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, 2010

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** ü **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** ü

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** ü **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** ü **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 ü 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** ü

Aggregate market value of the voting and non-voting common stock held by nonaffiliates of the registrant:
$1,340,088,830 as of June 30, 2010

The number of shares outstanding of common stock:
Common Stock, $1 Par Value, 45,784,435 shares as of February 15, 2011

DOCUMENTS INCORPORATED BY REFERENCE

Description	Part Into Which Incorporated
Annual Report to Shareholders for the Year Ended December 31, 2010	Parts I, II, and IV
2011 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 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 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 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 14 of the Notes to Consolidated Financial Statements, which is included in the 2010 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, 2010, Southwest purchased and distributed or transported natural gas to 1,837,000 residential, commercial, and industrial customers in geographically diverse portions of Arizona, Nevada, and California. The southwestern United States has historically been one of the highest growth regions of the country. However, the customer growth levels experienced in recent years have greatly diminished due to the overall slowdown in the new housing market and increase in idle/vacant homes, resulting from foreclosures and challenging economic conditions. Southwest completed 16,000 first-time meter sets over the last twelve months. These meter sets led to 13,000 net additional active customers during 2010, an increase of less than one percent. Given the current housing and economic downturn, management expects customer growth will be one percent or less in the near term. Management cannot predict the timing of when currently idle and vacant homes will return to service, or when customer growth levels will improve, but it is not likely to occur in the near term.

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, 2010	86%	4%	10%
December 31, 2009	86%	4%	10%
December 31, 2008	86%	5%	9%

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 46 percent of total system throughput in 2010. Customers who utilized this service transported 100 million dekatherms in 2010, 104 million dekatherms in 2009, and 116 million dekatherms in 2008. Although these volumes are significant, these customers provided a much smaller proportionate share of operating margin.

The demand for natural gas is seasonal. Variability in weather from normal temperatures can materially impact results of operations. It is the opinion of management that comparisons of earnings for interim periods do not reliably reflect overall trends and changes in operations. 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 a 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 Lake Tahoe and North Lake Tahoe, 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.

In California, CPUC regulations allow Southwest to separate or "decouple" the recovery of operating margin from natural gas consumption. In Nevada, a decoupled rate structure applies to most customer classes providing stability in annual operating margin. In Arizona, Southwest filed a general rate case in November 2010 which requested a rate structure to decouple recovery of the Company's fixed costs from fluctuations in usage, both higher and lower, and enable the Company to aggressively advocate for increased energy efficiency by its customers.

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 2010 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	Pending
	General rate case	August 2007	December 2008
California:			
Northern and Southern	Annual attrition	October 2010	January 2011
Northern and Southern	General rate case	December 2007	January 2009
Nevada:			
Northern and Southern	General rate case	April 2009	November 2009
FERC:			
Paiute	General rate case	February 2009	April 2010

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 six 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. Extreme weather conditions coupled with temporarily restricted gas supplies resulted in a limited curtailment in Southwest’s Arizona jurisdiction in early February 2011. Southwest maintains no significant backlog on its orders for gas service.

Natural Gas Supply

Southwest is responsible for acquiring (purchasing) and arranging delivery of (transporting via interstate pipelines) natural gas to its system for all sales customers.

The primary objective of Southwest in acquiring gas supply is to ensure that adequate supplies of natural gas are available from reliable sources at the best cost. Gas is acquired from a wide variety of sources and a mix of purchase provisions, including spot market purchases and firm supplies with a variety of terms. During 2010, Southwest acquired natural gas from 46 suppliers. Southwest regularly monitors the number of suppliers, their quality, and their relative contribution to the overall customer supply portfolio. New suppliers are contracted whenever possible, and solicitations for supplies are extended to the largest practicable list of suppliers. Competitive pricing, flexibility in meeting Southwest’s requirements, and aggressive participation by suppliers who have demonstrated reliability of service are key to their inclusion in the annual portfolio mix. The goal of this practice is to mitigate the risk of nonperformance by any one supplier and ensure competitive prices for customer supplies.

Balancing reliable supply assurances with the associated costs 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. Firm and spot market natural gas purchases are made in a competitive bid environment.

To mitigate customer exposure to market price volatility, Southwest seeks to fix the price on a portion (ranging from 25 percent to 50 percent, 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. For the 2010/2011 heating season, fixed-price contracts ranged in price from approximately $4 to $7 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.

The firm, fixed-price arrangements are structured such that a stated volume of gas is required to be scheduled by Southwest and delivered by the supplier. If the gas is not needed by Southwest or cannot be procured by the supplier, the contract provides for fixed or market-based penalties to be paid by the non-performing party.

Southwest has a hedging program utilizing standalone derivative instruments as part of its price volatility mitigation program. This hedging program is currently utilized in both Arizona and Nevada. The combination of fixed-price contracts and derivative instruments is designed to increase flexibility for Southwest and increase supplier diversification. The costs of such derivative financial instruments are recovered from customers through the PGA mechanisms.

Storage availability can influence the average annual price of gas, as storage allows a company to purchase natural gas in larger 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 Arizona or southern Nevada rate jurisdictions. Limited storage availability exists in southern and northern California and northern Nevada. A contract with Southern California Gas Company is intended for delivery only within Southwest’s southern California rate jurisdiction. In addition, a contract with Paiute for its LNG facility allows for peaking capability only in northern Nevada and northern California. Gas is purchased for injection during the off-peak period for use in the high demand months, but is limited in its 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. As such, this storage provides limited operational flexibility to adjust daily flowing supplies to meet demand, as permitted by conditions on NWPL’s system, and has limited impact on the overall price of gas supplies.

Gas supplies for the southern system of Southwest (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 gas from Rocky Mountain producing areas and from Canada.

Southwest arranges for transportation of 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. Supply and pipeline capacity availability on both short- and long-term bases is regularly monitored by Southwest 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 and also has interruptible contracts in place that allow additional capacity to be acquired.

Southwest believes that the current level of contracted firm interstate capacity is sufficient to serve each of its service territories under normal circumstances. 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 or by purchasing capacity on the open market.

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 experienced continued growth in the new home market among the 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 finds, 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; its use can help energy users to comply with stricter environmental air quality standards.

The Environmental Protection Agency (“EPA”) has issued regulations that require the reporting of greenhouse gas emissions (“GHG”) from large sources and suppliers in the United States in order to facilitate the development of policies and programs to reduce GHGs. The EPA requires annual reporting from large facilities with combustion emissions exceeding 25,000 tons per year. The Company completed GHG inventories for all Southwest and Paiute facilities, based on California emission reporting protocols. These inventories showed that Southwest and Paiute do not operate, control, or own any facilities which have the potential to exceed the 25,000 tons per year threshold.

In 2010, the Company began reporting to the EPA under the Mandatory Reporting Rule (“MRR”) the volumes of natural gas received for distribution to LDC customers. While some parts of the MRR do not apply to Southwest, other required information is already being reported to the Department of Transportation or is available in existing Company databases. A recent addition to the MRR will require the Company to implement new methods for inventorying pipeline components and creating or modifying an existing data management system. The Company is in the process of identifying the most feasible procedures for collecting the information required by this new regulation, but does not expect to incur any material expenditures for compliance with any MRR requirements. The Company is monitoring other climate legislation which may trigger additional reporting requirements or have financial implications.

Employees

At December 31, 2010, the natural gas operations segment had 2,349 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 energy services contractor that provides utility companies with trenching and installation, replacement, and maintenance services for 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 business operations is main and service replacement as well as new business installations. 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. Construction activity is also cyclical and can be significantly impacted by changes in general and local economic conditions, including interest rates, employment levels, housing market, job growth, equipment resale market, and local and federal tax rates and incentives. The continued slowdown in construction activities observed in regional and national markets since 2007 has negatively impacted the amount of work received under existing blanket contracts, the amount of bid work, and the equipment resale market. During 2010, there was an improvement from the prior two years in the amount of replacement and bid work; however, the new construction market continues at a low level. It is anticipated that there will continue to be improvements in the replacement market, while the new construction market is expected to continue to be slow throughout 2011.

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 2010, approximately 96 percent of revenue was earned under unit-price contracts. As of December 31, 2010, no significant backlog existed with respect to outstanding 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 competitors in what has been a largely fragmented industry. Several national competitors also exist within the industry. NPL currently operates in 17 major markets nationwide. Its customers are the primary LDCs in those markets. During 2010, NPL served 57 major customers, with Southwest accounting for approximately 19 percent of NPL revenues. Additionally, five long-term LDC customers accounted for approximately 46 percent of total revenue.

Employment fluctuates between seasonal construction periods, which are normally heaviest in the summer and fall months. At December 31, 2010, NPL had 2,453 regular full-time equivalent employees. Employment peaked in October 2010 when there were 2,523 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 15 field locations with corporate headquarters located in Phoenix, Arizona. Buildings are normally leased from third parties. The lease terms are typically five years or less. Field location facilities consist of a small building for repairs and land to store equipment.

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 percent interest in IntelliChoice Energy ("ICE") and consolidates ICE as a majority owned subsidiary. ICE was established in late 2009 and markets natural gas engine-driven heating, ventilating, and air conditioning ("HVAC") technology and products.

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.*

Our earnings are greatly affected by variations in temperature during the winter heating season.

The demand for natural gas is seasonal and is greatly affected by temperature. On cold days, use of gas by residential and commercial customers can be six times greater than on warm days because of the increased use of gas for space heating. Variability in weather from normal temperatures can materially impact results of operations. This is most pronounced in Arizona, where rates are highly leveraged. Rate design is the primary mechanism available to mitigate weather risk. In December 2010, the Arizona Corporation Commission approved a Policy Statement that allows utilities to file proposals for alternative rate mechanisms, including revenue per customer decoupling, in their next general rate case to address the financial disincentives to utilities of promoting energy efficiency. Southwest's November 2010 Arizona rate case filing proposed a rate structure to decouple recovery of the Company's fixed costs from fluctuations in usage, both higher and lower, in anticipation of the approval of the Policy Statement. In Nevada, a decoupled rate structure applies to most customer classes providing stability in annual operating margin by insulating us from the effects of lower usage (including volumes associated with unusual weather). The existing rate structure in our California territories includes a balanced margin mechanism which also has an insulating effect on usage volume variability.

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 and policies, can reduce our earnings. Risks and uncertainties relating to delays in obtaining regulatory approvals, conditions imposed in regulatory approvals, or 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.

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

The current economic slowdown in the United States, and particularly in our service areas, has resulted in a marked decline in the new housing market and increases in the inventory of idle/vacant homes. Commercial entities (including restaurants and other service establishments) are also being impacted, resulting in reductions in operations or closures. In addition, a prolonged economic downturn could result in customers voluntarily reducing consumption. If these trends continue, our financial condition, results of operations, and cash flows could be adversely affected.

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, 2010 of approximately $193 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 $70 million at December 31, 2010 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 2010, Southwest recognized in Other income (deductions) a net increase in the cash surrender values of its company-owned life insurance policies (including net death benefits recognized) of $9.8 million (compared to a net increase of $8.5 million in 2009). 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 is 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 2011, 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 a 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, 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 and vandalism. 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. Our current liability insurance policies require us to be responsible for the first $1 million dollars (self-insured retention) of each incident plus the first $5 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.

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.

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 and the administrative offices in Phoenix, Arizona. Total gas plant, exclusive of leased property, at December 31, 2010 was $4.6 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 on page 5 of 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. [REMOVED AND RESERVED]

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 15, 2011, there were 17,727 holders of record of common stock, and the market price of the common stock was $37.90. The quarterly market price of, and dividends on, Company common stock required by this item are included in the 2010 Annual Report to Shareholders filed as an exhibit hereto and incorporated herein by reference.

The Company's common stock dividend policy states that common stock dividends will be paid at a prudent level within the normal dividend payout range for its respective businesses, and that dividends will be established at a level considered sustainable in order to minimize business risk and maintain a strong capital structure throughout all economic cycles. The quarterly common stock dividend declared was 22.5 cents per share throughout 2008, 23.75 cents per share throughout 2009, and 25 cents per share throughout 2010. In February 2011, the Board of Directors increased the quarterly dividend payout to 26.5 cents per share, effective with the June 2011 payment.

Item 6. SELECTED FINANCIAL DATA

Information required by this item is included in the 2010 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 2010 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 (one year or less) fixed-price contracts and variable-price contracts (firm and spot). Southwest has experienced price volatility over the past several years. Price volatility is expected to continue into 2011 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 a volatility mitigation program to attempt to further reduce price volatility for customers. Under this program Southwest fixes the price of a portion (ranging from 25 percent to 50 percent, 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.

Southwest's natural gas purchase 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

A significant portion of the Company's operating margin is volume-driven with current rates based on an assumption of normal weather. Demand for natural gas is greatly affected by temperature. On cold days, use of gas by residential and commercial customers can be six times greater than on warm days because of increased use of gas for space heating. Space heating-related volumes are the primary component of billings for these customer classes and are concentrated in the months of November to March. Variances in temperatures from normal levels, especially during these months, have a significant impact on the margin and associated net income of the Company. This impact is most pronounced in Arizona, where 54 percent of Southwest's customers are located and where rates are highly leveraged.

Rate design is the primary mechanism available to Southwest to 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, the basic service charge provides some protection against weather-risk but commodity rates are highly leveraged, leaving a significant portion of operating margin subject to weather variations.

In December 2010, the ACC approved a Policy Statement that allows utilities to file proposals for alternative rate mechanisms, including revenue per customer decoupling, in their next general rate case to address financial disincentives to utilities of promoting energy efficiency. Southwest's November 2010 Arizona rate case filing proposed a rate structure to decouple recovery of the Company's fixed costs from fluctuations in usage, both higher and lower, in anticipation of the approval of the Policy Statement.

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 $100 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, 2010 and 2009, Southwest had $100 million and $192 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 one percent change in interest rates would increase or decrease interest expense for the next twelve months by approximately $1 million.

The Company is also exposed to interest rate risk associated with new debt financing needed to fund maturities of long-term debt. Southwest has $200 million of long-term debt maturing in May 2012 and plans to fund that obligation by issuing $200 million of debentures by the maturity date. In connection with the planned debt issuance, the Company, in January 2010, entered into a forward-starting interest rate swap ("FSIRS") agreement to hedge the risk of interest rate variability during the period leading up to the planned issuance. The counterparties to the agreement comprise four major banking institutions. The FSIRS has a notional amount of $100 million (with Southwest as the fixed-rate payer at a rate of 4.78%) and has a mandatory termination date on or before March 20, 2012. Southwest designated the FSIRS agreement as a cash flow hedge of forecasted future interest payments.

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 2010 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, 2010, 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 2010 Annual Report to Shareholders under the caption “Management’s Report on Internal Control Over Financial Reporting” on page 83.

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 2010 Annual Report to Shareholders under the caption “Report of Independent Registered Public Accounting Firm” on page 84.

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 2011 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, 2010 are as follows:

Name	Age	Position	Period Position Held
Jeffrey W. Shaw	52	Chief Executive Officer	2006-Present
James P. Kane	64	President	2006-Present
George C. Biehl	63	Executive Vice President	2010-Present
		Executive Vice President/Chief Financial Officer and Corporate Secretary	2006-2010
Roy R. Centrella	53	Senior Vice President/Chief Financial Officer	2010-Present
		Vice President/Controller and Chief Accounting Officer	2006-2010
John P. Hester	48	Senior Vice President/Regulatory Affairs & Energy Resources	2006-Present
Edward A. Janov	56	Senior Vice President/Corporate Development	2010-Present
		Senior Vice President/Finance	2006-2010
James F. Wunderlin	65	Senior Vice President/Engineering and Business Operations and Technical Support	2009-Present
		Vice President/Engineering	2006-2009
Karen S. Haller	47	Vice President/General Counsel, Compliance Officer, and Corporate Secretary	2010-Present
		Vice President/General Counsel and Compliance Officer	2008-2010
		Vice President/Deputy General Counsel and Compliance Officer	2008
		Assistant General Counsel and Director/Legal Affairs	2006-2008
		Assistant General Counsel	2006
Kenneth J. Kenny	48	Vice President/Finance/Treasurer	2010-Present
		Vice President/Treasurer	2006-2010
Laura Lopez Hobbs	51	Vice President/Administration	2010-Present
		Vice President/Human Resources	2008-2010
		Director/Human Resources	2006-2008
Gregory J. Peterson	51	Vice President/Controller and Chief Accounting Officer	2010-Present
		Assistant Controller	2006-2010

(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 2011 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 2011 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 2011 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 2010 with the reporting requirements of Section 16(a) of the Exchange Act, except for the following Form 4s:

The purchase of Company common stock by Robert L. Boughner, Director, consisting of 2,000 shares on September 13, 2010, was reported on January 27, 2011.

The addition of Company common stock pursuant to dividend credits by Roy R. Centrella, Senior Vice President/Chief Financial Officer, consisting of 91.3 shares on September 1, 2010, was reported on February 4, 2011.

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 2011 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 2011 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 2011 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 2011 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 2011 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, 2010, 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.

Equity Compensation Plan Information

Plan category	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)
(Thousands of shares)			
Equity compensation plans approved by security holders	369	$ 28.04	-
Equity compensation plans not approved by security holders	-	-	-
Total	369	$ 28.04	-

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	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)
(Thousands of shares)			
Equity compensation plans approved by security holders	366	$ 27.54	413
Equity compensation plans not approved by security holders	-	-	-
Total	366	$ 27.54	413

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	Number of securities to be issued upon vesting of restricted stock units	Weighted-average grant date fair value of award	Number of securities remaining available for future issuance (excluding securities reflected in column a)
	(a)	(b)	(c)
(Thousands of shares)			
Equity compensation plans approved by security holders	170	$ 27.42	140
Equity compensation plans not approved by security holders	-	-	-
Total	170	$ 27.42	140

Additional information regarding the three equity compensation plans is included in Note 11 of the Notes to Consolidated Financial Statements in the 2010 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 2011 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 2011 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 2010 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**.

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 10-Q for the quarter ended June 30, 2010, 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	Form of Deposit Agreement. Incorporated herein by reference to Exhibit 4.01 to Form S-3 dated September 26, 1994, File No. 33-55621.
4.03	Form of Depositary Receipt (attached as Exhibit A to Form of Deposit Agreement included as Exhibit 4.02 hereto). Incorporated herein by reference to Exhibit 4.01 to Form S-3 dated September 26, 1994, File No. 33-55621.
4.04	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.
4.05	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.
4.06	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.
4.07	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.
4.08	Third Supplemental Indenture between the Company and The Bank of New York, as successor to Harris Trust and Savings Bank, dated as of February 13, 2001, supplementing and amending the Indenture dated as of July 15, 1996, with respect to the $200,000,000, 8.375% Notes, due 2011. Incorporated herein by reference to Exhibit 4.01 to Form 8-K dated February 8, 2001, File No. 1-07850.
4.09	Fourth Supplemental Indenture of the Company to The Bank of New York, as successor to Harris Trust and Savings Bank, dated as of May 6, 2002, supplementing and amending the Indenture dated as of July 15, 1996, with respect to the 7.625% Senior Unsecured Notes due 2012. Incorporated herein by reference to Exhibit 4.01 to Form 8-K dated May 1, 2002, File No. 1-07850.
4.10	Certificate of Trust of Southwest Gas Capital II. Incorporated herein by reference to Exhibit 4.03 to Form S-3 dated August 7, 2003, File No. 333-106419.

4.11	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.
4.12	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.
4.13	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.
4.14	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.
4.15	Form of Common Stock Certificate. Incorporated herein by reference to Exhibit 4 to Form 8-K dated July 22, 2003, File No. 1-07850.
4.16	Form of Preferred Trust Security. Incorporated herein by reference to Exhibit 4.16 to Form 8-K dated August 20, 2003, File No. 1-07850.
4.17	Form of Indenture with respect to the 7.70% Junior Subordinated Debentures. Incorporated herein by reference to Exhibit 4.14 to Form 8-K dated August 20, 2003, File No. 1-07850.
4.18	Form of 7.70% Junior Subordinated Debentures. Incorporated herein by reference to Exhibit 4.17 to Form 8-K dated August 20, 2003, File No. 1-07850.
4.19	Form of Amended and Restated Trust Agreement of Southwest Gas Capital II. Incorporated herein by reference to Exhibit 4.09 to Form 8-K dated August 20, 2003, File No. 1-07850.
4.20	Form of Guarantee Agreement with respect to the Preferred Trust Securities. Incorporated herein by reference to Exhibit 4.13 to Form 8-K dated August 20, 2003, File No. 1-07850.
4.21	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.
4.22	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.
4.23	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.
4.24	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.
4.25	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.

4.26	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.
4.27	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.
4.28	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.
4.29	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.
4.30	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.
4.31	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.
4.32	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 percent of the consolidated total assets of Southwest Gas Corporation and its subsidiaries.
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	Financing Agreement between the Company and Clark County, Nevada, dated as of October 1, 1999. Incorporated herein by reference to Exhibit 10.16 to Form 10-K for the year ended December 31, 1999, File No. 1-07850.
10.06 *	Amended Form of Employment Agreement with Company Officers. Incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 1998, Exhibit 10.1 to Form 10-Q for the

	quarter ended September 30, 2000, Exhibit 10 to Form 10-Q for the quarter ended September 30, 2001, Form 8-K dated September 21, 2004, Form 8-K dated August 1, 2006, and Exhibit 10.19 to Form 10-K for the year ended December 31, 2006, File No. 1-07850.
10.07 *	Amended Form of Change in Control Agreement with Company Officers. Incorporated herein by reference to Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 1998, Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2000, Exhibit 10 to Form 10-Q for the quarter ended September 30, 2001, Form 8-K dated September 21, 2004, Form 8-K dated August 1, 2006, and Exhibit 10.19 to Form 10-K for the year ended December 31, 2006, File No. 1-07850.
10.08 *	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.
10.09 *	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.
10.10 *	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.
10.11 *	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.
10.12	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.
10.13 *	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.
10.14	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.
10.15	$300 million Credit Facility. Incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2005, File No. 1-07850. First Amendment to $300 million Credit Facility. Incorporated herein by reference to Exhibit 10.01 to Form 10-Q for the quarter ended June 30, 2006, File No. 1-07850. Second Amendment to $300 million Credit Facility. Incorporated herein by reference to Exhibit 10.01 to Form 10-Q for the quarter ended June 30, 2007, File No. 1-07850. Third Amendment to $300 million Credit Facility. Incorporated herein by reference to Exhibit 10.02 to Form 10-Q for the quarter ended June 30, 2007, File No. 1-07850.
10.16	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.

10.17	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.
10.18	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.
10.19 *	Southwest Gas Corporation 2006 Restricted Stock/Unit Plan, amended and restated May 7, 2008. Incorporated herein by reference to Exhibit 10.01 to Form 10-Q for the quarter ended June 30, 2008, File No. 1-07850. Appendix A to the 2006 Restricted Stock/Unit Plan. Incorporated herein by reference to Exhibit 10.01 to Form 10-Q for the quarter ended September 30, 2010, File No. 1-07850.
10.20	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.
10.21	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.
12.01	Computation of Ratios of Earnings to Fixed Charges of Southwest Gas Corporation.
13.01	Portions of 2010 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, 2010, formatted in Extensible Business Reporting Language (“XBRL”): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Income, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Statements of Equity and Comprehensive Income, and (v) the Notes to the Consolidated Financial Statements, tagged as blocks of text.

* Management Contracts or Compensation Plans

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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 28, 2011

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

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 28, 2011
/s/ THOMAS E. CHESTNUT (Thomas E. Chestnut)	Director	February 28, 2011
/s/ STEPHEN C. COMER (Stephen C. Comer)	Director	February 28, 2011
/s/ RICHARD M. GARDNER (Richard M. Gardner)	Director	February 28, 2011
/s/ LEROY C. HANNEMAN, JR. (LeRoy C. Hanneman, Jr.)	Director	February 28, 2011
/s/ JAMES J. KROPID (James J. Kropid)	Chairman of the Board of Directors	February 28, 2011
/s/ MICHAEL O. MAFFIE (Michael O. Maffie)	Director	February 28, 2011
/s/ ANNE L. MARIUCCI (Anne L. Mariucci)	Director	February 28, 2011
/s/ MICHAEL J. MELARKEY (Michael J. Melarkey)	Director	February 28, 2011
/s/ JEFFREY W. SHAW (Jeffrey W. Shaw)	Director and Chief Executive Officer	February 28, 2011
/s/ A. RANDALL THOMAN (A. Randall Thoman)	Director	February 28, 2011
/s/ THOMAS A. THOMAS (Thomas A. Thomas)	Director	February 28, 2011
/s/ TERRENCE L. WRIGHT (Terrence L. Wright)	Director	February 28, 2011
/s/ ROY R. CENTRELLA (Roy R. Centrella)	Senior Vice President/ Chief Financial Officer	February 28, 2011
/s/ GREGORY J. PETERSON (Gregory J. Peterson)	Vice President, Controller, and Chief Accounting Officer	February 28, 2011

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EXHIBIT INDEX

Exhibit Number	Description of Document
12.01	Computation of Ratios of Earnings to Fixed Charges of Southwest Gas Corporation.
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Exhibit 12.01

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

	December 31,				
	2010	2009	2008	2007	2006
1. Fixed charges:					
A) Interest expense	$ 75,481	$ 81,861	$ 90,403	$ 94,035	$ 92,878
B) Amortization	2,620	2,097	2,880	2,783	3,467
C) Interest portion of rentals	6,455	6,644	7,802	7,952	6,412
Total fixed charges	$ 84,556	$ 90,602	$101,085	$104,770	$102,757
2. Earnings (as defined):					
D) Pretax income fromcontinuing operations	$158,378	$132,035	$101,808	$131,024	$128,357
Fixed Charges (1. above)	84,556	90,602	101,085	104,770	102,757
Total earnings as defined	$242,934	$222,637	$202,893	$235,794	$231,114
	2.87	2.46	2.01	2.25	2.25

CONSOLIDATED SELECTED FINANCIAL STATISTICS

Year Ended December 31, (Thousands of dollars, except per share amounts)	2010	2009	2008	2007	2006
Operating revenues	$1,830,371	$1,893,824	$2,144,743	$2,152,088	$2,024,758
Operating expenses	1,598,254	1,685,433	1,936,881	1,929,788	1,811,608
Operating income	$ 232,117	$ 208,391	$ 207,862	$ 222,300	$ 213,150
Net income	$ 103,877	$ 87,482	$ 60,973	$ 83,246	$ 83,860
Total assets at year end	$3,984,193	$3,906,292	$3,820,384	$3,670,188	$3,484,965
Capitalization at year end					
Common equity	$1,166,996	$1,102,086	$1,037,841	$ 983,673	$ 901,425
Subordinated debentures	—	100,000	100,000	100,000	100,000
Long-term debt	1,124,681	1,169,357	1,185,474	1,266,067	1,286,354
	$2,291,677	$2,371,443	$2,323,315	$2,349,740	$2,287,779
Common stock data					
Common equity percentage of capitalization	50.9%	46.5%	44.7%	41.9%	39.4%
Return on average common equity	9.1%	8.1%	6.0%	8.8%	10.3%
Basic earnings per share	$ 2.29	$ 1.95	$ 1.40	$ 1.97	$ 2.07
Diluted earnings per share	$ 2.27	$ 1.94	$ 1.39	$ 1.95	$ 2.05
Dividends declared per share	$ 1.00	$ 0.95	$ 0.90	$ 0.86	$ 0.82
Payout ratio	44%	49%	64%	44%	40%
Book value per share at year end	$ 25.60	$ 24.44	$ 23.48	$ 22.98	$ 21.58
Market value per share at year end	$ 36.67	$ 28.53	$ 25.22	$ 29.77	$ 38.37
Market value per share to book value per share	143%	117%	107%	130%	178%
Common shares outstanding at year end (000)	45,599	45,092	44,192	42,806	41,770
Number of common shareholders at year end	17,821	20,489	22,244	22,664	23,610
Ratio of earnings to fixed charges	2.87	2.46	2.01	2.25	2.25

NATURAL GAS OPERATIONS

Year Ended December 31,	2010	2009	2008	2007	2006
(Thousands of dollars)					
Sales	$1,438,809	$1,547,081	$1,728,924	$1,754,913	$1,671,093
Transportation	73,098	67,762	62,471	59,853	56,301
Operating revenue	1,511,907	1,614,843	1,791,395	1,814,766	1,727,394
Net cost of gas sold	736,175	866,630	1,055,977	1,086,194	1,033,988
Operating margin	775,732	748,213	735,418	728,572	693,406
Expenses					
Operations and maintenance	354,943	348,942	338,660	331,208	320,803
Depreciation and amortization	170,456	166,850	166,337	157,090	146,654
Taxes other than income taxes	38,869	37,318	36,780	37,553	34,994
Operating income	$ 211,464	$ 195,103	$ 193,641	$ 202,721	$ 190,955
Contribution to consolidated net income	$ 91,382	$ 79,420	$ 53,747	$ 72,494	$ 71,473
Total assets at year end	$3,845,111	$3,782,913	$3,680,327	$3,518,304	$3,352,074
Net gas plant at year end	$3,072,436	$3,034,503	$2,983,307	$2,845,300	$2,668,104
Construction expenditures and property additions	$ 188,379	$ 212,919	$ 279,254	$ 312,412	$ 305,914
Cash flow, net					
From operating activities	$ 342,522	$ 371,416	$ 261,322	$ 320,594	$ 253,245
From (used in) investing activities	(178,685)	(265,850)	(237,093)	(306,396)	(277,980)
From (used in) financing activities	(107,779)	(81,744)	(34,704)	(5,347)	15,989
Net change in cash	$ 56,058	$ 23,822	$ (10,475)	$ 8,851	$ (8,746)
Total throughput (thousands of therms)					
Residential	704,693	669,736	704,986	698,063	677,605
Small commercial	300,940	294,225	314,555	310,666	309,856
Large commercial	111,833	117,241	125,121	127,561	128,255
Industrial/Other	58,922	72,623	97,702	103,525	149,243
Transportation	998,600	1,043,894	1,164,190	1,128,422	1,175,238
Total throughput	2,174,988	2,197,719	2,406,554	2,368,237	2,440,197
Weighted average cost of gas purchased ($/therm)	$ 0.62	$ 0.71	$ 0.84	$ 0.81	$ 0.79
Customers at year end	1,837,000	1,824,000	1,819,000	1,813,000	1,784,000
Employees at year end	2,349	2,423	2,447	2,538	2,525
Customer to employee ratio	782	753	743	714	706
Degree days – actual	1,998	1,824	1,902	1,850	1,826
Degree days – ten-year average	1,876	1,882	1,893	1,936	1,961

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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 in portions of Arizona, Nevada, and California. Southwest is the largest distributor 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 in portions of California, including the Lake Tahoe area and the high desert and mountain areas in San Bernardino County.

As of December 31, 2010, Southwest had 1,837,000 residential, commercial, industrial, and other natural gas customers, of which 991,000 customers were located in Arizona, 664,000 in Nevada, and 182,000 in California. Residential and commercial customers represented over 99 percent of the total customer base. During 2010, 54 percent of operating margin was earned in Arizona, 35 percent in Nevada, and 11 percent in California. During this same period, Southwest earned 86 percent of operating margin from residential and small commercial customers, 4 percent from other sales customers, and 10 percent from transportation customers. These general patterns are expected to continue.

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 operating margin are general rate relief, weather, conservation and efficiencies, and customer growth. Of these, weather is the primary reason for volatility in margin. Variances in temperatures from normal levels, primarily in Arizona, can have a significant impact on the margin and associated net income of the Company. A decoupled rate structure designed to mitigate the impact of weather variability as well as conservation on margin is utilized in the Nevada service territories. Weather impacts and conservation are also offset by the margin tracking mechanism in Southwest's California service territories.

NPL Construction Co. ("NPL" or the "construction services" segment), a wholly owned subsidiary, is a full-service underground piping contractor that provides utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems. NPL operates in 17 major markets nationwide. Construction activity is cyclical and can be significantly impacted by changes in 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 tax rates.

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. The natural gas operations segment accounted for an average of 89 percent 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,	2010	2009	2008
(In thousands, except per share amounts)			
Contribution to net income			
Natural gas operations	$ 91,382	$ 79,420	$ 53,747
Construction services	12,495	8,062	7,226
Consolidated	$103,877	$ 87,482	$ 60,973
Average number of common shares outstanding	45,405	44,752	43,476
Basic earnings per share			
Consolidated	$ 2.29	$ 1.95	$ 1.40
Natural Gas Operations			
Operating margin	$775,732	$748,213	$735,418

2010 Overview

Consolidated results for 2010 increased compared to 2009 due to improvements in both the natural gas and construction services segments. Basic earnings per share were $2.29 in 2010 compared to basic earnings per share of $1.95 in 2009.

Natural gas operations highlights include the following:

- Rate relief and improved weather significantly enhanced operating margin during 2010
- Operating margin increased more than $27 million, or four percent, compared to the prior year
- Operating expenses increased $11 million, or two percent, between years
- Net financing costs decreased $5 million between 2010 and 2009
- Southwest's liquidity position remains strong

Construction services highlights include the following:

- Revenues in 2010 increased $40 million compared to 2009, and contribution to net income increased $4 million

Rate Relief. During 2010, Southwest realized the benefits of rate relief in its Nevada and California regulatory jurisdictions which accounted for $18 million of incremental operating margin. See Rates and Regulatory Proceedings for additional details of the various rate decisions.

Weather and Conservation. The rate structures in each of Southwest's three states provide varying levels of protection from risks that drive operating margin volatility, particularly weather risk and conservation efforts. Southwest's exposure to these risks on operating margin is largely limited to its Arizona operating areas as both Nevada and California operations are under decoupled rate structures. During 2010, the estimated weather impact on operating margin was a decrease of $10 million as Arizona experienced one of its warmest Decembers on record. By comparison, during 2009, weather resulted in an estimated negative operating margin impact of $18 million, thereby resulting in a favorable comparative impact between years.

Additionally, throughout 2009 and 2010 Southwest experienced a decline in consumption over and above the more typical impacts of conservation from improvements in new construction practices and energy efficient appliances. This excess decline was attributed to the impact of the difficult economic environment and, in particular, vacant homes. Southwest continues to note an excessive number of vacant homes as compared to historical levels. Consequently, further economic-related declines are possible.

In December 2010, the Arizona Corporation Commission ("ACC") issued a Policy Statement which allows utilities to file proposals for alternative mechanisms including revenue per customer decoupling, in their next general rate case to address the financial disincentives to utilities of promoting energy efficiency. In anticipation of the Policy Statement, the Company's recent Arizona rate case filing requested a rate structure to decouple recovery of the Company's fixed costs from fluctuations in usage, both higher and lower, to enable the Company to aggressively advocate for increased energy efficiency by its customers by eliminating the existing financial disincentive. For more information see the Rates and Regulatory Proceedings discussion.

Customer Growth. Southwest completed 18,000 and 16,000 first-time meter sets in 2009 and 2010, respectively. These meter sets led to 5,000 and 13,000 net additional active customers between years, respectively. Southwest continues to project net customer growth of 1% or less for 2011.

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 $193 million at December 31, 2010. 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 $70 million at December 31, 2010 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, 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. During 2010, Southwest recorded in Other income (deductions) a net increase in the cash surrender values of its COLI policies of $9.8 million (including recognized net death benefits), compared to a net increase of $8.5 million in 2009. 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 towards the ultimate death benefits are also recorded without tax consequences. Currently, the Company intends to hold the COLI policies for their duration and purchase additional policies as necessary.

Liquidity. Southwest believes its liquidity position remains strong. Southwest has a $300 million credit facility maturing in May 2012, $150 million of which is designated for working capital needs. The facility is provided through a consortium of eight major banking institutions. Usage of the facility was minimal during 2010, even during the winter heating season when gas purchases normally require temporary financing, and there was no balance outstanding at December 31, 2010 leaving the entire $300 million available for long-term and working capital needs. The lower usage was primarily due to existing cash reserves, natural gas prices that were relatively stable, and gas cost-related rate mechanisms that favorably impacted operating cash flows. The current slowdown in housing construction has also allowed Southwest to fund construction expenditures primarily with internally generated cash.

Results of Natural Gas Operations

Year Ended December 31,	2010	2009	2008
(Thousands of dollars)			
Gas operating revenues	$1,511,907	$1,614,843	$1,791,395
Net cost of gas sold	736,175	866,630	1,055,977
Operating margin	775,732	748,213	735,418
Operations and maintenance expense	354,943	348,942	338,660
Depreciation and amortization	170,456	166,850	166,337
Taxes other than income taxes	38,869	37,318	36,780
Operating income	211,464	195,103	193,641
Other income (deductions)	4,016	6,590	(13,469)
Net interest deductions	75,113	74,091	83,096
Net interest deductions on subordinated debentures	1,912	7,731	7,729
Income before income taxes	138,455	119,871	89,347
Income tax expense	47,073	40,451	35,600
Contribution to consolidated net income	$ 91,382	$ 79,420	$ 53,747

2010 vs. 2009

Contribution to consolidated net income from natural gas operations increased $12 million in 2010 compared to 2009. The increase was a result of higher operating margin and reduced financing costs, partially offset by an increase in operating expenses.

Operating margin increased more than $27 million between years. Rate relief provided $18 million toward the operating margin increase, consisting of $15 million in Nevada and $3 million in California. Differences in heating demand caused primarily by weather variations between years resulted in an $8 million operating margin increase as warmer-than-normal temperatures were experienced during both years (during 2010, operating margin was negatively impacted by $10 million, while the negative impact in 2009 was $18 million). Customer growth contributed $1 million of the operating margin increase.

Operations and maintenance expense increased $6 million, or two percent, principally due to the impact of higher employee-related benefit costs and general cost increases. The increase was mitigated by cost containment efforts (including lower staffing levels) and by a decline in uncollectible expense, partially due to the impacts of the tracking mechanism in Nevada for the gas-cost portion of uncollectible accounts.

Depreciation expense increased $3.6 million, or two percent, as a result of additional plant in service, partially offset by lower depreciation rates in the Nevada rate jurisdiction ($2.3 million annualized reduction) effective in June 2009. Average gas plant in service for 2010 increased $139 million, or three percent, as compared to 2009. This was attributable to reinforcement work, franchise requirements, routine pipe replacement activities, and new business.

Other income declined $2.6 million between 2010 and 2009. This was primarily due to higher costs associated with certain Arizona non-recoverable pipe replacement work, partially offset by an increase in the cash surrender values of COLI policies. The current year includes a $9.8 million increase in the cash surrender values (and recognized net death benefits) of COLI policies. The prior year included an $8.5 million increase in COLI cash surrender values. COLI income in both periods was very high due to strong equity-market returns on investments underlying the policies.

Net financing costs decreased $4.8 million between 2010 and 2009 due to the redemption of the $100 million subordinated debentures in March 2010.

2009 vs. 2008

Contribution to consolidated net income from natural gas operations increased $25.7 million in 2009 compared to 2008. The increase was a result of a $20 million improvement in other income, higher operating margin, and reduced financing costs, partially offset by an increase in operating expenses.

Operating margin increased $13 million between years. Rate relief provided $30 million toward the operating margin increase, consisting of $25 million in Arizona, $3 million in California, and $2 million in Nevada. Conservation, resulting from current economic conditions and energy efficiency, negatively impacted operating margin by an estimated $11 million. Differences in heating demand caused primarily by weather variations between years resulted in a $7 million operating margin decrease as warmer-than-normal temperatures were experienced during both years (during 2009, operating margin was negatively impacted by $18 million, while the negative impact in 2008 was $11 million). Customer growth contributed $1 million of the operating margin increase.

Operations and maintenance expense increased $10.3 million, or three percent, principally due to the impact of general cost increases and higher employee-related benefit costs. The increase was mitigated by slightly lower staffing levels.

Depreciation expense increased $513,000, or less than one percent, as a result of additional plant in service, substantially offset by lower depreciation rates in the California ($3 million annualized reduction) and Nevada ($2.3 million annualized reduction) rate jurisdictions effective in January and June 2009, respectively. Average gas plant in service for 2009 increased $193 million, or five percent, as compared to 2008. This was attributable to new business, reinforcement work, franchise requirements, routine pipe replacement activities, and the addition of two new operations centers in southern Nevada.

Other income improved $20.1 million between 2009 and 2008. This was primarily due to an $8.5 million increase in the cash surrender values of COLI policies in 2009 compared to cash surrender value declines in 2008 of $12 million, partially offset by a $1.9 million reduction in interest income between the years.

Net financing costs decreased $9 million between 2009 and 2008 primarily due to a reduction in outstanding debt, including the redemption of $75 million of long-term debt in December 2008, and lower interest rates associated with Southwest’s commercial credit and other variable-rate facilities.

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 are in place in California and Nevada. Southwest continues to pursue rate design changes in Arizona.

Arizona Energy Efficiency and Decoupling Proceeding. The ACC convened a series of workshops starting in 2009 to evaluate "rate and regulatory incentives" and establish standards to promote energy efficiency and conservation for utility customers. In conjunction with these workshops, Southwest and other interested parties submitted proposed regulations to the ACC in June 2009. Rate designs which would decouple revenues from customer usage were the topic of much discussion in the proceeding, and were incorporated in several of the parties' draft regulations. In August 2010, the ACC issued a Notice of Proposed Rulemaking on Gas Energy Efficiency, which adopted an energy efficiency requirement for Arizona's gas utilities, including Southwest, to achieve cumulative annual energy savings of six percent by December 2020. In October 2010, the Chairman of the ACC issued a draft Policy Statement, which will allow utilities to file proposals for alternative mechanisms including revenue per customer decoupling, in their next general rate case to address the financial disincentives to utilities of promoting energy efficiency. The Policy Statement was approved by the ACC in December 2010.

Arizona General Rate Case. Southwest filed a general rate application with the ACC in November 2010 requesting an increase in authorized annual operating revenues of $73.2 million, or 9.26 percent, to reflect increased operating costs, investments in infrastructure, and costs of capital, as well as margin attrition due to decreased average usage by customers. The application requests an overall rate of return of 9.73% on original cost rate base of $1.074 billion, an 11% return on common equity, and a capital structure utilizing 52% common equity.

The rate case filing also requested a rate structure to decouple recovery of the Company's fixed costs from fluctuations in usage, both higher and lower, and enable the Company to aggressively advocate for increased energy efficiency by its customers. The filed structure anticipated the approval of the Policy Statement discussed in the *Arizona Energy Efficiency and Decoupling Proceeding* section above. The proposed mechanism, referred to as the Energy Efficiency Enabling Provision ("EEEP"), is a revenue-per-customer decoupling mechanism designed to eliminate the link between volumetric sales and revenues that currently exists with traditional rate designs, such that the existing financial disincentive associated with the Company's pursuit of cost effective energy efficiency is eliminated. This will allow management to focus on customers and to concentrate its attention on the cost of providing service. The pursuit of increased energy efficiency by customers is supported by the requested approval of a detailed energy efficiency and renewable energy resource plan. A decision by the ACC is expected in late 2011 or early 2012.

California General Rate Cases. Effective January 2009, Southwest received general rate relief in California. The California Public Utilities Commission ("CPUC") decision authorized an overall increase of $2.8 million in 2009 with an additional $400,000 deferred to 2010. In addition, attrition increases were approved and made effective for the years 2010-2013 of 2.95% in southern and northern California and approximately $100,000 per year for the South Lake Tahoe rate jurisdiction. In October 2009, Southwest filed for attrition increases, which were made effective January 2010, in the amount of $2.7 million (including the $400,000 previously deferred). In October 2010, Southwest filed annual attrition increases, which were made effective January 2011, in the amount of $2.3 million.

Nevada General Rate Case. Southwest filed a general rate application with the Public Utilities Commission of Nevada ("PUCN") in April 2009 requesting an increase in authorized annual operating revenues of $28.8 million in the Company's southern Nevada rate jurisdiction and $1.7 million in the northern Nevada rate jurisdiction. The PUCN issued its Order in this proceeding in October 2009 with rates effective November 2009. The Order provided for a revenue increase of $17.6 million in southern Nevada and a revenue decrease of $0.5 million in northern Nevada. On a combined basis, the rate case decision is designed to increase operating income by $19.1 million. The Company was also authorized to implement a decoupled rate structure based on PUCN regulations that will help stabilize operating margin by insulating the Company from the effects of lower usage (including volumes associated with unusual weather). It also allows the Company to more aggressively pursue customer conservation opportunities through implementation of substantive conservation and energy efficiency programs. The PUCN Order also adopted the Company's recommendation to offset a $20.5 million deferred gain on the sale of the former southern Nevada operations facility against the cost of the land purchased for new facilities by $12.8 million and eliminated approximately $5.9 million of deferred costs associated with a government-mandated pipe inspection program (the remaining $1.8 million will be accreted to income over 4 years). In addition, a tracking mechanism for gas cost-related uncollectible expense was approved.

FERC General Rate Case. Paiute Pipeline Company, a subsidiary of the Company, filed a general rate case with the Federal Energy Regulatory Commission ("FERC") in February 2009. The filing fulfilled an obligation from the settlement agreement reached in the 2005 Paiute general rate case. The application requested an increase in operating revenues of approximately $3.9 million. In accordance with FERC requirements, the requested new rates went into effect in September 2009, subject to refund. In April 2010, the FERC approved an offer of settlement from Paiute which resolved all issues related to its general rate case. The settlement provided for an increase of approximately $900,000 in Paiute's annual operating income. Paiute had been accruing a liability for the difference between the requested rates and the anticipated settlement rates since September 2009 and refunded the over-collected amounts in the second quarter of 2010.

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- and under-collections. At December 31, 2010, over-collections in Arizona and Nevada resulted in a liability of $123.4 million and under-collections in California resulted in an asset of $356,000 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):

	2010	2009
Arizona	$ (45.2)	$(33.2)
Northern Nevada	(8.4)	1.2
Southern Nevada	(69.8)	(60.0)
California	0.4	2.0
	$(123.0)	$(90.0)

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 current over-collected balance to customers. On an annual basis, the surcredit is designed to refund approximately $40 million; however, continued low natural gas prices have resulted in a net increase in the balance due customers. 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 provide the most timely recovery of gas costs in any Southwest jurisdiction and are designed to send appropriate pricing signals to customers.

Nevada Gas Cost Filings. In Nevada, quarterly gas cost changes, that are based on a twelve-month rolling average, are utilized. Annual deferred energy account adjustments are subject to a prudence review and audit of the natural gas costs incurred. In June 2010, Southwest filed its annual rate adjustment application with the PUCN to establish revised Deferred Energy Account Adjustment (“DEAA”) rates (in addition to adjustments to the Variable Interest Expense Recovery, the Uncollectible Gas Cost Expense rates, and other rate-related items). In October 2010, Southwest filed a stipulation to settle all issues in this case, which was approved by the PUCN effective November 2010. Accordingly, this settlement reduces customer DEAA rates and is designed to result in decreases over the fourteen-month period ending December 2011 of $42.1 million, or 9.58%, in southern Nevada and $11.9 million, or 9.75%, in northern Nevada, which should allow the Company to significantly decrease the Nevada PGA balances.

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 fixed-for-floating swap contracts (“Swaps”) under its volatility mitigation programs for a portion (ranging from 25 percent to 50 percent, depending on the jurisdiction) of its annual normal weather supply needs. For the 2010/2011 heating season, contracts contained in the fixed-price portion of the portfolio range in price from approximately $4 to $7 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.

Capital Resources and Liquidity

Cash on hand and cash flows from operations have generally been sufficient over the past three years to provide for net investing activities (primarily construction expenditures and property additions). During the same three-year period, the Company has been able to reduce the net amount of debt outstanding (including subordinated debentures and short-term borrowings). The Company's capitalization strategy is to maintain an appropriate balance of equity and debt.

To facilitate future financings, the Company has a universal shelf registration statement providing for the issuance and sale of registered securities from time to time, which may consist of secured debt, unsecured debt, preferred stock, or common stock. The number and dollar amount of securities issued under the universal shelf registration statement, which was filed with the Securities and Exchange Commission ("SEC") and automatically declared effective in December 2008, will be determined at the time of the offerings and presented in the applicable prospectuses.

Cash Flows

Operating Cash Flows. Cash flows provided by consolidated operating activities decreased $34.8 million in 2010 as compared to 2009. An increase in net income was more than offset by temporary fluctuations in working capital components and a $32.1 million increase in pension contributions between years, which is included in the caption Changes in other liabilities and deferred credits.

Investing Cash Flows. Cash used in consolidated investing activities decreased $61.9 million in 2010 as compared to 2009. The current period includes cash inflows from the draw-down of funds, restricted for construction activities, associated with an industrial development revenue bond issuance in 2009.

Financing Cash Flows. Cash used in consolidated financing activities increased $15.2 million during 2010 as compared to 2009 primarily due to debt repayments, including the redemption in March 2010 of the $100 million 7.7% Subordinated Debentures, and the pay down of a revolving credit facility, partially offset by cash inflows from the issuance of new debt. See also *2010 Financing Activity* below. Dividends paid increased in 2010 as compared to 2009 as a result of a quarterly dividend increase 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. The capital requirements and resources of the construction services segment are not material to the overall capital requirements and resources of the Company.

2010 Construction Expenditures

During the three-year period ended December 31, 2010, total gas plant increased from $4 billion to $4.6 billion, or at an annual rate of four percent. Replacement, reinforcement, and franchise work was a substantial portion of the plant increase and customer growth also required increased expenditures as the Company set 67,000 meters resulting in 24,000 net new customers during the three-year period.

During 2010, construction expenditures for the natural gas operations segment were $188 million. The majority of these expenditures represented costs associated with routine and targeted replacement of existing transmission, distribution, and general plant. Cash flows from operating activities of Southwest were $342 million which provided sufficient funding for construction expenditures and dividend requirements of the natural gas operations segment.

2010 Financing Activity

In March 2010, the Company redeemed the $100 million, 7.70% Subordinated Debentures (Preferred Securities) at par. The Company facilitated the redemption using existing cash and borrowings under the $300 million credit facility, though there were no borrowings outstanding on the credit facility by year-end 2010.

In December 2010, the Company issued $125 million in 4.45% Senior Notes, due December 2020 at a discount of 0.182%. A portion of the net proceeds was used to pay down borrowings under the credit facility. In February 2011, the Company used approximately $75 million of the remaining net proceeds in connection with its repayment of $200 million of maturing debt. The remaining proceeds are intended for general corporate purposes.

During 2010, the Company issued shares of common stock through the Dividend Reinvestment and Stock Purchase Plan ("DRSPP") and Stock Incentive Plan, raising approximately $11 million. The Company ceased issuing new common stock under the DRSPP in mid 2010 (the DRSPP will purchase shares on the open market as needed).

Bonus Depreciation. In September 2010, the Small Business Jobs Act of 2010 ("Act") was signed into law. The Act provides a 50 percent bonus tax depreciation deduction for qualified property acquired or constructed and placed in service in 2010. In December 2010, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 ("Tax Relief Act") was signed into law. The Tax Relief Act, among other things, extends the availability of the 50 percent bonus tax depreciation deduction through December 31, 2012. In addition, the Tax Relief Act provides for a temporary 100 percent bonus tax depreciation deduction for qualified property acquired or constructed and placed in service after September 8, 2010 and before January 1, 2012.

As a result of the two acts signed into law in 2010, 50 percent bonus tax depreciation is now available for qualified property acquired or constructed and placed in service from January 1, 2010 through September 8, 2010 and from January 1, 2012 through December 31, 2012. Bonus tax depreciation of 100 percent is available for qualified property acquired or constructed and placed in service from September 9, 2010 through December 31, 2011. Based on forecasted qualifying construction expenditures, Southwest estimates the bonus depreciation provisions of the two acts will defer the payment of approximately $20 million, $50 million, and $20 million of federal income taxes during 2010, 2011, and 2012, respectively.

Three-Year Construction Expenditures, Debt Maturities, and Financing

In connection with the financial benefits of bonus depreciation, Southwest plans to accelerate approximately $110 million of its pipe replacement, reinforcement, and other future capital expenditures into 2011 and 2012. Including the accelerated amounts, Southwest estimates natural gas segment construction expenditures during the three-year period ending December 31, 2013 will be approximately $680 million. Of this amount, approximately $280 million are expected to be incurred in 2011. During the three-year period, cash flows from operating activities of Southwest (including the bonus depreciation benefits) are expected to provide approximately 80% of the gas operations total construction expenditures and dividend requirements. During the three-year period, the Company expects to raise approximately $15 million from its various common stock programs. Southwest also has $37.8 million in restricted cash from a 2009 Industrial Development Revenue Bond offering that is available to fund qualifying construction expenditures in southern Nevada. Any cash requirements not met by operating activities are expected to be provided by existing credit facilities and/or other external financing sources. The timing, types, and amounts of these additional external financings will be dependent on a number of factors, including conditions in the capital markets, timing and amounts of rate relief, growth levels in Southwest's service areas, and earnings. These external financings may include the issuance of both debt and equity securities, bank and other short-term borrowings, and other forms of financing.

During the three-year period, Southwest has a total of $400 million of maturing debt (including $200 million in February 2011 and $200 million in May 2012). In November 2010, the Company entered into a note purchase agreement with certain institutional investors pursuant to which the Company agreed to issue $125 million of 6.1% Senior Notes to them. The Senior Notes will be unsecured and unsubordinated obligations of the Company, due in February 2041. In February 2011, the Company issued $125 million of 6.1% Senior Notes pursuant to the agreement and used the proceeds to partially fund the redemption of $200 million in maturing debt. Southwest also has $200 million of long-term debt maturing in May 2012 and plans to fund that obligation by issuing $200 million of debentures by the maturity date.

In connection with a portion of planned debt issuances, the Company, in January 2010, entered into two forward-starting interest rate swap ("FSIRS") agreements to hedge the risk of interest rate variability during the period leading up to planned issuances. The counterparties to each agreement are four major banking institutions. The first FSIRS had a notional amount of $125 million, constituting a hedge related to the 4.45% Senior Notes issued in December (discussed in *2010 Financing Activity* above), and terminated on the date of the new debt agreement. At settlement, Southwest paid $11.7 million to the four counterparties. The second FSIRS has a notional amount of $100 million (with Southwest as the fixed-rate payer at a rate of 4.78%) and has a mandatory termination date on or before March 20, 2012. The remaining FSIRS agreement is designated as a cash flow hedge of forecasted future interest payments.

Liquidity

Liquidity refers to the ability of an enterprise to generate sufficient amounts of cash through its operating activities and external financing 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 generally 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. At December 31, 2010, the combined balance in the PGA accounts totaled an over-collection of $123 million. See PGA Filings for more information on recent regulatory filings.

The Company has a $300 million credit facility that expires in May 2012. Southwest has designated $150 million of the $300 million facility as long-term debt and the remaining $150 million for working capital purposes. At December 31, 2010, no borrowings were outstanding on either the long-term or short-term portion of the credit facility. During 2010, the short-term portion of the facility was not used. Usage of the long-term portion during 2010 was minimal. The credit facility can be used as necessary to meet liquidity requirements, including temporarily financing under-collected PGA balances, if any, or meeting the refund needs of over-collected balances. 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. Management believes the Company currently has a solid liquidity position.

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., the better the rating, the lower the cost to borrow funds).

In April 2010, Standard & Poor's Ratings Services ("S&P") affirmed the Company's BBB rating and revised the Company's outlook to "positive." S&P cited the Company's stronger financial performance and an improved debt to capital ratio. S&P debt ratings range from AAA (highest rating possible) to D (obligation is in default). The S&P rating of BBB indicates the issuer of the debt is regarded as having an adequate capacity to pay interest and repay principal.

In May 2010, Moody's Investors Service, Inc. ("Moody's") upgraded the Company's senior unsecured debt rating to Baa2 from Baa3 (the outlook remains stable). Moody's cited improvements in the Company's cash flow credit metrics and generally robust financial results in 2009. Moody's applies a Baa rating to obligations which are considered medium grade obligations with adequate security. A numerical modifier of 1 (high end of the category) through 3 (low end of the category) is included with the Baa to indicate the approximate rank of a company within the range.

In June 2010, Fitch, Inc. ("Fitch") upgraded the Company's rating outlook to positive from stable. Fitch affirmed the Company's unsecured long-term debt rating at BBB. Fitch debt ratings range from AAA (highest credit quality) to D (defaulted debt obligation). The Fitch rating of BBB indicates a credit quality that is considered prudent for investment.

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. Certain debt instruments also have leverage ratio caps and minimum net worth requirements. At December 31, 2010, the Company is in compliance with all of its covenants. Under the most restrictive of the covenants, the Company could issue over $1.5 billion in additional debt and meet the leverage ratio requirement and has at least $600 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, 2010 (millions of dollars):

	Payments due by period				
Contractual Obligations	Total	2011	2012-2013	2014-2015	Thereafter
Operating activities:					
Operating leases (Note 2)	$ 25	$ 5	$ 10	$ 6	$ 4
Gas purchase obligations	315	241	73	1	—
Pipeline capacity	805	112	141	141	411
Derivatives (Note 13)	19	12	7	—	—
Other commitments	14	7	5	1	1
Financing activities:					
Long-term debt (Note 7)	1,200	75	200	—	925
Interest on long-term debt	989	62	92	92	743
Other	16	—	—	1	15
Total	$3,383	$514	$ 528	$ 242	$ 2,099

Obligations for Operating Activities: The table 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 184 million dekatherms. Fixed-price contracts range in price from approximately $4 to $7 per dekatherm. Variable-price contracts reflect minimum contractual obligations.

Southwest has pipeline capacity 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.

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. The $75 million due in 2011 reflects the net of the $200 million maturing note, offset by $125 million pursuant to the Note Purchase Agreement dated November 2010.

Other: Estimated funding for pension and other postretirement benefits during calendar year 2011 is $29 million. The Company has an insignificant amount of liabilities in connection with uncertainty surrounding income tax positions taken or expected to be taken.

Results of Construction Services

Year Ended December 31,	2010	2009	2008
(Thousands of dollars)			
Construction revenues	$318,464	$278,981	$353,348
Operating expenses:			
Construction expenses	277,804	242,461	311,745
Depreciation and amortization	20,007	23,232	27,382
Operating income	20,653	13,288	14,221
Other income (deductions)	(166)	55	63
Net interest deductions	564	1,179	1,823
Income before income taxes	19,923	12,164	12,461
Income tax expense	7,852	4,466	5,235
Net income	12,071	7,698	7,226
Net income (loss) attributable to noncontrolling interest	(424)	(364)	—
Contribution to consolidated net income attributable to NPL	$ 12,495	$ 8,062	$ 7,226

2010 vs. 2009

Contribution to consolidated net income from construction services for 2010 increased $4.4 million compared to 2009. The increase was due primarily to revenue growth and a reduction in depreciation expense. Gains on sales of equipment were $1.5 million for 2010 and $3.3 million for 2009.

The prolonged economic downturn and general slowdown in the new housing market have dramatically reduced the amount of new construction activities. NPL has been able to offset reductions in new construction with replacement work received under existing blanket contracts and incremental bid work in 2010. New construction work is expected to remain sluggish in 2011, although continued opportunities for incremental replacement work appear favorable.

Revenues increased $39.5 million due primarily to increased replacement and bid work. The construction revenues include NPL contracts with Southwest totaling $61.3 million in 2010 and $52.6 million in 2009. NPL accounts for the services provided to Southwest at contractual (market) prices.

Construction expenses increased $35.3 million due primarily to the overall increase in construction work, partially offset by cost savings initiatives and a $1.1 million payroll tax credit from the Hiring Incentives to Restore Employment Act. Depreciation expense decreased $3.2 million as a result of a reduction in the construction equipment fleet. Interest expense decreased $615,000 between years due to a reduction in outstanding debt.

NPL 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. Generally, revenues and profits are lowest during the first quarter of the year due to unfavorable winter weather conditions. Operating results typically improve as more favorable weather conditions occur during the summer and fall months.

2009 vs. 2008

Contribution to consolidated net income from construction services for 2009 increased $836,000 compared to 2008. The increase was due primarily to a reduction in construction expenses and lower interest deductions. Gains on sales of equipment were $3.3 million for 2009 and $2.1 million for 2008.

The general slowdown in the new housing market and associated construction activities that started in 2007, continued throughout 2008 and 2009. The adverse economic conditions experienced in 2009 negatively impacted the amount of work under existing blanket contracts, and reduced the amount of profitable bid work.

Revenues decreased $74.4 million due primarily to less new construction work and a decrease in bid work. The construction revenues above include NPL contracts with Southwest totaling $52.6 million in 2009 and $63.1 million in 2008. NPL accounts for the services provided to Southwest at contractual (market) prices.

Construction expenses decreased $69.3 million due primarily to the overall reduction in construction work, cost savings initiatives, and lower fuel and fuel-related expenses. Interest expense decreased $644,000 between years due to a reduction in outstanding debt.

Income tax expense improved from the prior year due to certain beneficial impacts of tax regulations in effect in 2009.

In November 2009, NPL entered into a venture to market natural gas engine-driven heating, ventilating, and air conditioning (“HVAC”) technology and products. NPL has a 65 percent interest in the entity (IntelliChoice Energy, “ICE”) and consolidates ICE as a majority-owned subsidiary.

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, net revenues for natural gas that has been delivered but not yet billed are accrued. This accrued utility revenue is estimated each month based on daily sales volumes, applicable rates, number of customers, rate structure, analyses reflecting significant historical trends, weather, and experience. In periods of extreme weather conditions, the interplay of these assumptions could impact the variability of the accrued utility revenue estimates, particularly in the Company's Arizona rate jurisdiction which currently does not have a decoupled rate structure.

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 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.

At December 31, 2010, the Company lowered the discount rate to 5.75% from 6.00% at December 31, 2009. The methodology utilized to determine the discount rate was consistent with prior years. The weighted-average rate of compensation increase and the asset return assumption remain at 3.25% and 8.00%, respectively. Favorable asset returns were experienced during 2010 relative to the assumed rate of return. This partially offset significant losses experienced in 2008. The combined asset return experience, however, coupled with the reduction in the discount rate will increase the expense level for 2011. Pension expense for 2011 is estimated to increase by $2.8 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.

Certifications

The 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, 2010 are included as exhibits to the 2010 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, projections, strategies, future events or performance, and underlying assumptions. The words "may," "will," "should," "could," "expect," "plan," "anticipate," "believe," "estimate," "predict," "continue," "forecast," and similar words and expressions are generally used and intended to identify forward-looking statements. For example, statements regarding operating margin patterns, customer growth, economic-related declines, the composition of our customer base, price volatility, seasonal patterns, the sufficiency of the level of contracted firm interstate capacity, payment of debt, the Company's COLI strategy, timing of improvements in the housing market, replacement market and new construction market, amount and timing for completion of estimated future construction expenditures, forecasted operating cash flows and results of operations, funding sources of cash requirements, sufficiency of working capital, the Company's views regarding its liquidity position, ability to raise funds and receive external financing, the amount and form of any such financing, the effectiveness of forward-starting interest rate swap agreements in hedging against changing interest rates, pension and post-retirement benefits, liquidity, certain tax benefits from the Act and the Tax Relief Act, the effect of rate decoupling in Arizona, the impact of fuel switching by large customers, expenditures for compliance with any EPA requirements, statements regarding future gas prices, gas purchase contracts and derivative financial instruments, 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, the impact of weather variations on customer usage, customer growth rates, conditions in the housing market, our ability to recover costs through our PGA mechanisms, 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, renewal of franchises, easements and rights-of-way, 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, acquisitions and management's plans related thereto, 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 operations and maintenance 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, 2010.

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

	2010		2009		Dividends Declared	
	High	Low	High	Low	2010	2009
First quarter	$30.70	$26.28	$26.38	$17.08	$0.2500	$ 0.2375
Second quarter	32.91	28.12	22.32	18.96	0.2500	0.2375
Third quarter	34.06	28.58	26.64	21.58	0.2500	0.2375
Fourth quarter	37.25	33.41	29.48	24.81	0.2500	0.2375
					$1.0000	$ 0.9500

The principal market on which the common stock of the Company is traded is the New York Stock Exchange. At February 15, 2011, there were 17,727 holders of record of common stock, and the market price of the common stock was $37.90.

The Company has a common stock dividend policy which states that common stock dividends will be paid at a prudent level that is within the normal dividend payout range for its respective businesses, and that the dividend will be established at a level considered sustainable in order to minimize business risk and maintain a strong capital structure throughout all economic cycles. The quarterly common stock dividend declared was 22.5 cents per share throughout 2008, 23.75 cents per share throughout 2009, and 25 cents per share throughout 2010. In February 2011, the Board of Directors increased the quarterly dividend from 25 cents to 26.5 cents per share, effective with the June 2011 payment.

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

December 31,	2010	2009
ASSETS		
Utility plant:		
Gas plant	$ 4,569,105	$ 4,418,286
Less: accumulated depreciation	(1,535,429)	(1,431,106)
Acquisition adjustments, net	1,271	1,451
Construction work in progress	37,489	45,872
Net utility plant (Note 2)	3,072,436	3,034,503
Other property and investments	134,648	115,860
Restricted cash	37,781	49,769
Current assets:		
Cash and cash equivalents	116,096	65,315
Accounts receivable, net of allowances (Note 3)	147,605	157,722
Accrued utility revenue	64,400	71,700
Income taxes receivable, net	21,514	8,549
Deferred income taxes (Note 12)	8,046	22,410
Deferred purchased gas costs (Note 4)	356	3,251
Prepaids and other current assets (Note 4)	87,877	88,685
Total current assets	445,894	417,632
Deferred charges and other assets (Notes 4 and 13)	293,434	288,528
Total assets	$ 3,984,193	$ 3,906,292

CONSOLIDATED BALANCE SHEETS - Continued

December 31,	2010	2009
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, $1 par (authorized - 60,000,000 shares; issued and outstanding - 45,599,036 and 45,091,734 shares) (Note 11)	$ 47,229	$ 46,722
Additional paid-in capital	807,885	792,339
Accumulated other comprehensive income (loss), net (Note 5)	(30,784)	(22,250)
Retained earnings	343,131	285,316
Total Southwest Gas Corporation equity	1,167,461	1,102,127
Noncontrolling interest	(465)	(41)
Total equity	1,166,996	1,102,086
Subordinated debentures due to Southwest Gas Capital II (Note 6)	—	100,000
Long-term debt, less current maturities (Note 7)	1,124,681	1,169,357
Total capitalization	2,291,677	2,371,443
Commitments and contingencies (Note 9)		
Current liabilities:		
Current maturities of long-term debt (Note 7)	75,080	1,327
Accounts payable	165,536	158,856
Customer deposits	86,891	91,668
Accrued general taxes	40,438	40,868
Accrued interest	20,162	19,644
Deferred purchased gas costs (Note 4)	123,344	93,226
Other current liabilities (Notes 4 and 13)	85,510	68,641
Total current liabilities	596,961	474,230
Deferred income taxes and other credits:		
Deferred income taxes and investment tax credits (Note 12)	466,628	436,113
Taxes payable	1,234	3,079
Accumulated removal costs (Note 4)	211,000	189,000
Other deferred credits (Notes 4 and 10)	416,693	432,427
Total deferred income taxes and other credits	1,095,555	1,060,619
Total capitalization and liabilities	$3,984,193	$3,906,292

The accompanying notes are an integral part of these statements.

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

Year Ended December 31,	2010	2009	2008
Operating revenues:			
Gas operating revenues	$1,511,907	$1,614,843	$1,791,395
Construction revenues	318,464	278,981	353,348
Total operating revenues	1,830,371	1,893,824	2,144,743
Operating expenses:			
Net cost of gas sold	736,175	866,630	1,055,977
Operations and maintenance	354,943	348,942	338,660
Depreciation and amortization	190,463	190,082	193,719
Taxes other than income taxes	38,869	37,318	36,780
Construction expenses	277,804	242,461	311,745
Total operating expenses	1,598,254	1,685,433	1,936,881
Operating income	232,117	208,391	207,862
Other income and (expenses):			
Net interest deductions (Notes 7 and 8)	(75,677)	(75,270)	(84,919)
Net interest deductions on subordinated debentures (Note 6)	(1,912)	(7,731)	(7,729)
Other income (deductions)	3,850	6,645	(13,406)
Total other income and (expenses)	(73,739)	(76,356)	(106,054)
Income before income taxes	158,378	132,035	101,808
Income tax expense (Note 12)	54,925	44,917	40,835
Net income	103,453	87,118	60,973
Net income (loss) attributable to noncontrolling interest	(424)	(364)	—
Net income attributable to Southwest Gas Corporation	$ 103,877	$ 87,482	$ 60,973
Basic earnings per share (Note 15)	$ 2.29	$ 1.95	$ 1.40
Diluted earnings per share (Note 15)	$ 2.27	$ 1.94	$ 1.39
Average number of common shares outstanding	45,405	44,752	43,476
Average shares outstanding (assuming dilution)	45,823	45,062	43,775

The accompanying notes are an integral part of these statements.

SOUTHWEST GAS CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY AND COMPREHENSIVE INCOME
(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	Comprehensive Income (Loss)
	Shares	Amount						
DECEMBER 31, 2007	42,806	$ 44,436	$ 732,319	$ (12,850)	$ 219,768	$ —	$ 983,673	
Common stock issuances	1,386	1,386	38,144				39,530	
Net income					60,973		60,973	$ 60,973
Net actuarial gain (loss) arising during the period, less amortization of unamortized benefit plan cost, net of $4 million of tax (Note 10)				(6,576)			(6,576)	(6,576)
Dividends declared Common: $0.90 per share					(39,759)		(39,759)	
2008 Comprehensive Income								$ 54,397
DECEMBER 31, 2008	44,192	45,822	770,463	(19,426)	240,982	—	1,037,841	
Common stock issuances	900	900	21,876				22,776	
Net income (loss)					87,482	(364)	87,118	$ 87,118
Noncontrolling interest capital investment						323	323	
Net actuarial gain (loss) arising during the period, less amortization of unamortized benefit plan cost, net of $1.7 million of tax (Note 10)				(2,824)			(2,824)	(2,824)
Dividends declared Common: $0.95 per share					(43,148)		(43,148)	
2009 Comprehensive Income								$ 84,294
Comprehensive income (loss) attributable to noncontrolling interest								(364)
Comprehensive income attributable to Southwest Gas Corporation								$ 84,658
DECEMBER 31, 2009	45,092	46,722	792,339	(22,250)	285,316	(41)	1,102,086	
Common stock issuances	507	507	15,546				16,053	
Net income (loss)					103,877	(424)	103,453	$ 103,453
Net actuarial gain (loss) arising during the period, less amortization of unamortized benefit plan cost, net of $1.7 million of tax (Notes 5 and 10)				2,842			2,842	2,842
FSIRS realized and unrealized loss, net of $7 million of tax (Notes 5 and 13)				(11,436)			(11,436)	(11,436)
Amounts reclassified to net income, net of $37,000 of tax (Note 13)				60			60	60
Dividends declared Common: $1.00 per share					(46,062)		(46,062)	
2010 Comprehensive Income								$ 94,919
Comprehensive income (loss) attributable to noncontrolling interest								(424)
Comprehensive income attributable to Southwest Gas Corporation								$ 95,343
DECEMBER 31, 2010	45,599*	$ 47,229	$ 807,885	$ (30,784)	$ 343,131	$ (465)	$ 1,166,996	

*At December 31, 2010, 2.3 million common shares were registered and available for issuance under provisions of the Company's various stock issuance plans. In addition, approximately 369,000 common shares are registered for issuance upon the exercise of options granted under the Stock Incentive Plan (see Note 11).

The accompanying notes are an integral part of these statements.

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

Year Ended December 31,	2010	2009	2008
CASH FLOW FROM OPERATING ACTIVITIES:			
Net Income	$103,453	$ 87,118	$ 60,973
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	190,463	190,082	193,719
Deferred income taxes	50,111	42,798	36,135
Changes in current assets and liabilities:			
Accounts receivable, net of allowances	10,117	11,107	34,831
Accrued utility revenue	7,300	900	2,300
Deferred purchased gas costs	33,013	56,902	20,931
Accounts payable	6,680	(32,578)	(29,297)
Accrued taxes	(15,240)	22,497	(21,837)
Other current assets and liabilities	12,895	32,733	(3,636)
Gains on sale	(1,547)	(3,291)	(2,068)
Changes in undistributed stock compensation	4,429	3,942	3,825
AFUDC and property-related changes	(945)	(1,221)	(561)
Changes in other assets and deferred charges	(12,262)	(15,553)	(5)
Changes in other liabilities and deferred credits	(17,474)	10,366	4,438
Net cash provided by operating activities	370,993	405,802	299,748

CONSOLIDATED STATEMENTS OF CASH FLOWS - Continued

Year Ended December 31,	2010	2009	2008
CASH FLOW FROM INVESTING ACTIVITIES:			
Construction expenditures and property additions	(215,439)	(216,985)	(300,217)
Restricted cash	11,988	(49,769)	—
Changes in customer advances	(830)	(2,476)	4,044
Receipt of exchange fund deposit	—	—	28,000
Miscellaneous inflows	4,075	7,933	17,656
Miscellaneous outflows	(2,800)	(3,620)	(2,693)
Net cash used in investing activities	(203,006)	(264,917)	(253,210)
CASH FLOW FROM FINANCING ACTIVITIES:			
Issuance of common stock, net	11,098	18,401	35,391
Dividends paid	(44,846)	(41,950)	(38,705)
Interest rate swap settlement	(11,691)	—	—
Issuance of long-term debt, net	123,960	49,834	103,875
Retirement of long-term debt	(3,327)	(15,654)	(198,691)
Redemption of subordinated debentures	(100,000)	—	—
Change in long-term portion of credit facility	(92,400)	(57,600)	—
Change in short-term debt	—	(55,000)	46,000
Net cash used in financing activities	(117,206)	(101,969)	(52,130)
Change in cash and cash equivalents	50,781	38,916	(5,592)
Cash and cash equivalents at beginning of period	65,315	26,399	31,991
Cash and cash equivalents at end of period	$ 116,096	$ 65,315	$ 26,399
Supplemental information:			
Interest paid, net of amounts capitalized	$ 87,000	$ 80,771	$ 91,211
Income taxes paid (received)	$ 19,200	$ (21,616)	$ 22,472

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 to customers in portions of Arizona, Nevada, and California. The public utility rates, practices, facilities, and service territories of Southwest are subject to regulatory oversight. 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 provides utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems. In November 2009, NPL entered into a venture to market natural gas engine-driven heating, ventilating, and air conditioning ("HVAC") technology and products. NPL has a 65 percent interest in the entity (IntelliChoice Energy, "ICE") and consolidates ICE 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 the 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.

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.

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.

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 $211 million and $189 million, as of December 31, 2010 and 2009, respectively, of estimated removal costs from accumulated depreciation to accumulated removal costs within the liabilities section of the balance sheets.

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 amount of natural gas distributed, 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 accruals.

The Company acts as an agent for state and local taxing authorities in the collection and remission of a variety of taxes, including franchise fees, sales and use taxes, and surcharges. These taxes are not included in gas operating revenues, except for certain franchise fees in California operating jurisdictions which are not significant. 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 is based on costs expended to date relative to anticipated final contract costs. Revisions in estimates of costs and earnings during the course of the 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.

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 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 salvage value, removal costs, 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 Company capitalized $1.5 million in 2010, $2.2 million in 2009, and $1.2 million in 2008 of AFUDC related to natural gas utility operations. 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. The debt portion of AFUDC was $512,000, $957,000, and $635,000 for 2010, 2009, and 2008, respectively. 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.

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):

	2010	2009	2008
Change in COLI policies	$ 9,770	$ 8,546	$ (12,041)
Interest income	194	271	2,212
Pipe replacement costs	(5,024)	(2,642)	(1,942)
Miscellaneous income and (expense)	(1,090)	470	(1,635)
Total other income (deductions)	$ 3,850	$ 6,645	$ (13,406)

Included in the table above is the change in cash surrender values of company-owned life insurance ("COLI") policies (including net death benefits recognized). 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, the change 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.

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.

(In thousands)	2010	2009	2008
Average basic shares	45,405	44,752	43,476
Effect of dilutive securities:			
Stock options	56	14	60
Performance shares	260	216	193
Restricted stock units	102	80	46
Average diluted shares	45,823	45,062	43,775

Subsequent Events. Management of the Company monitors significant 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. See Note 7 – Long-Term Debt for information regarding debt issued subsequent to December 31, 2010.

Note 2 – Utility Plant

Net utility plant as of December 31, 2010 and 2009 was as follows (thousands of dollars):

December 31,	2010	2009
Gas plant:		
Storage	$ 20,396	$ 20,326
Transmission	274,646	271,467
Distribution	3,847,731	3,716,881
General	279,402	270,825
Other	146,930	138,787
	4,569,105	4,418,286
Less: accumulated depreciation	(1,535,429)	(1,431,106)
Acquisition adjustments, net	1,271	1,451
Construction work in progress	37,489	45,872
Net utility plant	$ 3,072,436	$ 3,034,503

Depreciation and amortization expense on gas plant was $167 million in 2010 and $162 million in both 2009 and 2008.

Operating Leases and Rentals. Southwest leases a portion of its corporate headquarters office complex in Las Vegas and its administrative offices in Phoenix. The leases provide for current terms which expire in 2017 and 2014, respectively, with optional renewal terms available at the expiration dates. The rental payments for the corporate headquarters office complex are $2 million in each of the years 2011 through 2015 and $4 million cumulatively thereafter. The rental payments for the Phoenix administrative offices are $1.4 million in each of the years 2011 through 2013, and $243,000 in 2014 when the lease expires. 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 treated as such for regulatory purposes. Rentals included in operating expenses for all operating leases were $19.4 million in 2010, $19.9 million in 2009, and $23.4 million in 2008. These amounts include NPL lease expenses of approximately $11.8 million in 2010, $11.3 million in 2009, and $13.9 million in 2008, for various short-term operating leases of equipment and temporary office sites.

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, 2010 (thousands of dollars):

Year Ending December 31,	
2011	$ 5,547
2012	4,904
2013	4,697
2014	3,138
2015	2,754
Thereafter	3,599
Total minimum lease payments	$24,639

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. At December 31, 2010, the gas utility customer accounts receivable balance was $110 million. Approximately 54 percent of the gas utility customers were in Arizona, 36 percent in Nevada, and 10 percent in California. 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 based on experience and recorded monthly, as needed. They are included in the ratemaking process as a cost of service. Beginning in November 2009, a regulatory mechanism was implemented in the Nevada jurisdictions 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 for uncollectibles is summarized as follows (thousands of dollars):

	Allowance for Uncollectibles
Balance, December 31, 2007	$ 2,947
Additions charged to expense	7,047
Accounts written off, less recoveries	(6,206)
Balance, December 31, 2008	3,788
Additions charged to expense	6,658
Accounts written off, less recoveries	(6,493)
Balance, December 31, 2009	3,953
Additions charged to expense	2,646
Accounts written off, less recoveries	(3,405)
Balance, December 31, 2010	$ 3,194

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"). Southwest accounting policies 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,	2010	2009
Regulatory assets:		
Accrued pension and other postretirement benefit costs (1)	$ 224,913	$ 224,261
Unrealized loss on non-trading derivatives (Swaps) (2)	11,482	1,496
Deferred purchased gas costs (3)	356	3,251
Accrued purchased gas costs (4)	14,000	12,500
Unamortized premium on reacquired debt (5)	19,881	17,095
Other (8)	28,402	28,055
	299,034	286,658
Regulatory liabilities:		
Deferred purchased gas costs (3)	(123,344)	(93,226)
Accumulated removal costs	(211,000)	(189,000)
Unrealized gain on non-trading derivatives (Swaps) (2)	(656)	(2,618)
Deferred gain on southern Nevada division operations facility (6)	(1,246)	(1,686)
Rate refunds due customers (7)	(546)	—
Unamortized gain on reacquired debt (6)	(13,006)	(13,543)
Other (6)	(2,811)	(2,486)
Net regulatory assets (liabilities)	$ (53,575)	$ (15,901)

(1) Included in Deferred charges and other assets on the Consolidated Balance Sheets. Recovery period is greater than five years. (See Note 10)
(2) Regulatory asset included in Prepaids and other current assets ($11.5 million and $1.4 million) in 2010 and 2009, respectively. Regulatory asset included in Deferred charges and other assets ($75,000) in 2009. Regulatory liability included in Other deferred credits ($656,000 and $58,000) in 2010 and 2009, respectively. Regulatory liability included in Other current liabilities ($2.6 million) in 2009. The actual amounts, when realized at settlement, become a component of gas costs. (See Note 13)
(3) Balance recovered or refunded on an ongoing basis with interest.
(4) Included in Prepaids and other current assets on the Consolidated Balance Sheets and recovered over one year or less.
(5) Included in Deferred charges and other assets on the Consolidated Balance Sheets. Recovered over life of debt instruments.
(6) Included in Other deferred credits on the Consolidated Balance Sheets.
(7) Included in Other current liabilities on the Consolidated Balance Sheet.
(8) 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, net income taxes, and deferred post-retirement benefits other than pensions. Recovery periods vary.

Note 5 – Accumulated Other Comprehensive Income

AOCI - Rollforward
(Thousands of dollars)

	Defined Benefit Plans (Note 10)			FSIRS (Note 13)			
	Before-Tax	Tax (Expense) Benefit	After-Tax	Before-Tax	Tax (Expense) Benefit	After-Tax	AOCI
Beginning Balance AOCI December 31, 2009	$(35,887)	$ 13,637	$(22,250)	$ —	$ —	$ —	$(22,250)
Current period change	4,583	(1,741)	2,842*	(18,349)	6,973	(11,376)**	(8,534)
Ending Balance AOCI December 31, 2010	$(31,304)	$ 11,896	$(19,408)	$(18,349)	$ 6,973	$(11,376)	$(30,784)

* Net actuarial gain (loss), less amortization of unamortized benefit plan cost
**FSIRS unrealized $4.2 million loss recorded in other comprehensive income; FSIRS realized $7.2 million loss, less amounts reclassified to net income, recorded in other comprehensive income.

Approximately $725,000 of realized losses (net of tax) related to the FSIRS reported in AOCI at December 31, 2010 will be reclassified into expense within the next twelve months as the related interest payments on long-term debt occur.

Note 6 - Preferred Trust Securities and Subordinated Debentures

In June 2003, the Company created Southwest Gas Capital II ("Trust II"), a wholly owned subsidiary, as a financing trust for the sole purpose of issuing preferred trust securities for the benefit of the Company. In August 2003, Trust II publicly issued $100 million of 7.70% Preferred Trust Securities ("Preferred Trust Securities"). In connection with the Trust II issuance of the Preferred Trust Securities and the related purchase by the Company for $3.1 million of all of the Trust II common securities ("Common Securities"), the Company issued $103.1 million principal amount of its 7.70% Junior Subordinated Debentures ("Subordinated Debentures") to Trust II. The Subordinated Debentures became redeemable at the option of the Company in August 2008.

In February 2010, the Company notified holders of the Subordinated Debentures that all of these debentures (and the associated preferred and common securities) would be redeemed (at par) by the Company in March 2010. All of the outstanding Subordinated Debentures were redeemed in March 2010. The Company accomplished the redemption using existing cash and borrowings under the $300 million credit facility.

Payments and amortizations associated with the Subordinated Debentures are classified on the consolidated statements of income as Net interest deductions on subordinated debentures. The estimated market value of the subordinated debentures at December 31, 2009 was $102 million.

Note 7 – Long-Term Debt

December 31,	2010		2009	
	Carrying Amount	Market Value	Carrying Amount	Market Value
(Thousands of dollars)				
Debentures:				
Notes, 8.375%, due 2011	$ 200,000	$201,560	$ 200,000	$213,012
Notes, 7.625%, due 2012	200,000	214,666	200,000	219,240
Notes, 4.45%, due 2020	125,000	125,325	—	—
8% Series, due 2026	75,000	99,968	75,000	87,005
Medium-term notes, 7.59% series, due 2017	25,000	30,295	25,000	27,858
Medium-term notes, 7.78% series, due 2022	25,000	32,063	25,000	28,275
Medium-term notes, 7.92% series, due 2027	25,000	33,211	25,000	28,848
Medium-term notes, 6.76% series, due 2027	7,500	8,956	7,500	7,723
Unamortized discount	(2,534)		(2,196)	
	679,966		555,304	
Revolving credit facility and commercial paper, due 2012	—	—	92,400	92,400
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:				
6.10% 1999 Series A, due 2038	12,410	11,968	12,410	11,443
5.95% 1999 Series C, due 2038	14,320	13,594	14,320	12,922
5.55% 1999 Series D, due 2038	8,270	7,468	8,270	7,038
5.45% 2003 Series C, due 2038 (rate resets in 2013)	30,000	31,547	30,000	31,422
5.25% 2003 Series D, due 2038	20,000	17,474	20,000	16,701
5.80% 2003 Series E, due 2038 (rate resets in 2013)	15,000	15,436	15,000	15,683
5.25% 2004 Series A, due 2034	65,000	58,574	65,000	55,979
5.00% 2004 Series B, due 2033	31,200	27,295	31,200	26,096
4.85% 2005 Series A, due 2035	100,000	84,485	100,000	79,469
4.75% 2006 Series A, due 2036	24,855	20,518	24,855	19,139
Unamortized discount	(3,502)		(3,644)	
	517,553		517,411	
Other	2,242	2,473	5,569	5,712
	1,199,761		1,170,684	
Less: current maturities	(75,080)		(1,327)	
Long-term debt, less current maturities	$1,124,681		$1,169,357	

The Company has a $300 million credit facility scheduled to expire in May 2012. The Company uses $150 million of the $300 million as long-term debt and the remaining $150 million for working capital purposes. Interest rates for the facility are calculated at either the London Interbank Offering Rate plus an applicable margin, or the greater of the prime rate or one-half of one percent plus the Federal Funds rate. At December 31, 2010, no borrowings were outstanding on the short-term portion of the credit facility (see Note 8 – Short-Term Debt) and no borrowings were outstanding on the long-term portion. The effective interest rate on the borrowings on the long-term portion of the credit facility was 0.87% at December 31, 2009.

In November 2010, the Company entered into a note purchase agreement with Metropolitan Life Insurance Company, John Hancock Life Insurance Company (U.S.A.), certain of their respective affiliates, and Union Fidelity Life Insurance Company (collectively, the "Purchasers"), pursuant to which the Company agreed to issue $125 million of 6.1% Senior Notes to the Purchasers. The Senior Notes will be unsecured and unsubordinated obligations of the Company, due in February 2041. The full net proceeds from the Senior Notes will be used to partially repay the maturing 8.375% $200 million debentures due in February 2011. Therefore, $125 million of the maturing notes continue to be shown as long-term obligations. In February 2011, the Company issued $125 million of 6.1% Senior Notes pursuant to the agreement and used the proceeds to partially redeem the 8.375% debentures.

In December 2010, the Company issued $125 million in 4.45% Senior Notes due December 2020 at a 0.182% discount. The notes will mature on December 1, 2020. In February 2011, the Company used $75 million of the proceeds to repay a portion of the $200 million 8.375% Notes; the remaining net proceeds are intended for general corporate purposes.

In December 2009, the Company issued $50 million in Clark County, Nevada variable-rate 2009 Series A Industrial Development Revenue Bonds ("IDRBs"), supported by a letter of credit with JPMorgan Chase Bank. At December 31, 2009 and 2010, $49.8 million and $37.8 million, respectively, in proceeds from the issuance of the IDRBs remained in trust and are shown as restricted cash on the consolidated balance sheets.

The effective interest rates on the 2003 Series A, 2008 Series A, and 2009 Series A variable-rate IDRBs were 1.20%, 2.72%, and 2.68%, respectively, at December 31, 2010. The effective interest rate on the 2003 Series A, 2008 Series A, and 2009 Series A variable-rate IDRBs were 1.14%, 3.76%, and 3.68%, respectively, at December 31, 2009. The effective interest rates on the tax-exempt Series A variable-rate IDRBs were 1.18% and 1.12% at December 31, 2010 and 2009, respectively. In Nevada, interest fluctuations due to changing interest rates on the 2003 Series A and 2008 Series A variable-rate IDRBs are tracked and recovered from ratepayers through an interest balancing account.

The fair values of the revolving credit facility and the variable-rate IDRBs approximate carrying value. Market values for the debentures, fixed-rate IDRBs, and other indebtedness were determined based on dealer quotes using trading records for December 31, 2010 and 2009, as applicable, and other secondary sources which are customarily consulted for data of this kind.

Estimated maturities of long-term debt for the next five years are $75.1 million, $200.1 million, $91,000, $97,000, and $103,000, respectively.

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, 2010, the Company is in compliance with all of its covenants. Under the most restrictive of the covenants, the Company could issue over $1.5 billion in additional debt and meet the leverage ratio requirement and has at least $600 million of cushion in equity relating to the minimum net worth requirement.

Note 8 - Short-Term Debt

As discussed in Note 7, Southwest has a $300 million credit facility that expires in May 2012, of which $150 million has been designated by management for working capital purposes (and related outstanding amounts, if any, are shown as short-term debt). Southwest had no short-term borrowings outstanding on the credit facility at December 31, 2010 or December 31, 2009.

Note 9 - 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 has been 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. The self-insured retention amount associated with general liability claims is $1 million per incident plus payment of the first $5 million in aggregate claims above $1 million in the policy year.

Note 10 – 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 deductions of a percentage of base compensation, subject to IRS limitations. Southwest matches up to one-half of amounts deferred. The maximum matching contribution is three and one-half percent of an employee's annual compensation. The cost of the plan was $4.6 million in 2010, $4.5 million in 2009, and $4.4 million in 2008. NPL has a separate plan, the cost and liability of which are not significant.

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 percent of annual cash compensation. Southwest matches one-half of amounts deferred by officers. The maximum matching contribution is three and one-half percent 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 percent 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. The changes in actuarial gains and losses, prior service costs and transition assets or obligations pertaining to the regulatory asset will be recognized as an adjustment to the regulatory asset account as these amounts are 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. The current 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 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 the continuing low interest rate environment for high-quality fixed income investments, the Company lowered the discount rate from 6.00% at December 31, 2009 to 5.75% at December 31, 2010. The methodology utilized to determine the discount rate was consistent with prior years. The weighted-average rate of compensation increase and the asset return assumption remain at 3.25% and 8.00%, respectively. Favorable asset returns were experienced during 2010 and 2009 relative to the assumed rate of return. This partially offset the significant losses experienced in 2008. The combined asset return experience, however, coupled with the reduction in the discount rate will increase the expense level for 2011. Pension expense for 2011 is estimated to increase by $2.8 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 status and amounts recognized on the Consolidated Balance Sheets and Statements of Income.

	2010			2009		
	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)	$ 606,276	$ 35,339	$ 42,322	$ 523,011	$ 31,786	$ 35,915
Service cost	16,932	372	856	15,390	195	729
Interest cost	35,614	2,045	2,491	34,527	2,065	2,370
Actuarial loss (gain)	27,680	(3,480)	2,632	55,356	3,785	4,546
Benefits paid	(24,368)	(2,416)	(1,536)	(22,008)	(2,492)	(1,238)
Benefit obligation at end of year (PBO/PBO/APBO)	662,134	31,860	46,765	606,276	35,339	42,322
Change in plan assets						
Market value of plan assets at beginning of year	392,975	—	25,511	323,460	—	19,436
Actual return on plan assets	53,224	—	3,181	69,523	—	4,540
Employer contributions	54,100	2,416	1,348	22,000	2,492	1,535
Benefits paid	(24,368)	(2,416)	(400)	(22,008)	(2,492)	—
Market value of plan assets at end of year	475,931	—	29,640	392,975	—	25,511
Funded status at year end	$ (186,203)	$ (31,860)	$ (17,125)	$ (213,301)	$ (35,339)	$ (16,811)
Weighted-average assumptions (benefit obligation)						
Discount rate	5.75%	5.75%	5.75%	6.00%	6.00%	6.00%
Weighted-average rate of compensation increase	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%

The accumulated benefit obligation for the retirement plan was $591 million and $530 million, and for the SERP was $30.7 million and $31.5 million at December 31, 2010 and 2009, respectively.

Estimated funding for the plans above during calendar year 2011 is approximately $29 million of which $28 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.

Pension benefits expected to be paid for each of the next five years beginning with 2011 are the following: $28 million, $29 million, $31 million, $33 million, and $35 million. Pension benefits expected to be paid during

2016 to 2020 total $204 million. Retiree welfare benefits expected to be paid for each of the next five years beginning with 2011 are the following: $2 million, $2.1 million, $2.3 million, $2.5 million, and $2.6 million. Retiree welfare benefits expected to be paid during 2016 to 2020 total $15 million. SERP benefits expected to be paid in 2011 are $2.3 million, and they are approximately $2.5 million for each of the next four years beginning with 2012. SERP benefits expected to be paid during 2016 to 2020 total $13 million. No assurance can be made that actual funding and benefits paid will match these estimates.

For PBOP measurement purposes, the per capita cost of covered health care benefits medical rate trend assumption is eight percent declining to five percent. The Company makes fixed contributions for health care benefits of employees who retire after 1988, but pays up to 100 percent of 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		
	2010	2009	2008	2010	2009	2008	2010	2009	2008
(Thousands of dollars)									
Service cost	$ 16,932	$ 15,390	$ 16,108	$ 372	$ 195	$ 97	$ 856	$ 729	$ 730
Interest cost	35,614	34,527	32,491	2,045	2,065	2,041	2,491	2,370	2,324
Expected return on plan assets	(36,538)	(35,221)	(34,714)	—	—	—	(2,093)	(1,603)	(2,138)
Amortization of prior service costs (credits)	—	(2)	(11)	—	—	—	—	—	—
Amortization of transition obligation	—	—	—	—	—	—	867	867	867
Amortization of net actuarial loss	10,478	4,253	3,104	1,155	909	997	489	434	—
Net periodic benefit cost	$ 26,486	$ 18,947	$ 16,978	$3,572	$3,169	$3,135	$ 2,610	$ 2,797	$ 1,783
Weighted-average assumptions (net benefit cost)									
Discount rate	6.00%	6.75%	6.50%	6.00%	6.75%	6.50%	6.00%	6.75%	6.50%
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	3.25%	3.75%	4.00%	3.25%	3.75%	4.00%	3.25%	3.75%	4.00%

Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income

	2010				2009			
	Total	Qualified Retirement Plan	SERP	PBOP	Total	Qualified Retirement Plan	SERP	PBOP
(Thousands of dollars)								
Net actuarial loss (gain) (a)	$ 9,058	$ 10,994	$(3,480)	$1,544	$ 26,448	$ 21,054	$3,785	$1,609
Amortization of prior service credit (b)	—	—	—	—	2	2	—	—
Amortization of transition obligation (b)	(867)	—	—	(867)	(867)	—	—	(867)
Amortization of net actuarial loss (b)	(12,122)	(10,478)	(1,155)	(489)	(5,596)	(4,253)	(909)	(434)
Regulatory adjustment	(652)	(464)	—	(188)	(15,431)	(15,123)	—	(308)
Recognized in other comprehensive (income) loss	$ (4,583)	$ 52	$(4,635)	$ —	$ 4,556	$ 1,680	$2,876	$ —
Total of amount recognized in net periodic benefit cost and other comprehensive (income) loss	$ 28,085	$ 26,538	$(1,063)	$2,610	$ 29,469	$ 20,627	$6,045	$2,797

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.

Related Tax Effects Allocated to Each Component of Other Comprehensive Income

	2010			2009		
(Thousands of dollars)	Before-Tax Amount	Tax (Expense) or Benefit (1)	Net-of-Tax Amount	Before-Tax Amount	Tax (Expense) or Benefit (1)	Net-of-Tax Amount
Defined benefit pension plans:						
Net actuarial loss (gain)	$ 9,058	$ (3,442)	$ 5,616	$ 26,448	$ (10,050)	$16,398
Amortization of prior service credit	—	—	—	2	(1)	1
Amortization of transition obligation	(867)	329	(538)	(867)	329	(538)
Amortization of net loss	(12,122)	4,606	(7,516)	(5,596)	2,126	(3,470)
Regulatory adjustment	(652)	248	(404)	(15,431)	5,864	(9,567)
Other comprehensive (income) loss	$ (4,583)	$ 1,741	$(2,842)	$ 4,556	$ (1,732)	$ 2,824

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

The estimated net loss that will be amortized from accumulated other comprehensive income or regulatory assets into net periodic benefit cost over the next year is $14.4 million for the qualified retirement plan and $600,000 for the SERP. The estimated amounts for the PBOP that will be amortized from regulatory assets into net periodic benefit cost over the next year are $600,000 related to net loss and $870,000 for the transition obligation.

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, 2010 and December 31, 2009. The SERP has no assets.

	December 31, 2010			December 31, 2009		
	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						
Cash equivalents	$ 48	$ 2	$ 50	$ 39	$ 1	$ 40
Common stock	213,853	6,978	220,831	175,247	5,719	180,966
Real estate investment trusts	4,504	147	4,651	2,731	89	2,820
Mutual funds	49,994	14,234	64,228	42,070	12,604	54,674
Government fixed income	11,020	360	11,380	6,580	215	6,795
Preferred securities	—	—	—	169	5	174
Futures contracts	(51)	(2)	(53)	(51)	(2)	(53)
Total Level 1 Assets (1)	$ 279,368	$21,719	$301,087	$ 226,785	$18,631	$245,416
Level 2 - Significant other observable inputs						
Cash equivalents	$ —	$ —	$ —	$ 3	$ —	$ 3
Commercial paper	—	—	—	1,414	46	1,460
Government fixed income and mortgage backed	39,201	1,279	40,480	36,078	1,177	37,255
Corporate fixed income	54,197	1,768	55,965	40,646	1,326	41,972
Pooled funds and mutual funds	8,230	1,974	10,204	9,588	1,767	11,355
State and local obligations	626	20	646	262	9	271
Total Level 2 assets (2)	$ 102,254	$ 5,041	$107,295	$ 87,991	$ 4,325	$ 92,316
Level 3 - Significant unobservable inputs						
Commingled equity funds	$ 94,389	$ 3,080	$ 97,469	$ 75,418	$ 2,461	$ 77,879
Total Level 3 assets (3)	$ 94,389	$ 3,080	$ 97,469	$ 75,418	$ 2,461	$ 77,879
Total Plan assets at fair value	$ 476,011	$29,840	$505,851	$ 390,194	$25,417	$415,611
Guaranteed investment contracts/guaranteed annuity contracts (4)	5,342	—	5,342	5,673	—	5,673
Total Plan assets (5)	$ 481,353	$29,840	$511,193	$ 395,867	$25,417	$421,284

(1) Equity securities, Real Estate Investment Trusts, 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. 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

(4) The guaranteed investment contracts/guaranteed annuity 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 $5.6 million (qualified retirement plan - $5.4 million, PBOP – $200,000), 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)

	Commingled Equity Funds
(Thousands of dollars):	
Balance, December 31, 2008	$ 57,017
Actual return on plan assets:	
Relating to assets still held at the reporting date	20,466
Relating to assets sold during the period	816
Purchases, sales, and settlements	(420)
Transfers in and/or out of Level 3	—
Balance, December 31, 2009	$ 77,879
Actual return on plan assets:	
Relating to assets still held at the reporting date	13,090
Relating to assets sold during the period	—
Purchases, sales, and settlements	6,500
Transfers in and/or out of Level 3	—
Balance, December 31, 2010	$ 97,469

Note 11 – Stock-Based Compensation

At December 31, 2010, the Company had three stock-based compensation plans: a stock option plan, a performance share stock plan, and a restricted stock/unit plan. Total stock-based compensation expense recognized in the consolidated statements of income for the years ended December 31, 2010, December 31, 2009, and December 31, 2008 were $5.9 million (net of related tax benefits of $3.6 million), $5.2 million (net of related tax benefits of $3.2 million), and $4.9 million (net of related tax benefits of $3 million), respectively.

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):

	2010			2009			2008		
	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	651	$	27.49	731	$	27.12	798	$	26.85
Granted during the year	—		—	—		—	—		—
Exercised during the year	(273)		26.67	(66)		23.18	(64)		23.70
Forfeited or expired during the year	(9)		29.51	(14)		28.88	(3)		27.72
Outstanding at year end	369	$	28.04	651	$	27.49	731	$	27.12
Exercisable at year end	369	$	28.04	651	$	27.49	663	$	26.55

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 was $3.2 million, $1.7 million, and $661,000 at December 31, 2010, 2009, and 2008, respectively. The aggregate intrinsic value of exercised options was $1.7 million, $294,000, and $339,000 during 2010, 2009, and 2008, respectively. The market value of Southwest Gas stock was $36.67, $28.53, and $25.22 at December 31, 2010, 2009, and 2008, respectively.

The weighted-average remaining contractual life for outstanding options was 4.5 years for 2010. All outstanding options are fully vested and exercisable. The following table summarizes information about stock options outstanding at December 31, 2010 (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	102	3.0 Years	$22.61
$24.50 to $26.10	94	4.4 Years	$25.78
$29.08 to $33.07	173	5.5 Years	$32.49

The total grant date fair value of options vested was $405,000 and $824,000 during 2009 and 2008, respectively. The Company received $7.3 million in cash from the exercise of options during 2010 and a corresponding tax benefit of $625,000 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 and 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/unit plan was also established to attract, motivate, and retain experienced and knowledgeable independent directors. The restricted stock/units vest 40 percent at the end of year one and 30 percent at the end of years two and three.

The following table summarizes the activity of the performance share stock and restricted stock/unit plans as of December 31, 2010 (thousands of shares):

	Performance Shares	Weighted-average grant date fair value	Restricted Stock/Units	Weighted-average grant date fair value
Nonvested at beginning of year	320	$ 29.20	146	$ 26.47
Granted	137	29.04	85	29.04
Dividends	12		5	
Forfeited or expired	—	—	—	—
Vested and issued*	(103)	35.15	(66)	27.74
Nonvested at December 31, 2010	366	$ 27.54	170	$ 27.42

*Includes shares converted for taxes and retiree payouts.

The average grant date fair value of performance shares granted in 2009 and 2008 was $24.46 and $29.31, respectively. The average grant date fair value of restricted stock/units granted in 2009 and 2008 was $24.46 and $27.25, respectively.

Note 12 - Income Taxes

As of December 31, 2010 and 2009, the Company had $1.4 million of uncertain tax liabilities which, if recognized, would favorably impact the effective tax rate. There was no change to the balance of unrecognized tax benefits during 2010. The Company expects the balance of unrecognized tax benefits to be reduced to zero in the next twelve months. The Company recognizes interest expense and income and penalties related to income tax matters in income tax expense. Tax-related interest income of $500,000, $200,000, and $900,000 is included in the consolidated statements of income for 2010, 2009, and 2008, respectively. Tax-related interest payable of $100,000 is included in the consolidated balance sheets at December 31, 2010 and December 31, 2009.

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 2006, and is subject to examination by the various state taxing authorities for years after 2005.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (thousands of dollars):

	2010	2009
Unrecognized tax benefits at beginning of year	$1,445	$1,445
Gross increases – tax positions in prior period	—	—
Gross decreases – tax positions in prior period	—	—
Gross increases – current period tax positions	—	—
Gross decreases – current period tax positions	—	—
Settlements	—	—
Lapse of statute of limitations	—	—
Unrecognized tax benefits at end of year	$1,445	$1,445

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

Year Ended December 31,	2010	2009	2008
Current:			
Federal	$ 4,204	$ (1,020)	$ 5,420
State	4,442	3,101	1,106
	8,646	2,081	6,526
Deferred:			
Federal	44,778	41,410	32,569
State	1,501	1,426	1,740
	46,279	42,836	34,309
Total income tax expense	$54,925	$44,917	$40,835

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

Year Ended December 31,	2010	2009	2008
Deferred federal and state:			
Property-related items	$43,420	$46,201	$ 53,978
Purchased gas cost adjustments	(315)	(4,167)	(15,918)
Employee benefits	8,753	(452)	(1,884)
All other deferred	(4,711)	2,122	(999)
Total deferred federal and state	47,147	43,704	35,177
Deferred ITC, net	(868)	(868)	(868)
Total deferred income tax expense	$46,279	$42,836	$ 34,309

The consolidated effective income tax rate for the period ended December 31, 2010 and the two prior periods differ from the federal statutory income tax rate. The sources of these differences and the effect of each are summarized as follows:

Year Ended December 31,	2010	2009	2008
Federal statutory income tax rate	35.0%	35.0%	35.0%
Net state taxes	2.8	2.5	2.4
Property-related items	0.2	0.2	0.2
Effect of income tax settlements	(0.3)	(0.2)	(0.9)
Tax credits	(0.5)	(0.7)	(0.9)
Company owned life insurance	(2.3)	(2.5)	4.0
All other differences	(0.2)	(0.3)	0.3
Consolidated effective income tax rate	34.7%	34.0%	40.1%

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

December 31,	2010	2009
Deferred tax assets:		
Deferred income taxes for future amortization of ITC	$ 4,280	$ 4,817
Employee benefits	31,384	41,877
Alternative minimum tax credit	15,495	19,894
Interest rate swap	6,973	—
Other	8,026	7,129
	66,158	73,717
Deferred tax liabilities:		
Property-related items, including accelerated depreciation	500,216	456,795
Regulatory balancing accounts	836	1,151
Property-related items previously flowed through	3,910	5,014
Unamortized ITC	6,860	7,728
Debt-related costs	4,824	5,011
Other	8,094	11,721
	524,740	487,420
Net deferred tax liabilities	$458,582	$413,703
Current	$ (8,046)	$ (22,410)
Noncurrent	466,628	436,113
Net deferred tax liabilities	$458,582	$413,703

Note 13 – 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. Southwest also 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.

The fixed-price contracts and Swaps are utilized by Southwest under its volatility mitigation programs to effectively fix the price on a portion (ranging from 25 percent to 50 percent, depending on the jurisdiction) of its natural gas portfolios. The maturities of the Swaps highly correlate to forecasted purchases of natural gas, during time frames ranging from January 2011 through October 2012. Under such contracts, Southwest pays the counterparty at 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 (approximately 14.2 million dekatherms at December 31, 2010 and 13.6 million dekatherms at December 31, 2009). 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, 2010, 2009, and 2008 and their location in the income statements (thousands of dollars):

Derivatives not designated as hedging instruments:

	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative		
		Year Ended December 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Swaps	Net cost of gas sold	$ (27,690)	$ (4,391)	$ (18,351)
Swaps	Net cost of gas sold	27,690*	4,391*	18,351*
Total		$ —	$ —	$ —

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

In January 2010, Southwest entered into two forward starting interest rate swaps ("FSIRS") to hedge the risk of interest rate variability during the period leading up to the planned issuance of fixed-rate debt to replace $200 million of debt maturing in February 2011 and $200 million maturing in May 2012. The counterparties to each agreement are four major banking institutions. The first FSIRS was a designated cash flow hedge and had a notional amount of $125 million. It terminated in December 2010 concurrent with the related issuance of $125 million 4.45% 10-year Senior Notes. At settlement of the first FSIRS, Southwest paid an aggregate $11.7 million to the counterparties. The second FSIRS has a notional amount of $100 million (with Southwest as the fixed-rate payer at a rate of 4.78%) and has a mandatory termination date on or before March 20, 2012.

Southwest previously designated the second FSIRS agreement as a cash flow hedge of forecasted future interest payments. At the inception of the hedge, the terms of the derivative were the same as a perfect hypothetical derivative; thus, there is an expectation that there will be no ineffectiveness, and that the effective portion of unrealized gains and losses on the FSIRS leading up to the forecasted debt issuance will be reported as a component of other comprehensive income. At termination, the final value will be reclassified from accumulated other comprehensive income into earnings over the terms of the debt issuance which is the same period the hedged forecasted transaction affects earnings. However, should conditions occur that indicate the existence of ineffectiveness (e.g., deterioration of counterparty creditworthiness, delay in the forecasted debt issuances, etc.), Southwest will measure ineffectiveness by comparing changes in the fair value of the FSIRS with changes in the fair value of a hypothetical swap (the hypothetical derivative method). Gains and losses due to ineffectiveness will be recognized immediately in earnings. At December 31, 2010, the remaining FSIRS continued to qualify as an effective hedge. There was no gain or (loss) reclassified from accumulated other comprehensive income ("AOCI") into income (effective portion) and no gain or (loss) recognized in income (ineffective portion) for the Company's second derivative designated as a hedging instrument.

The following table sets forth the gains and (losses) on a before-tax basis recognized on the Company's FSIRS (thousands of dollars):

Derivatives designated as hedging instruments:

Gains (losses) on derivatives in cash flow hedging relationships:

	Gains (losses) on interest rate swaps — FSIRS Year Ended December 31, 2010
Amount of Gain or (Loss) on Unrealized FSIRS Recognized in Other Comprehensive Income on Derivative (Effective Portion)	$ (6,755)
Amount of Gain or (Loss) on Realized FSIRS Recognized in Other Comprehensive Income on Derivative	(11,691)
Total	$ (18,446)

There were no gains or (losses) on derivatives designated as cash flow hedging instruments for the years ended December 31, 2009 and 2008.

The following table sets forth the fair values of the Company's Swaps and FSIRS and their location in the balance sheets (thousands of dollars):

Fair values of derivatives not designated as hedging instruments:

December 31, 2010	Balance Sheet Location	Asset Derivatives	Liability Derivatives	Net Total
Swaps	Deferred charges and other assets	$ 656	$ —	$ 656
Swaps	Other current liabilities	65	(11,547)	(11,482)
Total		$ 721	$ (11,547)	$ (10,826)

December 31, 2009	Balance Sheet Location	Asset Derivatives	Liability Derivatives	Net Total
Swaps	Deferred charges and other assets	$ 85	$ (27)	$ 58
Swaps	Prepaids and other current assets	2,921	(361)	2,560
Swaps	Other current liabilities	309	(1,730)	(1,421)
Swaps	Other deferred credits	25	(100)	(75)
Total		$ 3,340	$ (2,218)	$ 1,122

Fair values of derivatives designated as hedging instruments:

December 31, 2010	Balance Sheet Location	Asset Derivatives	Liability Derivatives	Net Total
FSIRS	Other deferred credits	$ —	$ (6,755)	$ (6,755)

There were no derivatives designated as hedging instruments at December 31, 2009.

The estimated fair values of the Swaps 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.

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. During the year ended December 31, 2010, Southwest paid counterparties $16.6 million in settlement of matured Swaps and received $831,000 from counterparties in settlement of matured Swaps. During the years ended December 31, 2009 and 2008, Southwest paid counterparties $19.7 million and $4.2 million, respectively, in settlements of matured Swaps. Neither changes in the fair value of the Swaps nor realized amounts have a direct effect on earnings or other comprehensive income.
At December 31, 2010, regulatory assets/liabilities offsetting the amounts in the above table were recorded in Prepaids and other current assets ($11.5 million) and Other deferred credits ($656,000). At December 31, 2009, regulatory assets/liabilities offsetting the amounts in the balance sheet were recorded in Prepaids and other current assets ($1.4 million), Other current liabilities ($2.6 million), Other deferred credits ($58,000), and Deferred charges and other assets ($75,000).

Fair Value Measurements. The estimated fair values of Southwest's Swaps were determined at December 31, 2010 and 2009 using NYMEX futures settlement prices for delivery of natural gas at Henry Hub, adjusted by the price of New York Mercantile Exchange ("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 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 estimated fair value of Southwest's FSIRS was determined using a discounted cash flow model that utilizes forward interest rate curves. The inputs to the model are the terms of the FSIRS. These Level 2 inputs are observable in the marketplace throughout the full term of the FSIRS, but have been credit-risk adjusted with no significant impact to the overall fair value measure.

See Note 10 – Pension and Other Postretirement Benefits for definitions of the levels of the fair value hierarchy. The following table sets forth, by level within the fair value hierarchy, the Company's financial asset and liability derivatives that were accounted for at fair value:

Level 2 - Significant other observable inputs

(Thousands of dollars)	December 31, 2010	December 31, 2009
Assets at fair value:		
Prepaids and other current assets — swaps	$ —	$ 2,560
Deferred charges and other assets — swaps	656	58
Liabilities at fair value:		
Other current liabilities — swaps	(11,482)	(1,421)
Other deferred credits — swaps	—	(75)
Other deferred credits — FSIRS	(6,755)	—
Net Assets (Liabilities)	$ (17,581)	$ 1,122

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

Related Tax Effects of Designated Hedging Activities Allocated to Each Component of Other Comprehensive Income

	2010		
(Thousands of dollars)	Before-Tax Amount	Tax (Expense) or Benefit (1)	Net-of-Tax Amount
FSIRS:			
Unrealized/realized loss	$ (18,446)	$ 7,010	$ (11,436)
Amounts reclassified into net income	97	(37)	60
Other comprehensive (income) loss	$ (18,349)	$ 6,973	$ (11,376)

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

There were no FSIRS for the years ended December 31, 2009 and 2008.

See Note 5 – Accumulated Other Comprehensive Income for more information on the FSIRS.

Note 14 – 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, transporting, and distributing natural gas. Revenues are generated from the sale and transportation of natural gas. The construction services segment is 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 December 31, 2010 and 2009, accounts receivable for these services totaled $8.1 million and $5.3 million, respectively, which were not eliminated during consolidation.

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, 2010 is as follows (thousands of dollars):

2010	Gas Operations	Construction Services	Adjustments (a)	Total
Revenues from unaffiliated customers	$1,511,907	$ 257,213		$1,769,120
Intersegment sales	—	61,251		61,251
Total	$1,511,907	$ 318,464		$1,830,371
Interest revenue	$ 158	$ 36		$ 194
Interest expense	$ 77,025	$ 564		$ 77,589
Depreciation and amortization	$ 170,456	$ 20,007		$ 190,463
Income tax expense	$ 47,073	$ 7,852		$ 54,925
Segment income	$ 91,382	$ 12,495		$ 103,877
Segment assets	$3,845,111	$ 139,082		$3,984,193
Capital expenditures	$ 188,379	$ 27,060		$ 215,439

2009	Gas Operations	Construction Services	Adjustments (a)	Total
Revenues from unaffiliated customers	$1,614,843	$ 226,407		$1,841,250
Intersegment sales	—	52,574		52,574
Total	$1,614,843	$ 278,981		$1,893,824
Interest revenue	$ 189	$ 82		$ 271
Interest expense	$ 81,822	$ 1,179		$ 83,001
Depreciation and amortization	$ 166,850	$ 23,232		$ 190,082
Income tax expense	$ 40,451	$ 4,466		$ 44,917
Segment income	$ 79,420	$ 8,062		$ 87,482
Segment assets	$3,782,913	$ 124,755	$ (1,376)	$3,906,292
Capital expenditures	$ 212,919	$ 4,066		$ 216,985

2008	Gas Operations	Construction Services	Adjustments (a)	Total
Revenues from unaffiliated customers	$1,791,395	$ 290,218		$2,081,613
Intersegment sales	—	63,130		63,130
Total	$1,791,395	$ 353,348		$2,144,743
Interest revenue	$ 2,107	$ 105		$ 2,212
Interest expense	$ 90,825	$ 1,823		$ 92,648
Depreciation and amortization	$ 166,337	$ 27,382		$ 193,719
Income tax expense	$ 35,600	$ 5,235		$ 40,835
Segment income	$ 53,747	$ 7,226		$ 60,973
Segment assets	$3,680,327	$ 140,057		$3,820,384
Capital expenditures	$ 279,254	$ 20,963		$ 300,217

(a) Construction services segment assets include income taxes payable of $1.4 million in 2009, which were netted against gas operations segment income taxes receivable, net during consolidation.

Note 15 - Quarterly Financial Data (Unaudited)

	Quarter Ended			
	March 31	June 30	September 30	December 31
(Thousands of dollars, except per share amounts)				
2010				
Operating revenues	$668,751	$385,825	$ 307,683	$ 468,112
Operating income	121,732	24,031	184	86,170
Net income (loss)	64,648	(933)	(4,823)	44,985
Basic earnings (loss) per common share*	1.43	(0.02)	(0.11)	0.99
Diluted earnings (loss) per common share*	1.42	(0.02)	(0.11)	0.98
2009				
Operating revenues	$689,862	$387,648	$ 317,509	$ 498,805
Operating income	102,729	14,685	522	90,455
Net income (loss)	49,981	(594)	(8,297)	46,392
Basic earnings (loss) per common share*	1.13	(0.01)	(0.18)	1.03
Diluted earnings (loss) per common share*	1.12	(0.01)	(0.18)	1.02
2008				
Operating revenues	$813,607	$447,304	$ 374,422	$ 509,410
Operating income	104,685	18,256	2,900	82,021
Net income (loss)	49,152	(2,725)	(16,686)	31,232
Basic earnings (loss) per common share*	1.14	(0.06)	(0.38)	0.71
Diluted earnings (loss) per common share*	1.14	(0.06)	(0.38)	0.71

* 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 the 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. 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, 2010. The effectiveness of the Company's internal control over financial reporting as of December 31, 2010 has been audited by PricewaterhouseCoopers, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

February 28, 2011

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 cash flows and of equity and comprehensive income present fairly, in all material respects, the financial position of Southwest Gas Corporation and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 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, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). 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.

/s/ PricewaterhouseCoopers LLP
Los Angeles, California
February 28, 2011

EXHIBIT 21.01

SOUTHWEST GAS CORPORATION
LIST OF SUBSIDIARIES OF THE REGISTRANT
AT DECEMBER 31, 2010

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

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-156420 and 333-157930) and Form S-8 (Nos. 333-168731, 333-147952, 333-155581, and 333-106762) of Southwest Gas Corporation of our report dated February 28, 2011 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

Los Angeles, California
February 28, 2011

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 28, 2011

/s/ JEFFREY W. SHAW

Jeffrey W. Shaw
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 28, 2011

/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, 2010 as filed with the Securities and Exchange Commission (the "Report"), I, Jeffrey W. Shaw, the 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 28, 2011

/s/ Jeffrey W. Shaw
Jeffrey W. Shaw
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, 2010 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 28, 2011

/s/ Roy R. Centrella

Roy R. Centrella
Senior Vice President/Chief Financial Officer