primarily due to additional pipe replacement work in 2013. Despite these increases, the construction expense variance between years was favorably impacted as the prior year included a $15 million pretax loss associated with the above-noted large fixed-price contract. This fixed-price contract is substantially complete. General and administrative expense (included in construction expenses) increased approximately $6 million due to changes that were implemented to match NPL's increased size and business complexity. In addition, NPL recorded approximately $4 million in 2013 associated with a legal settlement relating to former employees; no similar matters are pending. Depreciation expense increased $5.6 million between the current year and the prior year due to additional equipment purchased to support growth in the volume of work being performed. Gains on sale of equipment (reflected as an offset to construction expenses) were $4.1 million and $8 million in 2013 and 2012, respectively.

During the past several years, NPL has focused its efforts on obtaining pipe replacement work under both blanket contracts and incremental bid projects. In 2013, NPL experienced a slight increase in the volume of new construction installations. For 2013 and 2012, revenues from replacement work were 70% and 75%, respectively, of total revenues. Federal and state pipeline safety-related programs and bonus depreciation incentives have resulted in many utilities undertaking multi-year distribution pipe replacement projects. NPL continues to successfully bid on pipe replacement projects throughout the country.

2012 vs. 2011

Contribution to consolidated net income from construction services for 2012 decreased $4.2 million compared to 2011. The decline was primarily due to a loss on a large fixed-price contract in 2012, partially offset by additional replacement work and increased gains on sale of equipment.

Revenues increased $122 million, or 25%, when compared to 2011 due primarily to an increase in the volume of replacement work. Construction revenues included NPL contracts with Southwest totaling $83.4 million in 2012 and $92.1 million in 2011. NPL accounts for services provided to Southwest at contractual (market) prices at contract inception.

Construction expenses increased $118 million, or 28%, due to an increase in replacement construction work and a $15 million pretax loss on a large fixed-price contract. Depreciation expense increased $12.2 million between 2012 and 2011 due to an increase in equipment purchases. Gains on sale of equipment, included in construction expenses, were $8 million and $3.3 million in 2012 and 2011, respectively.

Outlook for 2014

NPL's revenues and operating profits are influenced by weather, customer requirements, mix of work, local economic conditions, bidding results, the equipment resale market, and the credit market. Typically, revenues are lowest during the first quarter of the year due to unfavorable winter weather conditions. Revenues typically improve as more favorable weather conditions occur during the summer and fall months. The current low interest rate environment, and the regulatory environment (encouraging the natural gas industry to replace aging pipeline infrastructure) are having a positive influence on NPL's results.

Management has an improved infrastructure in place on which to grow the business and is seeking to increase revenues by approximately 5% to 8% on average over the long term. Ultimately, revenues are subject to the timing and amount of work awarded to NPL by its utility customers. Extreme winter weather conditions during January and February 2014 have hindered normal construction work in most of the operating areas, with the exception of the Southwest. It is too early to predict if this will impact revenues for the full year. Overall, operating expenses are expected to increase in proportion to the growth in revenue.

Rates and Regulatory Proceedings

General Rate Relief and Rate Design

Rates charged to customers vary according to customer class and rate jurisdiction and are set by the individual state and federal regulatory commissions that govern Southwest's service territories. Southwest makes periodic filings for rate adjustments as the costs of providing service (including the cost of natural gas purchased) change, and as additional investments in new or replacement pipeline and related facilities are made. Rates are intended to provide for recovery of all prudently incurred costs and provide a reasonable return on investment. The mix of fixed and variable components in rates assigned to various customer classes (rate design) can significantly impact the operating margin actually realized by Southwest. Management has worked with its regulatory commissions in designing rate structures that strive to provide affordable and reliable service to its customers while mitigating the volatility in prices to customers and stabilizing returns to investors. Such rate structures were in place in all of Southwest's operating areas during 2012 and 2013.

Nevada General Rate Case. In the fourth quarter of 2012, a decision was reached at a public hearing (the "Decision") in the general rate application Southwest filed with the Public Utilities Commission of Nevada ("PUCN"), with rates effective November 2012. The Decision provided an annual revenue increase of $5.8 million in southern Nevada based on an overall rate of return of 6.49% and a 9.85% return on 42.6% common equity on original cost rate base of $825 million. For northern Nevada, the Decision provided a revenue increase of $1.2 million with an overall rate of return of 8.01% and a 9.20% return on 65.6% common equity on original cost rate base of $116 million. The Decision also included a reduction in annualized depreciation expense of $5.2 million and $1.7 million in southern and northern Nevada, respectively. In addition, the Decision reclassified approximately $2.5 million of modified business and mill taxes from pass-through items to operating expenses. On a combined basis, the Decision was expected to increase annual operating income by $11.4 million.

Following the Decision, the Company filed a Petition for Reconsideration requesting reconsideration of the findings in the Decision relating to the capital structure and other cost of service issues. In March 2013, the PUCN reached a decision in the rehearing (the "Rehearing Decision") relating to the capital structure issue. The Rehearing Decision retained an alternative capital structure, as opposed to utilizing Southwest's proposed capital structure, and authorized an overall rate of return of 6.56% and a 10.0% return on 42.7% common equity in southern Nevada and an overall rate of return of 7.88% and a 9.30% return on 59.1% common equity in northern Nevada. When compared to the original Decision, the Rehearing Decision is expected to result in an annual revenue increase of $1.0 million in southern Nevada and an annual revenue decrease of $0.5 million in northern Nevada.

Nevada Infrastructure Replacement Mechanisms. As part of the Nevada general rate case application in April 2012, Southwest requested to implement an infrastructure replacement mechanism to defer and recover certain costs associated with up to $40 million annually of proposed accelerated replacement of early vintage plastic ("EVPP") and steel pipe. As part of its fourth quarter 2012 decision, the PUCN indicated a separate rulemaking docket would be needed to address the regulatory issues necessary to implement such a mechanism. In January 2013, the PUCN authorized the opening of a new docket to review the merits of such mechanisms. An initial round of comments and reply comments were submitted and a workshop on the matter was convened. The scope of the rulemaking was expanded in order to consider additional forms of recovery mechanisms. In July, the Administrative Law Judge in the docket forwarded a draft regulation to the Nevada Legislative Counsel Bureau ("LCB") for review. The draft regulation provided for the establishment of regulatory assets that recover the depreciation expense and authorized pre-tax rate of return of infrastructure replacement investments in between rate cases. Southwest would then be able to develop rates to recover the associated amounts in a future general rate case proceeding, at which time the plant would be "rolled into" rate base naturally. The LCB proposed slight modifications to the regulation and returned it to the PUCN in August. In January 2014, the PUCN concluded the rulemaking process by approving final rules.

Separately, in March 2013, Southwest submitted a petition to the PUCN requesting authority to defer certain costs associated with the proposed accelerated 2013 replacement of certain EVPP to coincide with bonus depreciation tax relief extended by The American Taxpayer Relief Act of 2012. In June 2013, a stipulation (the "Stipulation"), which provided regulatory asset treatment for specific infrastructure replacement projects occurring during 2013 in the amount of $2 million in northern Nevada and approximately $13.6 million in southern Nevada, was reached by all parties and was approved by the PUCN. While the above-noted infrastructure replacement regulation was being finalized, the Company submitted a filing to the PUCN in November 2013 requesting authority to replace $18.9 million of EVPP in 2014; the PUCN approved the request in January 2014. The new rules (noted above) will additionally enable the Company to make a filing in 2014 identifying projects that Southwest proposes to be replaced beginning in January 2015.

Effectively, as a result of these mechanisms, the increase in depreciation expense, ordinarily arising from related capital expenditures, will be netted to zero by the deferral process. Incremental operating margin associated with these infrastructure replacements will materialize after the PUCN authorizes a surcharge, anticipated to commence during the first quarter of 2016.

California Annual Attrition. As part of the 2009 rate decision by the California Public Utilities Commission ("CPUC") in Southwest's last California general rate case, attrition increases were authorized for the years 2010-2013. The level of increase authorized for 2013 was $1.8 million in southern California, $500,000 in northern California, and $100,000 in South Lake Tahoe. However, the continued low interest rate environment triggered an automatic rate of return adjustment mechanism (or Automatic Trigger Mechanism), which resulted in offsetting decreases of $700,000 in southern California, $500,000 in northern California, and $100,000 in South Lake Tahoe. The resulting net margin impact for the California rate jurisdictions was an overall increase of $1.1 million in 2013.

California General Rate Case. In December 2012, Southwest filed a general rate case application with the CPUC requesting annual revenue increases of $5.6 million for southern California, $3.2 million for northern California, and $2.8 million for the South Lake Tahoe rate jurisdiction. The application includes a capital structure consisting of 43% debt and 57% common equity and a return on equity of 10.7%, with an overall rate of return of 7.32% in southern California and 8.61% in both northern California and South Lake Tahoe. Southwest is also seeking to continue a Post-Test Year Ratemaking Mechanism, which allows for annual attrition increases. The application includes the addition of an Infrastructure Reliability and Replacement Adjustment Mechanism ("IRRAM") to facilitate and complement projects involving the enhancement and replacement of gas infrastructure, promoting timely cost recovery for qualifying non-revenue producing capital expenditures. A proposed decision was issued by the administrative law judge and includes a total overall revenue increase of approximately $7.5 million, a capital structure consisting of 45% debt and 55% equity and a return on equity of 10.1%, acceptance of Company-proposed changes to the Automatic Trigger Mechanism, and approval of the IRRAM, including a Customer-Owned Yardline Program. The proposed decision is expected to be voted on by the CPUC in the first quarter of 2014.

Arizona Decoupling Mechanism. In December 2011, the Arizona Corporation Commission ("ACC") approved a settlement (effective January 2012) associated with Southwest's general rate application in November 2010. The settlement approved a revenue increase of $52.6 million with a return on equity of 9.50%. The settlement also approved a full revenue decoupling mechanism and a monthly weather adjustor. For 2012, the weather adjustor resulted in approximately $18 million being added to customer bills to offset warmer-than-normal temperatures, while in 2013 nearly $12 million was subtracted from customer bills to offset colder-than-normal temperatures. In addition, during 2012 the Company recorded a net $2 million payable to customers associated with the margin tracking deferral mechanism (the corresponding payable for 2013 was approximately $10 million). The ACC Staff recently completed a review of the decoupling mechanism (and a related report) for 2012. The ACC Staff found the mechanism to be working as designed and recommended its continuation. The ACC approved the decoupling report in December 2013 and authorized the Company to refund the over-collected balance that existed at December 31, 2012.

Customer-Owned Yardline ("COYL") Program. The Company received approval, in connection with its most recent Arizona general rate case, to implement a program to conduct leak surveys, and if leaks were present, to replace and relocate service lines and meters for approximately 100,000 Arizona customers whose meters are set-off from the customer's home, which is not a traditional configuration. Customers with this configuration were previously responsible for the cost of maintaining these lines and were subject to the immediate cessation of natural gas service if low-pressure leaks occurred. To facilitate this program, the Company was authorized to collect estimated leak survey costs in rates commencing in 2012. Effective June 2013, the ACC authorized a surcharge of $0.00101 per therm (approximately $600,000 annually) to recover the costs of depreciation and pre-tax return the Company would have received if the additional pipe replacement costs themselves (approximately $4 million through December 2012) had been included in rate base concurrent with the most recent Arizona rate case. (During 2013, approximately $6 million in additional COYL-related pipe replacement costs were added to plant.) The surcharge is expected to be revised annually as the program progresses, with the undepreciated plant balance to be incorporated in base rates at the time of the next Arizona general rate case. Management has not determined the timing of filing its next general rate case in Arizona; however, Southwest agreed in the settlement in its most recent Arizona general rate case filing to not file a general rate case in Arizona until April 30, 2016. In November 2013, the Company filed a request to modify or clarify the COYL provision to add a "Phase II" component to the COYL program to include the replacement of non-leaking COYLs. This request was approved by the ACC in January 2014, and requires that these replacements are coordinated with the Company's other pipeline replacement projects and that the Company will prioritize leaking COYLs over non-leaking COYLs. The revised surcharge request is expected to be filed in February 2014 with a proposed effective date of June 2014. Approximately 85% of COYLs were tested through December 2013 with nearly 4,000 relocations completed.

Proposed LNG Facility. In January 2014, Southwest filed an application with the ACC seeking preapproval to construct, operate and maintain a 233,000 dekatherm LNG facility in southern Arizona and to recover the actual costs, including the establishment of a regulatory asset. The LNG facility is designed to enhance service reliability and flexibility in natural gas deliveries in the southern Arizona area. Southwest requested approval of the actual cost of the project (including those facilities necessary to connect the proposed storage tank to Southwest's existing distribution system) not to exceed $55 million. The proposed LNG facility would provide a local storage option, operated by Southwest and connected directly to its distribution system, providing greater flexibility to serve customers. An ACC decision is expected to occur during 2014. If approved, construction is expected to be complete within approximately 24 to 30 months after ACC approval.

Federal Energy Regulatory Commission ("FERC") Jurisdiction. During the third quarter of 2013, Paiute Pipeline Company, a wholly owned subsidiary of Southwest, notified present and potential shippers of its plans to expand its existing transmission system to provide additional firm transportation-service capacity in the Elko County, Nevada area. This additional capacity is required to meet growing natural gas demands caused by increased residential and business load and the greater energy needs of mining operations in the area. Through the "open season" process, shippers responded with substantial interest. Dependent upon several variables, including the ultimate route of the project, the price of materials, and factors such as environmental impacts, the cost to complete this project has been estimated at approximately $35 million and has a targeted in-service date of November 2015. In October 2013, Paiute submitted a filing with the FERC requesting that its Staff initiate a pre-filing review of the proposed expansion project; a comprehensive application for the project is expected to follow completion of the pre-filing review.

Paiute Pipeline Company will file a general rate case with the FERC by the end of February 2014. The filing will fulfill an obligation from the settlement agreement reached in the 2009 Paiute general rate case. The application is expected to request an increase in operating revenues of approximately $9 million. In accordance with FERC requirements, new rates will go into effect in September 2014, subject to refund, if a settlement among the parties has not been approved by the FERC by that time. Paiute's most recent general rate case was filed in 2009.

PGA Filings

The rate schedules in all of Southwest's service territories contain provisions that permit adjustments to rates as the cost of purchased gas changes. These deferred energy provisions and purchased gas adjustment clauses are collectively referred to as "PGA" clauses. Differences between gas costs recovered from customers and amounts paid for gas by Southwest result in over- or under-collections. At December 31, 2013, under-collections in all three states resulted in an asset of $18.2 million on the Company's balance sheet. Filings to change rates in accordance with PGA clauses are subject to audit by state regulatory commission staffs.

PGA changes impact cash flows but have no direct impact on profit margin. However, gas cost deferrals and recoveries can impact comparisons between periods of individual income statement components. These include Gas operating revenues, Net cost of gas sold, Net interest deductions, and Other income (deductions).

Southwest had the following outstanding PGA balances receivable/(payable) at the end of its two most recent fiscal years (millions of dollars):

	2013	2012
Arizona	$ 3.2	$ (46.6)
Northern Nevada	4.4	(7.1)
Southern Nevada	4.1	(45.2)
California	6.5	6.0
	$18.2	$ (92.9)

Arizona PGA Filings. In Arizona, Southwest adjusts rates monthly for changes in purchased gas costs, within pre-established limits measured on a twelve-month rolling average. A temporary surcredit of $0.08 per therm was put into place in December 2009 to help accelerate the refund of the over-collected balance to customers. In order to accelerate the refunds to customers, Southwest filed to temporarily increase this rate to $0.10 per therm effective January 2013, which was approved by the ACC in December 2012. During 2013, approximately $49 million was refunded to customers via the surcredit. The temporary surcredits were eliminated in January 2014. A prudence review of gas costs is conducted in conjunction with general rate cases.

California Gas Cost Filings. In California, a monthly gas cost adjustment based on forecasted monthly prices is utilized. Monthly adjustments modeled in this fashion provide the timeliest recovery of gas costs in any Southwest jurisdiction and are designed to send appropriate pricing signals to customers.

Nevada Annual Rate Adjustment ("ARA") Application. In June 2013, Southwest filed its ARA application with the PUCN to establish revised Deferred Energy Account Adjustment ("DEAA") rates (in addition to adjustments to the Variable Interest Expense rate, the Uncollectible Gas Cost Expense rates, and other rate-related items), which was approved effective January 2014. As part of the most recent ARA and associated stipulation in Nevada, the Company, at least in the short term, agreed to suspend further fixed-for-floating swap contracts ("Swaps") and fixed-price purchases pursuant to the Volatility Mitigation Program ("VMP") for its Nevada service territories. The decision will not impact previously executed purchase arrangements. The Company along with its regulators will continue to evaluate this strategy in light of prevailing or anticipated changing market conditions. Southwest makes quarterly DEAA adjustments based upon a twelve-month rolling average. During 2013, approximately $51 million was refunded to customers via billing credits. See *Gas Price Volatility Mitigation* below for information on the Company's Swaps.

Gas Price Volatility Mitigation

Regulators in Southwest's service territories have encouraged Southwest to take proactive steps to mitigate price volatility to its customers. To accomplish this, Southwest periodically enters into fixed-price term contracts and Swaps under its collective volatility mitigation programs for a portion (for the 2013/2014 heating season, ranging from 25% to 35%, depending on the jurisdiction) of its annual normal weather supply needs. For the 2013/2014 heating season, contracts contained in the fixed-price portion of the portfolio included pricing of approximately $4 per dekatherm. Natural gas purchases not covered by fixed-price contracts are made under variable-price contracts with firm quantities, and on the spot market. Prices for these contracts are not known until the month of purchase. As noted above, the VMP in Nevada has been suspended and is subject to future evaluation given changing market conditions.

Capital Resources and Liquidity

Over the past three years, cash on hand and cash flows from operations have generally provided the majority of cash used in investing activities (primarily construction expenditures and property additions). Certain pipe replacement work was accelerated during 2011, 2012, and 2013 to take advantage of bonus depreciation tax incentives and to fortify system integrity and reliability. Tax incentives have not been extended for years after 2013. During the same three-year period, the Company was able to achieve cost savings from debt refinancing and strategic debt redemptions. The Company's capitalization strategy is to maintain an appropriate balance of equity and debt to maintain strong investment-grade credit ratings which should minimize interest costs.

Cash Flows

Operating Cash Flows. Cash flows provided by consolidated operating activities decreased $40.1 million in 2013 as compared to 2012. The decline in operating cash flows was attributable to temporary decreases in cash flows from working capital components overall (notably, refunds of PGA balances), partially offset by higher net income and non-cash depreciation expense.

Investing Cash Flows. Cash used in consolidated investing activities decreased $26 million in 2013 as compared to 2012. The decrease was primarily due to reduced equipment purchases by NPL.

Financing Cash Flows. Net cash provided by consolidated financing activities increased $26.1 million in 2013 as compared to 2012. The increase was primarily due to the 2012 $21.8 million settlement (at maturity) of the second FSIRS contract. In addition, cash provided by debt financing (net of retirements and credit facility changes) increased in 2013 as compared to 2012. The current year includes issuance of $250 million of 4.875% senior notes, partially offset by the repayment of $30 million of 5.45% IDRBs, $15 million of 5.8% of IDRBs, $8.27 million of 5.55% IDRBs, and the repayment of outstanding borrowings on the credit facility. The prior-year period included debt repayments of the $12.4 million 1999 6.1% Series A fixed-rate IDRBs (repaid in January 2012), the $200 million 7.625% senior notes (repaid in May 2012), the $14.3 million 1999 5.95% Series C fixed-rate IDRBs (repaid in August 2012). Those repayments were partially offset by the issuance of new debt in the prior-year period, including the $250 million of 3.875% senior notes and borrowings under the long-term portion of the credit facility. The remaining issuance amounts and retirements of long-term debt in both years primarily relate to borrowings and repayments under NPL's line of credit, and in 2013, borrowing under note agreements with two banking institutions (entered into during the second quarter of 2013). Dividends paid increased in 2013 as compared to 2012 as a result of an increase in the quarterly dividend rate and an increase in the number of shares outstanding.

The capital requirements and resources of the Company generally are determined independently for the natural gas operations and construction services segments. Each business activity is generally responsible for securing its own financing sources.

2013 Construction Expenditures
During the three-year period ended December 31, 2013, total gas plant increased from $4.6 billion to $5.3 billion, or at an average annual rate of 5%. Replacement, reinforcement, and franchise work was a substantial portion of the plant increase. To a lesser extent, customer growth impacted expenditures as the Company set approximately 51,000 meters during the three-year period.

During 2013, construction expenditures for the natural gas operations segment were $315 million. The majority of these expenditures represented costs associated with scheduled and accelerated replacement of existing transmission, distribution, and general plant to fortify system integrity and reliability and to take advantage of certain tax incentives (see also *Bonus Depreciation* below). Cash flows from operating activities of Southwest were $265 million and provided approximately 70% of construction expenditures and dividend requirements of the natural gas operations segment. Other necessary funding was provided by cash on hand, external financing activities, and, as needed, existing credit facilities.

2013 Financing Activity
In March 2013, the Company redeemed at par its $30 million 2003 5.45% Series C IDRBs and $15 million 2003 5.8% Series E IDRBs. In September 2013, the Company redeemed at par the $8.27 million 5.55% 1999 Series D IDRBs originally due in 2038. In October 2013, the Company issued $250 million of 4.875% senior notes at a 0.078% discount. The notes will mature in October 2043. A portion of the net proceeds were used to temporarily pay down amounts outstanding under the credit facility. The remaining net proceeds were used for general corporate purposes.

During 2013, the Company issued shares of common stock through its various stock plans, including the Stock Incentive Plan, raising approximately $1.6 million.

Bonus Depreciation. In January 2013, the American Taxpayer Relief Act of 2012 ("Taxpayer Relief Act") was enacted extending the 50% bonus tax depreciation deduction provided for by earlier legislation for qualified property acquired or constructed and placed in-service during 2013. This tax deduction was not extended for years after 2013. Based on forecasted qualifying construction expenditures, Southwest estimates the bonus depreciation provision of the Taxpayer Relief Act deferred the payment of approximately $26 million of federal income taxes for 2013.

Three-Year Construction Expenditures, Debt Maturities, and Financing
Southwest estimates natural gas segment construction expenditures during the three-year period ending December 31, 2016 will be approximately $1.1 billion. Of this amount, approximately $375 million are expected to be incurred in 2014. Southwest plans to accelerate projects that improve system flexibility and reliability (including replacement of early vintage plastic and steel pipe). Significant replacement activities are expected to continue during the next several years. See also **Rates**

and Regulatory Proceedings for discussion of Nevada infrastructure, California IRRAM, Arizona COYL, a planned LNG facility, and planned Paiute expansion. During the three-year period, cash flows from operating activities of Southwest are expected to provide approximately 85% of the funding for the gas operations total construction expenditures and dividend requirements. Any additional cash requirements are expected to be provided by existing credit facilities and/or other external financing sources. The timing, types, and amounts of any additional external financings will be dependent on a number of factors, including the cost of gas purchases, conditions in the capital markets, timing and amounts of rate relief, growth levels in Southwest's service areas, and earnings. External financings could include the issuance of both debt and equity securities, bank and other short-term borrowings, and other forms of financing.

Liquidity

Liquidity refers to the ability of an enterprise to generate sufficient amounts of cash through its operating activities and external financings to meet its cash requirements. Several general factors (some of which are out of the control of the Company) that could significantly affect liquidity in future years include: variability of natural gas prices, changes in the ratemaking policies of regulatory commissions, regulatory lag, customer growth in the natural gas segment's service territories, Southwest's ability to access and obtain capital from external sources, interest rates, changes in income tax laws, pension funding requirements, inflation, and the level of Company earnings. Natural gas prices and related gas cost recovery rates have historically had the most significant impact on Company liquidity.

On an interim basis, Southwest defers over- or under-collections of gas costs to PGA balancing accounts. In addition, Southwest uses this mechanism to either refund amounts over-collected or recoup amounts under-collected as compared to the price paid for natural gas during the period since the last PGA rate change went into effect. During 2013, refunds were made to customers and the net over-collected PGA balance declined $111 million resulting in an under-collection of $18.2 million at December 31, 2013. See **PGA Filings** for more information.

The Company has a $300 million revolving credit facility that expires in March 2017. Southwest has designated $150 million of the $300 million facility for long-term borrowing needs and the remaining $150 million for working capital purposes. The maximum amount outstanding during 2013 was $195 million ($150 million outstanding on the long-term portion of the credit facility (including $50 million on the commercial paper program), and $45 million outstanding on the short-term portion) in the fourth quarter. At December 31, 2013, $10 million was outstanding on the long-term portion of the credit facility (all of which was under the commercial paper program), and no borrowings were outstanding on the short-term portion. The maximum amount outstanding on the credit facility (including the commercial paper program) during the first, second, and third quarters was $152 million, $125 million, and $183 million, respectively. The credit facility can be used as necessary to meet liquidity requirements, including temporarily financing under-collected PGA balances, if any, meeting the refund needs of over-collected balances, or temporarily funding capital expenditures. This credit facility has been, and is expected to continue to be, adequate for Southwest's working capital needs outside of funds raised through operations and other types of external financing.

The Company has a $50 million commercial paper program. Any issuance under the commercial paper program is supported by the Company's current revolving credit facility and, therefore, does not represent additional borrowing capacity. Any borrowing under the commercial paper program will be designated as long-term debt. Interest rates for the commercial paper program are calculated at the then current commercial paper rate. At December 31, 2013, $10 million were outstanding on the commercial paper program. The maximum amount outstanding during the year was $50 million.

NPL has a $75 million credit facility that is scheduled to expire in June 2015. At December 31, 2013, no borrowings were outstanding on the NPL credit facility.

Credit Ratings

The Company's borrowing costs and ability to raise funds are directly impacted by its credit ratings. Securities ratings issued by nationally recognized ratings agencies provide a method for determining the credit worthiness of an issuer. Company debt ratings are important because long-term debt constitutes a significant portion of total capitalization. These debt ratings are a factor considered by lenders when determining the cost of debt for the Company (i.e., generally the better the rating, the lower the cost to borrow funds).

In March 2013, Standard & Poor's Ratings Services ("S&P") upgraded the Company's unsecured long-term debt ratings from BBB+ (with a stable outlook) to A- (with a stable outlook). S&P cited the Company's sustained improvements in cash flow and leverage measures and improved regulatory relationships in all three service territories. S&P debt ratings range from AAA (highest rating possible) to D (obligation is in default). The S&P rating of A- indicates the issuer of the debt is regarded as having a strong capacity to meet financial commitments.

In May 2013, Fitch Ratings ("Fitch") upgraded the Company's senior unsecured ratings including IDRBs from A- (with a positive outlook) to A (with a stable outlook). Fitch cited the Company's stronger credit metrics and improved business risk profile. Fitch debt ratings range from AAA (highest credit quality) to D (defaulted debt obligation). The Fitch rating of A indicates low default risk and a strong ability to pay financial commitments.

In January 2014, Moody's Investors Service, Inc. ("Moody's") upgraded the Company's senior unsecured ratings from Baa1 with a stable outlook to A3 with a stable outlook. Moody's cited the Company's improved regulatory environment in its service territories. Moody's debt ratings range from Aaa (highest rating possible) to C (lowest quality, usually in default). Moody's applies an A rating to obligations which are considered upper-medium grade obligations with low credit risk. A numerical modifier of 1 (high end of the category) through 3 (low end of the category) is included with the A to indicate the approximate rank of a company within the range.

A securities rating is not a recommendation to buy, sell, or hold a security and is subject to change or withdrawal at any time by the rating agency. The foregoing securities ratings are subject to change at any time in the discretion of the applicable ratings agencies. Numerous factors, including many that are not within the Company's control, are considered by the ratings agencies in connection with assigning securities ratings.

No debt instruments have credit triggers or other clauses that result in default if Company bond ratings are lowered by rating agencies. Certain Company debt instruments contain securities ratings covenants that, if set in motion, would increase financing costs if debt ratings deteriorated. Certain debt instruments also have leverage ratio caps and minimum net worth requirements. At December 31, 2013, the Company is in compliance with all of its covenants. Under the most restrictive of the covenants, the Company could issue over $1.9 billion in additional debt and meet the leverage ratio requirement. The Company has at least $800 million of cushion in equity relating to the minimum net worth requirement.

Inflation

Inflation can impact the Company's results of operations. Natural gas, labor, employee benefits, consulting, and construction costs are the categories most significantly impacted by inflation. Changes to the cost of gas are generally recovered through PGA mechanisms and do not significantly impact net earnings. Labor and employee benefits are components of the cost of service, and construction costs are the primary component of rate base. In order to recover increased costs, and earn a fair return on rate base, general rate cases are filed by Southwest, when deemed necessary, for review and approval by regulatory authorities. Regulatory lag, that is, the time between the date increased costs are incurred and the time such increases are recovered through the ratemaking process, can impact earnings. See **Rates and Regulatory Proceedings** for a discussion of recent rate case proceedings.

Off-Balance Sheet Arrangements
All Company debt is recorded on its balance sheets. The Company has long-term operating leases, which are described in **Note 2 – Utility Plant** of the Notes to Consolidated Financial Statements, and included in the Contractual Obligations Table below.

Contractual Obligations
The Company has various contractual obligations such as long-term purchase contracts, significant non-cancelable operating leases, gas purchase obligations, and long-term debt agreements. The Company has classified these contractual obligations as either operating activities or financing activities, which mirrors their presentation in the Consolidated Statement of Cash Flows. No contractual obligations for investing activities exist at this time. The table below summarizes the Company's contractual obligations at December 31, 2013 (millions of dollars):

	Payments due by period				
Contractual Obligations	Total	2014	2015-2016	2017-2018	Thereafter
Operating activities:					
Operating leases (Note 2)	$ 21	$ 7	$ 10	$ 3	$ 1
Gas purchase obligations	163	122	41	—	—
Pipeline capacity/storage	776	99	156	103	418
Other commitments	20	9	10	1	—
Financing activities:					
Long-term debt, including current maturities (Note 6)	1,392	11	21	45	1,315
Interest on long-term debt	1,134	63	125	120	826
Other	10	—	1	1	8
Total	$3,516	$311	$ 364	$ 273	$ 2,568

Obligations for Operating Activities: The table above provides a summary of the Company's obligations associated with operating activities. Operating leases represent multi-year obligations for office rent and certain equipment. Gas purchase obligations include fixed-price and variable-rate gas purchase contracts covering approximately 139 million dekatherms. The fixed-price contracts have an approximate price of $4 per dekatherm. Variable-price contracts reflect minimum contractual obligations.

Southwest has pipeline capacity/storage contracts for firm transportation service, both on a short- and long-term basis, with several companies for all of its service territories, some with terms extending to 2044. Southwest also has interruptible contracts in place that allow additional capacity to be acquired should an unforeseen need arise. Costs associated with these pipeline capacity contracts are a component of the cost of gas sold and are recovered from customers primarily through the PGA mechanism. Included in the pipeline capacity payments shown in the above table, are payments associated with storage that Southwest has contracted for in southern California and Arizona. The terms of these contracts extend through 2024 and 2019, respectively.

Obligations for Financing Activities: Contractual obligations for financing activities are debt obligations consisting of scheduled principal and interest payments over the life of the debt. Interest rates in effect at December 31, 2013 on variable rate long-term debt were assumed to remain in effect in the future periods disclosed in the table.

Other: Estimated funding for pension and other postretirement benefits during calendar year 2014 is $36 million.

Application of Critical Accounting Policies

A critical accounting policy is one which is very important to the portrayal of the financial condition and results of a company, and requires the most difficult, subjective, or complex judgments of management. The need to make estimates about the effect of items that are uncertain is what makes these judgments difficult, subjective, and/or complex. Management makes subjective judgments about the accounting and regulatory treatment of many items and bases its estimates on historical experience and on various other assumptions that it believes to be reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained, and as the Company's operating environment changes. The following are accounting policies that are deemed critical to the financial statements of the Company. For more information regarding the significant accounting policies of the Company, see **Note 1 – Summary of Significant Accounting Policies**.

Regulatory Accounting

Natural gas operations are subject to the regulation of the Arizona Corporation Commission, the Public Utilities Commission of Nevada, the California Public Utilities Commission, and the Federal Energy Regulatory Commission. The accounting policies of the Company conform to generally accepted accounting principles applicable to rate-regulated entities and reflect the effects of the ratemaking process. As such, the Company is allowed to defer as regulatory assets, costs that otherwise would be expensed, if it is probable that future recovery from customers will occur. The Company reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. If rate recovery is no longer probable, due to competition or the actions of regulators, the Company is required to write-off the related regulatory asset (which would be recognized as current-period expense). Regulatory liabilities are recorded if it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. The timing and inclusion of costs in rates is often delayed (regulatory lag) and results in a reduction of current-period earnings. Refer to **Note 4 – Regulatory Assets and Liabilities** for a list of regulatory assets and liabilities.

Accrued Utility Revenues

Revenues related to the sale and/or delivery of natural gas are generally recorded when natural gas is delivered to customers. However, the determination of natural gas sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, margin associated with natural gas service that has been provided but not yet billed is accrued. This accrued utility revenue is estimated each month based primarily on applicable rates, number of customers, rate structure, analyses reflecting significant historical trends, seasonality, and experience. The interplay of these assumptions can impact the variability of the accrued utility revenue estimates. All Company rate jurisdictions have decoupled rate structures, limiting variability due to extreme weather conditions.

Accounting for Income Taxes

The income tax calculations of the Company require estimates due to known future tax rate changes, book to tax differences, and uncertainty with respect to regulatory treatment of certain property items. The Company uses the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Regulatory tax assets and liabilities are recorded to the extent the Company believes they will be recoverable from or refunded to customers in future rates. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The Company regularly assesses financial statement tax provisions to identify any change in the regulatory treatment or tax-related estimates, assumptions, or enacted tax rates that could have a material impact on cash flows, the financial position, and/or results of operations of the Company.

Accounting for Pensions and Other Postretirement Benefits

Southwest has a noncontributory qualified retirement plan with defined benefits covering substantially all employees. In addition, Southwest has a separate unfunded supplemental retirement plan which is limited to officers. The Company's pension obligations and costs for these plans are affected by the amount and timing of cash contributions to the plans, the return on plan assets, discount rates, and by employee demographics, including age, compensation, and length of service. Changes made to the provisions of the plans may also impact current and future pension costs. Actuarial formulas are used in the determination of pension obligations and costs and are affected by actual plan experience and assumptions about future experience. Key actuarial assumptions include the expected return on plan assets, the discount rate used in determining the projected benefit obligation and pension costs, and the assumed rate of increase in employee compensation. Relatively small changes in these assumptions (particularly the discount rate) may significantly affect pension obligations and costs for these plans. For example, a change of 0.25% in the discount rate assumption would change the pension plan projected benefit obligation by approximately $30.6 million and future pension expense by $3.4 million. A change of 0.25% in the employee compensation assumption would change the pension obligation by approximately $7.4 million and expense by $1.6 million. A 0.25% change in the expected asset return assumption would change pension expense by approximately $1.7 million (but has no impact on the pension obligation).

At December 31, 2013, the Company raised the discount rate to 5.00% from a rate of 4.25% at December 31, 2012. The methodology utilized to determine the discount rate was consistent with prior years. The weighted-average rate of compensation escalation increased to 3.25% at December 31, 2013 from 2.75% in the prior year. The asset return assumption to be used for 2014 expense was reduced to 7.75% from 8.00%. The significant increase in the discount rate will decrease the expense level for 2014. Pension expense for 2014 is estimated to decrease by $9 million compared to 2013. Future years' expense level movements (up or down) will continue to be greatly influenced by long-term interest rates, asset returns, and funding levels.

Certifications

The Securities and Exchange Commission ("SEC") requires the Company to file certifications of its Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") regarding reporting accuracy, disclosure controls and procedures, and internal control over financial reporting as exhibits to the Company's periodic filings. The CEO and CFO certifications for the period ended December 31, 2013 are included as exhibits to the 2013 Annual Report on Form 10-K filed with the SEC.

Forward-Looking Statements

This annual report contains statements which constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995 ("Reform Act"). All statements other than statements of historical fact included or incorporated by reference in this annual report are forward-looking statements, including, without limitation, statements regarding the Company's plans, objectives, goals, intentions, projections, strategies, future events or performance, and underlying assumptions. The words "may," "if," "will," "should," "could," "expect," "plan," "anticipate," "believe," "estimate," "predict," "project," "continue," "forecast," "intend," "promote," "seek," and similar words and expressions are generally used and intended to identify forward-looking statements. For example, statements regarding operating margin patterns, customer growth, the composition of our customer base, price volatility, seasonal patterns, payment of debt, interest savings, the Company's COLI strategy, annual COLI returns, replacement market and new construction market, bonus depreciation tax deductions, amount and timing for completion of estimated future construction expenditures, including the planned LNG facility in southern Arizona and the proposed Paiute expansion in Elko County, Nevada, forecasted operating cash flows and results of operations, incremental operating margin in 2014, operating expense increases in 2014, funding sources of cash requirements, sufficiency of working capital and current credit facility, bank lending practices, the Company's views regarding its liquidity position, ability to raise funds and receive external financing capacity, future dividend increases, earnings trends, NPL's projected financial performance and related market growth potential, pension and post-retirement benefits, certain benefits of tax acts, the effect of any rate changes or regulatory proceedings, including the Rehearing Decision and the Stipulation from the PUCN, the California general rate case filing, the Paiute Pipeline Company general rate case filing, infrastructure replacement mechanisms and the COYL program, statements regarding future gas prices, gas purchase contracts and derivative financial instruments, recoverability of regulatory assets, the impact of certain legal proceedings, and the timing and results of future rate hearings and approvals are forward-looking statements. All forward-looking statements are intended to be subject to the safe harbor protection provided by the Reform Act.

A number of important factors affecting the business and financial results of the Company could cause actual results to differ materially from those stated in the forward-looking statements. These factors include, but are not limited to, customer growth rates, conditions in the housing market, the ability to recover costs through the PGA mechanisms or other regulatory assets, the effects of regulation/deregulation, the timing and amount of rate relief, changes in rate design, changes in gas procurement practices, changes in capital requirements and funding, the impact of conditions in the capital markets on financing costs, changes in construction expenditures and financing, changes in operations and maintenance expenses, effects of pension expense forecasts, accounting changes, future liability claims, changes in pipeline capacity for the transportation of gas and related costs, results of NPL bid work, impacts of structural and management changes at NPL, NPL construction expenses, differences between actual and originally expected outcomes of NPL bid or other fixed-price construction agreements, competition, and our ability to raise capital in external financings. In addition, the Company can provide no assurance that its discussions regarding certain trends relating to its financing and operating expenses will continue in future periods. For additional information on the risks associated with the Company's business, see Item 1A. Risk Factors and **Item 7A. Quantitative and Qualitative Disclosures About Market Risk** in the Company's Annual Report on Form 10-K for the year ended December 31, 2013.

All forward-looking statements in this annual report are made as of the date hereof, based on information available to the Company as of the date hereof, and the Company assumes no obligation to update or revise any of its forward-looking statements even if experience or future changes show that the indicated results or events will not be realized. **We caution you not to unduly rely on any forward-looking statement(s).**

Common Stock Price and Dividend Information

	2013		2012		Dividends Declared	
	High	Low	High	Low	2013	2012
First quarter	$48.11	$42.02	$43.64	$40.51	$ 0.330	$ 0.295
Second quarter	51.52	45.11	44.64	39.46	0.330	0.295
Third quarter	50.99	45.70	46.08	42.19	0.330	0.295
Fourth quarter	56.03	48.76	44.83	39.01	0.330	0.295
					$ 1.320	$ 1.180

The principal market on which the common stock of the Company is traded is the New York Stock Exchange. At February 18, 2014, there were 15,314 holders of record of common stock, and the market price of the common stock was $54.35.

In reviewing dividend policy, the Board of Directors ("Board") considers the adequacy and sustainability of earnings and cash flows of the Company and its subsidiaries; the strength of the Company's capital structure; the sustainability of the dividend through all business cycles; and whether the dividend is within a normal payout range for its respective businesses. The quarterly common stock dividend declared was 26.5 cents per share throughout 2011, 29.5 cents per share throughout 2012, and 33 cents per share throughout 2013. As a result of its ongoing review of dividend policy, in February 2014, the Board increased the quarterly dividend from 33 cents to 36.5 cents per share, effective with the June 2014 payment. This marks the eighth consecutive year in which the dividend was increased. Over time, the Board intends to increase the dividend such that the payout ratio approaches a local distribution company peer group average, while maintaining the Company's stable and strong credit ratings and the ability to effectively fund future rate base growth. The timing and amount of any future increases will be based upon the Board's continued review of the Company's dividend rate in the context of the performance of the Company's two operating segments and their future growth prospects.

SOUTHWEST GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Thousands of dollars, except par value)

December 31,	2013	2012
ASSETS		
Utility plant:		
Gas plant	$ 5,252,469	$ 5,019,500
Less: accumulated depreciation	(1,868,504)	(1,750,795)
Acquisition adjustments, net	730	911
Construction work in progress	101,413	74,178
Net utility plant (Note 2)	3,486,108	3,343,794
Other property and investments (Note 1)	260,871	242,096
Current assets:		
Cash and cash equivalents	41,077	25,530
Accounts receivable, net of allowances (Note 3)	219,469	196,913
Accrued utility revenue	72,700	72,000
Income taxes receivable, net	3,790	2,945
Deferred income taxes (Note 11)	31,130	47,088
Deferred purchased gas costs (Note 4)	18,217	6,031
Prepaids and other current assets (Notes 1, 4, and 12)	108,289	107,910
Total current assets	494,672	458,417
Deferred charges and other assets (Notes 4 and 12)	323,523	443,750
Total assets	$ 4,565,174	$ 4,488,057

CONSOLIDATED BALANCE SHEETS - Continued

December 31,	2013	2012
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, $1 par (authorized - 60,000,000 shares; issued and outstanding - 46,356,125 and 46,147,788 shares) (Note 10)	$ 47,986	$ 47,778
Additional paid-in capital	840,521	828,777
Accumulated other comprehensive income (loss), net (Note 5)	(41,698)	(50,745)
Retained earnings	567,714	484,369
Total Southwest Gas Corporation equity	1,414,523	1,310,179
Noncontrolling interest	(2,128)	(1,681)
Total equity	1,412,395	1,308,498
Long-term debt, less current maturities (Note 6)	1,381,327	1,268,373
Total capitalization	2,793,722	2,576,871
Commitments and contingencies (Note 8)		
Current liabilities:		
Current maturities of long-term debt (Note 6)	11,105	50,137
Accounts payable	183,511	155,667
Customer deposits	73,367	77,858
Accrued general taxes	39,681	37,644
Accrued interest	17,920	16,080
Deferred purchased gas costs (Note 4)	—	98,957
Other current liabilities (Notes 4 and 12)	108,580	98,786
Total current liabilities	434,164	535,129
Deferred income taxes and other credits:		
Deferred income taxes and investment tax credits (Note 11)	674,411	616,184
Taxes payable	284	551
Accumulated removal costs (Note 4)	279,000	256,000
Other deferred credits (Notes 4, 9, and 12)	383,593	503,322
Total deferred income taxes and other credits	1,337,288	1,376,057
Total capitalization and liabilities	$4,565,174	$4,488,057

The accompanying notes are an integral part of these statements.

SOUTHWEST GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per share amounts)

Year Ended December 31,	2013	2012	2011
Operating revenues:			
Gas operating revenues	$1,300,154	$1,321,728	$1,403,366
Construction revenues	650,628	606,050	483,822
Total operating revenues	1,950,782	1,927,778	1,887,188
Operating expenses:			
Net cost of gas sold	436,001	479,602	613,489
Operations and maintenance	384,914	369,979	358,498
Depreciation and amortization	236,817	223,422	200,469
Taxes other than income taxes	45,551	41,728	40,949
Construction expenses	573,284	541,523	423,703
Total operating expenses	1,676,567	1,656,254	1,637,108
Operating income	274,215	271,524	250,080
Other income and (expenses):			
Net interest deductions (Notes 6 and 7)	(63,700)	(68,020)	(69,602)
Other income (deductions)	12,300	4,411	(5,412)
Total other income and (expenses)	(51,400)	(63,609)	(75,014)
Income before income taxes	222,815	207,915	175,066
Income tax expense (Note 11)	77,942	75,276	63,303
Net income	144,873	132,639	111,763
Net income (loss) attributable to noncontrolling interest	(447)	(692)	(524)
Net income attributable to Southwest Gas Corporation	$ 145,320	$ 133,331	$ 112,287
Basic earnings per share (Note 14)	$ 3.14	$ 2.89	$ 2.45
Diluted earnings per share (Note 14)	$ 3.11	$ 2.86	$ 2.43
Average number of common shares outstanding	46,318	46,115	45,858
Average shares outstanding (assuming dilution)	46,758	46,555	46,291

The accompanying notes are an integral part of these statements.

SOUTHWEST GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Thousands of dollars)

Year Ended December 31,	2013	2012	2011
Net Income	$144,873	$132,639	$111,763
Other comprehensive income (loss), net of tax			
Defined benefit pension plans (Notes 5 and 9):			
Net actuarial gain (loss)	62,214	(46,409)	(84,005)
Amortization of prior service cost	220	—	—
Amortization of transition obligation	—	538	537
Amortization of net actuarial loss	21,190	15,870	9,653
Prior service cost	—	(1,502)	—
Regulatory adjustment	(76,651)	26,518	65,677
Net defined benefit pension plans	6,973	(4,985)	(8,138)
Forward-starting interest rate swaps:			
Unrealized/realized gain (loss) (Notes 5 and 12)	—	1,834	(11,134)
Amounts reclassified into net income (Notes 5 and 12)	2,074	1,737	725
Net forward-starting interest rate swaps	2,074	3,571	(10,409)
Total other comprehensive income (loss), net of tax	9,047	(1,414)	(18,547)
Comprehensive income	153,920	131,225	93,216
Comprehensive income (loss) attributable to noncontrolling interest	(447)	(692)	(524)
Comprehensive income attributable to Southwest Gas Corporation	$154,367	$131,917	$ 93,740

The accompanying notes are an integral part of these statements.

SOUTHWEST GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Thousands of dollars)

Year Ended December 31,	2013	2012	2011
CASH FLOW FROM OPERATING ACTIVITIES:			
Net Income	$ 144,873	$ 132,639	$ 111,763
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	236,817	223,422	200,469
Deferred income taxes	68,639	66,280	56,467
Changes in current assets and liabilities:			
Accounts receivable, net of allowances	(22,556)	12,333	(61,641)
Accrued utility revenue	(700)	(1,700)	(5,900)
Deferred purchased gas costs	(111,143)	22,823	(52,885)
Accounts payable	27,668	(25,998)	15,826
Accrued taxes	925	113	14,979
Other current assets and liabilities	5,084	(18,948)	(3,347)
Gains on sale	(4,112)	(8,040)	(3,307)
Changes in undistributed stock compensation	6,958	5,137	6,125
AFUDC and property-related changes	(2,274)	(1,943)	(1,154)
Changes in other assets and deferred charges	(21,719)	(15,367)	11,025
Changes in other liabilities and deferred credits	17,749	(4,427)	(36,378)
Net cash provided by operating activities	346,209	386,324	252,042

CONSOLIDATED STATEMENTS OF CASH FLOWS - Continued

Year Ended December 31,	2013	2012	2011
CASH FLOW FROM INVESTING ACTIVITIES:			
Construction expenditures and property additions	(364,276)	(395,712)	(380,991)
Restricted cash	—	12,785	24,996
Changes in customer advances	7,773	(3,025)	(7,771)
Miscellaneous inflows	8,465	13,963	7,686
Miscellaneous outflows	—	(2,004)	(2,719)
Net cash used in investing activities	(348,038)	(373,993)	(358,799)
CASH FLOW FROM FINANCING ACTIVITIES:			
Issuance of common stock, net	1,635	1,581	7,402
Dividends paid	(59,535)	(53,040)	(47,929)
Interest rate swap settlement	—	(21,754)	—
Issuance of long-term debt, net	311,290	489,518	274,598
Retirement of long-term debt	(137,013)	(427,043)	(330,473)
Change in credit facility and commercial paper	(101,000)	2,000	109,000
Other	1,999	—	—
Net cash provided by (used in) financing activities	17,376	(8,738)	12,598
Change in cash and cash equivalents	15,547	3,593	(94,159)
Cash and cash equivalents at beginning of period	25,530	21,937	116,096
Cash and cash equivalents at end of period	$ 41,077	$ 25,530	$ 21,937
Supplemental information:			
Interest paid, net of amounts capitalized	$ 58,730	$ 87,439	$ 69,842
Income taxes paid (received)	$ 6,850	$ 2,843	$ (13,635)

The accompanying notes are an integral part of these statements.

SOUTHWEST GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(In thousands, except per share amounts)

	Southwest Gas Corporation Equity						
	Common Stock		Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest	Total
	Shares	Amount					
DECEMBER 31, 2010	45,599	$47,229	$ 807,885	$ (30,784)	$343,131	$ (465)	$1,166,996
Common stock issuances	357	357	13,755				14,112
Net income (loss)					112,287	(524)	111,763
Net actuarial gain (loss) arising during the period, less amortization of unamortized benefit plan cost, net of tax (Notes 5 and 9)				(8,138)			(8,138)
FSIRS realized and unrealized loss, net of tax (Notes 5 and 12)				(11,134)			(11,134)
Amounts reclassified to net income, net of tax (Notes 5 and 12)				725			725
Dividends declared Common: $1.06 per share					(49,293)		(49,293)
DECEMBER 31, 2011	45,956	47,586	821,640	(49,331)	406,125	(989)	1,225,031
Common stock issuances	192	192	7,137				7,329
Net income (loss)					133,331	(692)	132,639
Net actuarial gain (loss) arising during the period, less amortization of unamortized benefit plan cost, net of tax (Notes 5 and 9)				(4,985)			(4,985)
FSIRS realized and unrealized gain, net of tax (Notes 5 and 12)				1,834			1,834
Amounts reclassified to net income, net of tax (Notes 5 and 12)				1,737			1,737
Dividends declared Common: $1.18 per share					(55,087)		(55,087)

CONSOLIDATED STATEMENTS OF EQUITY - Continued

	Southwest Gas Corporation Equity						
	Common Stock		Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest	Total
	Shares	Amount					
DECEMBER 31, 2012	46,148	47,778	828,777	(50,745)	484,369	(1,681)	1,308,498
Common stock issuances	208	208	11,744				11,952
Net income (loss)					145,320	(447)	144,873
Net actuarial gain (loss) arising during the period, less amortization of unamortized benefit plan cost, net of tax (Notes 5 and 9)				6,973			6,973
Amounts reclassified to net income, net of tax (Notes 5 and 12)				2,074			2,074
Dividends declared Common: $1.32 per share					(61,975)		(61,975)
DECEMBER 31, 2013	46,356*	$47,986	$ 840,521	$ (41,698)	$567,714	$ (2,128)	$1,412,395

* At December 31, 2013, 2.1 million common shares were registered and available for issuance under provisions of the Company's various stock issuance plans. In addition, approximately 52,000 common shares are registered for issuance upon the exercise of options granted under the Stock Incentive Plan (see Note 10).

The accompanying notes are an integral part of these statements.

Note 1 – Summary of Significant Accounting Policies

Nature of Operations. Southwest Gas Corporation and its subsidiaries (the "Company") consist of two segments: natural gas operations ("Southwest" or the "natural gas operations" segment) and construction services. Southwest is engaged in the business of purchasing, distributing, and transporting natural gas for customers in portions of Arizona, Nevada, and California. Public utility rates, practices, facilities, and service territories of Southwest are subject to regulatory oversight. The timing and amount of rate relief can materially impact results of operations. Natural gas purchases and the timing of related recoveries can materially impact liquidity. NPL Construction Co. ("NPL" or the "construction services" segment), a wholly owned subsidiary, is a full-service underground piping contractor that primarily provides utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems. NPL also holds a 65% interest in a venture to market natural gas engine-driven heating, ventilating, and air conditioning ("HVAC") technology and products. NPL consolidates the entity (IntelliChoice Energy, LLC) as a majority-owned subsidiary.

Basis of Presentation. The Company follows generally accepted accounting principles in the United States ("U.S. GAAP") in accounting for all of its businesses. Accounting for the natural gas utility operations conforms with U.S. GAAP as applied to regulated companies and as prescribed by federal agencies and commissions of the various states in which the utility operates. The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Consolidation. The accompanying financial statements are presented on a consolidated basis and include the accounts of Southwest Gas Corporation and all subsidiaries. All significant intercompany balances and transactions have been eliminated with the exception of transactions between Southwest and NPL in accordance with accounting treatment for rate-regulated entities.

Net Utility Plant. Net utility plant includes gas plant at original cost, less the accumulated provision for depreciation and amortization, plus the unamortized balance of acquisition adjustments. Original cost includes contracted services, material, payroll and related costs such as taxes and benefits, general and administrative expenses, and an allowance for funds used during construction, less contributions in aid of construction.

Other Property and Investments. Other property and investments includes (millions of dollars):

	2013	2012
NPL property and equipment	$ 320	$ 287
NPL accumulated provision for depreciation and amortization	(163)	(136)
Net cash surrender value of COLI policies	93	80
Other property	11	11
Total	$ 261	$ 242

Deferred Purchased Gas Costs. The various regulatory commissions have established procedures to enable Southwest to adjust its billing rates for changes in the cost of natural gas purchased. The difference between the current cost of gas purchased and the cost of gas recovered in billed rates is deferred. Generally, these deferred amounts are recovered or refunded within one year.

Prepaids and other current assets. Prepaids and other current assets includes gas pipe inventory and operating supplies of $21 million in 2013 and $25 million in 2012.

Income Taxes. The Company uses the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period that includes the enactment date. For regulatory and financial reporting purposes, investment tax credits ("ITC") related to gas utility operations are deferred and amortized over the life of related fixed assets.

Cash and Cash Equivalents. For purposes of reporting consolidated cash flows, cash and cash equivalents include cash on hand and financial instruments with a purchase-date maturity of three months or less. Cash and cash equivalents fall within Level 1 (quoted prices for identical financial instruments) of the three-level fair value hierarchy that ranks the inputs used to measure fair value by their reliability. During 2012 and 2013, approximately $20 million and $9.3 million, respectively, of customer advances, upon contract expiration, were applied as contributions toward utility construction activity and represent a non-cash investing activity.

Accumulated Removal Costs. Approved regulatory practices allow Southwest to include in depreciation expense a component to recover removal costs associated with utility plant retirements. In accordance with the Securities and Exchange Commission's ("SEC") position on presentation of these amounts, management has reclassified estimated removal costs from accumulated depreciation to accumulated removal costs within the liabilities section of the balance sheets. The reclassified amounts are presented in the table below (thousands of dollars):

	December 31, 2013	December 31, 2012
Accumulated removal costs	$ 279,000	$ 256,000

Gas Operating Revenues. Revenues are recorded when customers are billed. Customer billings are based on monthly meter reads and are calculated in accordance with applicable tariffs and state and local laws, regulations, and agreements. An estimate of the margin associated with natural gas service provided, but not yet billed, to residential and commercial customers from the latest meter reading date to the end of the reporting period is also recognized as accrued utility revenue. Revenues also include the net impacts of margin tracker/decoupling accruals.

The Company acts as an agent for state and local taxing authorities in the collection and remission of a variety of taxes, including sales and use taxes and surcharges. These taxes are not included in gas operating revenues. The Company uses the net classification method to report taxes collected from customers to be remitted to governmental authorities.

Construction Revenues. The majority of NPL contracts are performed under unit-price contracts. Generally, these contracts state prices per unit of installation. Typical installations are accomplished in two weeks or less. Revenues are recorded as installations are completed. Long-term fixed-price contracts use the percentage-of-completion method of accounting and, therefore, take into account the cost, estimated earnings, and revenue to date on contracts not yet completed. The amount of revenue recognized on fixed-price contracts is based on costs expended to date relative to anticipated final contract costs. Revisions in estimates of costs and earnings during the course of work are reflected in the accounting period in which the facts requiring revision become known. If a loss on a contract becomes known or is anticipated, the entire amount of the estimated ultimate loss is recognized at that time in the financial statements. Some unit-price contracts contain caps, that if encroached, trigger revenue and loss recognition similar to a fixed-price contract model.

In 2011, NPL recorded $5 million in estimated pretax profit associated with a large fixed-price contract. In connection with significant changes in estimated costs to complete the fixed-price contract, NPL results for 2012 reflected a pretax loss of $15 million ($0.20 per share, after tax). The estimated cost changes that resulted in the loss recognized included reductions in projected productivity and higher costs of restoration work. During 2013, profitability on this contract was minimal and as of December 31, 2013, this fixed-price contract is substantially complete.

Construction Expenses. The construction expenses classification in the income statement includes payroll expenses, job-related equipment costs, direct construction costs, gains and losses on equipment sales, general and administrative expenses, and office-related fixed costs of NPL.

Net Cost of Gas Sold. Components of net cost of gas sold include natural gas commodity costs (fixed-price and variable-rate), pipeline capacity/transportation costs, and actual settled costs of natural gas derivative instruments. Also included are the net impacts of PGA deferrals and recoveries.

Operations and Maintenance Expense. For financial reporting purposes, operations and maintenance expense includes Southwest's operating and maintenance costs associated with serving utility customers, uncollectible expense, administrative and general salaries and expense, employee benefits expense, and legal expense (including injuries and damages).

Depreciation and Amortization. Utility plant depreciation is computed on the straight-line remaining life method at composite rates considered sufficient to amortize costs over estimated service lives, including components which compensate for removal costs (net of salvage value), and retirements, as approved by the appropriate regulatory agency. When plant is retired from service, the original cost of plant, including cost of removal, less salvage, is charged to the accumulated provision for depreciation. Other regulatory assets, including acquisition adjustments, are amortized when appropriate, over time periods authorized by regulators. Nonutility and construction services-related property and equipment are depreciated on a straight-line method based on the estimated useful lives of the related assets. Costs and gains related to refunding utility debt and debt issuance expenses are deferred and amortized over the weighted-average lives of the new issues and become a component of interest expense.

Allowance for Funds Used During Construction ("AFUDC"). AFUDC represents the cost of both debt and equity funds used to finance utility construction. AFUDC is capitalized as part of the cost of utility plant. The debt portion of AFUDC is reported in the consolidated statements of income as an offset to net interest deductions and the equity portion is reported as other income. Utility plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into operation, and general rate relief is requested and granted.

(In thousands)	2013	2012	2011
AFUDC:			
Debt portion	$1,260	$1,129	$ 718
Equity portion	2,274	1,943	1,154
AFUDC capitalized as part of utility plant	$3,534	$3,072	$1,872

Other Income (Deductions). The following table provides the composition of significant items included in Other income (deductions) on the consolidated statements of income (thousands of dollars):

	2013	2012	2011
Change in COLI policies	$12,400	$ 6,600	$ 700
Interest income	461	924	485
Pipe replacement costs	(132)	(2,680)	(4,761)
Miscellaneous income and (expense)	(429)	(433)	(1,836)
Total other income (deductions)	$12,300	$ 4,411	$(5,412)

Included in the table above is the change in cash surrender values of company-owned life insurance ("COLI") policies (including net death benefits recognized). Changes in cash surrender values are directly influenced by the investment portfolio underlying the insurance policies. These life insurance policies on members of management and other key employees are used by Southwest to indemnify itself against the loss of talent, expertise, and knowledge, as well as to provide indirect funding for certain nonqualified benefit plans. Current tax regulations provide for tax-free treatment of life insurance (death benefit) proceeds. Therefore, changes in the cash surrender value components of COLI policies, as they progress towards the ultimate death benefits, are also recorded without tax consequences. Pipe replacement costs include amounts associated with certain Arizona non-recoverable pipe replacement work. The replacement program work subject to non-recoverability was substantially completed in 2012.

Earnings Per Share. Basic earnings per share ("EPS") are calculated by dividing net income by the weighted-average number of shares outstanding during the period. Diluted EPS includes the effect of additional weighted-average common stock equivalents (stock options, performance shares, and restricted stock units). Unless otherwise noted, the term "Earnings Per Share" refers to Basic EPS. A reconciliation of the shares used in the Basic and Diluted EPS calculations is shown in the following table. Net income was the same for Basic and Diluted EPS calculations.

	2013	2012	2011
(In thousands)			
Average basic shares	46,318	46,115	45,858
Effect of dilutive securities:			
Stock options	26	42	52
Performance shares	231	254	271
Restricted stock units	183	144	110
Average diluted shares	46,758	46,555	46,291

Subsequent Events. Management of the Company monitors events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued or disclosures to be made, and has reflected them where appropriate.

Note 2 – Utility Plant

Net utility plant as of December 31, 2013 and 2012 was as follows (thousands of dollars):

December 31,	2013	2012
Gas plant:		
Storage	$ 21,282	$ 20,503
Transmission	313,306	301,505
Distribution	4,410,598	4,224,560
General	324,490	310,936
Other	182,793	161,996
	5,252,469	5,019,500
Less: accumulated depreciation	(1,868,504)	(1,750,795)
Acquisition adjustments, net	730	911
Construction work in progress	101,413	74,178
Net utility plant	$ 3,486,108	$ 3,343,794

Depreciation and amortization expense on gas plant was as follows (thousands of dollars):

	2013	2012	2011
Depreciation and amortization expense	$185,283	$182,612	$172,712

Operating Leases and Rentals. Southwest leases a portion of its corporate headquarters office complex in Las Vegas. A lease on the administrative offices in Phoenix recently expired. A new facility was acquired to replace the previously leased facility. The Company owns the new facility which is included in net utility plant above. The table below presents the rental payments and the current term expiration dates. The corporate headquarters lease has optional renewal terms available and the Company will consider alternatives at that time.

(In thousands)	2014	2015	2016	2017	2018
Corporate headquarters (expires in 2017)	$2,190	$2,270	$2,343	$1,194	$ —
Phoenix administrative offices (expired in 2014)	243	—	—	—	—

In addition to the above, the Company leases certain office and construction equipment. The majority of these leases are short-term. These leases are accounted for as operating leases and, for the gas segment, are also treated as such for regulatory purposes. NPL has various short-term operating leases of equipment and temporary office sites. The table below presents Southwest rental payments and NPL lease payments that are included in operating expenses (in thousands):

	2013	2012	2011
Southwest Gas	$ 8,308	$ 7,762	$ 7,812
NPL	27,118	24,054	19,017
Consolidated rental payments/lease expense	$35,426	$31,816	$26,829

The following is a schedule of future minimum lease payments for significant non-cancelable operating leases (with initial or remaining terms in excess of one year) as of December 31, 2013 (thousands of dollars):

Year Ending December 31,	
2014	$ 6,780
2015	5,231
2016	4,370
2017	2,716
2018	928
Thereafter	1,206
Total minimum lease payments	$21,231

Note 3 – Receivables and Related Allowances

Business activity with respect to gas utility operations is conducted with customers located within the three-state region of Arizona, Nevada, and California. The table below contains information about the gas utility customer accounts receivable balance (net of allowance) at December 31, 2013, and the percentage of customers in each of the three states.

Gas utility customer accounts receivable balance (in thousands)	$	121,082

	December 31, 2013
Percent of customers by state	
Arizona	54%
Nevada	36%
California	10%

Although the Company seeks to minimize its credit risk related to utility operations by requiring security deposits from new customers, imposing late fees, and actively pursuing collection on overdue accounts, some accounts are ultimately not collected. Customer accounts are subject to collection procedures that vary by jurisdiction (late fee assessment, noticing requirements for disconnection of service, and procedures for actual disconnection and/or reestablishment of service). After disconnection of service, accounts are generally written off approximately one month after inactivation. Dependent upon the jurisdiction, reestablishment of service requires both payment of previously unpaid balances and additional deposit requirements. Provisions for uncollectible accounts are recorded monthly based on experience, customer and rate composition, and write-off processes. They are included in the ratemaking process as a cost of service. The Nevada jurisdictions have a regulatory mechanism associated with the gas cost-related portion of uncollectible accounts. Such amounts are deferred and collected through a surcharge in the ratemaking process. Activity in the allowance account for uncollectibles is summarized as follows (thousands of dollars):

	Allowance for Uncollectibles
Balance, December 31, 2010	$ 3,194
Additions charged to expense	2,678
Accounts written off, less recoveries	(2,690)
Balance, December 31, 2011	3,182
Additions charged to expense	2,471
Accounts written off, less recoveries	(3,149)
Balance, December 31, 2012	2,504
Additions charged to expense	3,583
Accounts written off, less recoveries	(4,362)
Balance, December 31, 2013	$ 1,725

At December 31, 2013, the construction services segment (NPL) had $93 million in customer accounts receivable. Both the allowance for uncollectibles and write-offs have been insignificant and are not reflected in the table above.

Note 4 – Regulatory Assets and Liabilities

Natural gas operations are subject to the regulation of the Arizona Corporation Commission ("ACC"), the Public Utilities Commission of Nevada ("PUCN"), the California Public Utilities Commission ("CPUC"), and the Federal Energy Regulatory Commission ("FERC"). Accounting policies of Southwest conform to U.S. GAAP applicable to rate-regulated entities and reflect the effects of the ratemaking process. Accounting treatment for rate-regulated entities allows for deferral as regulatory assets, costs that otherwise would be expensed, if it is probable that future recovery from customers will occur. If rate recovery is no longer probable, due to competition or the actions of regulators, Southwest is required to write-off the related regulatory asset. Regulatory liabilities are recorded if it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process.

The following table represents existing regulatory assets and liabilities (thousands of dollars):

December 31,	2013	2012
Regulatory assets:		
Accrued pension and other postretirement benefit costs (1)	$ 249,985	$ 373,615
Unrealized net loss on non-trading derivatives (Swaps) (2)	160	2,395
Deferred purchased gas costs (3)	18,217	6,031
Accrued purchased gas costs (4)	31,500	30,300
Unamortized premium on reacquired debt (5)	19,614	19,452
Other (6)	48,945	44,927
	368,421	476,720
Regulatory liabilities:		
Deferred purchased gas costs (3)	—	(98,957)
Accumulated removal costs	(279,000)	(256,000)
Unrealized net gain on non-trading derivatives (Swaps) (2)	(981)	(6)
Deferred gain on southern Nevada division operations facility (7)	(253)	(392)
Unamortized gain on reacquired debt (8)	(11,398)	(11,934)
Other (9)	(26,482)	(6,951)
Net regulatory assets	$ 50,307	$ 102,480

(1) Included in Deferred charges and other assets on the Consolidated Balance Sheets. Recovery period is greater than five years. (See Note 9).

(2) The following table details the regulatory assets/(liabilities) offsetting the derivatives (Swaps) at fair value in the balance sheets (thousands of dollars). The actual amounts, when realized at settlement, become a component of purchased gas costs under the Company's purchased gas adjustment ("PGA") mechanisms. (See Note 12).

Instrument	Balance Sheet Location	2013	2012
Swaps	Deferred charges and other assets	$ 4	$ 319
Swaps	Prepaids and other current assets	156	2,076
Swaps	Other current liabilities	(801)	—
Swaps	Other deferred credits	(180)	(6)

(3) Balance recovered or refunded on an ongoing basis with interest.

(4) Included in Prepaids and other current assets on the Consolidated Balance Sheets. Balance recovered or refunded on an ongoing basis.

(5) Included in Deferred charges and other assets on the Consolidated Balance Sheets. Recovered over life of debt instruments.

(6) Other regulatory assets including deferred costs associated with rate cases, regulatory studies, and state mandated public purpose programs (including low income and conservation programs), as well as margin and interest-tracking accounts, amounts associated with accrued absence time, and deferred post-retirement benefits other than pensions. Recovery periods vary.

(7) Balance was originally being amortized over a four-year period beginning in the fourth quarter of 2009. As a result of the most recent Nevada general rate case, the amortization period was extended through 2015.

(8) Included in Other deferred credits on the Consolidated Balance Sheet. Amortized over life of debt instruments.

(9) Other regulatory liabilities includes amounts associated with income tax and gross-up.

Note 5 – Other Comprehensive Income and Accumulated Other Comprehensive Income (“AOCI”)

The following information provides insight into amounts impacting Other Comprehensive Income (Loss), both before and after-tax, within the Consolidated Statements of Comprehensive Income, which also impact Accumulated Other Comprehensive Income in the Company’s Consolidated Balance Sheets and Consolidated Statements of Equity.

Related Tax Effects Allocated to Each Component of Other Comprehensive Income (Loss)

	2013			2012			2011		
	Before-Tax Amount	Tax (Expense) or Benefit (1)	Net-of-Tax Amount	Before-Tax Amount	Tax (Expense) or Benefit (1)	Net-of-Tax Amount	Before-Tax Amount	Tax (Expense) or Benefit (1)	Net-of-Tax Amount
(Thousands of dollars)									
Defined benefit pension plans:									
Net actuarial gain/(loss)	$ 100,345	$ (38,131)	$ 62,214	$(74,853)	$ 28,444	$(46,409)	$(135,492)	$ 51,487	$(84,005)
Amortization of prior service cost	355	(135)	220	—	—	—	—	—	—
Amortization of transition obligation	—	—	—	867	(329)	538	867	(330)	537
Amortization of net actuarial (gain)/loss	34,177	(12,987)	21,190	25,597	(9,727)	15,870	15,569	(5,916)	9,653
Prior service cost	—	—	—	(2,423)	921	(1,502)	—	—	—
Regulatory adjustment	(123,630)	46,979	(76,651)	42,771	(16,253)	26,518	105,931	(40,254)	65,677
Pension plans other comprehensive income (loss)	11,247	(4,274)	6,973	(8,041)	3,056	(4,985)	(13,125)	4,987	(8,138)
FSIRS (designated hedging activities):									
Unrealized/realized gain (loss)	—	—	—	2,959	(1,125)	1,834	(17,958)	6,824	(11,134)
Amounts reclassified into net income	3,345	(1,271)	2,074	2,801	(1,064)	1,737	1,169	(444)	725
FSIRS other comprehensive income (loss)	3,345	(1,271)	2,074	5,760	(2,189)	3,571	(16,789)	6,380	(10,409)
Total other comprehensive income (loss)	$ 14,592	$ (5,545)	$ 9,047	$ (2,281)	$ 867	$ (1,414)	$ (29,914)	$ 11,367	$(18,547)

(1) Tax amounts are calculated using a 38% rate.

The estimated amounts that will be amortized from accumulated other comprehensive income or regulatory assets into net periodic benefit cost over the next year are summarized below (in thousands):

Retirement plan net actuarial loss	$23,000
SERP net actuarial loss	800
PBOP prior service cost	400

Approximately $2.1 million of previously realized losses (net of tax) related to the forward-starting interest rate swaps ("FSIRS"), included in AOCI at December 31, 2013, will be reclassified into interest expense within the next twelve months as the related interest payments on long-term debt occur.

The following table represents a rollforward of AOCI, presented on the Company's Consolidated Balance Sheets and its Consolidated Statements of Equity:

AOCI – Rollforward
(Thousands of dollars)

	Defined Benefit Plans (Note 9)			FSIRS (Note 12)			
	Before-Tax	Tax (Expense) Benefit	After-Tax	Before-Tax	Tax (Expense) Benefit	After-Tax	AOCI
Beginning Balance AOCI December 31, 2012	$ (52,470)	$ 19,939	$(32,531)	$(29,378)	$ 11,164	$(18,214)	$(50,745)
Net actuarial gain/(loss)	100,345	(38,131)	62,214	—	—	—	62,214
Other comprehensive income before reclassifications	100,345	(38,131)	62,214	—	—	—	62,214
FSIRS amounts reclassified from AOCI (1)	—	—	—	3,345	(1,271)	2,074	2,074
Amortization of prior service cost (2)	355	(135)	220	—	—	—	220
Amortization of net actuarial loss (2)	34,177	(12,987)	21,190	—	—	—	21,190
Regulatory adjustment (3)	(123,630)	46,979	(76,651)	—	—	—	(76,651)
Net current period other comprehensive income (loss)	11,247	(4,274)	6,973	3,345	(1,271)	2,074	9,047
Ending Balance AOCI December 31, 2013	$ (41,223)	$ 15,665	$(25,558)	$(26,033)	$ 9,893	$(16,140)	$(41,698)

(1) The FSIRS reclassification amounts are included in the Net interest deductions line item on the Consolidated Statements of Income.
(2) These AOCI components are included in the computation of net periodic benefit cost (see Note 9 – Pension and Other Postretirement Benefits for additional details).
(3) The regulatory adjustment represents the portion of the activity above that is expected to be recovered through rates in the future (the related regulatory asset is included in the Deferred charges and other assets line item on the Consolidated Balance Sheets).

The following table represents amounts (before income tax impacts) included in Accumulated other comprehensive income (in the table above), that have not yet been recognized in net periodic benefit cost, as of December 31, 2013 and 2012:

Amounts Recognized in AOCI (Before Tax)
(Thousands of dollars)

	2013	2012
Net actuarial (loss) gain	$(289,141)	$(423,662)
Prior service cost	(2,067)	(2,423)
Less: amount recognized in regulatory assets	249,985	373,615
Recognized in AOCI	$ (41,223)	$ (52,470)

See **Note 9 – Pension and Other Postretirement Benefits** for more information on the defined benefit pension plans and **Note 12 – Derivatives and Fair Value Measurements** for more information on the FSIRS.

Note 6 – Long-Term Debt

Carrying amounts of the Company's long-term debt and their related estimated fair values as of December 31, 2013 and December 31, 2012 are disclosed in the following table. The fair values of the revolving credit facility (including commercial paper), the NPL revolving credit facility, and the variable-rate Industrial Development Revenue Bonds ("IDRBs") approximate their carrying values, and are categorized as Level 1 (quoted prices for identical financial instruments) within the three-level fair value hierarchy that ranks the inputs used to measure fair value by their reliability. The market values of debentures (except the 6.1% Notes) and fixed-rate IDRBs are categorized as Level 2. The 6.1% Notes (private placement) and NPL other debt obligations (not actively traded) are categorized as Level 3 (based on significant unobservable inputs to their fair values). Fair values for the debentures, fixed-rate IDRBs, and NPL other debt obligations were determined through a market-based valuation approach, where fair market values are determined based on evaluated pricing data, such as broker quotes and yields for similar securities adjusted for observable differences. Significant inputs used in the valuation generally include benchmark yield curves and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, as applicable.

December 31,	2013		2012	
	Carrying Amount	Market Value	Carrying Amount	Market Value
(Thousands of dollars)				
Debentures:				
Notes, 4.45%, due 2020	$125,000	$130,953	$125,000	$141,771
Notes, 6.1%, due 2041	125,000	141,873	125,000	165,779
Notes, 3.875%, due 2022	250,000	252,485	250,000	277,950
Notes, 4.875%, due 2043	250,000	257,280	—	—
8% Series, due 2026	75,000	96,263	75,000	111,501
Medium-term notes, 7.59% series, due 2017	25,000	28,741	25,000	30,710
Medium-term notes, 7.78% series, due 2022	25,000	30,586	25,000	34,637
Medium-term notes, 7.92% series, due 2027	25,000	31,497	25,000	36,953
Medium-term notes, 6.76% series, due 2027	7,500	8,468	7,500	10,058
Unamortized discount	(5,560)		(3,403)	
	901,940		654,097	
Revolving credit facility and commercial paper	10,000	10,000	111,000	111,000

December 31,	2013		2012	
	Carrying Amount	Market Value	Carrying Amount	Market Value
(Thousands of dollars)				
Industrial development revenue bonds:				
Variable-rate bonds:				
Tax-exempt Series A, due 2028	50,000	50,000	50,000	50,000
2003 Series A, due 2038	50,000	50,000	50,000	50,000
2008 Series A, due 2038	50,000	50,000	50,000	50,000
2009 Series A, due 2039	50,000	50,000	50,000	50,000
Fixed-rate bonds:				
5.55% 1999 Series D, due 2038	—	—	8,270	8,375
5.45% 2003 Series C, due 2038	—	—	30,000	30,152
5.25% 2003 Series D, due 2038	20,000	20,150	20,000	20,571
5.80% 2003 Series E, due 2038	—	—	15,000	15,102
5.25% 2004 Series A, due 2034	65,000	64,522	65,000	66,955
5.00% 2004 Series B, due 2033	31,200	30,284	31,200	31,655
4.85% 2005 Series A, due 2035	100,000	95,192	100,000	101,184
4.75% 2006 Series A, due 2036	24,855	22,974	24,855	25,189
Unamortized discount	(2,776)		(3,195)	
	438,279		491,130	
NPL credit facility	—	—	41,562	41,562
NPL other debt obligations	42,213	42,119	20,721	20,991
	1,392,432		1,318,510	
Less: current maturities	(11,105)		(50,137)	
Long-term debt, less current maturities	$1,381,327		$1,268,373	

In March 2013, the Company redeemed at par the 5.45% Series 2003C and the 5.80% Series 2003E IDRBs originally due in 2038. The Company facilitated the redemption primarily from borrowings under its $300 million credit facility. In September 2013, the Company redeemed at par the $8.27 million 5.55% 1999 Series D IDRBs originally due in 2038. The Company facilitated the redemption primarily from borrowings under its $300 million credit facility.

In October 2013, the Company issued $250 million of 4.875% senior notes at a 0.078% discount. The notes will mature in October 2043. A portion of the net proceeds were used to temporarily pay down amounts outstanding under the credit facility. The remaining net proceeds were used for general corporate purposes.

The Company has a $300 million revolving credit facility that expires in March 2017. Interest rates for the credit facility are calculated at either the London Interbank Offered Rate ("LIBOR") or an "alternate base rate," plus in each case an applicable margin that is determined based on the Company's senior unsecured debt rating. At December 31, 2013, the applicable margin is 1% for loans bearing interest with reference to LIBOR and 0% for loans bearing interest with reference to the alternative base rate. Southwest has designated $150 million of the $300 million facility for long-term borrowing needs and the remaining $150 million for working capital purposes. At December 31, 2013, no borrowings were outstanding on the credit facility (see commercial paper program discussion below). Borrowings under the credit facility ranged from none during the fourth quarter of 2013 to a high of $195 million during October 2013. There were no borrowings outstanding on the short-term portion of the credit facility at December 31, 2012 and 2013. (See **Note 7 – Short-Term Debt**).

The Company has a $50 million commercial paper program. Any issuance under the commercial paper program is supported by the Company's current revolving credit facility and, therefore, does not represent additional borrowing capacity. Any borrowing under the commercial paper program will be designated as long-term debt. Interest rates for the program are calculated at the then current commercial paper rate. At December 31, 2013, $10 million was outstanding on the commercial paper program. The effective interest rate on the commercial paper program was 0.54% at December 31, 2013.

NPL has a $75 million credit facility that is scheduled to expire in June 2015. Interest rates for the credit facility are calculated at either LIBOR or a base rate, plus, in each case, 1.00% or 0.75% depending on NPL's leverage ratio at the end of each quarter. At December 31, 2013, no borrowings were outstanding on the NPL credit facility.

The effective interest rates on the variable-rate IDRBs are included in the table below:

	December 31, 2013	December 31, 2012
2003 Series A	1.43%	1.71%
2008 Series A	1.41%	1.59%
2009 Series A	1.01%	1.14%
Tax-exempt Series A	1.07%	1.25%

In Nevada, interest fluctuations due to changing interest rates on the 2003 Series A, 2008 Series A, and 2009 Series A variable-rate IDRBs are tracked and recovered from ratepayers through an interest balancing account.

Estimated maturities of long-term debt for the next five years are (in thousands):

2014	$11,105
2015	11,100
2016	10,200
2017	42,210
2018	2,598

No debt instruments have credit triggers or other clauses that result in default if Company bond ratings are lowered by rating agencies. Certain Company debt instruments contain securities ratings covenants that, if set in motion, would increase financing costs. Certain debt instruments also have leverage ratio caps and minimum net worth requirements. At December 31, 2013, the Company is in compliance with all of its covenants. Under the most restrictive of the covenants, the Company could issue over $1.9 billion in additional debt and meet the leverage ratio requirement. The Company has at least $800 million of cushion in equity relating to the minimum net worth requirement.

Note 7 – Short-Term Debt

As discussed in Note 6, Southwest has a $300 million credit facility that is scheduled to expire in March 2017, of which $150 million has been designated by management for working capital purposes. The Company had no short-term borrowings outstanding at December 31, 2012 or 2013.

Note 8 – Commitments and Contingencies

The Company is a defendant in miscellaneous legal proceedings. The Company is also a party to various regulatory proceedings. The ultimate dispositions of these proceedings are not presently determinable; however, it is the opinion of management that no litigation or regulatory proceeding to which the Company is currently subject will have a material adverse impact on its financial position or results of operations.

The Company maintains liability insurance for various risks associated with the operation of its natural gas pipelines and facilities. In connection with these liability insurance policies, the Company is responsible for an initial deductible or self-insured retention amount per incident, after which the insurance carriers are responsible for amounts up to the policy limits. The self-insured retention amount associated with general liability claims is $1 million per incident plus payment of the first $4 million in aggregate claims above $1 million in the policy year.

Note 9 – Pension and Other Postretirement Benefits

Southwest has an Employees' Investment Plan that provides for purchases of various mutual fund investments and Company common stock by eligible Southwest employees through deduction of a percentage of base compensation, subject to IRS limitations. Southwest matches up to one-half of amounts deferred. The maximum matching contribution is 3.5% of an employee's annual compensation. NPL has a separate plan, the cost and liability of which are not significant. The cost of the Southwest plan is listed below (in thousands):

	2013	2012	2011
Employee Investment Plan cost	$4,850	$4,707	$4,626

Southwest has a deferred compensation plan for all officers and a separate deferred compensation plan for members of the Board of Directors. The plans provide the opportunity to defer up to 100% of annual cash compensation. Southwest matches one-half of amounts deferred by officers, up to a maximum matching contribution of 3.5% of an officer's annual base salary. Upon retirement, payments of compensation deferred, plus interest, are made in equal monthly installments over 10, 15, or 20 years, as elected by the participant. Directors have an additional option to receive such payments over a five-year period. Deferred compensation earns interest at a rate determined each January. The interest rate equals 150% of Moody's Seasoned Corporate Bond Rate Index.

Southwest has a noncontributory qualified retirement plan with defined benefits covering substantially all employees and a separate unfunded supplemental retirement plan ("SERP") which is limited to officers. Southwest also provides postretirement benefits other than pensions ("PBOP") to its qualified retirees for health care, dental, and life insurance benefits.

The Company recognizes the overfunded or underfunded positions of defined benefit postretirement plans, including pension plans, in its balance sheets. Any actuarial gains and losses, prior service costs and transition assets or obligations are recognized in accumulated other comprehensive income under stockholders' equity, net of tax, until they are amortized as a component of net periodic benefit cost.

In accordance with regulatory deferral accounting treatment under U.S. GAAP for rate-regulated entities, the Company has established a regulatory asset for the portion of the total amounts otherwise chargeable to accumulated other comprehensive income that are expected to be recovered through rates in future periods. Changes in actuarial gains and losses and prior service costs pertaining to the regulatory asset will be recognized as an adjustment to the regulatory asset account as these amounts are amortized and recognized as components of net periodic pension costs each year.

Investment objectives and strategies for the qualified retirement plan are developed and approved by the Pension Plan Investment Committee of the Board of Directors of the Company. They are designed to enhance capital, maintain minimum liquidity required for retirement plan operations and effectively manage pension assets.

A target portfolio of investments in the qualified retirement plan is developed by the Pension Plan Investment Committee and is reevaluated periodically. Asset return assumptions are determined by evaluating performance expectations of the target portfolio. Projected benefit obligations are estimated using actuarial assumptions and Company benefit policy. A target mix of assets is then determined based on acceptable risk versus estimated returns in order to fund the benefit obligation. At December 31, 2013, the percentage ranges of the target portfolio are:

Type of Investment	Percentage Range
Equity securities	59 to 71
Debt securities	31 to 37
Other	up to 5

The Company's pension costs for these plans are affected by the amount and timing of cash contributions to the plans, the return on plan assets, discount rates, and by employee demographics, including age, compensation, and length of service. Changes made to the provisions of the plans may also impact current and future pension costs. Actuarial formulas are used in the determination of pension costs and are affected by actual plan experience and assumptions about future experience. Key actuarial assumptions include the expected return on plan assets, the discount rate used in determining the projected benefit obligation and pension costs, and the assumed rate of increase in employee compensation. Relatively small changes in these assumptions, particularly the discount rate, may significantly affect pension costs and plan obligations for the qualified retirement plan.

U.S. GAAP states that the assumed discount rate should reflect the rate at which the pension benefits could be effectively settled. In making this estimate, in addition to rates implicit in current prices of annuity contracts that could be used to settle the liabilities, employers may look to rates of return on high-quality fixed-income investments available on December 31 of each year and expected to be available during the period to maturity of the pension benefits. In determining the discount rate, the Company matches the plan's projected cash flows to a spot-rate yield curve based on highly rated corporate bonds. Changes to the discount rate from year-to-year, if any, are generally made in increments of 25 basis points.

Due to a higher interest rate environment for high-quality fixed income investments, the Company raised the discount rate at December 31, 2013 from 2012. The methodology utilized to determine the discount rate was consistent with prior years. The weighted-average rate of compensation increase was also raised (consistent with management's expectations overall). The asset return assumption (which impacts the following year's expense) was reduced. The rates are presented in the table below:

	December 31, 2013	December 31, 2012
Discount rate	5.00%	4.25%
Weighted-average rate of compensation increase	3.25%	2.75%
Asset return assumption	7.75%	8.00%

The significant increase in the discount rate will decrease the expense level for 2014. Pension expense for 2014 is estimated to decrease by $9 million. Future years expense level movements (up or down) will continue to be greatly influenced by long-term interest rates, asset returns, and funding levels.

The following table sets forth the retirement plan, SERP, and PBOP funded statuses and amounts recognized on the Consolidated Balance Sheets and Statements of Income.

	2013			2012		
	Qualified Retirement Plan	SERP	PBOP	Qualified Retirement Plan	SERP	PBOP
(Thousands of dollars)						
Change in benefit obligations						
Benefit obligation for service rendered to date at beginning of year (PBO/PBO/APBO)	$ 902,812	$ 37,373	$ 59,704	$ 780,571	$ 33,827	$ 52,182
Service cost	23,056	373	1,220	20,319	274	977
Interest cost	37,607	1,535	2,482	38,266	1,629	2,547
Plan amendments	—	—	—	—	—	2,423
Actuarial loss (gain)	(44,768)	(661)	(4,073)	92,409	4,111	2,775
Benefits paid	(31,993)	(2,477)	(1,313)	(28,753)	(2,468)	(1,200)
Benefit obligation at end of year (PBO/PBO/APBO)	886,714	36,143	58,020	902,812	37,373	59,704
Change in plan assets						
Market value of plan assets at beginning of year	609,750	—	35,250	521,829	—	29,944
Actual return on plan assets	96,187	—	7,319	68,174	—	4,454
Employer contributions	46,000	2,477	169	48,500	2,468	1,256
Benefits paid	(31,993)	(2,477)	(424)	(28,753)	(2,468)	(404)
Market value of plan assets at end of year	719,944	—	42,314	609,750	—	35,250
Funded status at year end	$ (166,770)	$(36,143)	$(15,706)	$ (293,062)	$(37,373)	$(24,454)
Weighted-average assumptions (benefit obligation)						
Discount rate	5.00%	5.00%	5.00%	4.25%	4.25%	4.25%
Weighted-average rate of compensation increase	3.25%	3.25%	3.25%	2.75%	2.75%	2.75%

Estimated funding for the plans above during calendar year 2014 is approximately $39 million of which $36 million pertains to the retirement plan. Management monitors plan assets and liabilities and could, at its discretion, increase plan funding levels above the minimum in order to achieve a desired funded status and avoid or minimize potential benefit restrictions.

The accumulated benefit obligation for the retirement plan and the SERP is presented below (in thousands):

	December 31, 2013	December 31, 2012
Retirement plan	$ 794,919	$ 811,184
SERP	33,894	35,362

Benefits expected to be paid for the pension, PBOP, and the SERP over the next 10 years are as follows (in millions):

	2014	2015	2016	2017	2018	2019-2023
Pension	$35.8	$37.4	$39.7	$41.7	$44.0	$ 257.3
PBOP	2.9	3.1	3.3	3.5	3.6	18.3
SERP	2.5	2.5	2.5	2.6	2.6	13.0

No assurance can be made that actual funding and benefits paid will match these estimates.

For PBOP measurement purposes, the per capita cost of the covered health care benefits medical rate trend assumption is 6.5% declining to 5%. The Company makes fixed contributions for health care benefits of employees who retire after 1988, but pays all covered health care costs for employees who retired prior to 1989. The medical trend rate assumption noted above applies to the benefit obligations of pre-1989 retirees only.

Components of net periodic benefit cost

	Qualified Retirement Plan			SERP			PBOP		
	2013	2012	2011	2013	2012	2011	2013	2012	2011
(Thousands of dollars)									
Service cost	$ 23,056	$ 20,319	$ 17,725	$ 373	$ 274	$ 217	$ 1,220	$ 977	$ 858
Interest cost	37,607	38,266	37,276	1,535	1,629	1,766	2,482	2,547	2,631
Expected return on plan assets	(49,840)	(45,780)	(40,114)	—	—	—	(2,824)	(2,404)	(2,379)
Amortization of prior service cost	—	—	—	—	—	—	355	—	—
Amortization of transition obligation	—	—	—	—	—	—	—	867	867
Amortization of net actuarial loss	32,261	23,883	14,348	971	683	631	945	1,031	590
Net periodic benefit cost	$ 43,084	$ 36,688	$ 29,235	$2,879	$2,586	$2,614	$ 2,178	$ 3,018	$ 2,567
Weighted-average assumptions (net benefit cost)									
Discount rate	4.25%	5.00%	5.75%	4.25%	5.00%	5.75%	4.25%	5.00%	5.75%
Expected return on plan assets	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Weighted-average rate of compensation increase	2.75%	3.00%	3.25%	2.75%	3.00%	3.25%	2.75%	3.00%	3.25%

Other Changes in Plan Assets and Benefit Obligations Recognized in Net Periodic Benefit Cost and Other Comprehensive Income

	2013				2012				2011			
	Total	Qualified Retirement Plan	SERP	PBOP	Total	Qualified Retirement Plan	SERP	PBOP	Total	Qualified Retirement Plan	SERP	PBOP
(Thousands of dollars)												
Net actuarial loss (gain) (a)	$(100,345)	$ (91,115)	$ (662)	$(8,568)	$ 74,853	$ 70,016	$4,111	$ 726	$ 135,492	$ 127,651	$2,427	$ 5,414
Amortization of prior service cost (b)	(355)	—	—	(355)	—	—	—	—	—	—	—	—
Amortization of transition obligation (b)	—	—	—	—	(867)	—	—	(867)	(867)	—	—	(867)
Amortization of net actuarial loss (b)	(34,177)	(32,261)	(971)	(945)	(25,597)	(23,883)	(683)	(1,031)	(15,569)	(14,348)	(631)	(590)
Prior service cost	—	—	—	—	2,423	—	—	2,423	—	—	—	—
Regulatory adjustment	123,630	113,762	—	9,868	(42,771)	(41,520)	—	(1,251)	(105,931)	(101,974)	—	(3,957)
Recognized in other comprehensive (income) loss	(11,247)	(9,614)	(1,633)	—	8,041	4,613	3,428	—	13,125	11,329	1,796	—
Net periodic benefit costs recognized in net income	48,141	43,084	2,879	2,178	42,292	36,688	2,586	3,018	34,416	29,235	2,614	2,567
Total of amount recognized in net periodic benefit cost and other comprehensive (income) loss	$ 36,894	$ 33,470	$ 1,246	$ 2,178	$ 50,333	$ 41,301	$6,014	$ 3,018	$ 47,541	$ 40,564	$4,410	$ 2,567

The table above discloses the net gain or loss, prior service cost, and transition amount recognized in other comprehensive income, separated into (a) amounts initially recognized in other comprehensive income, and (b) amounts subsequently recognized as adjustments to other comprehensive income as those amounts are amortized as components of net periodic benefit cost.

See also **Note 5 – Other Comprehensive Income and Accumulated Other Comprehensive Income (“AOCI”)**.

U.S. GAAP states that a fair value measurement should be based on the assumptions that market participants would use in pricing the asset or liability and establishes a fair value hierarchy that ranks the inputs used to measure fair value by their reliability. The three levels of the fair value hierarchy are as follows:

Level 1 – quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access at the measurement date.

Level 2 – inputs other than quoted prices included within Level 1 that are observable for similar assets or liabilities, either directly or indirectly.

Level 3 – unobservable inputs for the asset or liability. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date.

The following table sets forth, by level within the three-level fair value hierarchy, the fair values of the assets of the qualified pension plan and the PBOP as of December 31, 2013 and December 31, 2012. The SERP has no assets. There were no transfers between Levels 1 and 2 during 2013.

	December 31, 2013			December 31, 2012		
	Qualified Retirement Plan	PBOP	Total	Qualified Retirement Plan	PBOP	Total
Assets at fair value (thousands of dollars):						
Level 1 – Quoted prices in active markets for identical financial assets						
Common stock						
Agriculture	$ 8,224	$ 244	$ 8,468	$ 8,878	$ 269	$ 9,147
Capital equipment	3,891	115	4,006	3,510	106	3,616
Chemicals/materials	8,228	244	8,472	6,741	204	6,945
Consumer goods	54,329	1,611	55,940	49,247	1,492	50,739
Energy and mining	36,126	1,071	37,197	39,454	1,195	40,649
Finance/insurance	37,643	1,116	38,759	28,861	874	29,735
Healthcare	40,426	1,199	41,625	29,615	897	30,512
Information technology	24,636	731	25,367	30,534	925	31,459
Services	31,212	926	32,138	25,316	767	26,083
Telecommunications/utilities	24,270	720	24,990	24,355	738	25,093
Other	16,455	488	16,943	11,420	346	11,766
Real estate investment trusts	5,779	171	5,950	6,572	199	6,771
Mutual funds	76,764	22,495	99,259	67,749	17,802	85,551
Government fixed income securities	34,495	1,023	35,518	18,663	565	19,228
Total Level 1 Assets (1)	$ 402,478	$32,154	$434,632	$ 350,915	$26,379	$377,294

	December 31, 2013			December 31, 2012		
	Qualified Retirement Plan	PBOP	Total	Qualified Retirement Plan	PBOP	Total
Level 2 – Significant other observable inputs						
Commercial paper	$ 1,411	$ 42	$ 1,453	$ 635	$ 19	$ 654
Government fixed income and mortgage backed securities	51,434	1,525	52,959	42,997	1,302	44,299
Corporate fixed income securities						
Asset-backed and mortgage-backed	12,998	385	13,383	16,637	504	17,141
Banking	19,004	564	19,568	17,966	544	18,510
Insurance	6,481	192	6,673	4,737	144	4,881
Utilities	5,278	156	5,434	4,107	124	4,231
Other	25,212	748	25,960	24,188	732	24,920
Pooled funds and mutual funds	8,111	1,150	9,261	20,636	1,789	22,425
State and local obligations	1,370	41	1,411	1,273	39	1,312
Total Level 2 assets (2)	$ 131,299	$ 4,803	$136,102	$ 133,176	$ 5,197	$138,373
Level 3 – Significant unobservable inputs						
Commingled equity funds	$ 189,452	$ 5,618	$195,070	$ 123,719	$ 3,748	$127,467
Total Level 3 assets (3)	$ 189,452	$ 5,618	$195,070	$ 123,719	$ 3,748	$127,467
Total Plan assets at fair value	$ 723,229	$42,575	$765,804	$ 607,810	$35,324	$643,134
Insurance company general account contracts (4)	4,296	—	4,296	4,626	—	4,626
Total Plan assets (5)	$ 727,525	$42,575	$770,100	$ 612,436	$35,324	$647,760

(1) Common stock, Real Estate Investment Trusts, Mutual funds, and U.S. Government securities listed or regularly traded on a national securities exchange are valued at quoted market prices as of the last business day of the calendar year.

The Mutual funds category above is an intermediate-term bond fund whose manager employs multiple concurrent strategies and takes only moderate risk in each, thereby reducing the risk of poor performance arising from any single source, and a balanced fund that invests in a diversified portfolio of common stocks, preferred stocks and fixed-income securities. Strategies utilized by the bond fund include duration management, yield curve or maturity structuring, sector rotation, and all bottom-up techniques including in-house credit and quantitative research. Strategies employed by the balanced fund include pursuit of regular income, conservation of principal, and an opportunity for long-term growth of principal and income.

(2) The fair value of investments in debt securities with remaining maturities of one year or more is determined by dealers who make markets in such securities or by an independent pricing service, which considers yield or price of bonds of comparable quality, coupon, maturity, and type.

The pooled funds and mutual funds are two collective short-term funds that invest in Treasury bills and money market funds. These funds are used as a temporary cash repository for the pension plan’s various investment managers.

(3) Assets not considered Level 1 or Level 2 are valued using assumptions based on the best information available under the circumstances, such as investment manager pricing.

The commingled equity funds include private equity funds that invest in international securities (predominately Level 1 assets) regularly traded on securities exchanges. These funds are shown in the above table at net asset value. Investment strategies employed by the funds include:

- Investing in various industries with growth and reasonable valuations, avoiding highly cyclical industries
- Diversification by country, limiting exposure in any one country
- Emerging markets

The terms and conditions under which shares in the commingled equity funds may be redeemed vary among the funds; the notice required ranges from one day to 30 days prior to the valuation date (month end). One of the commingled equity funds requires the payment of a minimal impact fee to be applied to redemptions and subscriptions of $5 million or greater; the relative fee diminishes the greater the transaction. Other such funds may impose fees to recover direct costs incurred by the fund at redemption, but are indeterminable prior to redemption.

(4) The insurance company general account contracts are annuity insurance contracts used to pay the pensions of employees who retired prior to 1989. The balance of the account disclosed in the above table is the contract value, which is the result of deposits, withdrawals, and interest credits.

(5) The assets in the above table exceed the market value of plan assets shown in the funded status table by $7,842,000 (qualified retirement plan – $7,581,000, PBOP – $261,000) and $2,760,000 (qualified retirement plan – $2,685,000, PBOP – $75,000) for 2013 and 2012, respectively, which includes a payable for securities purchased, partially offset by receivables for interest, dividends, and securities sold.

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)

(Thousands of dollars):	Commingled Equity Funds
Balance, December 31, 2011	$ 100,273
Actual return on plan assets:	
Relating to assets still held at the reporting date	21,552
Relating to assets sold during the period	342
Purchases	6,800
Sales	(1,500)
Settlements	—
Transfers in and/or out of Level 3	—
Balance, December 31, 2012	127,467
Actual return on plan assets:	
Relating to assets still held at the reporting date	21,903
Relating to assets sold during the period	—
Purchases	45,700
Sales	—
Settlements	—
Transfers in and/or out of Level 3	—
Balance, December 31, 2013	$ 195,070

Note 10 – Stock-Based Compensation

At December 31, 2013, the Company had three stock-based compensation plans: a stock option plan, a performance share stock plan which includes a cash award, and a restricted stock/unit plan. The table below shows total stock-based plan compensation expense, including the cash award, which was recognized in the consolidated statements of income (in thousands):

	2013	2012	2011
Stock-based compensation plan expense, net of related tax benefits	$8,012	$7,396	$7,262
Stock-based compensation plan related tax benefits	4,910	4,533	4,451

Under the option plan, the Company previously granted options to purchase shares of common stock to key employees and outside directors. The last option grants were in 2006 and no future grants are anticipated. Each option has an exercise price equal to the market price of Company common stock on the date of grant and a maximum term of ten years.

The following tables summarize Company stock option plan activity and related information (thousands of options):

	2013		2012		2011	
	Number of options	Weighted-average exercise price	Number of options	Weighted-average exercise price	Number of options	Weighted-average exercise price
Outstanding at the beginning of the year	125	$ 28.13	177	$ 27.28	369	$ 28.04
Exercised during the year	(72)	28.44	(52)	25.25	(192)	28.75
Forfeited or expired during the year	(1)	33.07	—	—	—	—
Outstanding and exercisable at year end	52	$ 27.57	125	$ 28.13	177	$ 27.28

The intrinsic value of a stock option is the amount by which the market value of the underlying stock exceeds the exercise price of the option. The aggregate intrinsic value of outstanding and exercisable options, and options that were exercised, are presented in the table below (in thousands):

	2013	2012	2011
Outstanding and exercisable	$1,473	$1,788	$2,697
Exercised	1,402	928	1,949

	December 31, 2013	December 31, 2012	December 31, 2011
Market value of Southwest Gas stock	$ 55.91	$ 42.41	$ 42.49

The weighted-average remaining contractual life for outstanding options was 1.6 years for 2013. All outstanding options are fully vested and exercisable. The following table summarizes information about stock options outstanding at December 31, 2013 (thousands of options):

	Options Outstanding and Exercisable		
Range of Exercise Price	Number outstanding	Weighted-average remaining contractual life	Weighted-average exercise price
$20.49 to $23.40	13	0.5 Years	$ 23.27
$25.00 to $26.10	18	1.5 Years	$ 25.74
$29.08 to $33.07	21	2.5 Years	$ 31.91

The Company received $2 million in cash from the exercise of options during 2013 and a corresponding tax benefit of $446,000 which was recorded in additional paid-in capital.

Under the performance share stock plan, the Company may issue performance shares to encourage key employees to remain in its employment and to achieve short-term and long-term performance goals. Plan participants are eligible to receive a cash bonus (i.e., short-term incentive) and performance shares (i.e., long-term incentive). The performance shares vest three years after grant (and are subject to a final adjustment as determined by the Board of Directors) and are then issued as common stock.

The Company awards restricted stock/units under the restricted stock/unit plan to attract, motivate, retain, and reward key employees with an incentive to attain high levels of individual performance and improved financial performance of the Company. The restricted stock/units vest 40% at the end of year one and 30% at the end of years two and three and are issued annually as common stock in accordance with the percentage vested. The restricted stock/unit plan was also established to attract, motivate, and retain experienced and knowledgeable independent directors. Vesting for grants to directors followed the vesting schedule for employees; however, beginning with grants in 2012, the directors' restricted stock/units vest immediately upon grant. The issuance of common stock for directors occurs when their service on the Board ends.

The following table summarizes the activity of the performance share stock and restricted stock/unit plans as of December 31, 2013 (thousands of shares):

	Performance Shares	Weighted-average grant date fair value	Restricted Stock/Units	Weighted-average grant date fair value
Nonvested/unissued at beginning of year	348	$ 36.03	207	$ 37.18
Granted	106	44.83	100	44.83
Dividends	8		7	
Forfeited or expired	(3)	39.74	(1)	41.66
Vested and issued*	(136)	27.56	(68)	35.59
Nonvested/unissued at December 31, 2013	323	$ 39.16	245	$ 38.00

* Includes shares for retiree payouts and those converted for taxes.

The average grant date fair value of performance shares and restricted stock/units granted in 2012 and 2011 was $41.34 and $37.87, respectively.

As of December 31, 2013, total compensation cost related to nonvested performance shares and restricted stock/units not yet recognized is $3 million.

Note 11 – Income Taxes

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various states. The Company is subject to examinations by the Internal Revenue Service for years after 2009, and is subject to examination by the various state taxing authorities for years after 2008.

The Company recognizes interest expense and income and penalties related to income tax matters in income tax expense. Tax-related interest income included in income tax expense in the consolidated statements of income is shown in the table below (in thousands):

	2013	2012	2011
Tax-related interest income	$ —	$ 24	$100

The Company had no uncertain tax liabilities at December 31, 2013, nor at any time during 2013. The Company expects no change in unrecognized tax benefits in the next twelve months.

Income tax expense (benefit) consists of the following (thousands of dollars):

Year Ended December 31,	2013	2012	2011
Current:			
Federal	$ 3,549	$ 2,296	$ (265)
State	5,107	5,744	2,122
	8,656	8,040	1,857
Deferred:			
Federal	67,414	65,551	58,584
State	1,872	1,685	2,862
	69,286	67,236	61,446
Total income tax expense	$77,942	$75,276	$63,303

Deferred income tax expense (benefit) consists of the following significant components (thousands of dollars):

Year Ended December 31,	2013	2012	2011
Deferred federal and state:			
Property-related items	$62,737	$64,249	$51,710
Purchased gas cost adjustments	16,189	1,755	(92)
Employee benefits	(2,769)	564	11,766
All other deferred	(6,010)	1,529	(1,070)
Total deferred federal and state	70,147	68,097	62,314
Deferred ITC, net	(861)	(861)	(868)
Total deferred income tax expense	$69,286	$67,236	$61,446

A reconciliation of the federal statutory rate to the consolidated effective tax rate for 2011, 2012, and 2013 (and the sources of these differences and the effect of each) are summarized as follows:

Year Ended December 31,	2013	2012	2011
Federal statutory income tax rate	35.0 %	35.0 %	35.0 %
Net state taxes	2.4	2.6	2.7
Property-related items	0.1	0.2	0.2
Effect of income tax settlements	—	—	(0.9)
Tax credits	(0.4)	(0.4)	(0.6)
Company owned life insurance	(2.1)	(1.3)	(0.1)
All other differences	—	0.1	(0.1)
Consolidated effective income tax rate	35.0 %	36.2 %	36.2 %

Deferred tax assets and liabilities consist of the following (thousands of dollars):

December 31,	2013	2012
Deferred tax assets:		
Deferred income taxes for future amortization of ITC	$ 2,679	$ 3,211
Employee benefits	25,591	27,097
Alternative minimum tax credit	19,739	18,467
Net operating losses and credits	15,113	36,206
Interest rate swap	9,893	11,164
Other	22,334	17,866
Valuation allowance	(200)	(141)
	95,149	113,870
Deferred tax liabilities:		
Property-related items, including accelerated depreciation	694,024	652,380
Regulatory balancing accounts	18,688	2,498
Property-related items previously flowed through	836	1,729
Unamortized ITC	4,271	5,131
Debt-related costs	4,713	4,602
Other	15,898	16,626
	738,430	682,966
Net deferred tax liabilities	$643,281	$569,096
Current	$ (31,130)	$ (47,088)
Noncurrent	674,411	616,184
Net deferred tax liabilities	$643,281	$569,096

At December 31, 2013, the Company has a federal net operating loss carryforward of $43 million which expires in 2031. At December 31, 2013, the Company also has federal general business credits of $576,000, which begin to expire in 2031. The Company also has federal net capital loss carryforwards of $494,000, which begin to expire in 2016.

Final and Proposed Income Tax Regulations. In September 2013, the United States Department of the Treasury and the Internal Revenue Service ("IRS") issued final and proposed regulations for the tax treatment of tangible property. The final regulations include standards for determining whether and when a taxpayer must capitalize costs incurred in acquiring, maintaining, or improving tangible property. The final regulations are generally effective for tax years beginning on or after January 1, 2014, and may be adopted in earlier years under certain circumstances. Proposed regulations were also released that revise the rules for dispositions of tangible property and general asset accounts. The proposed regulations addressing dispositions and general asset accounts are also expected (when finalized) to be effective for tax years starting on or after January 1, 2014, and may be adopted in earlier years under certain circumstances. The Company expects the IRS to issue natural gas industry guidance which will facilitate its analysis regarding the regulations' impact on natural gas distribution networks. Based upon preliminary analysis of the final and proposed regulations, and in anticipation of specific guidance for the natural gas industry, the Company expects the regulations could result in a modest acceleration of tax deductibility, and the deferral of tax payments.

Note 12 – Derivatives and Fair Value Measurements

Derivatives. In managing its natural gas supply portfolios, Southwest has historically entered into fixed- and variable-price contracts, which qualify as derivatives. Additionally, Southwest utilizes fixed-for-floating swap contracts ("Swaps") to supplement its fixed-price contracts. The fixed-price contracts, firm commitments to purchase a fixed amount of gas in the future at a fixed price, qualify for the normal purchases and normal sales exception that is allowed for contracts that are probable of delivery in the normal course of business, and are exempt from fair value reporting. The variable-price contracts have no significant market value. The Swaps are recorded at fair value.

As part of the most recent Nevada Annual Rate Adjustment and associated stipulation in Nevada, the Company decided to suspend further swaps and fixed-price purchases pursuant to the Volatility Mitigation Program for its Nevada service territories. The decision will not impact previously executed purchase arrangements. The Company, along with its regulators, will continue to evaluate this strategy in light of prevailing or anticipated changing market conditions.

The fixed-price contracts and Swaps are utilized by Southwest under its volatility mitigation programs to effectively fix the price on a portion (for the 2013/2014 heating season, ranging from 25% to 35%, depending on the jurisdiction) of its natural gas supply portfolios. The maturities of the Swaps highly correlate to forecasted purchases of natural gas, during time frames ranging from January 2014 through March 2016. Under such contracts, Southwest pays the counterparty a fixed rate and receives from the counterparty a floating rate per MMBtu ("dekatherm") of natural gas. Only the net differential is actually paid or received. The differential is calculated based on the notional amounts under the contracts, which are detailed in the table below (thousands of dekatherms):

	December 31, 2013	December 31, 2012
Contract notional amounts	13,571	14,579

Southwest does not utilize derivative financial instruments for speculative purposes, nor does it have trading operations.

The following table sets forth the gains and (losses) recognized on the Company's Swaps (derivatives) for the years ended December 31, 2013, 2012, and 2011 and their location in the Consolidated Statements of Income (thousands of dollars):

Gains (losses) recognised in income for derivatives not designated as hedging instruments:
(Thousands of dollars)

Instrument	Location of Gain or (Loss) Recognized in Income on Derivative	2013	2012	2011
Swaps	Net cost of gas sold	$ 976	$(4,854)	$(18,201)
Swaps	Net cost of gas sold	(976)*	4,854*	18,201*
Total		$ —	$ —	$ —

* Represents the impact of regulatory deferral accounting treatment under U.S. GAAP for rate-regulated entities.

In January 2010, Southwest entered into two FSIRS (both, designated cash flow hedges) to partially hedge the risk of interest rate variability during the period leading up to the planned issuance of fixed-rate debt to replace maturing debt. The first FSIRS terminated in December 2010. The second FSIRS had a notional amount of $100 million and terminated in March 2012 concurrent with the related issuance of $250 million of 3.875% 10-year senior notes. At settlement of the second FSIRS, Southwest paid an aggregate $21.8 million to the counterparties. No gain or loss (ineffective portion) was recognized in income for either FSIRS during any period, including the period presented in the following table.

Gains (losses) recognised in other comprehensive income for derivatives designated as cash flow hedging instruments:

(Thousands of dollars)	Year Ended December 31, 2013	Year Ended December 31, 2012	Year Ended December 31, 2011
Amount of gain/(loss) realized/unrealized on FSIRS recognized in other comprehensive income on derivative	$ —	$ 2,959	$ (17,958)

The following table sets forth the fair values of the Company's Swaps and their location in the Consolidated Balance Sheets (thousands of dollars):

Fair values of derivatives not designated as hedging instruments:

December 31, 2013 Instrument	Balance Sheet Location	Asset Derivatives	Liability Derivatives	Net Total
Swaps	Deferred charges and other assets	$ 257	$ (77)	$ 180
Swaps	Prepaids and other current assets	1,054	(253)	801
Swaps	Other current liabilities	126	(282)	(156)
Swaps	Other deferred credits	7	(11)	(4)
Total		$ 1,444	$ (623)	$ 821

December 31, 2012 Instrument	Balance Sheet Location	Asset Derivatives	Liability Derivatives	Net Total
Swaps	Deferred charges and other assets	$ 132	$ (126)	$ 6
Swaps	Other current liabilities	391	(2,467)	(2,076)
Swaps	Other deferred credits	233	(552)	(319)
Total		$ 756	$ (3,145)	$(2,389)

The estimated fair values of the natural gas derivatives were determined using future natural gas index prices (as more fully described below). The Company has master netting arrangements with each counterparty that provide for the net settlement of all contracts through a single payment. As applicable, the Company has elected to reflect the net amounts in its balance sheets. The Company had no outstanding collateral associated with the Swaps during either period shown in the above table.

Pursuant to regulatory deferral accounting treatment for rate-regulated entities, Southwest records the unrealized gains and losses in fair value of the Swaps as a regulatory asset and/or liability. When the Swaps mature, Southwest reverses any prior positions held and records the settled position as an increase or decrease of purchased gas under the related purchased gas adjustment ("PGA") mechanism in determining its deferred PGA balances. Neither changes in fair value, nor settled amounts, of Swaps have a direct effect on earnings or other comprehensive income.

The following table shows the amounts Southwest paid to and received from counterparties for settlements of matured Swaps.

(Thousands of dollars)	Year ended December 31, 2013	Year ended December 31, 2012	Year ended December 31, 2011
Paid to counterparties	$ 3,148	$ 14,843	$ 17,283
Received from counterparties	$ 915	$ 634	$ —

The following table details the regulatory assets/(liabilities) offsetting the derivatives at fair value in the Consolidated Balance Sheets (thousands of dollars).

December 31, 2013

Instrument	Balance Sheet Location	Net Total
Swaps	Other deferred credits	$ (180)
Swaps	Other current liabilities	(801)
Swaps	Prepaids and other current assets	156
Swaps	Deferred charges and other assets	4

December 31, 2012

Instrument	Balance Sheet Location	Net Total
Swaps	Other deferred credits	$ (6)
Swaps	Prepaids and other current assets	2,076
Swaps	Deferred charges and other assets	319

Fair Value Measurements. The estimated fair values of Southwest's Swaps were determined at December 31, 2013 and 2012 using New York Mercantile Exchange ("NYMEX") futures settlement prices for delivery of natural gas at Henry Hub adjusted by the price of NYMEX ClearPort basis Swaps, which reflect the difference between the price of natural gas at a given delivery basin and the Henry Hub pricing points. These Level 2 inputs (inputs, other than quoted prices, for similar assets or liabilities) are observable in the marketplace throughout the full term of the Swaps, but have been credit-risk adjusted with no significant impact to the overall fair value measure.

The following table sets forth, by level within the three-level fair value hierarchy that ranks the inputs used to measure fair value by their reliability, the Company's financial assets and liabilities that were accounted for at fair value (see **Note 9 – Pension and Other Post Retirement Benefits** for definitions of the levels of the fair value hierarchy):

Level 2 – Significant other observable inputs

(Thousands of dollars)	December 31, 2013	December 31, 2012
Assets at fair value:		
Prepaids and other current assets - Swaps	$ 801	$ —
Deferred charges and other assets - Swaps	180	6
Liabilities at fair value:		
Other current liabilities - Swaps	(156)	(2,076)
Other deferred credits - Swaps	(4)	(319)
Net Assets (Liabilities)	$ 821	$ (2,389)

No financial assets or liabilities accounted for at fair value fell within Level 1 or Level 3 of the fair value hierarchy.

Note 13 – Segment Information

Company operating segments are determined based on the nature of their activities. The natural gas operations segment is engaged in the business of purchasing, distributing, and transporting natural gas. Revenues are generated from the distribution and transportation of natural gas. The construction services segment is primarily engaged in the business of providing utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems.

The accounting policies of the reported segments are the same as those described within **Note 1 – Summary of Significant Accounting Policies**. NPL accounts for the services provided to Southwest at contractual (market) prices at contract inception. Accounts receivable for these services, which are not eliminated during consolidation, are presented in the table below (in thousands).

	December 31, 2013	December 31, 2012
Accounts receivable for NPL services	$ 10,787	$ 8,179

The financial information pertaining to the natural gas operations and construction services segments for each of the three years in the period ended December 31, 2013 is as follows (thousands of dollars):

2013	Gas Operations	Construction Services	Adjustments (a)	Total
Revenues from unaffiliated customers	$1,300,154	$ 562,475		$1,862,629
Intersegment sales	—	88,153		88,153
Total	$1,300,154	$ 650,628		$1,950,782
Interest revenue	$ 456	$ 5		$ 461
Interest expense	$ 62,555	$ 1,145		$ 63,700
Depreciation and amortization	$ 193,848	$ 42,969		$ 236,817
Income tax expense	$ 65,377	$ 12,565		$ 77,942
Segment net income	$ 124,169	$ 21,151		$ 145,320
Segment assets	$4,272,029	$ 293,811	$ (666)	$4,565,174
Capital expenditures	$ 314,578	$ 49,698		$ 364,276

2012	Gas Operations	Construction Services	Adjustments	Total
Revenues from unaffiliated customers	$1,321,728	$ 522,676		$1,844,404
Intersegment sales	—	83,374		83,374
Total	$1,321,728	$ 606,050		$1,927,778
Interest revenue	$ 915	$ 9		$ 924
Interest expense	$ 66,957	$ 1,063		$ 68,020
Depreciation and amortization	$ 186,035	$ 37,387		$ 223,422
Income tax expense	$ 64,973	$ 10,303		$ 75,276
Segment net income	$ 116,619	$ 16,712		$ 133,331
Segment assets	$4,204,948	$ 283,109		$4,488,057
Capital expenditures	$ 308,951	$ 86,761		$ 395,712

2011	Gas Operations	Construction Services	Adjustments	Total
Revenues from unaffiliated customers	$1,403,366	$ 391,701		$1,795,067
Intersegment sales	—	92,121		92,121
Total	$1,403,366	$ 483,822		$1,887,188
Interest revenue	$ 465	$ 20		$ 485
Interest expense	$ 68,777	$ 825		$ 69,602
Depreciation and amortization	$ 175,253	$ 25,216		$ 200,469
Income tax expense	$ 49,576	$ 13,727		$ 63,303
Segment net income	$ 91,420	$ 20,867		$ 112,287
Segment assets	$4,048,613	$ 227,394		$4,276,007
Capital expenditures	$ 305,542	$ 75,449		$ 380,991

(a) Construction services segment assets include income taxes payable of $666,000 in 2013, which was netted against gas operations segment income taxes receivable, net during consolidation.

Note 14 – Quarterly Financial Data (Unaudited)

	Quarter Ended			
	March 31	June 30	September 30	December 31
(Thousands of dollars, except per share amounts)				
2013				
Operating revenues	$ 613,505	$ 411,574	$ 387,346	$ 538,357
Operating income	138,394	28,908	6,141	100,772
Net income (loss)	80,674	10,067	(3,057)	57,189
Net income (loss) attributable to Southwest Gas Corporation	80,773	10,108	(2,864)	57,303
Basic earnings (loss) per common share*	1.75	0.22	(0.06)	1.24
Diluted earnings (loss) per common share*	1.73	0.22	(0.06)	1.22
2012				
Operating revenues	$ 657,645	$ 409,768	$ 371,799	$ 488,566
Operating income	134,623	15,380	6,310	115,211
Net income (loss)	78,835	(3,888)	(4,414)	62,106
Net income (loss) attributable to Southwest Gas Corporation	78,919	(3,676)	(4,305)	62,393
Basic earnings (loss) per common share*	1.71	(0.08)	(0.09)	1.35
Diluted earnings (loss) per common share*	1.70	(0.08)	(0.09)	1.34

(Thousands of dollars, except per share amounts)	Quarter Ended			
	March 31	June 30	September 30	December 31
2011				
Operating revenues	$ 628,440	$ 388,505	$ 352,592	$ 517,651
Operating income	126,335	20,568	1,253	101,924
Net income (loss)	68,354	4,013	(15,747)	55,143
Net income (loss) attributable to Southwest Gas Corporation	68,549	4,055	(15,641)	55,324
Basic earnings (loss) per common share*	1.50	0.09	(0.34)	1.20
Diluted earnings (loss) per common share*	1.48	0.09	(0.34)	1.19

* The sum of quarterly earnings (loss) per average common share may not equal the annual earnings (loss) per share due to the ongoing change in the weighted-average number of common shares outstanding.

The demand for natural gas is seasonal, and it is the opinion of management that comparisons of earnings for interim periods do not reliably reflect overall trends and changes in the operations of the Company. Also, the timing of general rate relief can have a significant impact on earnings for interim periods. See Management's Discussion and Analysis for additional discussion of operating results.

MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Company management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined by Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of Company management, including the principal executive officer and principal financial officer, the Company conducted an evaluation of the effectiveness of internal control over financial reporting based on the *“Internal Control – Integrated Framework”* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992. Based upon the Company’s evaluation under such framework, Company management concluded that the internal control over financial reporting was effective as of December 31, 2013. The effectiveness of the Company’s internal control over financial reporting as of December 31, 2013 has been audited by PricewaterhouseCoopers, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

February 27, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Southwest Gas Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of comprehensive income, of cash flows and of equity present fairly, in all material respects, the financial position of Southwest Gas Corporation and its subsidiaries at December 31, 2013 and December 31, 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in 1992. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

Las Vegas, Nevada
February 27, 2014

EXHIBIT 21.01

SOUTHWEST GAS CORPORATION
LIST OF SUBSIDIARIES OF THE REGISTRANT
AT DECEMBER 31, 2013

SUBSIDIARY NAME	STATE OF INCORPORATION OR ORGANIZATION TYPE
Paiute Pipeline Company	Nevada
NPL Construction Co.	Nevada
Southwest Gas Transmission Company	Limited partnership between Southwest Gas Corporation and Utility Financial Corp.
Southwest Gas Capital II, III, IV	Delaware
Utility Financial Corp.	Nevada
The Southwest Companies	Nevada

Exhibit 23.01

<u>Consent of Independent Registered Public Accounting Firm</u>

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-180045) and Form S-8 (Nos. 333-185354, 333-168731, 333-147952, 333-155581, and 333-106762) of Southwest Gas Corporation of our report dated February 27, 2014 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in the Annual Report to Stockholders, which is incorporated in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

Las Vegas, Nevada
February 27, 2014

Exhibit 31.01

Certification

I, Jeffrey W. Shaw, certify that:

1. I have reviewed this annual report on Form 10-K of Southwest Gas Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2014

/S/ JEFFREY W. SHAW
Jeffrey W. Shaw
President and Chief Executive Officer
Southwest Gas Corporation

Certification

I, Roy R. Centrella, certify that:

1. I have reviewed this annual report on Form 10-K of Southwest Gas Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2014

/S/ ROY R. CENTRELLA
Roy R. Centrella
Senior Vice President/Chief Financial Officer
Southwest Gas Corporation

Exhibit 32.01

SOUTHWEST GAS CORPORATION

CERTIFICATION

In connection with the periodic report of Southwest Gas Corporation (the “Company”) on Form 10-K for the period ended December 31, 2013 as filed with the Securities and Exchange Commission (the “Report”), I, Jeffrey W. Shaw, the President and Chief Executive Officer of the Company, hereby certify as of the date hereof, solely for purposes of Title 18, Chapter 63, Section 1350 of the United States Code, that to the best of my knowledge:

(1) the Report fully complies with the requirements of section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company at the dates and for the periods indicated.

This Certification has not been, and shall not be deemed, “filed” with the Securities and Exchange Commission.

Dated: February 27, 2014

/s/ Jeffrey W. Shaw

Jeffrey W. Shaw
President and Chief Executive Officer

SOUTHWEST GAS CORPORATION

CERTIFICATION

In connection with the periodic report of Southwest Gas Corporation (the “Company”) on Form 10-K for the period ended December 31, 2013 as filed with the Securities and Exchange Commission (the “Report”), I, Roy R. Centrella, Senior Vice President/Chief Financial Officer of the Company, hereby certify as of the date hereof, solely for purposes of Title 18, Chapter 63, Section 1350 of the United States Code, that to the best of my knowledge:

(1) the Report fully complies with the requirements of section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company at the dates and for the periods indicated.

This Certification has not been, and shall not be deemed, “filed” with the Securities and Exchange Commission.

Dated: February 27, 2014

/s/ Roy R. Centrella

Roy R. Centrella

Senior Vice President/Chief Financial Officer