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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH-GAS") FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) AUTHORITY, TO THE EXTENT NECESSARY AS AN ALTERNATIVE REGULATORY PLAN, TO RECOVER ITS UNACCOUNTED FOR GAS COSTS AND THE GAS COST COMPONENT OF ITS BAD DEBT EXPENSE IN ITS GAS COST ADJUSTMENT FILINGS; (4) APPROVAL OF A DISTRIBUTION REPLACEMENT ADJUSTMENT TO RECOVER THE COSTS OF A PROGRAM FOR THE ACCELERATED REPLACEMENT OF CAST IRON MAINS AND BARE STEEL MAINS AND SERVICE LINES; (5) APPROVAL OF THE IMPLEMENTATION OF THE SALES RECONCILIATION COMPONENT OF THE ENERGY EFFICIENCY RIDER PROPOSED IN CAUSE NOS. 42943 AND 43046 OR OTHER RATE DESIGN CHANGES THAT UNLINK ITS FIXED COST RECOVERY FROM ITS SALES VOLUME; (6) APPROVAL AS AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-6 OF A RETURN ON EQUITY TEST TO BE USED IN LIEU OF THE STATUTORY NET OPERATING INCOME TEST IN ITS GAS COST ADJUSTMENT PROCEEDINGS; (7) AUTHORITY PURSUANT TO 170 IAC 5-1-27(F) FOR A NON-GAS COST REVENUE TEST TO DETERMINE WHEN DEPOSITS ARE REQUIRED FOR FACILITIES EXTENSIONS; AND (8) APPROVAL OF VARIOUS CHANGES TO ITS TARIFF FOR GAS SERVICE, INCLUDING INCREASES IN CERTAIN NON-RECURRING CHARGES.	)	CAUSE NO. 43112 APPROVED: AUG 0 1 2007

<u>BY THE COMMISSION</u>:
Larry S. Landis, Commissioner
Gregory D. Server, Commissioner
Abby R. Gray, Administrative Law Judge

On September 1, 2006, Southern Indiana Gas Company and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Petitioner," "Company" or "Vectren South") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking authority to increase its rates and charges for gas utility service and for approval of new schedules of rates and charges applicable thereto, the recovery of unaccounted for gas costs and the gas cost component of bad debt expense in its gas cost adjustment ("GCA") filings, a Distribution Replacement Adjustment to recover costs relating to the accelerated replacement of cast iron mains and bare steel mains and services, the implementation of the sales reconciliation component of its energy efficiency rider, a return on equity earnings test to be used in its GCA proceedings, changes in the deposit requirements for facility extensions and various other changes to its Tariff For Gas Service. The Petition provided notice of Petitioner's election to proceed under the Commission's rules on Minimum Standard Filing Requirements, 170 IAC 1-5-1 *et seq.* ("MSFRs").

Petitions to intervene were filed by Mead Johnson and AK Steel Corporation ("AK Steel") and the SIGECO Industrial Group ("Industrial Group"), whose only member is Alcoa, Inc. These petitions were granted and these entities were made parties to this Cause.

Pursuant to the Prehearing Conference on October 16, 2006, the Prehearing Conference Order dated November 21, 2006, and notice of hearing given as provided by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, a public hearing in this Cause was held on December 4-5, 2006, at which time Petitioner presented its case-in-chief and its witnesses were cross-examined.

Pursuant to Ind. Code § 8-1-2-61(b), a public field hearing was held on January 8, 2007 in the City of Evansville, the largest municipality in Petitioner's service area. At the field hearing, members of the public were afforded the opportunity to make statements to the Commission.

On January 30, 2007, the Indiana Office of Utility Consumer Counselor ("OUCC") and AK Steel filed the prepared testimony and exhibits constituting their respective cases-in-chief except for the OUCC's evidence on Petitioner's proposed Distribution Replacement Adjustment ("DRA"). On that same date, the Industrial Group filed a Notice of Agreement in Principle.

On February 2, 2007, the Commission issued a docket entry directing Petitioner to provide information on a number of matters.

On February 7, 2007, Petitioner and Alcoa filed a Stipulation and Settlement Agreement ("Alcoa Settlement") resolving issues between them in this cause and proposing approval of a new Natural Gas Transportation Agreement between them ("Alcoa Agreement").

On February 13, 2007, AK Steel filed cross-answering testimony and exhibits responding to the OUCC's prefiled evidence.

On February 16, 2007, Petitioner filed a Motion to Protect Certain Terms of the Alcoa Agreement from Disclosure. The Motion was granted on a preliminary basis by docket entry dated February 26, 2007.

On February 23, 2007, Petitioner filed its rebuttal testimony and exhibits and its supplemental testimony in support of the Alcoa Settlement.

On February 27, 2007, the OUCC filed its testimony on Petitioner's DRA proposal. On February 27, 2007, Petitioner filed a response to the Commission's docket entry dated February 2, 2007. On March 6, 2007, Petitioner filed its rebuttal testimony on the DRA.

On March 15, 2007, Petitioner, the OUCC and AK Steel filed a Stipulation and Settlement Agreement ("Settlement" or "OUCC Settlement") containing a proposed resolution of the issues in this proceeding. A copy of the OUCC Settlement Agreement is attached hereto as *Exhibit 1* and incorporated herein by reference. On March 16, 2007, Petitioner and the OUCC prefiled supplemental testimony and exhibits in support of the Settlement.

A hearing on the OUCC Settlement and Alcoa Settlement was held on March 23, 2007. At that time, the supplemental testimony and exhibits of Petitioner and the OUCC in support of the OUCC Settlement and Petitioner's supplemental evidence in support of the Alcoa Settlement were admitted. The witnesses providing testimony in support of the OUCC Settlement responded to questions from the bench. The prefiled case-in-chief of the OUCC and AK Steel, AK Steel's cross-answering testimony and Petitioner's prefiled rebuttal evidence were also admitted for the purpose of providing further evidentiary support for the reasonableness of the Settlement.

On March 26, 2007, pursuant to a request from the bench at the hearing on March 23, 2007, Petitioner filed workpapers providing detail on the pro forma adjustments that form the basis for the revenue requirement agreed to in the Settlement. On April 13, 2007, Petitioner filed a revised proposed Gas Tariff making certain corrections and incorporating certain language changes resulting from discussions between Petitioner, the OUCC and the Commission Staff.

Based upon the applicable law and evidence presented herein, the Commission now finds as follows:

1. **Notice and Jurisdiction.** Due, legal and timely notice of the filing of the Petition in this Cause was given and published by Petitioner as required by law. Proper and timely notice was given by Petitioner to its customers summarizing the nature and extent of the proposed changes in its rates and charges for gas service. Due, legal and timely notices of the Prehearing Conference and the public hearings in this Cause were given and published as required by law. Petitioner is a public utility as defined in Ind. Code § 8-1-2-1(a) and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana. Therefore, this Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. **Petitioner's Characteristics.** Petitioner is an Indiana corporation engaged in the business of rendering gas utility service to approximately 112,000 customers in nine (9) counties in southwestern Indiana. Petitioner renders such gas utility service by means of utility plant, property, equipment and related facilities owned, leased, operated, managed and controlled by it, which are used and useful for the convenience of the public in the production, treatment, transmission, distribution and sale of gas.

3. **Existing Rates.** Petitioner's existing basic rates and charges for gas utility service were established pursuant to the Commission's Order in Cause No. 42596 dated June 30,

2004 ("2004 Rate Order") that approved a Stipulation and Settlement agreement between Petitioner, the OUCC and Alcoa.

4. **Test Year.** As provided in the Prehearing Conference Order, the test year to be used for determining Petitioner's actual and pro forma operating revenues, expenses and operating income under present and proposed rates is the twelve months ended March 31, 2006. We find that the financial data for this test year, when adjusted for fixed, known and measurable changes as provided in the Prehearing Conference Order, is a proper basis for fixing new rates for Petitioner and testing the effect thereof.

5. **Evidence of the Parties.**

A. **Petitioner's Case-In-Chief.** In its case-in-chief, Petitioner requested an increase in its base rates of $10.4 million per year or 6.7%. Jerome A. Benkert, Jr., Petitioner's Executive Vice President and Chief Financial Officer, testified that Petitioner's earned return on equity ("ROE") had been inadequate for several years. According to Mr. Benkert, Petitioner agreed to the 5% increase approved in the 2004 Rate Order, which was less than 40% of its requested increase, in order to achieve earlier rate relief, avoid expensive and time consuming litigation and obtain other benefits, including a tracker to recover costs relating to the Pipeline Safety Improvement Act of 2002 ("Safety Act"). Mr. Benkert stated that even after the 2004 increase, Petitioner's customers continued to benefit from very low gas rates. Mr. Benkert discussed steps taken by Petitioner to address the challenges it faces from abnormal weather, declining customer usage, gas price volatility and environmental remediation. Mr. Benkert called attention to concerns expressed by credit rating agencies about declining per customer usage and the need for rate design modifications that decouple fixed cost recovery from customer usage. Mr. Benkert testified that Petitioner competes for capital with utilities that have decoupling mechanisms and other risk mitigation rate designs, including the peer group companies used by Mr. Moul to estimate Petitioner's cost of common equity. He noted that Petitioner's authorized ROE is no higher than other companies with such mechanisms. Mr. Benkert testified that he believed approval of the decoupling mechanism provided for in Petitioner's then-pending settlement agreement in Cause Nos. 42943 and 43046 ("Efficiency Settlement") should not result in a reduction to Petitioner's authorized rate of return.

Mr. Benkert noted that the Efficiency Settlement permitted Petitioner to propose in this cause a decoupling mechanism (referred to therein as the Sales Reconciliation Component or "SRC") that varies from that in the Efficiency Settlement so long as it provided non-commodity cost recovery regardless of usage. Petitioner proposed an SRC that would recoup 100% of such lost margins. In Mr. Benkert's opinion, there was no reason to implement an SRC for Petitioner that provides less than full margin recovery because all of Petitioner's costs, including its cost of capital, are being reviewed in this proceeding.

Mr. Benkert also identified the looming retirement segments of Petitioner's skilled workforce as a significant issue facing the Company. He stated replacing the retirees with qualified personnel was essential for Petitioner's future ability to operate reliably.

Mr. Benkert stated Petitioner's proposed tracker for the recovery of the cost of replacing obsolete bare steel and cast iron pipelines on an accelerated basis will support Petitioner's ability to raise the debt and equity capital needed for this important system improvement.

Mr. Benkert also described Petitioner's proposed treatment of the gas cost component of bad debt expense and unaccounted for gas costs, its incentive compensation plans and its multi-year Asset Management Transformation ("AMT") project to use new technology to improve its field work efficiency.

Mr. Benkert also discussed Petitioner's proposal to adopt an ROE earnings test ("ROE Test") in lieu of the statutory net operating income test ("NOI Test") used in its GCA proceedings. He said the ROE Test is a superior test because it will recognize investment changes over time which the static NOI Test does not.

Prior to the hearing on Petitioner's case-in-chief, the Commission issued its Order dated December 1, 2006 in Cause Nos. 42943 and 43046 ("Efficiency Order") approving the Efficiency Settlement with certain modifications. The Efficiency Order permits Petitioner to implement an SRC when a final order is issued in this cause. In commenting on this approval at the hearing, Mr. Benkert testified that Petitioner's peer companies in other states already had decoupling mechanisms, infrastructure trackers and ROE adjustment mechanisms, and decoupling approval will allow Petitioner to better compete for capital with them. Tr. A67-A69.

M. Susan Hardwick, Petitioner's Vice President, Controller and Assistant Treasurer, testified regarding Petitioner's actual and pro forma cost of gas service and the determination of its rate base and revenue requirement. She discussed each of the revenue and expense adjustments made to the test year financial results. She determined that a revenue increase of $10,436,430 was necessary to provide a 7.96% return (as determined by Petitioner's Witness Goocher) on Petitioner's net original cost rate base as of March 31, 2006. At the hearing on Petitioner's case-in-chief, Ms. Hardwick submitted an updated calculation of Petitioner's original cost rate base as of October 31, 2006 of $121,668,882. Pet. Ex. MSH-6.

Robert C. Sears, Director of Revenue Administration for Vectren Utility Holdings, Inc. ("VUHI"), testified regarding Petitioner's proposal to track the gas cost component of bad debt expense in its quarterly GCA proceedings. He provided information regarding the impact of volatile gas prices on Petitioner's bad debt expense and write-offs. He described this as an industry-wide concern and listed utilities with mechanisms to track such expenses. He stated that Petitioner aggressively manages its bad debt expense and discussed Company initiatives to control bad debts. He also stated that if Petitioner's proposal were approved, it would still have an incentive to control bad debts because Petitioner will be at risk for the margin component of bad debt expense. He explained that only the gas cost component (over which Petitioner has no control) would be tracked.

Paul R. Moul, a financial and regulatory consultant, testified regarding Petitioner's cost of equity capital. Mr. Moul expressed the opinion that Petitioner's cost of equity was within a range of 11.50% to 12.00% and recommended that an 11.75% ROE be used for purposes of this case. Mr. Moul's recommendation was based on the results of a discounted cash flow ("DCF") model, a risk premium analysis, a capital asset pricing model ("CAPM") and a comparable earnings approach. His studies used a proxy group of eight gas distribution companies ("Gas Group") that he asserted are comparable in risk to Petitioner. Mr. Moul said he selected publicly traded gas distribution companies not subject to a merger announcement that have at least 70% of their assets in the regulated sector. Mr. Moul asserted his analysis takes into account Petitioner's revenue decoupling and normal temperature adjustment mechanisms because all members of the Gas Group have margin stabilization mechanisms similar to those of Petitioner. He characterized the use of such mechanisms as a trend within the industry. He noted that Petitioner is subject to risk related to earnings attrition even with decoupling because other costs are rising while margins are flat, and customer growth is modest.

Robert L. Goocher, Petitioner's Vice President and Treasurer, testified regarding Petitioner's capital structure and cost of capital. Using the capital structure as of March 31, 2006, the weighted cost of long term debt, the cost of equity recommended by Mr. Moul and the other components of the ratemaking capital structure (customer deposits, cost free capital and investment tax credits), Mr. Goocher computed a weighted cost of capital of 7.96%.

William S. Doty, Petitioner's President, testified regarding Petitioner's plan to deal with its aging workforce, training and safety programs, the AMT project, maintenance and engineering programs, customer contract center, meter reading and billing costs and utility plant in service.

James M. Francis, Director of Technical Services for VUHI, testified regarding Petitioner's proposed bare steel and cast iron pipeline replacement program under which Petitioner would replace such infrastructure, consisting of 279 miles of pipe, over a 20-year period at an estimated cost in 2006 dollars of $90 million. He indicated these facilities are more susceptible to corrosion, fractures and leaks than facilities made from the types of materials used today, causing higher operating and maintenance expenses, greater line losses and safety and reliability risks. Mr. Francis identified fourteen other gas distribution companies with similar replacement programs. He said Stone & Webster Management Consultants ("S&W") performed an independent review of Petitioner's distribution system and concluded Petitioner should pursue the replacement program.

Mr. Francis also testified about Petitioner's compliance with the Integrity Management Program required by the Safety Act and the United States Department of Transportation's rules thereunder. These requirements apply to transmission pipelines in high consequence areas. Mr. Francis described an ongoing audit of the program by the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). He discussed the impact on Petitioner of PHMSA's anticipated rules requiring a Distribution Integrity Management Program.

John P. Kelly, an asset valuation specialist, testified regarding a valuation study he performed of Petitioner's gas utility properties. In his opinion, the reproduction cost new less depreciation value of these assets is about $242.8 million. To make sure the effect of technological change was fully reflected, he made a further downward adjustment using a factor of 2.25% per year from the date of installation recommended by Mr. Moul, resulting in a replacement cost after depreciation value of $172.8 million.

Ronald B. Keeping, Petitioner's Director of Economic Development and Market Research, testified about Petitioner's role in promoting economic development in southwestern Indiana and its proposed Economic Development ("ED") and Area Development ("AD") Riders. He described how the Company and its customers benefit from economic development. He stated the ED Rider would be a general purpose discounted rate for a period of 24 months for customers receiving assistance from a governmental entity for new or expanded businesses which create incremental new employment. He testified that the AD Rider will encourage a customer to make investments in specific locations within Petitioner's service area, by providing discounted rates for a period of five years. He stated that this Rider is proposed to encourage redevelopment of existing large, unused industrial buildings, Brownfield areas and designated economic development zones.

Kerry A. Heid, a rate consultant, performed a cost of service study for Petitioner's gas utility business and allocated the revenue requirement to the various rate schedules. Mr. Heid determined the rate of return on the rate base allocated to each rate schedule and the corresponding subsidies paid or received, as compared to equalized rates of return. He also calculated the subsidy levels at Petitioner's proposed rates. Mr. Heid explained how the proposed rates for each rate schedule were determined and identified increases that would be experienced by customers in each class. He also set forth the cost justification for Petitioner's proposed non-recurring charges.

Scott E. Albertson, Petitioner's Director of Regulatory Affairs, testified about Petitioner's proposed tracking of unaccounted for gas ("UAFG") costs (which currently are recovered only in base rates) within the GCA mechanism. He stated tracking of UAFG was more appropriate under current conditions of volatile and high market prices for gas. He noted that Petitioner's UAFG level is relatively low compared to other utilities. He also testified that tracking of UAFG will protect customers from the risk of over-recovery during times of declining gas prices. He provided an exhibit identifying many gas utilities that recover UAFG in gas cost tracking mechanisms and detailing the UAFG percentage of each company. Mr. Albertson further stated that Petitioner would report its UAFG percentage, volumes and costs in GCA filings and these costs can be audited for reasonableness. Mr. Albertson provided a similar explanation for Petitioner's proposal to track the gas cost component of bad debt expense in its GCA filings, rather than recover such costs solely in base rates.

Mr. Albertson also testified about Petitioner's proposed DRA, which would include the submission of construction plans, annual filings and reflection of offsetting maintenance expense savings. He sponsored an exhibit of proposed forms for the DRA filings with illustrative examples of how they would be used.

Mr. Albertson stated Petitioner proposes to include in this proceeding incremental expenses for Safety Act compliance activities that have been or will be deferred through March 31, 2007 pursuant to the 2004 Rate Order, which are eligible for recovery in Petitioner's Pipeline Safety Adjustment ("PSA") but which have not yet been included in the PSA and will not be included in the 2007 annual PSA filing because they exceed the annual cap. In Petitioner's proposed adjustment (Pet. Ex. MSH-3, Adj. A27), these amounts would be amortized over three years.

Mr. Albertson also sponsored Petitioner's proposed Gas Tariff and described how it differed from the existing tariff. The changes include determining the limit for free line extensions based on 5½ years of non-gas cost revenue, rather than three years of total revenue as is now the case. Mr. Albertson testified that high gas costs have made the three-year total revenue test inadequate to provide a fair return on the new investment and to protect existing customers from subsidizing customers requesting line extensions. He noted that 170 IAC 5-1-27(C)(2) permits departures from the total revenue test with Commission approval.

B. <u>OUCC's Case-In-Chief.</u> In its case-in-chief, the OUCC proposed an increase in Petitioner's rates of $5,103,622 in annual revenues. Lafayette K. Morgan, Jr., Senior Regulatory Analyst with Exeter Associates, Inc., testified regarding the OUCC's determination of Petitioner's revenue requirement and required rate increase.

Mr. Morgan used the updated original cost rate base as of October 31, 2006 quantified by Ms. Hardwick at the initial hearing but applied a 6.66% rate of return to that rate base in accordance with the recommendation of OUCC Witness Woolridge.

Mr. Morgan disagreed with Petitioner's adjustment to eliminate test year revenues of two large customers, Consolidated Grain Barge ("CGB") and Hoosier Magnetic, because they continued to take service after the end of the test year and CGB has agreed to transfer its lease to an ethanol plant developer.

With respect to operating expenses, Mr. Morgan made the following changes to Petitioner's pro forma adjustments:

(1) reduced injuries and damages expense because he believed an extraordinary claim was overstated and should be amortized over a longer period;

(2) reduced AMT project expense to reflect savings in regulator inspections and to remove a charge that he said should have been capitalized;

(3) reduced uncollectible accounts expense by using a three-year average ratio of write-offs to revenue (rather than a five-year ratio);

(4) eliminated a distribution operations expense adjustment on the grounds that it was not incremental to the annualized labor cost adjustment;

(5) reduced distribution maintenance expense to offset amounts incurred during the test year and to eliminate non-recurring right-of-way maintenance mowings;

(6) reduced property and risk insurance expense based on the most recent premiums;

(7) reduced restricted stock and stock option expense to be in line with a three-year average;

(8) reduced incentive plan expense to reflect actual experience in recent years;

(9) reduced the Aging Workforce Adjustment to eliminate Human Resources costs that he contended are indirect and not fixed, known and measurable; reflect updated costs produced in discovery; and to eliminate one of two contractors;

(10) reduced labor expense to eliminate unfilled positions;

(11) reduced payroll taxes by using a lower payroll loading rate;

(12) reduced the Vectren Utility Holdings, Inc. ("VUHI") asset charge to reflect the OUCC's proposed rate of return;

(13) eliminated meter reading incentives for discovering non-registering or diverted meters on the grounds that such discoveries will increase revenues;

(14) eliminated from the AMT adjustment maintenance costs on GPS units on the grounds that newly acquired units should not need maintenance; and

(15) removed Safety Act costs pursuant to OUCC Witness Grosskopf's recommendation.

Mark H. Grosskopf, a Utility Analyst in the OUCC's Natural Gas Division, testified regarding the OUCC's position on Safety Act expenses. He said the OUCC agreed with Petitioner that the PSA should continue beyond the three year review period provided for in the 2004 Rate Order. Mr. Grosskopf stated the intent of the PSA is to provide a dollar-for-dollar recovery of PSA costs and inclusion of a portion of such costs in base rates could result in over- or under-recoveries. He supported excluding any PSA costs from the base rates set in this proceeding and re-negotiating the annual deferred cost recovery cap and the treatment of the existing deferred cost balances. According to Mr. Grosskopf, discussions with Petitioner indicated the Company was in agreement with this approach.

Mr. Grosskopf said the ROE Test was not accepted by the Commission in the Efficiency Order, the OUCC accepted that modification by the Commission and the OUCC does not seek a change to the Commission's decision. He also testified that the OUCC had not had sufficient time to review the ROE Test calculation submitted by Petitioner for informational purposes in Vectren North's GCA 93 as required by the Efficiency Order.

J. Randall Woolridge, a finance professor at Pennsylvania State University, testified for the OUCC on Petitioner's cost of capital. He used Petitioner's proposed capital structure and debt cost rates and a cost of common equity of 9.00% to calculate a weighted cost of capital of 6.66%. He stated the 9.00% equity cost rate was supported by his analysis which indicated a cost of equity a range of 8.5% to 8.6% based primarily on the DCF model. He also performed a CAPM study, but gave those results less weight because he believed risk premium studies were less reliable. Dr. Woolridge accepted and used Mr. Moul's eight-member Gas Group in both his DCF model and CAPM study. However, Dr. Woolridge took issue with some of Mr. Moul's techniques and approaches.

Richard A. Galligan, a principal with Exeter Associates, Inc. testified about Petitioner's cost of service study and rate design proposals. Mr. Galligan disagreed with Petitioner's treatment of 30% of distribution and transmission mains as customer-related to be allocated based on number of customers of each rate class. Mr. Galligan supported allocating 80% of distribution and transmission system costs on the basis of average demand and 20% based on peak demand. Mr. Galligan developed an alternative allocation of the proposed rate increase to the rate classes based on his methods and recommended that any reduction in Petitioner's requested rate increase be scaled back in proportion to these rate spreads.

Mr. Galligan also recommended that the current residential customer facilities charge of $10.75 be retained, rather than increased as proposed by Mr. Heid. Further, he opposed Mr. Heid's proposal to increase the declining nature of the residential delivery service rates.

Mr. Galligan objected to Petitioner's proposal to track UAFG costs in the GCA on the grounds that such costs are not unanticipated, nonrecurring or extraordinary, tracking would reduce Petitioner's incentive to operate efficiently and the proposal would shift risk to customers. Mr. Galligan stated that an acceptable alternative would be to track the UAFG gas costs that change as gas prices change, while leaving the UAFG ratio fixed.

Mr. Galligan also opposed tracking the gas cost component of bad debt expense in the GCA. He stated Petitioner's proposal would provide dollar-for-dollar recovery of a cost not fully outside of Petitioner's control and regardless of the level of resources devoted to minimizing these costs. Mr. Galligan also asserted these costs were not unanticipated, nonrecurring or extraordinary. According to Mr. Galligan, an acceptable alternative would be a mechanism that used a fixed bad debt ratio determined in a rate case and tracked changes in the gas cost component of bad debts as gas prices change.

Tyler E. Bolinger, the OUCC's Director of Natural Gas, testified regarding Petitioner's proposed DRA. He said the DRA would be a capital cost tracker that would provide a return on and a return of investments made pursuant to the program. Although Mr. Bolinger emphasized that the OUCC did not oppose the replacement of Petitioner's bare steel and cast iron infrastructure, he said trackers like the DRA are often criticized as "piece meal" mechanisms that do not consider potentially off-setting revenue requirement changes. He stated the OUCC would not object to deferring further discussions about the DRA to see if the General Assembly takes action on capital cost tracking by gas utilities. Mr. Bolinger asserted that a middle ground alternative would be to allow the continued accrual of AFUDC and the deferral of depreciation on replacement program investments after the plant is placed in service and until it is reflected in rates in a base rate case.

C. <u>AK Steel's Direct and Cross-Answering Testimony.</u> AK Steel sponsored the testimony of Richard A. Baudino, a ratemaking consultant with J. Kennedy and Associates, Inc. Mr. Baudino disagreed with Petitioner's classification of 35% of its transmission plant investment as commodity-related to be allocated to the rate classes based on their respective annual throughput volumes. He contended this portion of the transmission plant should be classified as demand-related and allocated based on the peak demand of each class. He recommended that the Commission allocate the rate increase so that customer class subsidies in current rates are reduced by 50% based on his revised cost of service results. He asserted this approach would move the customer classes toward paying their fair share of costs while mitigating the revenue increase to residential customers.

Mr. Baudino supported Petitioner's proposed customer charge for Rate 170 (Contract Transportation Service) but proposed the remainder of the increase to Rate 170 be applied to current rates using an equal percentage. He opposed Petitioner's proposed change to the Rate 170 rate schedule to allow it to require the customer to provide a dedicated telephone line if the customer's existing line is frequently not available when Petitioner seeks to obtain measurement data. Mr. Baudino stated there was no showing that this change was needed and the proposed tariff language was vague.

In his cross-answering testimony, Mr. Baudino expressed disagreement with Mr. Galligan's proposal to treat 80% of transmission mains as commodity-related. He contended investment in mains is driven primarily by peak winter demands, not average use throughout the year. In response to Mr. Galligan's testimony that no part of transmission mains should be treated as customer-related, Mr. Baudino said it may be appropriate to treat transmission mains as entirely demand-related and showed the effect of allocating these costs on the basis of peak demand. He also asserted Mr. Galligan's proposed 85% increase to Rate 170 customers would be unreasonable and would penalize Rate 170 customers for providing valuable off-peak margins.

D. **Petitioner's Rebuttal.** In rebuttal, Mr. Benkert testified the ROE authorized by the Commission is a highly visible indicator of the Company's ability to provide investors with reasonable earnings performance and its regulatory support. Equity investors, Mr. Benkert commented, commonly are concerned about Petitioner's small market capitalization, its only moderate share liquidity, its trouble meeting earnings targets and its below average customer growth. On the other hand, regulatory support is viewed positively by investors and credit rating agencies and can help Petitioner overcome these perceived deficiencies.

Mr. Benkert said in competing for capital with larger, higher growth companies which already have margin stabilization mechanisms like decoupling in place, it is important that Petitioner's ROE be set at a fair level compared to its peers. This need is aggravated by Indiana's unique statutory NOI cap. He cited the allowed ROEs for the following peer companies in the Gas Group used by Mr. Moul and Dr. Woolridge which have decoupling or comparable rate designs: AGL (10.9%); Atmos (10.15%); Piedmont (12.5%); WGL (10.75%); and South Jersey (10.0%). He also provided a broader survey of companies with approved or pending decoupling mechanisms showing authorized ROEs from 10.0% to 11.35%, and averaging 10.69%. Mr. Benkert also stated allowed ROEs for gas companies receiving rate orders in 2005 averaged 10.36% and in 2006 averaged 10.29%. According to Mr. Benkert, ROEs allowed by commissions ranked favorably by analysts in 2006 were 11% or above. Mr. Benkert testified that to convincingly advocate to the financial community that Petitioner is solidly in the mix with its peers, particularly given its relatively small size and recent inability to earn at authorized levels, a commensurate ROE authorization is necessary. Mr. Benkert asserted that the industry is moving to a better (non-volumetric) rate design without any noticeable ROE reductions and Petitioner should be treated similarly.

Mr. Benkert testified that Petitioner's DRA request was cited by Standard & Poor's as a help to maintaining stable cash flow and better credit worthiness during aging pipeline replacement. Without the DRA, Mr. Benkert stated, Petitioner will suffer earnings attrition immediately after this rate case.

Ms. Hardwick testified in rebuttal regarding accounting issues. She provided updated information on changes in usage by large industrial customers. She disagreed with the OUCC's short term and long term incentive plan expense adjustment because it provides an amount below target levels which are set to provide employees with market compensation when combined with base pay. The OUCC's adjustment, according to Ms. Hardwick, would lock in below average/below market pay as the expected level of compensation.

Ms. Hardwick disputed the OUCC's contention that Petitioner's emergency preparedness training expense adjustment is duplicative of the labor cost adjustment. She said it is incremental because it represents a shift from capital project time to expense time.

Ms. Hardwick testified that Petitioner would agree to eliminate 16 still unfilled positions, but reinserted 8 positions eliminated by the OUCC that have since been filled.

Ms. Hardwick revised the aging workforce and distribution maintenance expense adjustments based on Mr. Doty's rebuttal testimony. She reduced the latter adjustment to eliminate a small amount of overlap with the test year expenses, but said there were no test year expenses for most of the specific programs.

Ms. Hardwick disagreed with the OUCC's use of a three-year average bad debt ratio but, as an alternative, used in her rebuttal exhibits the 2006 ratio of 0.7%. Ms. Hardwick also eliminated the PSA deferred cost amortization based on Mr. Albertson's rebuttal testimony.

Ms. Hardwick increased the downward adjustment for property and risk insurance based on current premiums (which were lower due to a substantial increase in Petitioner's deductibles) but corrected a premium omission of the OUCC. She agreed with OUCC witness Morgan that Petitioner's original claims expense adjustment was overstated, but disagreed with his proposal to amortize one large claim over five years, rather than three years.

Ms. Hardwick disagreed with the OUCC's proposal to reflect additional savings from the AMT project, but in rebuttal increased the proposed savings adjustment above what she originally proposed. Ms. Hardwick also disputed Mr. Morgan's elimination of GPS unit maintenance expenses although she revised certain GPS software costs to conform to a recently executed agreement with the vendor.

Mr. Moul submitted rebuttal testimony disagreeing with Dr. Woolridge's opinions on Petitioner's cost of common equity. He contended Dr. Woolridge's calculated ROE range of 8.5% to 8.6% and the OUCC's proposed authorized ROE of 9.0% were both too low by reference to returns expected by investors and granted by regulators both in Indiana and elsewhere. He also said these ROEs would not provide Petitioner with the level of regulatory support expected by investors, particularly given Petitioner's higher risk profile characterized by its relatively small size and high throughput to industrial customers. Mr. Moul testified that the annual survey of authorized ROEs published by PUR *Utility Regulatory News* in December 2006 showed the average gas utility allowance was around 10.5%. He further stated that *Value Line* forecasted that the gas distribution company industry would earn ROEs of 11.0% in 2006, 11.5% in 2007 and 12% during 2009-2011.

Mr. Doty submitted rebuttal testimony on the aging workforce and distribution maintenance system adjustments. With respect to the aging workforce issue, Mr. Doty stated Petitioner would agree to Mr. Morgan's proposed reduction in the estimated expense for contractors to be used during the five year period when new apprentices will be trained to replace retiring workers. However, he disputed Mr. Morgan's characterization of Human Resources ("HR") costs as indirect and said Petitioner's current HR team is not sufficiently staffed to recruit, train and oversee the new employees needed to replace baby boomers reaching retirement age. He sponsored an exhibit providing a more refined, specific and updated quantification of the HR costs which eliminated or reduced some of the costs in Petitioner's original adjustment. He also reduced safety training program expenses due to a mistake in the portion of these costs allocated to Petitioner. Mr. Doty also disagreed with Mr. Morgan's treatment of the costs of the distribution system maintenance program except for pipeline casing filling and bridge pipe recoating which Mr. Doty agreed to remove.

Mr. Heid responded to the testimony of Mr. Galligan and Mr. Baudino regarding Petitioner's cost of service study, proposed revenue distribution by rate class and proposed rate design. He testified that Petitioner properly allocated the customer-related component of mains based on a conventional zero-inch study, *i.e.*, a linear regression that determines the portion of mains costs that are not related to pipe diameter or customer demands. He testified that this is a widely used method for reflecting the fact that the length of mains is a function of the number of customers. He said Petitioner allocated 50% of the remaining mains costs based on peak day demand and 50% based on annual demand. Mr. Heid disagreed with Mr. Galligan's position that 80% of all mains costs should be allocated based on annual demand and 20% based on peak day demand. Mr. Heid also disagreed with Mr. Baudino's position that all mains costs other than the customer component should be allocated based on peak day demand. He expressed the opinion that Petitioner's methodology possesses objectivity and consistency and is unaffected by bias.

Mr. Heid also contested Mr. Baudino's proposal regarding subsidy reductions. He said Petitioner's proposal was superior because it would move all classes toward equal rates of return while limiting residential bill impacts to about 7%. He also noted the percentage increase to Rate 170 would be very small when gas costs were included, and added that utility bill payments are tax deductible to businesses.

Mr. Heid disputed Mr. Galligan's position that the customer facilities charge for residential customers should remain unchanged based on a marginal cost or avoided cost approach. According to Mr. Heid, the customer facilities charge should represent fixed costs of providing services that do not vary with volumes sold.

Mr. Heid testified that contrary to Mr. Galligan's testimony, Petitioner's proposed rates would increase the first and second block for Rate 110 (residential service) at almost the same percentage and would not be contrary to principles of conservation.

Mr. Albertson testified in rebuttal in opposition to Mr. Galligan's position regarding the recovery of UAFG gas costs. Mr. Albertson stated he believes UAFG is a large cost suitable for tracking because of its significant effect on NOI. He discussed the reasons why Petitioner will still have an incentive to minimize UAFG and said the symmetrical methodology proposed by

Petitioner will both reduce the risk of over payment by the customers and under recovery by Petitioner.

With respect to Mr. Galligan's position on the gas cost component of bad debts, Mr. Albertson commented that under Petitioner's proposal it would still be at risk for the 20% - 30% of bad debt expense that does not represent gas costs. He said gas costs are highly volatile and appropriate for GCA tracking via Petitioner's GCA.

Mr. Albertson testified that although he continued to believe his original proposals are more appropriate, accurate and equitable, Mr. Galligan's proposed alternatives of fixing the UAFG percentage and bad debt ratio and tracking gas cost changes within those limits were acceptable to Petitioner, provided agreement can be reached on the mechanics. Mr. Albertson also said Petitioner would accept Mr. Grosskopf's proposal regarding deferred Safety Act expenses and summarized Petitioner's views on a new annual cap and how the deferred expenses should be treated in the PSA.

Mr. Francis and Ms. Hardwick also submitted rebuttal testimony on Petitioner's proposed DRA. Mr. Francis noted that the issue was not whether the bare steel and cast iron pipelines would be replaced but rather how quickly that replacement will occur. Petitioner's proposal would result in accelerated replacement over 20 years in lieu of gradual replacement over 40 years or more. According to Mr. Francis, these replacements would not be "in the ordinary course of business," as assumed by Mr. Bolinger. He testified Petitioner cannot afford to dedicate such a large portion of its construction budget to this non-revenue producing plant without cost recovery. Ms. Hardwick testified that the inclusion of depreciation expense in the revenue requirement does not provide compensation for the capital costs for new investments made in the future. Without an alternative funding mechanism like the DRA, Petitioner will be required to find additional sources of funding, like debt and equity, that will require very frequent rate cases to create the opportunity to earn a fair and timely return.

6. Alcoa Settlement. Douglas A. Karl, Petitioner's Vice President of Marketing and Customer Service, described the Alcoa Settlement and the proposed Natural Gas Transportation Agreement ("Alcoa Agreement" or "Agreement") between Petitioner and Alcoa that is attached to the Settlement.

Mr. Karl testified the Alcoa Settlement resulted from Petitioner's efforts to maintain Alcoa as a gas transportation customer for Alcoa's aluminum smelting operations in the City of Newburgh in Warrick County ("Warrick Operations"). He stated that the Warrick Operations is one of the largest industries in Petitioner's service area. He described Alcoa as a major employer in Southwest Indiana, a long-time customer of Petitioner and one of Petitioner's largest customers. Mr. Karl testified Alcoa operates in a very competitive industry and has advised Petitioner that to reduce its gas costs it is actively considering a direct connection with an interstate pipeline regulated by the Federal Energy Regulatory Commission ("FERC"). Mr. Karl explained this type of bypass arrangement is permitted under FERC's rules and would result in Petitioner losing Alcoa as a customer. Because this would adversely affect Petitioner and its customers, Petitioner engaged in good faith arms length negotiations with Alcoa about what would be required to keep Alcoa as a customer on terms that would be reasonably economic for Petitioner. Mr. Karl reported that these negotiations were successful and culminated in the execution of the Alcoa Settlement pursuant to which Petitioner will provide local gas transportation service to the Warrick Operations under the agreed-upon terms and will be Alcoa's sole and exclusive supplier of gas transportation service for the Warrick Operations (including the generating facilities operated by Alcoa Power Generating Inc.) for the term of the Alcoa Agreement.

Mr. Karl testified that the loss of Alcoa as a customer would adversely affect Petitioner's other customers because Petitioner's costs of providing gas service are largely fixed. Therefore, he stated, if Alcoa leaves the system, the remaining customers ultimately will bear additional costs formerly recovered from Alcoa. However, Mr. Karl explained, if Alcoa can be retained as a customer on a basis that allows Petitioner to recover more than the incremental cost of serving Alcoa, the other customers will be better off due to the preservation of Alcoa's contribution to Petitioner's fixed cost recovery.

Mr. Karl stated Alcoa performed a study of the feasibility of its bypass plans and presented the results of the bypass study to Petitioner. Mr. Karl also sponsored as an exhibit a verified statement from Alcoa confirming its bypass plans. Mr. Karl expressed the opinion that approval of the Alcoa Agreement is necessary for Petitioner to retain Alcoa as a gas transportation customer.

Mr. Karl testified that Petitioner requested the following portions of the Alcoa Agreement to be treated as confidential information: (1) specific delivery information; (2) the customer facilities charge; (3) the distribution charges; (4) the term; (5) usage and volume based billing information; and (6) the storage entitlements and storage charges ("Confidential Information"). Mr. Karl said these provisions were negotiated between Alcoa and Petitioner on a confidential basis. He noted Petitioner is in the process of negotiating other economic development and business retention contracts. Mr. Karl testified that if these provisions became generally known or readily ascertainable to other parties with whom Petitioner is negotiating or to potential suppliers and marketers with whom Petitioner would compete, this knowledge would provide considerable economic value to such parties and establish a price ceiling in future negotiations, thereby limiting the potential benefits that could accrue to Petitioner and its other customers. According to Mr. Karl, disclosure of the Confidential Information also would allow interstate pipeline companies to more effectively compete with Petitioner to supply the large industrial customers in Petitioner's territory. He also commented that disclosure of the Confidential Information would be of significant value to Alcoa's competitors through knowledge of Alcoa's product output and its cost structure, which could prove harmful to Alcoa. Mr. Karl also described the efforts to protect the secrecy of the Confidential Information and to restrict access thereto to persons directly involved in negotiating, obtaining approval of and monitoring compliance with the Agreement.

Mr. Karl discussed the most significant provisions of the Alcoa Agreement. The rates and charges that will be paid by Alcoa which consist of: (a) a fixed monthly facilities charge; (b) volumetric rates applicable to monthly consumption up to 1,750,000 therms, over 1,750,000 therms and over 3,500,000 therms; and (c) charges pursuant to certain identified Appendices to Petitioner's Gas Tariff. The volumetric rates will be adjusted after a certain period. If the sum of the rates and charges provided in the Agreement exceed the normal Tariff rates for any billing period, Alcoa will pay the lower Tariff rates. After expiration of the specified term of the

Agreement, it will continue in effect on a year to year basis until terminated by either party on twelve months prior written notice. The Agreement provides that Petitioner shall be the sole and exclusive supplier of gas transportation service to the Warrick Operations during the term of the Agreement. Alcoa agrees that it will not bypass Petitioner during the term of the Agreement, with bypass being defined as delivering gas to the Warrick Operations through any pipeline other than that owned by Petitioner. Alcoa has storage nomination rights and will pay storage charges consisting of a capacity charge, an inventory charge, an injection charge and a minimum monthly charge.

Mr. Karl testified that the Agreement will provide stable and competitive gas transportation rates that will help maintain the viability of the Warrick Operations which is important for the economic health of Petitioner's service area. He testified that the Agreement will not adversely affect Petitioner's other rates or contracts or the adequacy or reliability of service provided to other customers.

7. **The OUCC Settlement.** In the OUCC Settlement, the settling parties state that they have devoted significant time to the review of data and discussion of issues and have succeeded in reaching agreement on all issues in this proceeding. The parties further state that with few exceptions, the agreed upon pro forma adjustments to test year results either reflect the testimonial rebuttal position of the Company or the testimonial position of the OUCC, and thus are founded upon documented positions that are in the record in this proceeding.

A. **Rate Increase.** The Settlement provides that Petitioner shall be authorized to increase its basic rates and charges (collectively "rates") for gas utility service with the rates being designed to produce additional annual revenues of $5,334,907 representing an overall revenue increase of approximately 3.4%. As discussed hereafter, the Settlement provides that UAFG costs and the gas cost component of bad debt expense will be removed from base rates and tracked in the GCA. Petitioner's Exhibit SEA-5S, Sch. 1, p. 1, shows these costs to be $2,130,463. As discussed by Mr. Benkert at the hearing on the Settlement, the annual revenue increase is about $7.5 million or 5% when these costs are included. Tr. E-20.

These rates reflect allocation of the revenue increase among all rate classes on an approximate across-the-board, gross margin basis (revenue less gas cost). Rates for residential sales service have been determined by increasing the monthly customer facilities charge from $10.75 to $11.00 and allocating the remaining revenue increase to the block rates on an equal per therm basis.

The agreed-upon rate increase reflects the following original cost rate base, cost of capital and financial results which the parties agree are reasonable for purposes of compromise and settlement:

Rate Base as of October 31, 2006

Utility Plant in Service	$195,820,638
Less: Accumulated Depreciation	82,745,039
Net Utility Plant	113,075,599
Materials and Supplies	1,046,526
Gas in Underground Storage	7,546,757
	$121,668,882

Capital Structure as of March 31, 2006

	Amount	Weight	Cost	Weighted Cost
Common Equity	$549, 508,000	47.05%	10.15%	4.78%
Long Term Debt	451,347,000	38.65%	6.04%	2.33%
Customer Deposits	5,601,000	0.48%	5.39%	0.03%
Cost Free Capital	152,477,000	13.06%	0.00%	0.00%
Post 1970 JDITC	8,920,000	0.76%	8.30%	0.06%
	$1,167,853,000	100.00%		7.20%

Pro Forma Proposed Rates

Revenue	$160,234,558
Gas Cost	117,558,782
Gross Margin	$42,675,776
O&M	$20,992,861
Depreciation	5,544,105
Income Taxes	4,246,740
Other Taxes	3,131,910
Total Operating Expense	$33,915,616
Net Operating Income	$8,760,160

Pursuant to the Settlement, Petitioner's authorized return for purposes of the earnings test component of the gas cost adjustment (Ind. Code §§ 8-1-2-42(g)(3)(C) and -42.3) shall be $8,760,160, representing a return of approximately 7.20% on an original cost rate base of $121,668,882.

Petitioner's current depreciation rates, as originally authorized in Cause No. 39593, and again authorized in Cause No. 40283, shall remain in effect.

B. Pro Forma Adjustments. All of the agreed upon pro forma adjustments are set forth in Appendix C which compares the Settlement adjustments to Petitioner's case-in-chief, the OUCC's case-in-chief and Petitioner's rebuttal. The Settlement explains the differences between the evidence of Petitioner and the OUCC on each disputed adjustment and how each was resolved for purposes of the Settlement. The adjustments about which there was conflicting evidence were resolved as follows:

Large Customer Revenue. The Settlement adopts the Company's position on rebuttal which adjusts test year revenue for change in usage by certain large customers. This adjustment includes a pro forma revenue adjustment related to the Alcoa Agreement.

Safety Act Costs. As reflected in both the OUCC's testimony and the Company's rebuttal testimony, consistent with the settlement agreement in the Company's last rate case, the PSA was to undergo a three year review in 2007. The parties have conducted such a review as part of this case and have agreed to (1) eliminate all pipeline safety costs and revenues from base rates, and (2) provide for the recovery of all deferred costs and prospective costs, subject to a negotiated cap, through the PSA.

Labor Adjustments. The Company's rebuttal supported use of target levels for ratemaking purposes. For purposes of settlement, the OUCC agreed to the rebuttal pro forma adjustments.

Training Expense. For purposes of settlement, the Company agreed to eliminate the adjustment.

Additional Employees. On rebuttal, the Company updated the adjustment to reflect only those additional employees that had been hired as of January, 2007. The resulting pro forma adjustment has been accepted as part of the Settlement.

Aging Workforce. On rebuttal, the Company accepted most of the OUCC's reductions, but preserved certain HR costs as being required in the short term to address necessary work requirements. The parties have agreed to the Company's rebuttal position.

Distribution Maintenance. On rebuttal, the Company agreed to reduce certain program costs, but further established the incremental nature of a majority of the disputed costs. The parties have agreed for purposes of settlement to adopt the Company's rebuttal position. The Company shall submit in its annual PSA filings detailed reports to the IURC and OUCC regarding the Company's regulator station maintenance program and right of way maintenance activities containing information set forth in the Settlement

Uncollectible Accounts Expense. The Settlement reflects the parties' agreement on use of a 0.65% bad debt ratio which represents the average of the OUCC and Company positions. This percentage is also used as the fixed ratio for purposes of recovering gas costs relating to bad debt as discussed below.

Property and Risk Insurance. The Stipulation reflects agreement on the reduction in this expense due to a reduction in insurance premiums that occurred while this case was pending.

Claims Expense. The OUCC's testimony reduced this expense to correct an error in the Company's calculation and to reflect a five year amortization of a large claim in lieu of the Company's use of a three year amortization. The Settlement adopts the OUCC's position.

AMT Costs and Savings. The Settlement reflects the agreement to eliminate both costs and savings from the case based on the fact that both projections, at this early stage of the project, are somewhat speculative.

Customer Service Costs. In response to concerns expressed at the public field hearing and following an extended collaboration between the Company and the OUCC, a number of customer payment method options and complaint handling options were considered. The OUCC and Company have agreed to implement three new customer service options: (1) the installation in the City of Evansville of a centrally located payment kiosk where, with no fee, customers can deposit cash payments in a programmed machine; (2) new payment sites in Evansville and Mt. Vernon where customers can pay gas bills at locations where water bill payments are currently collected; and (3) dedication of 1-2 new employees who will be trained to meet with customers to discuss complaints, thereby providing customers with the opportunity to engage in face to face communication with the Company. The cost of these new services, on an allocated basis to the Company, is a new adjustment included for settlement purposes.

Asset Charge. The VUHI Asset Charge has been calculated using the agreed-upon 10.15% ROE.

Income Taxes, IURT Taxes. There are no differences between the parties on these items which have been determined based upon the settlement amounts in this case.

C. ROE Test. The Company agreed to withdraw its request to replace the statutory NOI Test with an ROE Test. The existing statutory NOI test and earnings bank calculations shall be applicable to the Company.

D. UAFG Costs. The Company will be authorized to recover in its GCA the actual cost of UAFG volumes, up to a maximum UAFG percentage of 1.2%. No UAFG costs will be included in base rates. Transportation customers (including School Suppliers and Pool Operators) will continue to provide retained gas volumes to the Company subject to the terms and the percentage set forth in Appendix F of the Tariff, which is also 1.2%. The Settlement describes the procedures and methodology to be used in implementing GCA tracking which include determination of the actual UAFG percentage annually for the twelve months ending August 31 and an annual reconciliation. The OUCC and the Company will review this UAFG cost recovery methodology after three years. Either the OUCC or the Company may propose changes to the methodology at that time, which, if accepted by the Commission, would be effective prospectively.

E. Bad Debt Gas Costs. The Company will be authorized to recover in its GCA the gas cost component of bad debt expense at a fixed bad debt ratio of 0.65%. No gas costs associated with bad debt expense will be included in base rates. The margin (non gas cost) component of bad debt expense will remain embedded in base rates at the same ratio of 0.65%. The Settlement describes the procedures and methodology to be used in implementing GCA tracking. The OUCC and the Company will review this bad debt gas cost recovery methodology after three years. The OUCC and/or the Company may propose changes to the methodology at that time, which, if accepted by the Commission, would be effective prospectively.

F. **PSA.** The Company will be authorized to continue to recover incremental expenses caused by the requirements of the Safety Act through its PSA with certain modifications. Deferred expenses eligible for inclusion in each annual PSA filing will be capped at one million dollars ($1,000,000). Incremental deferred expenses above the annual cap may be included in subsequent annual PSA filings, without carrying costs, up to the amount of the annual cap. Amounts above the cap will be deferred and be eligible for future rate case or PSA recovery. Any deferred balance existing at March 31, 2007 will be amortized over a 3-year period within the PSA, without carrying costs. This amortized amount will be considered incremental to the $1.0 Million annual cap (i.e. the amortized amount does not count toward expenses that are deferred in each 12-month period that may be recovered under the cap). The amortized amount will be removed from the PSA at the end of the 3-year period. In each annual PSA filing, recoveries will be reconciled with recoverable costs. Recovery variances will also be considered incremental to the $1.0 million annual cap. Rate schedule margins as updated in this cause shall be used as the basis for allocating eligible deferred expenses in future annual PSA filings. The PSA will continue through the annual PSA filing for the twelve months ended March 31, 2010. At that time, the parties will review the PSA to consider the appropriateness of the annual cap, whether the PSA should continue, whether expenses have leveled sufficiently to be included in base rates, and any other related matters.

All other provisions of the Stipulation and Settlement Agreement, and Commission Order, in Cause No. 42596, as related to the PSA shall remain in effect. The Company's recovery of costs under this section of the Settlement will be on an interim, subject to refund basis, until both the OUCC and IURC have had a reasonable opportunity to review the results of the pending compliance review conducted by the Department of Transportation (DOT). The OUCC and the Company reserve their rights to file their respective positions on the impact on cost recovery with the Commission, after they have met and reviewed the report and have attempted to reach agreement on any cost recovery issues.

G. **Distribution Replacement Program.** The parties have agreed that the Company shall be authorized to continue to accrue AFUDC and to defer the accrual of depreciation expense after the in-service date of distribution system infrastructure projects installed pursuant to the Company's accelerated bare steel and cast iron pipeline replacement program (Program) on the terms described in the Settlement. The amount of investments made that are eligible for post-in service AFUDC and deferred depreciation treatment (Accounting Treatment) shall be limited to $3.0 Million per year. The Accounting Treatment shall terminate for each project after three years from the project's in-service date, unless the Company has filed a base rate proceeding before the end of the specific project's three year Accounting Treatment period. If the Company does file a base rate proceeding by such date, the Accounting Treatment shall continue for those projects (and investments in any subsequent projects that are included in rate base in that proceeding) until the date of a final order in that proceeding. The AFUDC earnings from the Accounting Treatment will be treated as below-the-line income for purposes of the GCA earnings test consistent with normal accounting procedures for AFUDC. The Company will file with the Commission and serve on the OUCC annual informational reports regarding the status of the Program and the investments made pursuant thereto in conjunction with its annual PSA filings.

H. Tariff. The Tariff for Gas Service, I.U.R.C. No. G-11, filed herein with the supporting Settlement Testimony, shall be approved, authorized, and accepted for filing by the Commission to be effective upon its approval by the Commission. This Tariff shall replace the gas tariff of the Company currently on file with the Commission. The new Tariff includes, among other things, provisions dealing with a new Rate 145, General Transportation Service; Rate 120 Contract requirements; Interim Supply Service; elimination of GCA demand allocators; changes in certain non-recurring charges; resetting the UAFG percentage applicable to transportation customers, school suppliers and pool operators; implementation of the SRC; and the two new economic development riders. All other changes to the Tariff for Gas Service set forth in the agreed upon form of the tariff shall be approved and authorized.

On April 13, 2007, Petitioner filed a revised copy of the proposed Gas Tariff reflecting additional language changes and corrections discussed with the Commission Staff and the OUCC.

I. Request for Prompt Approval by the Commission. The settling parties acknowledge that a significant motivation for the Company to enter into the Settlement is the expectation that an order will be issued promptly by the Commission authorizing increases in its rates and charges and ask that their request for prompt approval be seriously considered and acted upon.

J. Stipulation Effect, Scope and Approval. The Settlement provides that it is conditioned upon and subject to its acceptance and approval by the Commission in its entirety without any change or condition that is unacceptable to any party. The Settlement shall not constitute an admission or waiver by any party or be used as precedent in any other proceeding or for any other purpose except to the extent provided for herein or to the extent necessary to implement or enforce its terms. The settling parties stipulate that the evidence submitted in support of the Settlement constitutes substantial evidence sufficient to support the Settlement and provides an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of the Settlement.

8. Evidence of the Parties In Support of the OUCC Settlement.

A. Petitioner's Evidence. In support of the Settlement Agreement, Petitioner presented supplemental testimony by Mr. Benkert, Ms. Hardwick and Mr. Albertson.

Mr. Benkert explained that the parties to the OUCC settlement, including their counsel and technical experts, engaged in a series of meetings, discussions and information exchanges about the rate case over a period of several months. After good faith efforts, including scrutiny of the evidence submitted by the various parties and the give and take of settlement negotiations, the parties to the OUCC settlement were able to reach agreement on the Settlement which they proposed as a reasonable resolution of this proceeding and a means to avoid further litigation.

Mr. Benkert stated that the Settlement rates are designed to produce an overall revenue increase of 3.4%, which is a substantial reduction to Petitioner's original 6.7% requested rate increase. He noted that some of the difference is attributable to the removal from base rates of bad debt related and UAFG gas costs. Pursuant to the Settlement, these costs will be tracked within certain limits in Petitioner's GCA filings. Mr. Benkert said the agreed-upon revenue requirement represents a 7.20% rate of return on the original cost rate base, and includes an ROE of 10.15%. Mr. Benkert stated that while this ROE is less than what Petitioner would consider acceptable without a Settlement, the Company has agreed to it in order to achieve rate relief sooner than would otherwise be the case and because of other terms in the Settlement.

Mr. Benkert testified the OUCC and the Company dedicated significant time and effort to thoroughly understand the challenges facing the Company in particular and the industry in general, including the aging workforce issue and the unpredictability of bad debt expense caused by gas cost volatility. He said policy considerations concerning bad debt expense and UAFG have been discussed by the OUCC and the Company in depth for well over a year and that exchange of ideas contributed to the ability of the parties to reach an agreement in this proceeding. He referred to the Settlement provisions on the Distribution Replacement Program as a middle ground approach relative to Petitioner's initial request for timely cash recovery of the capital costs. He stated it would be difficult for Petitioner to proceed with this enhanced program without at least the accounting treatment for the program costs provided for in the Settlement. Mr. Benkert stated the Settlement provisions for additional bill payment site options and expanded opportunity for face-to-face communications between customers and the Company respond to customer concerns expressed at the field hearing. As part of the Settlement, Petitioner has also agreed to withdraw its proposed ROE Test and continue to use the existing statutory NOI Test and earnings bank calculations in its GCA proceedings.

Mr. Benkert indicated that the Settlement provision requesting prompt approval was critical from Petitioner's standpoint. He said Petitioner has agreed to a smaller increase than originally proposed, has withdrawn its ROE Test proposal and modified other proposals expectation that the Settlement will lead to prompt authorization of the agreed-upon rate increase, as has been the case in other Vectren Energy rate proceedings that were resolved by Settlement.

Ms. Hardwick testified that the Settlement addresses each of the pro forma adjustments originally recommended by Petitioner in this proceeding. She stated that Petitioner and the OUCC discussed each proposed adjustment, reviewed relevant data, and negotiated a meaningful outcome on each disputed item rather than simply agreeing to a "split the difference" approach. This is shown in Appendix C to the Settlement where the outcome of virtually every pro forma adjustment reflects either the OUCC's litigation position or Petitioner's rebuttal position. Ms. Hardwick stated that as a result of concessions made on rebuttal and in the Settlement, Petitioner reduced the requested pro forma net expense by nearly $1.7 million from the original filing, before consideration of the impact of removing certain gas cost recovery items from base rates.

Ms. Hardwick testified that in a review of the PSA, Petitioner and the OUCC reviewed costs incurred to date, agreed to reset the annual recovery cap, and moved all costs, including as yet unrecovered deferred costs that had accumulated, out of base rates. The accumulated costs will be recovered over a three year period through the PSA.

Ms. Hardwick stated the Settlement addresses the volatile nature of gas costs in two ways. First, the Settlement adopts a mechanism whereby the gas cost component of bad debt expense will be recovered through the GCA at a fixed bad debt ratio of 0.65% of revenues, while leaving the margin component in base rates. Therefore, Petitioner remains at risk for the margin component and for the level of the actual bad debt ratio. She said the effect of this approach is to remove $773,458 of bad debt related gas costs from base rate recovery. According to Ms. Hardwick, the fixed ratio of 0.65% was based on Petitioner's recent experience. Second, the Settlement provides that the cost of UAFG gas will be removed from base rates and be tracked through the GCA but capped at a fixed percentage. She stated the effect of this approach is to remove $1,324,409 of UAFG gas costs from base rate recovery.

Ms. Hardwick also explained the Settlement provisions that support Petitioner's accelerated replacement of bare steel and cast iron mains. She stated the settling parties dedicated time to a review of the program and participated in a technical conference on that issue. She noted the Settlement specifies the annual cap on such expenditures and establishes the accounting for the continuation of AFUDC and the deferral of depreciation for project expenditures up to the annual cap amount of $3.0 million during the period post in service up to the date those projects are included in a general rate proceeding.

Ms. Hardwick stated that the settling parties agreed to use an original cost rate base of $121,668,882 which reflects actual utility plant balances as of October 31, 2006 as well as thirteen month averages as of that date for certain working capital related items, like materials and supplies and gas in storage.

Ms. Hardwick concluded that after reflecting the terms of the Settlement, the revenue requirement increase is $5,334,907 and the resulting base rate revenue requirement is $160,234,558, which produces net operating income of $8,760,160. This compares to the case-in-chief filing that reflected an increased revenue requirement of $10,436,340, with a net operating income of $9,431,041.

Mr. Albertson testified that the Settlement provides for recovery of actual UAFG costs in the GCA, up to a maximum actual UAFG percentage of 1.2%. He testified that this methodology benefits customers in two ways. First, customers are no longer at risk of overpaying UAFG costs if gas prices decline. Second, customers are not at risk of paying for more UAFG volumes than the maximum level of 1.2%. Mr. Albertson stated this methodology also benefits the Company, in that the risk of under recovery of UAFG costs up to the 1.2% level due to potential gas price increases is removed. However, unlike the Company's initial proposal, Petitioner does remain at risk for UAFG volumes greater than 1.2%. Finally, the Settlement contemplates a review of this methodology after three (3) years. Mr. Albertson sponsored an exhibit of pro forma GCA schedules illustrating how UAFG costs will be projected and reconciled, both in cases where the actual UAFG percentage is less than 1.2% and in cases where the actual UAFG percentage exceeds 1.2%. Mr. Albertson also provided a step by step explanation of the UAFG cost recovery methodology and procedures.

Mr. Albertson summarized the terms of the Settlement related to recovery in the GCA of the gas cost component of bad debt expense. He said the Settlement provides an incentive for the Company to continue to diligently manage its bad debt expense, while ensuring that customers pay bad debt gas costs at the fixed ratio of 0.65%. Mr. Albertson explained that while this methodology does not provide for full recovery of bad debt gas costs, as initially proposed by the Company, it does mitigate Petitioner's risk of under recovery due to gas price volatility. He noted the margin component of bad debt expense will remain in base rates under this methodology, but the gas cost component will be removed. Finally, the Settlement contemplates a review of this methodology after three (3) years. Mr. Albertson sponsored an exhibit illustrating how bad debt gas costs will be projected and reconciled in GCA proceedings. He also provided a step by step explanation of the bad debt gas cost recovery methodology and procedures.

Mr. Albertson testified that Petitioner and the OUCC conducted the three year review of the PSA as provided for in the Settlement Agreement approved in the 2004 Rate Order. As a result of the review, the parties have agreed to: (1) eliminate all Safety Act costs and revenues from base rates; (2) continue the PSA under new terms; and (3) provide for the recovery of the deferred costs and prospective costs, subject to a revised negotiated cap, through the PSA. He also discussed the PSA procedures agreed to in the Settlement, including the treatment of deferred balances that exceed the cap, the reconciliation of variances, the allocation of expenses in accordance with the margins approved in this cause and the time schedule for the next PSA review.

Mr. Albertson described the changes to the Tariff agreed upon in the Settlement. He also sponsored the Settlement Tariff as an exhibit as well as a red-lined version showing all changes from the current tariff. Among the changes are:

> Creating a new Rate 145, General Transportation Service, that is applicable to any non-residential customer whose annual usage is greater than or equal to 50,000 therms and less than 500,000 therms, and whose maximum daily usage is less than 15,000 therms.
>
> Correspondingly, removing the transportation provisions from Rate 120, General Sales Service, and requiring Rate 120 customers using more than 250,000 therms annually to enter into a written contract which specifies their hourly and daily maximum gas requirements.
>
> Adding an Interim Supply Service provision of Rate 145 and Rate 160, Large Volume Transportation Service, in the event a customer is temporarily unable to obtain gas supply from a supplier or pool operator.
>
> Eliminating demand allocators because load factors for Rates 110 and 120 are approximately the same.
>
> Making the following changes to Other Charges in Appendix C:
>
>> the Reconnect Charge has been increased from $20.00 to $55.00
>>
>> the After Hours Charge has been increased from $22.00 to $45.00
>>
>> the Insufficient Funds Check Charge has been increased from $15.00 to $25.00

the Fraudulent or Unapproved Use of Gas minimum charge has been increased from $44.00 to $65.00

Resetting the UAFG percentage applicable to transportation customers, school suppliers and pool operators to 1.2%.

Implementing the Sales Reconciliation Component of the Energy Efficiency Rider.

Adding the new economic development riders, Rider ED, Economic Development Rider, and Rider AD, Area Development Rider.

Mr. Albertson testified the Parties have agreed that the new rates will reflect an allocation of the revenue increase among all rate classes on an across-the-board basis, resulting in approximately the same percentage increase for all rate schedules. Rates for Residential sales service will be determined by increasing the monthly Customer Facilities Charge from $10.75 to $11.00 and allocating the remaining revenue increase to the block rates on an equal per therm basis. Mr. Albertson sponsored an exhibit showing illustrative margins and bill comparisons for the various rate schedules as well as the monthly margins for SRC calculation purposes.

Mr. Albertson also provided a margin proof demonstrating the margin generated by the Settlement rates and charges. He also identified the customer facilities charge for each rate schedule and indicated the remainder of the increase was allocated to the block rates.

Mr. Albertson noted that the average residential customer would see an annual bill increase of $45.76 or 4.6% in the total bill including UAFG costs and the gas cost component of bad debt expense.

B. <u>OUCC's Evidence.</u> Mr. Bolinger testified for the OUCC in support of the Settlement. He described the settlement discussions as constructive, good faith negotiations resulting in reasonable compromises and an overall resolution of the case. He stated that the issues had been researched by the settling parties who were well informed about the issues and the costs and risks associated with the litigation alternative.

Mr. Bolinger described the discussions between the OUCC and Petitioner about the PSA. Mr. Bolinger confirmed that both parties believed they had adequate information to conduct the PSA review scheduled for the spring of 2007 by the settlement agreement in Cause No. 42596. The OUCC agreed in principle that the PSA should be extended because the costs of complying with the Safety Act remain highly uncertain. He noted the Settlement contains the terms of the parties' agreement to extend the PSA through the annual filing for the 12 months ended March 31, 2010 at which time there will be another review. Mr. Bolinger testified that a great deal of thought, discussion and effort went into the agreement on the PSA extension.

Mr. Bolinger referred to the embedding of UAFG costs in base rates without tracking as the traditional approach that arguably provides the maximum incentive for utilities to minimize UAFG. However, the traditional approach provides no relief to the utility for changes in the commodity cost of gas (over which management has little control) even if the utility carefully manages its UAFG ratio. The OUCC was willing to compromise on this issue if incentives to manage the UAFG ratio were retained. Mr. Bolinger stated that the negotiated 1.2% UAFG ratio cap for GCA recovery accomplishes this objective.

Likewise, Mr. Bolinger pointed out, bad debts have traditionally been embedded in base rates with no tracking between rate cases. In this case, the OUCC proposed a bad debt ratio of 0.60% and Petitioner proposed a bad debt ratio of 0.70%. In settlement, the parties agreed to use 0.65% which ratio is well supported by recent historical experience. Mr. Bolinger described Petitioner's proposal to split bad debt expense into a gas cost component and a margin (non-gas cost) component as logical and sound and as the means to differentiate the ratemaking treatment for the components representing gas supply service versus distribution/transportation service. Mr. Bolinger testified that Petitioner accepted the alternative treatment for the gas cost component described in Mr. Galligan's testimony - GCA tracking of gas cost changes at a fixed bad debt ratio. The margin component will be embedded in base rates with no tracking whatsoever. In Mr. Bolinger's opinion, this alternative provides improved opportunities for the utility to fully recover its gas costs and increased accuracy of recovery while maintaining strong incentives to manage bad debts and the bad debt ratio.

Mr. Bolinger commented that Petitioner's proposed bare steel and cast iron replacement program itself generated little, if any, controversy. However, there was disagreement about Petitioner's proposed DRA. The Settlement resolves the issue by allowing post-in-service AFUDC and deferred depreciation on projects up to a maximum investment of $3.0 million per year, generally limited to a three year period from the in service date of the project. Mr. Bolinger said these limitations will ensure that extremely large deferrals do not accumulate over time. Mr. Bolinger described this approach as a reasonable compromise responsive to Petitioner's concerns about earnings erosion and the OUCC's concerns about gas utility capital cost trackers.

In conclusion, Mr. Bolinger recommended approval of the Settlement which he said reflects good faith bargaining and compromise and is well supported by extensive evidence.

9. **<u>OUCC Settlement Findings.</u>** Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.,* 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coalition v. PSI Energy,* 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coalition,* 664 N.E.2d at 406.

Furthermore, any Commission decision, ruling, or order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *United States Gypsum,* 735 N.E.2d at 795 (citing *Citizens Action Coalition v. Public Service Co.,* 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Settlement Agreement, we must determine whether the evidence in this Cause sufficiently supports the conclusions that the Settlement Agreement is reasonable, just, and consistent with the purpose of Indiana Code § 8-1-2, and that such agreement serves the public interest.

Our review of the reasonableness of the Settlement is aided by the parties' express agreement on the rate base and rate of return to be used in determining Petitioner's revenue requirement and each pro forma adjustment to the test year results used to determine the adjusted financial results at present and settlement rates.[1] The agreed-upon pro forma adjustments represent amounts calculated in the OUCC's case-in-chief or Petitioner's rebuttal and the details underlying the adjustments are in the record and supplemented by the settlement workpapers. Therefore, we are able to examine the basis for all of the components of the increase in basic rates and charges provided for in the Settlement and hereby find they are reasonable for purposes of settlement and amply supported by the evidence of record.

The Settlement provides new rates that Petitioner indicated are significantly less than what Petitioner would seek without the Settlement. Approval of the Settlement eliminates the risks, uncertainty and consumption of time and resources that would otherwise be required in a fully litigated proceeding. The Settlement resolves various disputed issues about cost allocation and rate design. It addresses in a reasonable way a number of additional issues facing Petitioner, including the effect of volatile gas costs on UAFG and bad debt cost recovery, the uncertain costs of complying with the Safety Act, the need to replace bare steel and cast iron pipelines because of their susceptibility to corrosion, fractures and leaks, and the need to encourage economic development in Petitioner's service area.

We find it noteworthy that OUCC Witness Bolinger in his testimony in support of the Settlement and Petitioner's Witness Benkert at the hearing on the Settlement were in agreement that Petitioner would continue to have a financial incentive to minimize UAFG costs and bad debt expense due to limitations on the recovery of related gas costs in GCA proceedings and the fact that the non-gas component of bad debt expense would not be tracked. Mr. Benkert also confirmed the Company would continue with its past efforts to minimize these costs described in the evidentiary record. Tr. E-19. With respect to the Distribution Replacement Program, we note that the investments that will be eligible for post-in-service and deferred depreciation accounting treatment relate to non-revenue producing plant, *i.e.*, the replacement of existing facilities with new facilities using modern materials. Thus, these investments will not generate new revenue as would an extension adding new customers. We also find important that with respect to the UAFG, bad debt, PSA and Distribution Replacement Program provisions; the Settlement imposes time limits and in most cases provides for future reviews after experience has been gained.

The Commission is pleased that the parties incorporated into the Settlement new bill payment and customer service options that are responsive to comments made by customers at the

[1] Ind. Code § 8-1-2-6 requires the Commission to value a public utility's property at its "fair value." Therefore, absent settlement of the issues among the parties, the original cost determination utilized in this Cause and discussed throughout this Order would not necessarily, in and of itself, be an accurate reflection of the "fair value" of the Petitioner's property. However, as this matter has been resolved by agreement the Commission is satisfied that, based on the specific facts presented in this matter, "original cost" also constitutes an accurate reflection of the "fair value" of the Petitioner's property for purposes of our consideration of the Settlement Agreement and the requirements set-forth in Ind. Code § 8-1-2-6.

field hearing. At the settlement hearing, Mr. Doty indicated these improvements include a pay station kiosk at a convenient downtown location with an ATM-like device that customers can use to pay bills with cash. He said this convenience was targeted toward people without checking accounts. The machine will distribute a receipt which customers at risk of disconnection can use as proof of payment. Tr. E-53--E-56. Mr. Doty said the new customer service representatives would be available for face-to-face meetings with customers at a convenient Company office. Tr. E-56--E-57.

The Settlement also supports Petitioner's proactive plan to address its aging workforce by recruiting, training and developing replacements for the skilled workers who are expected to retire in upcoming years. We acknowledge that other regulatory commissions have recognized the importance of the aging workforce issue for public utilities. *E.g., New York State Electric & Gas Corp.*, 2006 N.Y. PUC. LEXIS 260 at *89, 252 PUR4th 165, 195 (NY Pub. Serv. Comm'n 8/23/06) (finding program to train 30 apprentices "is a laudable program and a useful device to maintain a skilled workforce that is fully capable of sustaining electric system reliability and on-going service quality" and recognizing that additional workers must be trained in time "to replace the seasoned employees who are reaching the time of their potential retirement"); *Central Vermont Pub. Serv. Corp.*, 2005 Vt. PUC LEXIS 65 at *236, 241 PUR4th 1, 72 (Vt. Pub. Serv. Bd. 3/29/05) ("We recognize that the aging of the workforce is an issue confronting the electric utility industry as a whole, and we are pleased that CVPS is planning for expected retirements"); *Connecticut Light and Power Co.*, 2003 Conn. PUC LEXIS 192 at *215, 229 PUR4th 380, 463 (Conn. Dep't of Pub. Util. Control 12/17/03) ("The Department agrees the pending retirement of lineworkers is a concern that must be addressed").

The Efficiency Settlement approved by the Efficiency Order dated December 1, 2006, provides for the implementation by both Petitioner and Vectren North of Energy Efficiency Riders containing an Energy Efficiency Funding Component and an SRC. The Efficiency Settlement provided that Vectren North's SRC would be implemented immediately but would reflect only 85% of the margin difference otherwise recoverable via the SRC (the difference between the actual margin and margin approved in the most recent rate case) "[t]o reflect the fact that implementation of the SRC will occur between rate cases without an opportunity to fully review the implications on Vectren Energy's overall financial performance." Efficiency Settlement ¶27. On the other hand, Petitioner's implementation of the SRC was delayed until the Commission approved new base rates. *Id.* ¶23. Because the Commission approves new base rates in this Order and all of the components of Petitioner's revenue requirement have been reviewed in this Cause, the Tariff approved herein will implement Petitioner's SRC with full recovery of the margin difference.

In reviewing the Settlement, we have considered the effect of this decoupling mechanism on Petitioner's risk, cost of capital and required ROE. Although we find that the 10.15% ROE for Vectren South provided for in the Settlement is reasonable, this issue warrants further discussion. The cost of equity evidence presented in this proceeding was based on a proxy group of eight natural gas companies with the following traits: engaged in the natural gas distribution business; have publicly-traded common stock; are contained in the Value Line Investment Survey; they have not recently cut or omitted their dividend; they are currently not the target of a merger or acquisition; they operate with a weather normalization and/or decoupling feature and they have at least 70% of their assets subject to utility regulation. Petitioner's direct case included much evidence as to why the recommended 11.5-12.00% cost of equity was conservative. Pet's Ex. PRM-1, pp. 6-7. The OUCC's witness concluded that the equity cost rate for the group of gas distribution companies was in the 8.5-8.6% range and recommended a 9.0% equity cost rate. Public's Ex. 3, pp. 52-53. Petitioner's witness employed the Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), Risk Premium (RP) and Comparable Earnings (CE) approaches in making his recommendation. OUCC witness employed the DCF and CAPM methodologies. Both witnesses applied their approaches to the same proxy group.

The Presiding Officers issued a Docket Entry dated February 2, 2007 asking several questions relating to Petitioner's case-in-chief. Several of the questions related to the proxy group used by Petitioner. One question was, in light of testimony that Vectren South Gas leans heavily on the financial results of Vectren South's electric operations for credit support[2], why were no integrated companies that might more closely resemble Petitioner's operations used in the proxy group. The answer offered was that prior to development of the group of proxy companies, Vectren South considered prior rate orders involving combination gas and electric utilities. Petitioner cited NIPSCO orders from 1982 and 1988 wherein the Commission expressed a preference for a proxy group of gas companies. Petitioner also responded that the selection of gas companies permitted selection of companies with decoupling and other tracking mechanisms. While we agree that companies with decoupling or other tracking mechanisms are useful in explaining the needs of Petitioner, we do not necessarily agree that what was applicable to NIPSCO in the 1980s holds true for the current marketplace and operations of today's utilities. The entire industry has changed radically in the interim.

Petitioner presented evidence that gas utilities with decoupling mechanisms have not been granted authorized ROEs less than 10.15%. Petitioner's response to our Docket Entry indicates that the allowed ROEs for all listed gas utilities with decoupling mechanisms exceed 10.15%. At the hearing on the Settlement, Mr. Benkert stated that the agreed-upon ROE recognized the reduction of residential customer usage risk from decoupling but that Petitioner remained at risk for other matters including loss of residential, commercial and industrial customers, increases in non-gas cost operating expenses, such as insurance and claims within Petitioner's increased $3 million deductible, and, in the case of UAFG costs and the gas cost component of bad debt expense, amounts that exceed the Settlement limitations for GCA recovery. Tr. E-22-23.

We find that an ROE of 10.15% for purposes of the Settlement is reasonable. However, even though the concerns discussed herein do not rise to the level of rejection of the Settlement, the inconsistencies and contradictions with regard to how the peer group was handled remain a disappointment. We are hopeful that Petitioner will address these concerns on a going forward basis and will reexamine its selection criteria for its proxy group. Specifically, the Company should look at integrated companies which may be more comparable to Petitioner and more closely resemble Vectren's operations, and reflect the financial realities of Vectren as testified to elsewhere by Petitioner. There is no question that selection criteria for the proxy group determines or affects the conclusion. Further, it is beyond peradventure that a rate case invokes advocacy by the parties. In reaching its decision, the Commission weighs, among other elements,

[2] Pet's Ex. JAB-1. p. 4, TR A-38-40, A-76.

the results of such advocacy. The Commission would observe that the process is not well served when advocacy is unchecked.

Another aspect of the Settlement we must discuss further is the matter of claims expense. Petitioner's witness Hardwick testified that Vectren South is self-insured for a portion of its injury and damage claims such that the insurance policies have a deductible of $1.0 million per occurrence. The company included a pro forma level of claims expense of $582,181 based on a three year average of actual claims paid and a three year amortization of a single major claim that was expensed in the test year. Pet's Ex. MSH-1 p. 17. The OUCC testimony states that the higher than usual expense for March 31, 2006 was caused by a $1,000,000 liability that was recognized in connection with an explosion which resulted in two fatalities. The OUCC witness states that since the $1 million liability was an extraordinary event and is non-recurring in nature, he normalized the cost over a 5-year period. Public's Ex. 1 pp. 8-9. The Stipulation and Settlement provides for a pro forma adjustment (29) which is an insurance claims expense. The Stipulation states that the OUCC's testimony reduced the expense to correct an error in a Company calculation and to reflect a 5 year amortization of a large claim in lieu of the Company's use of a 3 year amortization period. The Settlement adopts the OUCC position. The work papers that were filed by Petitioner on March 26, 2007 at the request of the Presiding Officers demonstrate that for the 12 months ended March 31, 2004, 2005 and 2006, Vectren South paid the sums of $44,307, $91,038 and $56,796 respectively for claims. These payouts would be the amounts paid in the ordinary course of business, without the large $1 million payout due to the explosion.

The evidence is uncontroverted that this $1,000,000 payout is an unusual expense and is a result of an extraordinary event. This expense is non-recurring in nature. Therefore, the Commission finds that the Company's $1,000,000 payout should not be included in the calculation of pro forma anticipated claims expenses, should not be borne by ratepayers. The Commission modifies the Stipulation and Settlement consistent with this finding.

We find that the remainder of the Settlement Agreement, including the provisions regarding UAFG costs, the gas cost component of bad debt expense, the PSA and the bare steel and cast iron pipeline replacement program, is reasonable, supported by the evidence of record and in the public interest and should be approved. However, we note that Petitioner must meet the requirements and deadlines found in the federal gas transmission integrity management regulations (49 CFR 192, SubPart O), established as a result of the Pipeline Safety Improvement Act of 2002. If Petitioner fails to meet the requirements, we will review the appropriateness of the continuation of the PSA tracker.

We also find that the new Tariff For Gas Service filed on April 13, 2007, including but not limited to the rates and charges set forth therein, after modification in compliance with this Order, is reasonable and should be approved subject to the terms and conditions contained in the Settlement. This Cause includes a three (3) year amortization period for Rate Case Expenses as originally proposed by the Petitioner and left undisturbed by the Settlement Agreement. Therefore, in order to effectuate the terms of the Settlement Agreement, the Commission recognizes that it will be necessary for the Petitioner to submit a compliance filing, along with a revised tariff, in this Cause, for approval by the Commission, that reflect revised rates as a result of the expiration of this amortization period.

We further find that for purposes of the earnings test component of the GCA, Petitioner's authorized annual net operating income shall be $8,760,160.

With regard to future citation of the Settlement Agreement, we find the Settlement Agreement and our approval of it should be treated in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434 (IURC 3/19/97).

10. **Alcoa Settlement Findings.** We have reviewed the Confidential Information *in camera*, and we find that its disclosure would have a substantial detrimental effect on Petitioner by placing it at a disadvantage in future negotiations of special contracts with industrial customers and in competing with interstate pipelines for service to industrial consumers located in its service area. If the Confidential Information became generally known or readily available to other parties with whom Petitioner may negotiate, this knowledge would provide considerable leverage to such parties and effectively establish benchmarks and price ceilings in future negotiations, thereby limiting the potential revenues and benefits that could accrue to ratepayers, shareholders and Petitioner in other cases. The Confidential Information is such that it may derive actual and independent economic value from being neither generally known to, nor readily ascertainable by, persons who could obtain economic value from its disclosure or use. We further find the Confidential Information is the subject of efforts that are reasonable under the circumstances to maintain its secrecy. Therefore, we find that the Confidential Information constitutes trade secrets within the meaning of Ind. Code § 5-14-3-4(a) as defined by Ind. Code § 24-2-3-2. We accordingly find that the Confidential Information should be exempt from public access under Ind. Code § 8-1-2-29 and shall be held confidential and protected from public disclosure by the Commission.

Ind. Code § 8-1-2-24 ("Section 24") provides:

> Nothing in this chapter shall be taken to prohibit a public utility from entering into any reasonable arrangement with its customers or consumers, or with its employees, or with any municipality in which any of its property is located, for the division or distribution of its surplus profits, or providing for a sliding scale of charges or other financial device that may be practicable and advantageous to the parties interested. No such arrangement or device shall be lawful until it shall be found by the commission, after investigation, to be reasonable and just and not inconsistent with the purpose of this chapter. Such arrangement shall be under the supervision and regulation of the commission.

Ind. Code § 8-1-2-25 provides:

> The commission shall ascertain, determine and order such rates, charges and regulations as may be necessary to give effect to such arrangement, but the right and power to make such other and further changes in rates, charges and regulations as the commission may ascertain and determine to be necessary and reasonable, and the right to revoke its approval and amend or rescind all orders relative thereto, is reserved and vested in the commission, notwithstanding any

such arrangement and mutual agreement.

Alcoa has entered into a written contract with Petitioner which specifies the terms and conditions of the service to be provided. The Agreement has been filed with this Commission for approval and the rates and charges for gas service are specified in the Agreement. An inspection of the Confidential Information demonstrates that the rates provide for the recovery of incremental costs of serving Alcoa plus a contribution to the recovery of Petitioner's fixed costs. Alcoa has agreed that during the term of the Agreement Petitioner shall be the sole and exclusive supplier of gas transportation service to the Warrick Operations and that it will not bypass Petitioner's system by the delivery of gas to the Warrick Operations through any pipeline other than that owned by Petitioner. The Alcoa Agreement is necessary to enable Petitioner to retain Alcoa as a customer. The Agreement is the result of arms length negotiations and will result in a direct benefit to Petitioner's other customers for the reasons discussed by Mr. Karl, including by the preservation of Alcoa's contribution to Petitioner's fixed cost recovery.

We find the Agreement and the rates and terms and conditions contained therein are just and reasonable, practical and advantageous to the parties and not inconsistent with the purposes of the Public Service Commission Act, Ind. Code § 8-1-2, and the Agreement to be in the public interest. We therefore find that the Agreement should be approved pursuant to Ind. Code §§ 8-1-2-24 and -25.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Stipulation and Settlement Agreement between Petitioner, the OUCC and AK Steel ("OUCC Settlement") filed in this Cause on March 15, 2007, shall be and hereby is approved, as modified consistent with the findings herein.

2. The proposed Tariff for Gas Service as filed on April 13, 2007, is approved and authorized, and shall be effective upon its filing with the Commission's Gas Division.

3. Petitioner is hereby authorized to implement the rates and charges for gas utility service described herein, in the OUCC Settlement and in the Tariff for Gas Service upon the filing of the new Tariff with the Gas Division in compliance with the findings herein.

4. Petitioner is hereby authorized to recover unaccounted for gas costs and the gas cost component of bad debt expense in its gas cost adjustment proceedings as provided in the OUCC Settlement.

5. Petitioner is authorized to defer and recover incremental Pipeline Safety Improvement Act expenses as provided in the OUCC Settlement, subject to review in the event Petitioner fails to meet the requirements and deadlines found in the federal gas transmission integrity management regulations (49 CFR 192, SubPart O).

6. Petitioner is authorized to continue to accrue post-in-service allowance for funds used during construction and to defer depreciation on investments made pursuant to its accelerated bare steel and cast iron pipeline replacement program as provided in the OUCC Settlement.

7. The Alcoa Agreement between Petitioner and Alcoa shall be and hereby is approved.

8. The Confidential Information contained in the Alcoa Agreement described herein is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and therefore exempt from public access and disclosure pursuant to Ind. Code § 5-14-3-1 and § 8-1-2-29.

9. This Order shall be effective on and after the date of its approval.

<u>HARDY, GOLC, LANDIS, SERVER AND ZIEGNER CONCUR</u>:
APPROVED:
AUG 0 1 2007

I hereby certify that the above is a true and correct copy of the Order as approved.

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission