ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF WESTFIELD GAS, LLC, D/B/A CITIZENS GAS OF WESTFIELD FOR (1) AUTHORITY TO INCREASE RATES AND CHARGES FOR GAS UTILITY SERVICE AND APPROVAL OF A NEW SCHEDULE OF RATES AND CHARGES; (2) APPROVAL OF CERTAIN REVISIONS TO ITS TERMS AND CONDITIONS APPLICABLE TO GAS UTILITY SERVICE; AND (3) APPROVAL PURSUANT TO INDIANA CODE SECTION 8-1-2.5-6 OF AN ALTERNATIVE REGULATORY PLAN UNDER WHICH IT WOULD CONTINUE ITS ENERGY EFFICIENCY PROGRAM PORTFOLIO AND ENERGY EFFICIENCY RIDER	)	**CAUSE NO. 44731** **APPROVED:** APR 26 2017

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Senior Administrative Law Judge

On December 30, 2015, Westfield Gas, LLC, d/b/a Citizens Gas of Westfield ("Citizens Gas of Westfield" or "Petitioner") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") seeking authority to increase its rates and charges for gas utility service rendered by it and approval of a new schedule of rates and charges applicable thereto, approval of certain revisions to its terms and conditions for gas utility service, and approval pursuant to Indiana Code § 8-1-2.5-6 of an alternative regulatory plan under which it would continue its energy efficiency ("EE") program portfolio and Energy Efficiency Rider ("EER").

On January 29, 2016, Petitioner filed an Amended Verified Petition. On June 17, 2016, Petitioner filed the direct testimony and attachments of the following witnesses: Aaron D. Johnson, President of Petitioner and Vice President of Strategy and Corporate Development of the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis d/b/a Citizens Energy Group ("Citizens Energy Group"); LaTona S. Prentice, Vice President, Regulatory & External Affairs of Citizens Energy Group; Sabine E. Karner, Vice President and Controller of Citizens Energy Group; Scott A. Miller, Certified Public Accountant and Partner of H.J. Umbaugh & Associates, Certified Public Accountants, LLP; and Adrien M. McKenzie, Vice President of FINCAP, Inc.

On June 23, 2016, Petitioner filed a Motion for Protective Order, requesting confidential treatment of certain customer specific information contained in workpapers submitted to the Commission. By Docket Entry dated July 5, 2016, the Commission granted the Motion for Protective Order.

On September 28, 2016, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the direct testimony and attachments of the following witnesses: Mark H. Grosskopf, Senior Utility Analyst; Debra K. Wilcox, Utility Analyst II; Leja D. Courter, Director of the Natural Gas Division; April M. Paronish, Utility Analyst; Bradley E. Lorton, Utility Analyst; and Brien R. Krieger, Utility Analyst.

On October 12, 2016, at 6:00 p.m., the Commission held a field hearing in the Westfield High School Cafeteria, 18250 N. Union Street, Westfield, Indiana.

On October 26, 2016, Petitioner filed the rebuttal testimony and attachments of Messrs. Johnson, Miller, and McKenzie and Misses Prentice and Karner.

On December 5, 2016, Petitioner and the OUCC (the "Parties") jointly filed a *Joint Notice of Settlement in Principle and Motion to Continue Procedural Schedule* (the "Joint Notice"). The Joint Notice indicated that a settlement in principle has been reached in this Cause, and sought a continuance of the evidentiary hearing so the agreement could be reduced to writing and submitted to the Commission for review.

On December 22, 2016, the Parties filed a Stipulation and Settlement Agreement (the "Settlement Agreement"). Also on December 22, 2016, Petitioner filed the settlement testimony of Ms. Prentice, and the OUCC filed the settlement testimony of Mr. Grosskopf.

On January 23, 2017, the Commission issued a Docket Entry requesting that Petitioner respond to certain requests for additional information. Petitioner filed responses on January 24, 2017.

On January 25, 2017, the Commission held an evidentiary hearing at 9:30 a.m. in Room 224, PNC Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner and the OUCC appeared and participated in the hearing. No members of the general public appeared. During the hearing, the evidence of Petitioner and the OUCC was offered and admitted into the record without objection.

Based upon the applicable law, the evidence presented, and being duly advised, the Commission now finds:

1. **<u>Notice and Jurisdiction</u>.** Notice of the filing of the Verified Petition in this Cause was published by Petitioner, as required by law. Notice of the public hearings conducted in this Cause was published by the Commission.

Petitioner is a public utility as defined in Indiana Code § 8-1-2-1. The Commission has authority to approve rates and charges for utility service under Indiana Code § 8-1-2-42. Additionally, in accordance with Indiana Code § 8-1-2.5-4, Petitioner has elected to become subject to Indiana Code §§ 8-1-2.5-5 and 6. Thus, the Commission has jurisdiction over Petitioner and the subject matter of this Cause.

2. **Petitioner's Characteristics.** Petitioner owns, operates, manages, and controls plant, property and equipment used and useful to provide natural gas utility service to approximately 3,800 customers in and around the City of Westfield, Indiana. Petitioner is an Indiana limited liability company ("LLC") with its principal office located at 2020 North Meridian Street, Indianapolis, Indiana 46202. Petitioner's sole membership interest is owned by Citizens Westfield Utilities, LLC ("CWU"), which is a subsidiary of Citizens By-Products Coal Company d/b/a Citizens Resources. Citizens Energy Group owns the stock of Citizens Resources.

3. **Test Year.** Petitioner requested that the calendar year ending December 31, 2015, be used as the test year, adjusted for changes that are fixed, known, and measurable and that occur within the 12 months following the end of the test year. We find the December 31, 2015 test year, as adjusted during the subsequent 12-month period, is sufficiently representative of Petitioner's normal utility operations to provide reliable data for ratemaking purposes.

4. **Current Rates and Relief Requested.** Petitioner's current base rates and charges were approved by the Commission in Cause No. 43624 by Order issued March 10, 2010, and were based on operating results for the test year ending March 31, 2008 and the fair value of used and useful utility property as of March 31, 2008. Following the Commission's issuance of the Order in Cause No. 43624, Petitioner filed compliance rates which went into effect on March 15, 2010. On December 22, 2010, Petitioner filed revised rate schedules which went into effect on January 1, 2011, and implemented an industrial customer transportation program approved in Cause No. 43624.

In its Order in Cause No. 43624, the Commission authorized Petitioner, pursuant to Indiana Code ch. 8-1-2.5, to implement an EE program portfolio, as well as an EER designed to both: (i) recover costs incurred to implement a portfolio of EE programs through a mechanism known as the Energy Efficiency Funding Component ("EEFC"); and (ii) decouple Petitioner's fixed cost recovery from sales of natural gas to its residential and commercial customers through a mechanism known as the Sales Reconciliation Component ("SRC"). In its Order dated April 10, 2013 in Cause No. 44124, the Commission authorized the extension of Petitioner's gas EE program portfolio, as well as the EER, through December 31, 2015. The Commission further authorized Petitioner to continue its EEFC and EE program portfolio by Docket Entry dated March 16, 2015 in Cause No. 44575. However, the Commission found in Cause No. 44124 that to the extent Petitioner intends to continue the SRC beyond December 31, 2015, such proposal shall be included as part of the requested relief in a base rate case, filed no later than December 30, 2015, in order for the SRC not to lapse.

In this case, Petitioner requests approval of an increase of its rates and charges for gas utility service that will enable it to realize net operating income adequate to provide safe and reliable natural gas utility service and an opportunity to earn a fair return on the fair value of the utility properties used to provide such service. Petitioner also requests approval of a new schedule of rates and charges reflecting the proposed increase, as well as proposes minor revisions to its Terms and Conditions for gas service. Petitioner also seeks an extension of its EE program portfolio, as well as authority to continue both components of the EER (*i.e.*, the EEFC and SRC).

5. **Petitioner's Evidence.** Aaron D. Johnson described the affiliation among Citizens Energy Group, its subsidiary Citizens Resources, its subsidiary CWU, and its subsidiary Petitioner. Mr. Johnson then provided an overview of Petitioner's gas utility business, and sponsored Petitioner's Amended Verified Petition.

Mr. Johnson testified that the significant recent growth in the City of Westfield has resulted in Petitioner's investment of over $2.9 million in plant in the last several years. Additionally, as of April 2016, over 70% of Petitioner's total capital expenditures related to new mains, services and growth projects. As such, in Mr. Johnson's opinion, Petitioner's currently authorized revenue requirement and existing rates and charges are inadequate and do not allow the utility an opportunity to earn a fair return on the fair value of its utility property. Therefore, Petitioner is requesting approval of an increase to total revenues of $361,071 or 9.21% (the equivalent of an increase in base rate revenues of 16.22%).

Mr. Johnson testified that, in its last rate case, Petitioner provided evidence regarding a number of efficiency improvements that were made possible by the acquisition of the utility from its prior owner, which continue to provide ongoing benefits to Petitioner's customers. Since its last rate case, Petitioner has taken additional steps to reduce costs and improve the utility's efficiency, most notably Petitioner's conversion from a C corporation to a single member LLC in order to achieve tax benefits. As a result, recovery of income taxes in base rates is no longer necessary.

Mr. Johnson next provided an overview of the other relief Petitioner is requesting, including the authority to make progress toward a straight-fixed-variable ("SFV") rate design, extension of its EE program portfolio, and continuation of its EER. Mr. Johnson explained that these measures will better align Petitioner's interest with its customers' interest in reducing usage through energy efficiency and improve Petitioner's ability to recover its non-gas costs and meet its operational requirements.

LaTona S. Prentice testified regarding Petitioner's revenue requirements and sponsored Attachment LSP-1 which showed among other things, Petitioner's actual per books income statement; pro forma adjustments for fixed, known, and measureable changes for the 12 months following the end of the test year, and the pro forma revenue requirement. Ms. Prentice indicated that Petitioner's pro forma revenue requirement totals $4,281,880, requiring an increase in total revenues of $361,017 in order to provide it with an opportunity to earn an adequate operating income. Ms. Prentice also described in detail the contents of Attachment LSP-1, including the accounting adjustments made by Petitioner to operating revenues, gas cost, other operating expenses, the Indiana Utility Receipts Tax, and other requirements.

Ms. Prentice next discussed the proposed rates and rate design objectives to fully recover its revenue requirement through its rates, move toward a SFV rate design, and continue the use of Petitioner's decoupling mechanism for the remaining portion of its rates that remain variable. Ms. Prentice explained the derivation of the proposed rates reflected in Attachment LSP-2. Ms. Prentice further testified the multi-step approach included: determining the revenue increase as a percent of sales margin, applying that percent increase in sales margin across-the-board to Petitioner's current base rates, preparing a revenue proof to determine the total pro forma margin to be recovered from each rate class, and applying a presumed fixed cost recovery percent to each class' total pro forma margin to determine the split between revenue to be recovered through a fixed charge and revenue to be recovered through a variable charge.

In terms of rate design, Ms. Prentice explained that Petitioner proposes to recover an increased level of its fixed costs through higher monthly facilities charges. Ms. Prentice testified that while 98% of Petitioner's total operating costs are fixed, only 13.23% of sales margin revenue is recovered through fixed charges.[1] Petitioner is proposing to move toward a SFV rate design, consistent with the Commission's guidance to Petitioner in its Order in Cause No. 44124. Ms. Prentice described the proposed gradual transition toward a SFV rate design by targeting an overall 30% fixed rate margin recovery in this rate case, which is an increase from its current 13.23% overall fixed rate margin recovery. Ms. Prentice indicated Petitioner would propose additional movement towards SFV rates in subsequent rate cases. Ms. Prentice testified that the proposed rates are fair and equitable and represent reasonable and just rates and charges for service.

Ms. Prentice next described Petitioner's request to continue its Energy Efficiency Adjustment ("EEA"), which is designed to support its efforts to provide EE programs by recovering costs incurred to implement a portfolio of EE programs through the EEFC mechanism and decouple Petitioner's fixed cost recovery from sales of natural gas to its residential and commercial customers through the SRC mechanism. The EEA was established by the Commission by its March 10, 2010 Order in Cause No. 43624, and the Commission authorized Petitioner to continue its EEFC and EE program portfolio in Cause No. 44575. However, the Commission found in Cause No. 44124 that to the extent Petitioner intends to continue the SRC beyond December 30, 2015, such proposal shall be included as part of the requested relief in a base rate case, which must be filed no later than December 30, 2015. Ms. Prentice explained that the programs offered year-to-year in the Energy Efficiency Portfolio may vary, but Petitioner intends to generally offer a residential rebate program for replacement of space heating equipment with high efficiency equipment options, and a commercial rebate program to incentivize customers to install natural gas energy efficiency improvements. Petitioner proposes to fund the Energy Efficiency Portfolio with $8,500 per year, and to not hire a third-party administrator to implement the program in order to reduce costs.

Ms. Prentice also explained Petitioner's proposal to continue its SRC mechanism, which is intended to ensure full margin recovery. Ms. Prentice testified that to the extent Petitioner's rate design does not recover all of its fixed costs through a fixed rate, the SRC will remain necessary. Ms. Prentice asserted that movement towards the SFV rate design should reduce the size of the SRC each year, and that it will be necessary for the decoupling mechanism to remain in effect so that Petitioner can earn a reasonable return. She explained that until SFV rates are in place to substantially recover its fixed costs through fixed charges, the SRC will continue to be necessary.

Finally, Ms. Prentice testified that Petitioner is proposing to reorganize its Terms and Conditions as part of a larger initiative to standardize the terms and conditions among Citizens Energy Group's various regulated utilities. Ms. Prentice also sponsored Petitioner's proposed rate schedules and appendices, in Attachments LSP-8 and LSP-9.

Sabine E. Karner sponsored the test year financial statements for Petitioner as Attachment

[1] The 98% represents the percentage of fixed costs to total operating costs after excluding gas costs.

SEK-1 upon which witness Prentice relied to form the basis for determining the pro forma revenue requirements.

Ms. Karner also sponsored the test year allocation of Shared Services costs to Petitioner. Ms. Karner described how Shared Services are assigned among the various Citizens Energy Group business units and the process for their allocation. Ms. Karner testified that Petitioner was allocated Shared Field Services ("SFS") at a rate of 0.44% or $100,717 for the test year, and was allocated Corporate Support Services ("CSS") at a rate of 0.84% or $711,374 for the test year. In addition, Ms. Karner noted that during the test year, Petitioner also was allocated approximately 0.11% of CSS as a result of the redistribution of such charges.

Ms. Karner next discussed Petitioner's pro forma adjustments related to certain operating expenses, and sponsored Attachment SEK-3, which presents a summary thereof during the test year. Ms. Karner discussed pro forma adjustments to payroll, payroll taxes, benefits, certain other operations and maintenance expenses, property taxes, and depreciation and amortization.

Finally, Ms. Karner presented pro forma rate base, Petitioner's overall cost of capital, and the fair return amount to be included in the revenue requirement as set forth on Attachment SEK-6. Ms. Karner computed that Petitioner's total rate base was $11,041,650 and also testified that Petitioner's actual capital structure was 99.18% common equity as of December 31, 2015, with the remaining 0.82% consisting of customer deposits. Ms. Karner next calculated that Petitioner's total recommended rate of return was 8.93% resulting in a return of $986,091.

Scott A. Miller provided testimony regarding the fair value or true current worth of Petitioner's property as of April 30, 2016, and sponsored a Special Purpose Accounting Report summarizing the results of his studies (Attachment SAM-1). Mr. Miller discussed the concept of fair value, explaining that it is the objective in a rate case proceeding to determine the actual current value of a utility's property as the basis for a fair value finding, so there can be a rational basis for determining the return requirement. To this end, Mr. Miller stated that there are a variety of methodologies available to the Commission to find the true current worth of the property being valued.

Mr. Miller employed the cost-based methodology to determine the fair value of Petitioner's assets, which is reflected in the Special Purpose Accounting Report. The Special Purpose Accounting Report contains the calculations and analysis Mr. Miller used to arrive at his opinion of the fair value of Petitioner's property. Mr. Miller also testified that it is appropriate to allocate a portion of the assets assigned to CSS and SFS to Petitioner when determining fair value, which is reflected in the Special Purpose Accounting Report. Mr. Miller also testified regarding other aspects of the Special Purpose Accounting Report, including reproduction cost calculations, the basis for cost index figures, and depreciation of assets. Mr. Miller concluded his testimony by stating his opinion that the fair value of Petitioner's utility assets is $10,666,117.

Adrien M. McKenzie testified regarding his assessment of the fair rate of return on fair value ("RFV") for Petitioner's gas utility operations, and included a review of fair value ratemaking and the development of a reasonable range for the cost of equity ("COE"). Mr. McKenzie opined that based upon the results of five methods – the discounted cash flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the empirical form of the CAPM ("ECAPM"), the risk premium approach, and the expected earnings approach the range of the COE is between 9.50% to 10.70%.

Mr. McKenzie further stated that 10.70% is a conservative estimate of investors' required COE for Petitioner. Mr. McKenzie explained that he based his conclusion on several factors. The risks and prospects associated with Petitioner's jurisdictional utility operations led Mr. McKenzie to focus his analysis on a proxy group of firms with gas utility operations. Because investors' required return on equity ("ROE") is unobservable and no single method should be viewed in isolation, Mr. McKenzie applied the DCF, CAPM, ECAPM, risk premium and expected earnings methods to estimate a fair ROE. Mr. McKenzie stated that, based on the results of these analyses, and giving less weight to extremes at the high and low ends of the range, he concluded that the COE for a regulated gas utility is in the 9.50% to 10.70% range. He concluded that a COE from the upper end is warranted here because of the additional uncertainties associated with Petitioner's relatively small size. Finally, because the proxy group utilities operate under a wide variety of adjustment mechanisms, including decoupling, the mitigation in risks associated with Petitioner's regulatory mechanisms is already reflected in the results of Mr. McKenzie's analysis, and no separate adjustment to the COE reflecting the availability of adjustment mechanisms is necessary or warranted.

Mr. McKenzie recommended a RFV applicable to the estimated current value of Petitioner's utility plant of 9.00%. Mr. McKenzie explained that investors' expectations of future inflation are likely to fall in the range of approximately 1.70% to 2.70%. The use of historical cost depreciation expense (as is typical and proposed by Petitioner in this case) will produce a return that falls short of investors' requirements under current value ratemaking. Therefore, Mr. McKenzie testified that in order to partially account for the attrition impact associated with historical cost depreciation expenses, he recommended that the return on fair value be calculated using the lower end of the inflation range, or 1.70%. Subtracting this inflation estimate from the 10.70% COE results in a recommended return on fair value of 9.00%.

Finally, Mr. McKenzie concluded that Petitioner's actual capital structure of nearly 100% common equity financing, represents a reasonable basis on which to establish Petitioner's return. This was the same capital structure used in Petitioner's last rate case, Cause No. 43624.

6. <u>OUCC's Evidence</u>. Mark H. Grosskopf addressed certain elements of Petitioner's request for a rate increase, including depreciation expense, rate base, capital structure, and the overall need for a rate increase, among others. Mr. Grosskopf testified that the OUCC's review supports a decrease in Petitioner's pro forma revenue requirement of $34,081, resulting in a 0.87% rate decrease. Mr. Grosskopf sponsored several attachments and schedules, including a comparison of Petitioner's and OUCC's revenue requirements and income statement adjustments (Public's Exhibit No. 1, Attachment MHG-1, Schedule 1).

After agreeing with Petitioner's depreciation expense adjustment using rates derived from the 2009 depreciation study, Mr. Grosskopf stated that he disagreed with Petitioner's proposed fair value rate base used to calculate the revenue requirement. Instead, Mr. Grosskopf recommended that the Commission use the original cost of Petitioner's rate base to calculate revenue requirements. Furthermore, Mr. Grosskopf opined that the fair value proposed by Petitioner is inappropriate. Specifically, Mr. Grosskopf criticized Mr. Miller's use of the Reproduction Cost New Less Depreciation ("RCNLD") value as the fair value of its assets and stated that RCNLD should be just one of the inputs the Commission may consider to determine the fair value of Petitioner's plant. Mr. Grosskopf was concerned that because Petitioner's plant was constructed in a piecemeal fashion over several decades, the RCNLD calculation is inappropriate in that it estimates a cost that assumes the plant would be reconstructed as it currently exists, and would not capture technological advances. As a result, Mr. Grosskopf maintained that Petitioner's RCNLD calculation overstates the fair value of the utility, as Mr. Miller did not make any necessary technology adjustment.

Mr. Grosskopf then recommended that the Commission use Petitioner's original cost rate base of $7,610,271 to establish rates. Mr. Grosskopf noted that, according to OUCC witness Lorton, an appropriate COE to apply to Petitioner's original cost rate base is 8.80%. Petitioner's proposed ROE, according to Mr. Grosskopf, exceeds a reasonable rate of return and is well above the ROE approved in recent years by the Commission. Mr. Grosskopf asserted that the main driver for Petitioner's proposed return is not increased operating costs, but rather additional profit to the utility.

Mr. Grosskopf also addressed the EER, including the SRC/EEFC cost-benefit analysis he conducted. Mr. Grosskopf recommended that the Commission deny Petitioner's request for continuation of the SRC mechanism, because, as currently designed, ratepayers bear the cost burden of energy efficiency to achieve significantly lower savings due to the EE programs. Mr. Grosskopf contended that the SRC mechanism diminishes the incentive for consumers to conserve energy, while the utility's incentive to reduce or maintain expense levels and generally control its costs to serve is also diminished. Mr. Grosskopf asserted that this decoupling revenue is a significant and excessive source of revenue for Petitioner.

Debra K. Wilcox addressed certain pro forma operating expenses of Petitioner. Ms. Wilcox testified that Ms. Prentice applied an improper IURC fee, which Ms. Wilcox stated should have been at a rate of 0.1171996%. Ms. Wilcox also asserted several invoices for goods or services provided were outside the test period, so she removed those invoices from Petitioner's test year expenses. Ms. Wilcox next addressed Petitioner's proposed Short Term Incentive Pay ("STIP") for executives allocated to Petitioner, asserting it is disproportionally high compared to non-executives. Ms. Wilcox proposed utilizing the non-executive's average 8.40% of STIP incentives to calculate a pro forma adjustment $8,487, which would also impact the pro forma payroll tax adjustment decrease.

Leja D. Courter provided testimony regarding rate case expenses, recommending any rate case expense approved by the Commission be shared between Petitioner's member CWU and its ratepayers because each receives appreciable benefits from the filing of a rate case. Mr. Courter recommended the 10% contingency for rate case expense be disallowed because Citizens Gas of Westfield did not provide any testimony supporting this amount. Mr. Courter testified rate case expense should be capped at $265,500, and before its new base rates are implemented that Citizens Gas of Westfield be required to true-up its final rate case expense to reflect only rate case expenses actually incurred. Mr. Courter also recommended rate case expense should be amortized over three years, and Citizens Gas of Westfield should file a revised tariff at the end of the three-year period to reflect the complete amortization of the rate case expense. Applying Mr. Courter's methodology, Mr. Grosskopf split the approved rate case expenses equally between Petitioner and the ratepayers in the revenue requirements.

Arpil M. Paronish asserted that Petitioner did not explain its reasoning or provide support for including an on-going amount of EE funding in a tracker. Ms. Paronish testified that in lieu of an EE Program Plan, Petitioner provided high-level, inadequate descriptions for one residential rebate program and one commercial rebate program that are subject to change from year-to-year. Ms. Paronish testified that without a plan detailing the budget and assumptions, the OUCC is unable to determine if the request for year-to-year funding is reasonable. Ms. Paronish stated Petitioner did not include ratepayer protections in this filing. These ratepayer protections include an Oversight Board and whether programs will be subjected to evaluation, measurement and verification ("EM&V"). Therefore, Ms. Paronish recommended that the Commission deny Petitioner's request to continue EE programs and recover EE expenditures of up to $8,500 per year.

Bradley E. Lorton testified regarding Petitioner's proposed cost of common equity capital and fair rate of return and provided the OUCC's position on the appropriate rates therefor. Mr. Lorton recommended an ROE of 8.80% for purposes of determining a return on Petitioner's original cost. Mr. Lorton explained that neither his DCF nor his CAPM analyses yielded a return nearly as high as Petitioner's current ROE or the 10.70% proposed by Petitioner in its case-in-chief. Mr. Lorton testified that current economic conditions, both nationally and in the State of Indiana, are best described as mature and slow recovery. Furthermore, Mr. Lorton maintained that data on bond and dividend yields, and economic growth projections do not support double digit rates of return. Finally, Mr. Lorton asserted that as a whole regulated public utilities tend to be less risky than the market.

Mr. Lorton also criticized Petitioner's assertion that its capital structure was 99.18% common equity and the remainder customer deposits. Mr. Lorton testified that Petitioner's member, CWU, is 86.20% debt financed, and Petitioner's requirement to make dividend payments are akin to debt service payments. This leads to a weighted average cost of capital of 8.732%. Mr. Lorton also maintains that historical inflation should not be included in the return on fair value, and if a fair value rate base is used, the rate of return should be reduced by 2.66%.

Brien R. Krieger also provided testimony for the OUCC regarding rate design. Mr. Krieger testified that Petitioner's across-the-board rate design does not represent the appropriate cost of service for each rate class. Specifically, Mr. Krieger explained that an across-the-board increase is problematic because Petitioner has not provided any analysis to establish that across-the-board increases appropriately allocate the cost of providing service to the customer classes. Mr. Krieger also noted that Petitioner's rates are based on a cost of service study ("COSS") performed nearly thirty years ago. Mr. Krieger recommended that Petitioner be required to perform and present a COSS in its next rate case. Mr. Krieger indicated the OUCC does not oppose Petitioner's proposal to increase its monthly customer service charges.

7. **Petitioner's Rebuttal Evidence.** Mr. Johnson provided rebuttal testimony to address the decrease to Petitioner's authorized revenue requirement proposed by the OUCC. Mr. Johnson commented that the proposed decrease ignores the tremendous growth the Westfield community has experienced for years and the millions of dollars Petitioner has invested to keep up with such growth. Mr. Johnson stated that the OUCC recommended a valuation of Petitioner's utility property that is almost $100,000 less than the value established in Petitioner's rate case eight years ago while also recommending a ROE that is 130-140 basis points lower than returns on equity the Commission has authorized for other gas utilities in recent cases. Mr. Johnson noted that the OUCC's proposal continues to refuse to accept fair value ratemaking as a legal requirement under Indiana law. Mr. Johnson also testified that the payroll and payroll tax adjustments proposed by OUCC witness Wilcox further demonstrated an overly zealous attempt to reduce Petitioner's revenue requirement by disallowing legitimate operating expenses.

Ms. Prentice rebutted the OUCC testimony with regard to the SRC, continuing the EE programs, rate case expense, the IURC fee adjustment, and a required COSS in Petitioner's next rate case. With regard to OUCC witness Grosskopf's recommendation that the Commission deny Petitioner's request for continuation of the SRC mechanism, Ms. Prentice noted that it constituted nothing but the same analysis he presented to the Commission on this issue in Cause No. 44124, which the Commission expressly rejected. Ms. Prentice provided the policy basis for natural gas decoupling, described recent relevant Commission Orders approving of natural gas decoupling, and recommended that the Commission approve the continuation of the SRC.

Ms. Prentice next testified that the Commission should allow Petitioner to continue providing a residential rebate program and commercial rebate program, which are programs within the norm of those offered by other Indiana utilities. Ms. Prentice described the programs that would be offered by Petitioner. Ms. Prentice rebutted OUCC witness Paronish's assertions that an expensive, detailed EE Program Plan is necessary under these circumstances because the Commission has previously found that forcing small gas utilities to incur similar expenses are unnecessary. Ms. Prentice noted that Ms. Paronish's recommendations would make it impossible for a small utility like Petitioner to offer EE programs to its customers.

Ms. Prentice also rebutted OUCC witness Courter's recommendation that approved rate case expenses be shared equally between CWU and Petitioner's ratepayers. Ms. Prentice pointed out that Mr. Courter cited no Indiana authority that permits the sharing of rate case expense, and simply rehashed an OUCC position in other cases that has been rejected by the Commission. Ms. Prentice testified that rate case expenses, like any other of Petitioner's operating expenses that are fixed, known and measureable, should be fully recoverable by the Petitioner.

Ms. Prentice also testified that while Petitioner did not object to OUCC witness Wilcox's recommendation with respect to the IURC fee, she rejected OUCC witness Krieger's assertion that an across-the-board increase is problematic. However, Ms. Prentice stated that Petitioner would be willing to engage a consultant to perform a COSS as part of its next rate case, as long as the cost of conducting such a study would constitute a rate case expense in that future case.

Ms. Karner responded to the OUCC's proposed Operation & Maintenance expense adjustments proposed by the OUCC. While the OUCC largely accepted her pro forma adjustments, Ms. Karner disagreed with the OUCC's proposed adjustments to out-of-period expenses. Additionally, based upon the rebuttal testimony of Mr. Johnson, Ms. Karner recommended that the OUCC's proposed adjustments to payroll and payroll taxes be rejected by the Commission.

Mr. Miller also provided testimony regarding issues raised by the OUCC about fair value rate base calculations. Mr. Miller disagreed with OUCC witness Grosskopf's opinion that Petitioner's fair value rate base is equivalent to its original cost of property. Mr. Miller reviewed the Commission's historical record regarding making fair value determinations and provided evidence that RCNLD should not be ignored by the Commission in determining fair value in this case. Mr. Miller concluded that, given the age and technology of Petitioner's assets, the most appropriate estimate of the fair value of Petitioner's utility assets is the RCNLD value, which is \$10,666,117. According to Mr. Miller, adding a 13-month average inventory balance of \$375,533 results in a total fair value rate base of \$11,041,650 for Petitioner.

Mr. McKenzie offered rebuttal testimony in response to OUCC witness Lorton. Mr. McKenzie testified that Mr. Lorton's ROE recommendation of 8.8% is extreme and below any reasonable level. Mr. McKenzie noted several technical flaws in the ROE analysis provided by Mr. Lorton, including his DCF study containing a faulty growth rate approach, his unreasonably low CAPM results, his failure to include any checks of reasonableness on his DCF results such as ECAPM, Utility Risk Premium, Expected Earnings, or Non-Utility DCF, his failure to recognize the implications of Petitioner's small size in evaluating his ROE recommendation, and misapplication of historical inflation in his criticism of Mr. McKenzie's RFV analysis. For all of these reasons, Mr. McKenzie concluded that Mr. Lorton's proposed 8.80% ROE recommendation would be an unprecedented outcome, especially in light of the 10.10% ROE granted to Petitioner in its last case in 2010 (Cause No. 43624) as well as out of line with returns from other state commissions.

8. Settlement Agreement. On December 22, 2016, the Parties filed the Settlement Agreement, which resolves each of the issues raised in the evidence presented by the parties. The following summarizes the terms of the Settlement Agreement:

a. Test Year and Rate Base Cutoff. The Parties agreed the period to be used for determining the revenues and expenses incurred by Petitioner to provide gas service to the public was the 12 months ended December 31, 2015. The Parties further agreed the utility properties used and useful for the provision of gas service to the public by Petitioner are properly valued for purposes of this proceeding as of April 30, 2016. The Parties stipulated that all statements of value contained in the Settlement Agreement were intended to be used exclusively for ratemaking purposes in this proceeding only and not necessarily to be reflective of the fair market value of the assets of Petitioner's gas system.

b. Fair Value Rate Base. The Parties agreed the regulatory fair value rate base of the utility properties used and useful for the provision of gas service by Petitioner to the public is \$10,800,000.

c. Operating Results at Present Rates. The Parties agreed total pro forma operating revenues at present rates for the Petitioner are \$3,920,810. The Parties also agreed

Petitioner's pro forma present operating expenses total for purposes of this proceeding is $3,268,962, which includes without limitation: (i) gas costs of $1,662,635; (ii) depreciation expense in the amount of $421,503; (iii) pro forma rate case expense of $230,000 to be amortized over three years for an annual revenue requirement of $76,667 based on the Parties having reached a settlement rather than fully litigating the case; (iv) taxes of $152,628; and (v) Indiana Utility Regulatory Commission fees ("IURC Fees") of $4,550. The Parties agreed the pro forma net operating income under present rates is $651,848, which is insufficient to cover Petitioner's necessary and reasonable operating expenses and provide the opportunity for Petitioner to earn a fair return on its used and useful plant. Accordingly, the Parties agreed Petitioner's existing rates and charges are unjust and unreasonable and should be increased.

d. Allowed Return. The Parties agreed Petitioner should be authorized a fair rate of return of 7.05%, based upon a fair value rate base of $10,800,000. The Parties agreed this fair rate of return will adequately and fairly compensate Petitioner for its investments, while maintaining the financial viability of the gas utility. Applying a 7.05% fair rate of return to the regulatory fair value rate base of approximately $10,800,000 would generate a fair return of $761,544 for GCA earnings test purposes.

e. Allowed Increase. The Parties agreed Petitioner's current recurring monthly rates and charges should be increased to levels sufficient to produce additional operating revenues of $111,720 from gas utility service, which reflects an approximate 2.85% increase in total operating revenues.

f. Allocation of Agreed Upon Increase in Operating Revenues. The Parties agreed the increase in operating revenues should be applied to Petitioner's rate classes on an across-the-board basis.

g. Customer Charges. The Parties agreed the monthly Customer Charges should be revised as proposed in Petitioner's case-in-chief to recover approximately 30% of Petitioner's total base revenues from fixed charges. The agreed-upon revised Customer Charges are set forth below:

Class	Customer Charge
Gas Rate No. D20	$12.00
Gas Rate No. D30	$110.73
Gas Rate No. D40	$37.00
Gas Rate No. D50	$1,158.56

Rate schedules setting forth the agreed-upon monthly Customer Charges and Delivery Charges for each customer class were attached to the Settlement Agreement as Joint Settlement Exhibit 3.

h. Continuation of the EE Programs and EER. The Parties agreed Petitioner should be authorized to continue its EE programs and EER until a final Order is issued in Petitioner's next base rate case. Petitioner will initially offer residential and commercial rebate programs as described in the Settlement Agreement, but will have the flexibility to modify the programs to be offered depending on the needs of the community. Any changes will be described in Petitioner's annual reports submitted to the Commission. The Parties agreed Petitioner will administer the programs "in-house," without using a third party administrator. The EE program budget will be $8,500 per year, $500 of which will be devoted to outreach efforts. For any year in which Petitioner spends less than the budgeted amount, the difference between the actual spend and the budget will be carried forward and increase the maximum permissible spend in future years. Rather than retaining an EM&V administrator, Petitioner will apply results from North's most recent EM&V analyses to the same measures offered by Petitioner.

The Parties agreed the EEFC will continue to be used to recover costs associated with implementation of the EE programs. The EEFC will remain in place unchanged and shall continue to operate in the manner approved by the Commission's Orders in Cause Nos. 43624 and 44124. In addition, the Parties agreed the SRC should continue to be used to calculate and recover, as applicable, the differences between actual margins and adjusted order granted margins for the applicable rate schedules (*i.e.*, the order granted monthly margins for each applicable rate schedule, as approved in this proceeding, as adjusted to reflect the change in number of End-Use Customers from the order granted End-Use Customer levels). The SRC shall continue to operate in the manner approved by the Commission's Orders in Cause Nos. 43624 and 44124. The residential margin differences eligible for recovery in the SRC annually will be capped at 8% of adjusted order granted residential margins applicable to the previous year. As approved in Cause No. 44124, any actual residential margin differences in excess of the 8% SRC cap will be deferred for future recovery either in a future SRC filing, with the annual residential SRC amount still subject to the 8% SRC cap, or in a future rate case. The total amount that may be deferred for recovery in a future rate case may not exceed $1 million.

i. Changes to Petitioner's Terms and Conditions for Service. The Parties agreed to the miscellaneous revisions to Petitioner's General Terms and Conditions for Gas Service set forth in Petitioner's case-in-chief.

j. Cost of Service Study. Petitioner agreed to engage a consultant to conduct a COSS for presentation in its next general rate case. The OUCC agreed the reasonable costs of such a study may be recovered as a rate case expense in that case. No less than 20 days before it files the rate case, Petitioner will provide to the OUCC a draft copy of the allocation factors that Petitioner intends to use in its COSS and an explanation of how the allocation factors may be used. The OUCC understands the draft allocation factors could be subject to change. Neither Party will be required to propose rates and charges based on the results of the COSS, but either Party may make recommendations regarding both the COSS and any proposed allocation of the revenue requirement.

k. Other Provisions. The Settlement Agreement provides that it shall have a non-precedential effect and does not constitute an admission by any Party in any other proceeding except as necessary to enforce its terms. The Settlement Agreement is without prejudice to and will not constitute a waiver of any position that a Party may take in future proceedings.

9. Evidence Supporting Settlement Agreement.

a. Petitioner's Evidence in Support of the Settlement Agreement. Ms. Prentice testified that the Settlement Agreement is the product of negotiations that began after Petitioner filed its rebuttal testimony, leading to extensive communications regarding a resolution by settlement. The Settlement Agreement, filed as Joint Settlement Exhibit 1, was the culmination of those negotiations.

Paragraph 5 of the Settlement Agreement provides that Petitioner's annual pro forma operating revenues from recurring monthly rates and charges should be increased by $111,720, representing an approximate increase of 2.85%. Petitioner had initially requested an overall operating revenue increase of 9.21%. Ms. Prentice stated that the agreed-upon operating revenue increase stemmed from an agreement that the regulatory fair value rate base is $10,800,000, and a fair rate of return of 7.05% should be utilized. This generates a fair return of $761,544 for GCA earnings test purposes, translating to a $111,720 increase over Petitioner's pro forma net operating income under present rates, inclusive of the increase to utility receipts tax, IURC fee, and net write-offs. Ms. Prentice asserted her belief that the agreed upon fair value rate base amount is reasonable and supported by the record. Ms. Prentice also testified in support of the agreed upon ROE of 7.11% and a weighted cost of capital of 7.05%.

Ms. Prentice next described the Parties' agreement that Petitioner's pro forma rate case expenses are $230,000, which should be amortized over three years for an annual revenue requirement of $76,667. Ms. Prentice opined that this is a reasonable amount in light of the Parties' agreement to not litigate the case and having reached a resolution on all issues. Ms. Prentice also described Petitioner's agreement to incorporate Ms. Wilcox's recommended pro forma IURC fee expense decrease of $157. Ms. Prentice asserted that the rates and charges resulting from the Settlement Agreement are reasonable and just, and will produce income sufficient to satisfy its service requirements and provide the opportunity for Petitioner to earn the fair return to which it is lawfully entitled.

Ms. Prentice testified that Paragraph 6 of the Settlement Agreement provides that the agreed-upon increase in operating revenues will be applied to Petitioner's rate classes on an across-the-board basis. Ms. Prentice stated that Petitioner has agreed to perform a COSS as part of its next rate case and to provide a draft copy of the allocation factors it intends to use in its COSS to the OUCC no less than twenty days before it files its next rate case. The Parties also agreed to revise Petitioner's customer charges to recover approximately 30% of Petitioner's total base revenue from fixed charges. Ms. Prentice testified that in her opinion, these agreements are fair and reasonable allocations of the rate increase, and are in the public interest.

Ms. Prentice next described the Parties' agreement that Petitioner continue offering EE programs, and that the EER should remain in place until a final Order is issued in Petitioner's next base rate case. Moreover, the Parties agreed that the EER will continue to function exactly as approved in Cause Nos. 43624 and 44124, including the 8% SRC cap. Ms. Prentice testified that the continuation of the SRC is an important component of the Settlement Agreement. In fact, according to Ms. Prentice, absent the OUCC's agreement regarding the SRC, any agreement by Petitioner to reduce its proposed net operating income would have placed Petitioner at a greater risk for under-recovering the revenues necessary to pay its non-gas costs, placing it in a financially precarious situation.

Ms. Prentice stated that the continuation of the EE programs continues to be in the public interest. Ms. Prentice stated that in her opinion, the EE programs continue to benefit customers. Ms. Prentice stated that the programs have and will continue to result in savings for Petitioner's customers.

In conclusion, Ms. Prentice recommended that the Commission approve the terms of the Settlement Agreement as consistent with the public interest, and requests it authorize Petitioner to implement the Settlement Agreement by Final Order.

b. OUCC's Evidence in Support of the Settlement Agreement. Mr. Grosskopf of the OUCC also submitted testimony in support of the Settlement Agreement. Mr. Grosskopf testified that the agreed-upon fair rate of return of 7.05% applied to a fair value rate base of $10,800,000, yields a return on rate base of $761,544. Mr. Grosskopf stated that the fair value rate base is approximately $240,000 less than Petitioner originally requested, and as such it is reasonable, supported by the evidence, and in the public interest.

Mr. Grosskopf also testified that the parties came to agreement on various pro forma adjustments, including the IURC fee recommended by the OUCC and a decrease in Petitioner's proposed rate case expenses of approximately $20,700 per year compared to Petitioner's original request. In terms of overall rate increase, the Parties agreed to an approximate 2.85% increase, while Petitioner initially requested a 9.21% increase, resulting in a net benefit to ratepayers.

Mr. Grosskopf next described the agreement with respect to the EER. The Parties agreed to continue the SRC in the manner approved by the Commission's Order in Cause Nos. 43624 and 44124, as well as maintaining the 8% SRC cap. The Settlement Agreement also addressed the concerns regarding Petitioner's energy efficiency expenditure tracking proposal voiced by OUCC Witness Paronish in her direct testimony.

Mr. Grosskopf further testified that the Settlement Agreement provided that Petitioner agreed to engage a consultant to conduct a COSS for presentation in its next general rate case. Mr. Grosskopf also addressed Petitioner's agreement to provide a draft copy of the allocation factors to the OUCC no less than 20 days in advance of filing the rate case. In conclusion, Mr. Grosskopf testified that the Settlement Agreement is reasonable, just and in the public interest, and recommended that the Commission approve it.

10. Commission Discussion and Findings.

a. Commission Review of Settlement Agreements. Settlements presented to the Commission are not ordinary contracts between private parties. *U.S. Gypsum, Inc. v. Ind. 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 Coal. of Ind., Inc. v. PSI Energy, Inc.*, 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 Coal.*, 664 N.E.2d at 406.

Further, any Commission decision, ruling, or order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *U.S. Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coal. of Ind., Inc. v. Public Service Co. of Ind., Inc.*, 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 ch. 8-1-2, and that such agreement serves the public interest.

i. Revenue Requirement. The Parties agreed for purposes of settlement that Petitioner's current recurring monthly rates and charges should be increased to levels sufficient to produce additional operating revenues of $111,720 from gas service, which reflects an approximate 2.85% increase in total operating revenues. This agreement is based on concurrence among the Parties regarding Petitioner's fair value rate base, a fair rate of return, and operating revenue and expenses. As is discussed in further detail below, we find that the Settlement Agreement regarding Petitioner's revenue requirement is reasonable, supported by evidence of record, and should be approved.

ii. Fair Value Rate Base. Petitioner presented evidence, which no Party disputed, that its utility properties, as included in its agreed upon fair value rate base, were used and useful and reasonably necessary for the convenience of the public and should be included in its fair value rate base, and we so find.

A first step in determining revenue requirements requires the Commission to value all property used and useful for the convenience of the public at its fair value. Indiana Code § 8-1-2-6. Petitioner, along with the other Settling Parties, have agreed that, for purposes of establishing rates in this case, the fair value of Petitioner's rate base at April 30, 2016, is $10,800,000 – approximately $240,000 less than Petitioner's proposed fair value rate base (including inventory). This agreed upon fair value rate base is supported by Petitioner's initial, rebuttal, and settlement testimony, as well as by the OUCC's testimony and settlement testimony. Accordingly, we find that Petitioner's fair value rate base at April 30, 2016 for purposes of this proceeding is $10,800,000 (including inventory), and that this fair value rate base should be used for purposes of determining a fair return on the fair value of Petitioner's used and useful property for purposes of this case.

iii. Fair Rate of Return. Having determined the fair value of Petitioner's used and useful property, we now turn to a determination of the level of net operating income that represents a reasonable return on that property. We are charged with providing the utility with the opportunity to earn a fair return on the fair value of its property. *See Gary-Hobart Water Corp. v. Ind. Util. Reg. Comm'n*, 591 N.E.2d 649, 653-54 (Ind. Ct. App. 1992) and *Office of Util. Consumer Counselor v. Gary-Hobart Water Corp.*, 650 N.E.2d 1201 (Ind. Ct. App. 1995). An accepted way of doing this is to determine Petitioner's capital structure and determine the cost of the various components of its capital. The Parties agreed for ratemaking purposes that Petitioner's capital structure at December 31, 2015 consists of 99.18% common equity and 0.82% customer deposits.

The evidence established that the cost of customer deposits was 0.50% (per IURC General Administrative Order 2015-02). In their respective cases, the Parties disagreed as to the COE. The record contains a number of different methods of estimating Petitioner's COE. We recognize that the COE cannot be precisely calculated and estimating it requires the use of judgment and the consideration of more than one methodology. The testimony of various witnesses in this case reflected initial views that Petitioner's COE was between 8.80% and 10.70%, and that a fair return on fair value rate base for Petitioner was between 6.14% and 9.00%. The Settling Parties concluded that applying a 7.05% fair rate of return to the agreed upon fair value rate base of $10,800,000 would provide Petitioner with the opportunity to earn a fair return of $761,544, and this amount should be used for Petitioner's GCA earnings test purposes.

Given due consideration to this evidence of record, including the Settlement Agreement and the risks and challenges facing natural gas utilities generally and Petitioner in particular, we find that the agreed upon fair rate of return to be applied to the agreed upon fair value falls within a reasonable range and within the range of fair rates of return presented by Petitioner and the OUCC. This authorized fair return for the purpose of setting rates in this proceeding (and for the purposes of Petitioner's GCA earnings test) is within the range of outcomes proposed and supported in testimony by all Parties. Accordingly, we find that the agreed upon fair rate of return of 7.05%, designed to produce a fair return of $761,544, is reasonable in this case.

Capital Structure

Description	**Amount**	**Percent of Total**	**Cost**	**Weighted Cost**
Equity	$10,519,230	99.18%	7.11%	7.05%
Long Term Debt	$0	0.00%	0.00%	0.00%
Customer Deposits	$86,535	0.82%	0.50%	0.00%
Deferred Income Taxes	$0	0.00%	0.00%	0.00%
Total	$10,605,765	100.00%		7.05%

iv. Operating Results at Present Rates. In the Settlement Agreement, the Parties agreed that total pro forma operating revenues at present rates for the gas utility are $3,920,810 for purposes of this proceeding. The Parties further agreed that the total pro forma operating expenses for purposes of this proceeding is $3,268,962, which includes but is not limited to (i) gas costs of $1,662,635; (ii) depreciation expense in the amount of $421,503; (iii) rate case expense of $230,000 to be amortized over three years for an annual revenue requirement of $76,667; (iv) taxes of $152,628; and (v) IURC Fees of $4,550. Thus, the resulting pro forma net operating income under present rates is $651,848. All such pro forma adjustments have been fully identified in the testimony supporting the Settlement Agreement and the evidence of record. Accordingly, we find all pro forma adjustments and the resulting pro forma operating revenues at present rates agreed upon in the Settlement Agreement are reasonable and supported by substantial evidence of record.

v. Allowed Increase. Petitioner's witness Prentice sponsored as Attachment LSP-S1 the revenue proof supporting the agreed-upon revenues. The Parties agreed that Petitioner's current recurring monthly rates and charges should be increased to levels sufficient to produce additional operating revenues of $111,720, which reflects an approximately 2.85% increase in total operating revenues. The Parties agreed that the allowed increase in additional revenues will provide Petitioner an opportunity to realize adequate utility operating income, enable Petitioner to maintain and support its credit and an opportunity to provide adequate financing, assure market confidence in its financial soundness, allow Petitioner to earn a return equal to that available on other investments of comparable risk, and permit it to obtain reasonable additional capital to enable Petitioner to render adequate, reliable and safe gas service to the public. The Commission finds that the rates estimated to produce these results are just and fair and should allow Petitioner an opportunity to earn a reasonable return on its property dedicated to providing gas utility services to the public.

b. Rate Design. In reaching a compromise, the Parties agreed an across-the-board increase was appropriate, with the stipulation described below that Petitioner perform a COSS in connection with its next rate case. The Parties further agreed that Petitioner's monthly Customer Charges should be revised as proposed in Petitioner's case-in-chief to recover approximately 30% of Petitioner's total base revenues from fixed charges. The revised monthly Customer Charges for each rate class were specifically delineated in the Settlement Agreement and revised rate schedules were attached as Joint Settlement Exhibit 3. We find these rate design modifications are reasonable. However, as discussed further below, we order Petitioner to conduct a COSS as part of its next rate case.

c. Cost of Service Study. Petitioner did not perform a COSS for use in this rate case, instead proposing an across-the-board increase. OUCC witness Krieger noted that Petitioner's rates are based on a COSS performed nearly 30 years ago. Mr. Krieger recommended that Petitioner be required to perform and present a COSS in its next rate case. Petitioner's witness Prentice stated that Petitioner would be willing to engage a consultant to perform a COSS as part of its next rate case as long as the cost of performing the study is recoverable in rates. The Settlement Agreement provides that Petitioner will engage a consultant to conduct a COSS for presentation in its next general rate case and the reasonable costs of such a study may be recovered as a rate case expense in that case. No less than 20 days before it files the rate case, Petitioner will provide to the OUCC a draft copy of the allocation factors that Petitioner intends to use in its COSS and an explanation of how the allocation factors may be used. Neither Party will be required to propose rates and charges based on the results of the COSS, but either party may make recommendations regarding both the COSS and any proposed allocation of the revenue requirement. The Commission agrees that this is a fair and reasonable compromise.

d. Continuation of the EE Programs. By its March 10, 2010 Order in Cause No. 43624, the Commission authorized Petitioner, pursuant to Indiana Code ch. 8-1-2.5, to implement an EE program portfolio. The Commission, by is Order dated April 10, 2013 in Cause No. 44124, authorized the extension of Petitioner's EE programs through December 31, 2015, and was also authorized to continue the EE programs through the issuance of a Final Order in this Cause. The Settlement Agreement provides that Petitioner, initially, shall continue offering a residential rebate program and a commercial rebate program, and will have the flexibility to modify the programs to be offered depending on the needs of the community. Any changes will be described in Petitioner's annual reports submitted to the Commission.

Initially, we note the Commission previously has found the provision of natural gas EE programs with accompanying funding to be appropriate and in the public interest for nearly every jurisdictional gas utility in the State of Indiana. On August 18, 2011, in Cause No. 44019, we approved a settlement agreement reached between the OUCC and Vectren Energy to extend Vectren Energy's efficiency programs. On December 28, 2011, we approved the expansion of NIPSCO's natural gas EE program in Cause No. 44001. On November 30, 2011 in Cause No. 43995, we authorized eight small gas utilities to implement EE programs.[2] We further authorized Citizens Gas to support a low-income weatherization program in its last base rate case. Natural gas EE programs reduce natural gas consumption by improving the energy efficiency of homes and businesses, space heating systems, water heating, and other gas appliances. This lowers the gas bills of consumers and businesses that adopt these measures, and provides broader societal benefits including reducing natural gas imports, reducing the risk of gas shortages, and putting downward pressure on natural gas prices.

As described by Petitioner's witness Prentice, the programs being proposed by Petitioner are: (i) a residential rebate program for natural gas furnaces, boilers, programmable thermostats and wi-fi thermostats; and (ii) a commercial rebate program for natural gas boilers, boiler tune-ups, natural gas furnaces and heaters, and natural gas water heaters. These are the same types of programs that Petitioner has previously offered to its customers and that are offered by other gas utilities in the State.

The EE program budget will be $8,500 per year, which is consistent with Petitioner's spending in 2016 less administration costs.[3] Of the $8,500, Petitioner will devote $500 to outreach efforts. In response to a question in the Commission's January 23, 2016 Docket Entry in this Cause, Petitioner stated the outreach efforts involve a school education program done in partnership with the National Energy Foundation and the Indianapolis Colts, which includes a poster contest where grade school students are challenged to create a poster showcasing ideas as to how to save energy in their home or community. Portions of the budget not spent annually will be carried forward and increase the maximum permissible spend in future years.

In order to make it possible for Petitioner to offer EE programs to its smaller customer base, the Parties agreed to various cost-conscious mechanisms. For instance, Petitioner will administer the programs "in-house," without using a third party administrator. Furthermore, in an effort to avoid the cost associated with retaining an EM&V administrator, Petitioner will apply results from Vectren North's most recent EM&V analyses to the same measures offered by Petitioner. However, if Petitioner offers measures that Vectren North does not offer, then the EM&V results will not be helpful in determining actual energy savings because those measures would not be evaluated. Therefore, Petitioner's energy efficiency measures should be limited to those offered by Vectren North. In addition, Petitioner has agreed to meet to discuss the EE programs with the OUCC. The Settlement Agreement eliminates the formal Oversight Board

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[2] The eight small gas utilities for which the Commission approved EE programs were Midwest Natural Gas Corporation; Indiana Utilities Corporation; South Eastern Indiana Natural Gas Company, Inc.; Boonville Natural Gas Corporation; Indiana Natural Gas Corporation; and Switzerland County Natural Gas Company, Inc.

[3] See Petitioner's Attachment LSP-R2, the Operating Plan filed in Cause No. 44124 for January through June of 2016, in which Petitioner budgeted $3,400 for commercial rebates and $3,938 for residential rebates. Petitioner also budgeted approximately $2,700 for administration costs that will no longer be necessary given that Petitioner will administer the programs.

structure, and therefore, the Settlement Agreement allows for possibly less than an annual meeting. The Commission would like to ensure regular collaboration occurs between the Settling Parties. Therefore, Petitioner and the OUCC shall meet at least annually. On or before March 31st of each year, the Commission orders Petitioner to file an energy efficiency scorecard which shows for the previous calendar year: the deemed savings attributable to the energy efficiency programs (and source used to derive the deemed savings); the number of customers participating by measure; incentive amount for each measure; the net-to-gross ratio, if any, by measure; and a break out of the energy budget by sector and program on an annual basis.

Based on the evidence of record, the Commission finds Petitioner should continue offering its EE programs in accordance with the terms of the Settlement Agreement and the above modifications. Further, in Cause No. 44598 we approved Vectren North's EE programs through December 31, 2019. As Petitioner is relying on the Vectren North's EM&V analyses it only makes sense that Petitioner's EE programs should also be approved through December 31, 2019. Thus, Petitioner's EE programs are approved through December 31, 2019.

e. Continuation of Energy Efficiency Rider. Petitioner's EER consists of the SRC and EEFC, and, as with the EE programs, was approved by the Commission's Orders in Cause Nos. 43624 and 44124. The parties agreed in the Settlement Agreement that each component would continue to operate in the manner approved in Cause Nos. 43624 and 44124.

The EEFC recovers the cost of offering the EE programs. Under the terms of the Settlement Agreement, the EEFC will continue to operate in the manner approved by the Commission in Cause No. 43624 and 44124. Based on the evidence of record, the Commission approves the continuation of the EEFC, which has been used to recover the cost of the programs since their inception in 2010.

The SRC is a decoupling mechanism that allows Petitioner to recover its non-gas costs as authorized in the most recent base rate case orders. The SRC was modeled after a similar mechanism the Commission approved for use by Vectren Energy in Consolidated Cause Nos. 42943 and 43046 (Order approved December 1, 2006). In that case, the Commission found:

> In the past, volumetric prices afforded gas utilities the opportunity to earn their authorized returns, even in the face of rising costs, because sales (and hence fixed cost recovery) were increasing. Today, volumetric pricing makes it difficult for an Indiana gas utility to earn its authorized return because usage per customer is declining. Under these conditions, this form of usage-based rate design has become an asymmetrical risk for the utilities.

Re Petition of Indiana Gas Company, Inc. and Southern Indiana Gas and Electric Company, Cause No. 42934 and 43046 (Dec. 1, 2006) at 39.

On September 9, 2015, the Commission approved the extension of the Vectren Energy SRCs through 2019 in Cause No. 44598. In that case, the Commission found the "SRC is working as intended." In addition to Vectren Energy, the Commission has authorized Petitioner (Cause No. 43624) and Citizens Gas (Order on Rehearing in Cause No. 42767, August 29, 2007) to implement similar SRC mechanisms. In addition to the foregoing cases approving SRCs, in our December 2006 Order initiating an investigation into rate design alternatives and energy efficiency measures for natural gas utilities, we expressed our anticipation that "decoupling mechanisms will be an important element in promoting utility stability and benefits to customers." *In re the Investigation on the Commission's Own Motion into Rate Design Alternatives and Energy Efficiency Measures for Natural Gas Utilities,* Cause No. 43180 (Dec. 1, 2006).

In this case, OUCC witness Grosskopf testified that the SRC requested by Petitioner in this Cause is the same or similar to the SRC approved in prior Orders. Petitioner's witness Prentice testified that "Petitioner's traditional volumetric rates have continued to result in under-collections due to declining usage." Ms. Prentice noted that Public's Attachment MHG-5 shows that over the approximate five-year period beginning in Fiscal Year 2010, Petitioner's traditional volumetric rates were under-collecting by approximately $2.4 million as a result of declining usage.[4] Accordingly, Ms. Prentice testified that "continuation of the SRC, without modification, continues to be critical for Petitioner." Ms. Prentice, in fact, stated that Petitioner would not have been motivated to reach the agreement it did with the OUCC with respect to reducing the overall rate increase absent the OUCC's agreement regarding continuation of the SRC. Ms. Prentice explained that the SRC is designed to prevent the under-collection of revenues necessary to cover Petitioner's non-gas costs. Absent the OUCC's agreement regarding the SRC, Ms. Prentice believed any agreement by Petitioner to reduce its proposed net operating income would have placed Petitioner at a greater risk for under-recovering the revenues necessary to pay its non-gas costs.

Based on the evidence of record, the Commission approves the continued operation of the SRC in the manner approved by the Commission in Cause No. 43624 and 44124. With regard to the SRC, the residential margin differences eligible for recovery in the SRC annually will be capped at 8% of adjusted order granted residential margins applicable to the previous year. Furthermore, as approved in Cause No. 44124, any actual residential margin differences in excess of the 8% SRC cap will be deferred for future recovery either in a future SRC filing, with the annual residential SRC amount still subject to the 8% SRC cap, or in a future rate case. The total amount that may be deferred for recovery in a future rate case may not exceed $1 million.

Consequently, we find that the proposed EER is reasonable, in the public interest, and should be approved and implemented in accordance with the terms of the Settlement Agreement. Consistent with the Commission's findings that the EE programs are approved through December 31, 2019, Petitioner's EER is also approved through December 31, 2019. This is consistent with the Commission's practice of approving SRCs with EE programs.

f. Terms and Conditions for Gas Service. The Parties agreed that the miscellaneous revisions to Petitioner's Terms and Conditions for Gas Service set forth in Petitioner's Attachments LSP-6 and LSP-7 and described in the direct testimony of Ms. Prentice should be approved by the Commission. The suggested revisions were described in the direct

[4] During the evidentiary hearing, Ms. Prentice was asked to describe the difference between "Therm Sales" shown on Public's Attachment MHG-5 and amounts reflected in Petitioner's annual reports. Ms. Prentice stated that there were "two differences." Ms. Prentices stated that the biggest difference is . . . that the numbers reflected on [the] exhibit are weather normalized. In addition, the annual report is on a calendar year basis and some of the years on MHG-5 are fiscal years. (Tr. at A-10.)

testimony of Petitioner's witness Prentice. We find that the miscellaneous revisions to Petitioner's Terms and Conditions for Gas Service agreed to in the Settlement Agreement are reasonable.

11. Conclusion Regarding Settlement Agreement. For all the foregoing reasons, we find that the Settlement Agreement with the above modifications is reasonable, supported by the evidence, and in the public interest. Therefore, we find that the Settlement Agreement should be approved with the above modifications.

12. Effect of Settlement Agreement. The Parties agreed that the Settlement Agreement should not be used as precedent in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce its terms. Consequently, with regard to future citation of the Settlement Agreement, we find that our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light,* Cause No. 40434, 1997 Ind. PUC LEXIS 459, at *19-22 (IURC March 19, 1997).

13. Confidentiality. Petitioner filed two motions seeking protective orders, which were supported by accompanying affidavits, showing certain workpapers, exhibits, and attachments to be submitted to the Commission contained confidential, proprietary and trade secret information of a third party within the scope of Indiana Code § 5-14-3-4(a)(4) and (9) and Indiana Code § 24-2-3-2. The Presiding Officers issued Docket Entries making preliminary findings of confidentiality after which Petitioner submitted the information to the Commission under seal. We find that all information submitted under seal by Petitioner is confidential pursuant to Indiana Code § 5-14-3-4 and Indiana Code § 24-2-3-2 and shall continue to be exempt from public access and disclosure by the Commission.

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

1. The Stipulation and Settlement Agreement between Citizens Gas of Westfield and the OUCC filed in this Cause on December 22, 2016, which is attached to this Order, is approved in its entirety and with the above modifications.

2. Petitioner is authorized to increase its rates and charges for natural gas service to levels sufficient to produce additional operating revenues of $111,720, which reflects an approximate 2.85% increase in operating revenues.

3. Petitioner shall file with the Commission's Energy Division a new schedule of rates and charges in the form set forth on Joint Settlement Exhibit 3 and, upon its approval, cancel its currently existing schedules of recurring monthly rates and charges.

4. The proposed changes to Petitioner's Terms and Conditions for Gas Service, which are reflected in Petitioner's Attachments LSP-6 and LSP-7, are approved. Petitioner shall file with the Commission's Energy Division Petitioner's updated Terms and Conditions for Gas Service.

5. The extension of Petitioner's energy efficiency programs and rate mechanisms are hereby approved pursuant to the terms forth in the Stipulation and Settlement Agreement and the above modifications.

6. The terms of the Stipulation and Settlement Agreement relating to the preparation of a COSS in connection with Petitioner's next general rate case are approved.

7. The documents identified in paragraph 13 of the findings qualify as confidential trade secret information within the scope of Indiana Code § 5-14-3-4(a)(4) and (9) and Indiana Code § 24-2-3-2. Pursuant to Indiana Code § 5-14-3-4 and Indiana Code § 24-2-3-2, these documents are exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

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

ATTERHOLT, FREEMAN, AND HUSTON CONCUR; WEBER AND ZIEGNER ABSENT:

APPROVED: APR 26 2017

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

Mary M. Becerra

Mary M. Becerra
Secretary of the Commission

OFFICIAL EXHIBITS

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF WESTFIELD GAS, LLC, D/B/A CITIZENS GAS OF WESTFIELD FOR (1) AUTHORITY TO INCREASE RATES AND CHARGES FOR GAS UTILITY SERVICE AND APPROVAL OF A NEW SCHEDULE OF RATES AND CHARGES; (2) APPROVAL OF CERTAIN REVISIONS TO ITS TERMS AND CONDITIONS APPLICABLE TO GAS UTILITY SERVICE; AND (3) APPROVAL PURSUANT TO INDIANA CODE SECTION 8-1-2.5-6 OF AN ALTERNATIVE REGULATORY PLAN UNDER WHICH IT WOULD CONTINUE ITS ENERGY EFFICIENCY PROGRAM PORTFOLIO AND ENERGY EFFICIENCY RIDER	)	**CAUSE NO. 44731** **APPROVED:**

IURC JOINT EXHIBIT No. 1
1-25-17 AT
DATE REPORTER

STIPULATION AND SETTLEMENT AGREEMENT

On December 30, 2015, Westfield Gas, LLC, d/b/a Citizens Gas of Westfield ("Citizens Gas of Westfield" or "Petitioner") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission")[1] seeking: (1) authority to increase its rates and charges for gas utility service rendered by it and approval of a new schedule of rates and charges applicable thereto; (ii) approval of certain revisions to its terms and conditions for gas utility service; and (iii) approval pursuant to Ind. Code § 8-1-2.5-6 of an alternative regulatory plan under which it would continue its energy efficiency program portfolio and Energy Efficiency Rider. Petitioner filed the testimony and exhibits constituting its case-in-chief on June 17, 2016. On September 28, 2016, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its direct testimony and exhibits. Petitioner filed rebuttal testimony and exhibits on October 26, 2016.

[1] The Verified Petition was amended on January 29, 2016.

After all testimony and exhibits had been filed, Petitioner and the OUCC (collectively the "Settling Parties") communicated with each other regarding potential resolution of the issues in this proceeding through a settlement agreement, subject to Commission approval. On November 23, 2016, the Settling Parties notified the Commission that they had reached an agreement with respect to all of the issues before the Commission, subject to preparation and execution of a written definitive agreement.

The Settling Parties, solely for purposes of compromise and settlement and having been duly advised by their respective staff, experts and counsel, stipulate and agree that the terms and conditions set forth in this Stipulation and Settlement Agreement ("Settlement Agreement") represent a fair, just and reasonable resolution of all matters raised in this proceeding, subject to their incorporation by the Commission into a final, non-appealable order without modification or further condition that may be unacceptable to any Settling Party ("Final Order").

I. INCREASE IN NET OPERATING INCOME.

1. Test Year and Rate Base Cutoff. The period used for determining the revenues and expenses incurred by Petitioner to provide gas service to the public was the twelve months ended December 31, 2015. The utility properties used and useful for the provision of gas service to the public by Petitioner are properly valued for purposes of this proceeding as of April 30, 2016. All statements of value contained in this Settlement Agreement are intended to be used exclusively in this proceeding for ratemaking purposes only and are not necessarily intended to be reflective of the fair market value of the assets of Petitioner's gas system.

2. Fair Value Rate Base. For purposes of this proceeding only, the regulatory fair value rate base of the utility properties used and useful for the provision of gas service by Petitioner to the public is **$10,800,000**.

3. Operating Results at Present Rates. As shown on Joint Settlement Exhibit 2, page 2, total pro forma operating revenues at present rates for the Petitioner are **$3,920,810** for purposes of this proceeding. With pro forma present total operating expenses for purposes of this proceeding at **$3,268,962**, which includes without limitation: (i) gas costs of $1,662,635; (ii) depreciation expense in the amount of **$421,503**; (iii) pro forma rate case expense of $230,000 to be amortized over three years for an annual revenue requirement of $76,667 based on the parties having reached an agreement in principle on November 23, 2016 rather than fully litigating the case; (iv) taxes of $152,628; and (v) Indiana Utility Regulatory Commission fees of $4,550. (See Joint Settlement Exhibit 2, pages 2 and 3.) The pro forma net operating income under present rates for purposes of this proceeding is **$651,848**. (See Joint Settlement Exhibit 2, page 3.) This net operating income amount is insufficient to cover Petitioner's necessary and reasonable operating expenses and provide the opportunity for Petitioner to earn the fair return to which Petitioner is lawfully entitled. The existing rates and charges are unjust and unreasonable and should be increased.

4. Allowed Return. The Settling Parties concur that Petitioner should be authorized a fair rate of return of **7.05%,** based upon a fair value rate base of $10,800,000\. The foregoing fair rate of return will adequately and fairly compensate Petitioner for its investments, while maintaining the financial viability of the gas utility. As shown on Joint Settlement Exhibit 2, page 1, applying a **7.05%** fair rate of return to the regulatory fair value rate base of approximately **$10,800,000** would generate for purposes of this proceeding a fair return of **$761,544** for GCA earnings test purposes.

5. Allowed Increases. As shown on Joint Settlement Exhibit 2, page 1, the Settling Parties agree for purposes of settlement that Petitioner's current recurring monthly rates and

charges should be increased to levels sufficient to produce additional operating revenues of **$111,720** from gas utility service, which reflects an approximately 2.85% increase in total operating revenues. The amount of that allowed increase in additional revenues will provide Petitioner an opportunity to realize adequate utility operating income, enable Petitioner to maintain and support its credit and provide adequate financing, assure market confidence in its financial soundness, allow Petitioner to earn a return equal to that available on other investments of comparable risk, and permit it to obtain reasonable additional capital to enable Petitioner to render adequate, reliable and safe gas service to the public.

6. Allocation of Agreed Upon Increase in Operating Revenues. The Settling Parties stipulate that the agreed-upon increase in operating revenues should be applied to Petitioner's rate classes on an across-the-board basis.

7. Customer Charges. The Settling Parties agree that the Monthly Customer Charges will be revised as proposed in Petitioner's case-in-chief to recover approximately 30% of Petitioner's total base revenues from fixed charges. The revised Customer Charges by rate class, based on the agreed upon increase in operating revenues, are set forth below:

Class	Customer Charge
Gas Rate No. D20	$12.00
Gas Rate No. D30	$110.73
Gas Rate No. D40	$37.00
Gas Rate No. D50	$1,158.56

8. Rate Schedules Implementing Agreed Upon Rate Increase. Joint Settlement Exhibit 3 includes the agreed-upon rate schedules for each rate class setting forth the Monthly Customer Charges and Delivery Charges for each customer class determined in the manner described above.

II. CONTINUATION OF ENERGY EFFICIENCY PROGRAMS AND ENERGY EFFICIENCY RIDER

9. Background. By its March 10, 2010 Order in Cause No. 43624, the Commission authorized Petitioner, pursuant to Ind. Code § 8-1-2.5, to implement an energy efficiency program portfolio, as well as an Energy Efficiency Rider. The Energy Efficiency Rider consists of: (i) the Sales Reconciliation Component ("SRC"), which "decouples" Petitioner's fixed cost recovery from sales of natural gas to its residential and commercial customers; and (ii) the Energy Efficiency Funding Component ("EEFC"), which recovers the cost of offering the energy efficiency programs. By Order dated April 10, 2013 in Cause No. 44124, the Commission authorized the extension of Petitioner's energy efficiency program portfolio, as well as the Energy Efficiency Rider through December 31, 2015 and directed that any requested extension of the SRC be included as part of the requested relief in Petitioner's next base rate case. Petitioner was authorized in Cause No. 44124 to continue the energy efficiency programs and the Energy Efficiency Rider through the issuance of a Final Order in this Cause.

10. Energy Efficiency Programs. Upon issuance of a Final Order, the Settling Parties agree Petitioner shall continue offering energy efficiency programs in accordance with the terms set forth below.

a. *Initial Energy Efficiency Programs.* Petitioner will initially offer the following programs:

(i) A residential rebate program designed to help customers that live in an existing single dwelling afford high efficiency equipment options when replacing space heating equipment. Rebates will be available for natural gas furnaces, boilers, programmable thermostats, efficient water heaters and Smart WIFI Thermostats.

(ii) A commercial rebate program that will provide cash-back incentives for general service customers for the installation of natural gas energy efficiency improvements. Cash-back incentives will be available for approved energy saving measures and equipment, including: natural gas boilers, boiler tune-ups, natural gas furnaces and heaters, and natural gas water heaters. The program will incentivize measures at existing and new facilities.

The Settling Parties agree Petitioner should have the flexibility to modify the particular energy efficiency programs to be offered depending on the needs of the community it serves. Changes to the foregoing program offerings will be described in the annual reports filed under subsection (e), below.

b. *Budget*. The energy efficiency program budget will be $8,500 per year, $500 of which will be devoted to outreach efforts. For any year in which Petitioner spends less than the foregoing budgeted amount, the difference between the actual spend and the budget will be carried forward and increase the maximum permissible spend in future years.

c. *Program Administration*. In order to minimize the cost of operating the programs, Petitioner will administer the programs "in-house," without using a third party administrator.

d. *Evaluation, Measurement & Verification ("EM&V")*. In order to avoid the cost associated with retaining an EM&V administrator, Petitioner will apply results from Vectren North's most recent EM&V analyses to the same measures offered by Petitioner.

e. *Reporting.* On or before March 31st of each year, Petitioner will submit in this Cause an energy efficiency scorecard which shows for the previous calendar year: the deemed savings attributable to the energy efficiency programs (and source used to derive the deemed savings); the number of customers participating by measure; incentive amount for each measure; the net-to-gross ratio, if any, by measure; and a break out of the energy budget by sector and program on an annual basis. Upon request by the OUCC, Petitioner will convene a meeting no more than once annually to collaborate with the OUCC and discuss the energy efficiency programs.

11. Energy Efficiency Funding Component. The EEFC shall continue to be used to recover the costs associated with implementation of the energy efficiency programs. The EEFC shall remain in place unchanged and shall continue to operate in the manner approved by the Commission's Orders in Cause Nos. 43624 and 44124.

12. Sales Reconciliation Component. The SRC shall continue to be used to calculate and recover, as applicable, the differences between actual margins and adjusted order granted margins for the applicable rate schedules (*i.e.*, the order granted monthly margins for each Applicable Rate Schedule, as approved in this proceeding, as adjusted to reflect the change in number of End-Use Customers from the order granted End-Use Customer levels). The SRC shall continue to operate in the manner approved by the Commission's Orders in Cause Nos. 43624 and 44124. The residential margin differences eligible for recovery in the SRC annually will be capped at 8% of adjusted order granted residential margins applicable to the previous year. As approved in Cause No. 44124, any actual residential margin differences in excess of the 8% SRC cap will be deferred for future recovery either in a future SRC filing, with the annual

residential SRC amount still subject to the 8% SRC cap, or in a future rate case. The total amount that may be deferred for recovery in a future rate case may not exceed $1 million.

13. Term of Extension. Petitioner shall continue offering energy efficiency programs, and the Energy Efficiency Rider shall remain effective, until a final Order is issued in Petitioner's next base rate case. To the extent Petitioner desires to extend the programs and the Energy Efficiency Rider (or any component thereof including the SRC) beyond the issuance of a final Order in Petitioner's next base rate case, such extension shall be sought by Petitioner as part of the base rate case filing.

III. TERMS AND CONDITIONS FOR GAS SERVICE

14. The Settling Parties agree the miscellaneous revisions to Petitioner's General Terms and Conditions for Gas Service set forth in Petitioner's Attachments LSP-6 and LSP-7 and described in the direct testimony of LaTona S. Prentice should be approved by the Commission.

IV. COST OF SERVICE STUDY

15. Petitioner shall engage a consultant to conduct a cost of service study for presentation in its next general rate case. The OUCC agrees the reasonable costs of such a study may be recovered as a rate case expense in that case. No less than 20 days before it files the rate case, Petitioner shall provide to the OUCC a draft copy of the allocation factors that Petitioner intends to use in its cost of service study and an explanation of how the allocation factors may be used. The OUCC understands that the draft allocation factors could be subject to change. Neither Petitioner, nor the OUCC, will be required to propose rates and charges based on the results of the cost of service study, but either party may make recommendations regarding both the cost of service study and any proposed allocation of the revenue requirement.

V. SETTLEMENT AGREEMENT -- SCOPE AND APPROVAL

16. Neither the making of this Settlement Agreement nor any of its provisions shall constitute in any respect an admission by any Settling Party in this or any other litigation or proceeding. The parties intend that neither the making of this Settlement Agreement, nor the provisions thereof, nor the entry by the Commission of a Final Order approving this Settlement Agreement, shall establish any principles or legal precedent applicable to Commission proceedings other than those resolved herein.

17. This Settlement Agreement shall not constitute nor be deemed an admission by any Settling Party in any other proceeding except as necessary to enforce its terms before the Commission, or any tribunal of competent jurisdiction. This Settlement Agreement is solely the result of compromise in the settlement process and, except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any of the Settling Parties may take with respect to any or all of the issues resolved herein in any future regulatory or other proceeding. Each of the Settling Parties has entered into this Agreement solely to avoid further disputes and litigation with the attendant inconvenience and expenses in this Cause. In accordance with the Order in *Re Petition of Richmond Power & Light*, Cause No. 40434, p. 10, the Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Agreement, or the Order approving it, not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission, or any court of competent jurisdiction on these particular issues.

18. This Settlement Agreement is conditioned upon and subject to Commission acceptance and approval of its terms in their entirety, without any change or condition that is unacceptable to any Settling Party. If the Settlement Agreement is not approved in its entirety by

the Commission, the Settling Parties agree that the terms herein shall not be admissible in evidence or discussed by any party in a subsequent proceeding. Moreover, the concurrence of the Settling Parties with the terms of this Settlement Agreement is expressly predicated upon the Commission's approval of the Settlement Agreement in its entirety without any material modification or any material condition deemed unacceptable by any Party. If the Commission does not approve the Settlement Agreement in its entirety, the Agreement shall be null and void and deemed withdrawn, upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that any modifications made by the Commission are unacceptable to it. In the event the Settlement Agreement is withdrawn, the Settling Parties will request that an Attorneys' Conference be convened to establish a procedural schedule for the continued litigation of this proceeding.

19. The Settling Parties stipulate that the evidence of record presented in this Cause constitutes substantial evidence sufficient to support this Settlement Agreement and provide an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Settlement Agreement, as filed. In addition, the Settling Parties shall offer supplemental testimony supporting the Commission's approval of this Settlement Agreement and will request that the Commission issue a Final Order incorporating the agreed proposed language of the Settling Parties and accepting and approving the same in accordance with its terms without any modification. Such supportive testimony will be agreed-upon by the Settling Parties. The direct, rebuttal and supplemental testimony filed in this proceeding will be offered into evidence without objection and the Settling Parties hereby waive cross-examination of each other's witnesses.

20. The Settling Parties will support this Settlement Agreement before the Commission and request that the Commission accept and approve the Settlement Agreement. This Settlement Agreement is a complete, interrelated package and is not severable, and shall be accepted or rejected in its entirety without modification or further condition(s) that may be unacceptable to any Settling Party.

21. The Settling Parties shall work together to prepare an agreed upon proposed order to be submitted in this Cause. The Settling Parties will request Commission acceptance and approval of this Settlement Agreement in its entirety, without any change or condition that is unacceptable to any party to this Settlement Agreement.

22. The Settling Parties will request that the Commission issue a Final Order promptly accepting and approving this Settlement Agreement in accordance with its terms. The Settling Parties also will work cooperatively on news releases or other announcements to the public about this Settlement Agreement.

23. The Settling Parties shall not appeal or seek rehearing, reconsideration or a stay of any Final Order entered by the Commission approving the Settlement Agreement in its entirety without changes or condition(s) unacceptable to any Party (or related orders to the extent such orders are specifically and exclusively implementing the provisions hereof) and shall not oppose this Settlement Agreement in the event of any appeal or a request for rehearing, reconsideration or a stay by any person not a party hereto.

24. The undersigned have represented and agreed that they are fully authorized to execute this Settlement Agreement on behalf of their designated clients, and their successors and assigns, who will be bound thereby.

25. The communications and discussions during the negotiations and conferences have been conducted based on the explicit understanding that said communications and discussions are or relate to offers of settlement and therefore are both inadmissible and privileged. All prior drafts of this Settlement Agreement and any settlement proposals and counterproposals also are or relate to offers of settlement and are both inadmissible and privileged.

Accepted and Agreed on this 22nd day of December, 2016.

[signature page follows]

Westfield Gas, LLC d/b/a Citizens Gas of Westfield

Lauren Toppen
An Attorney for Citizens Gas of Westfield

Indiana Office of Utility Consumer Counselor

Daniel Le Vay
An Attorney for the Indiana Office of Utility Consumer Counselor

Westfield Gas, LLC
d/b/a Citizens Gas of Westfield
Cause No. 44731

Comparison of Petitioner's and the OUCC's Proposed Revenue Requirements
to Agreed Upon Revenue Requirements

Description	A Per Petitioner	B Per OUCC	C Settlement Agreement
	Fair Value	*Original Cost*	*Fair Value*
Rate Base	$11,041,650	$7,610,271	$10,800,000
Times: Rate Of Return	8.93%	8.73%	7.05%
Net Operating Income	986,091	664,550	761,544
Economic Less Book Depreciation	0	0	0
Return on Rate Base	986,091	664,550	761,544
Less: Adjusted Net Operating Income	631,530	698,013	651,848 (1)
Increase In Net Operating Income	354,561	(33,463)	109,696
Divided by Revenue Conversion Factor	0.9819702	0.9815427	0.9818760
Recommended Revenue Increase (Decrease)	$361,071	($34,081)	$111,720
Overall Percentage Increase (Decrease)	9.21%	-0.87%	2.85%

WESTFIELD GAS, LLC
Summary of Pro Forma Revenue Requirement

Line No.		A Actual per Books	B Pro Forma Adjustments Increase (Decrease)	C Pro Forma Results Based on Current Rates	D Pro Forma Adjustments Increase (Decrease)	E Pro Forma Results Based on Proposed Rates	F Reference	G Change from Case-in Chief
	Operating Revenues							
1	Test Year Revenues	$4,395,109					Income Statement	
2	Normal Weather Adjustment		58,780				page 5	
3	Customer Charge Revenue Adjustment		11,795				page 5	
4	Unbilled Gas Revenue Adjustment		1,204				page 5	
5	NTA Adjustment		4,174				page 5	
6	Correction Factor Adjustment		(17)				page 5	
7	Rounding		0				page 5	
7	Non-Weather Related Adjustment		583,292				page 6	
8	Gas Price Adjustment		(536,641)				page 8	
9	Other Revenue		(596,886)				page 9	
10	Revenue Requirement Increase				$111,720		page 13	($249,350)
11	Total Operating Revenues	$4,395,109	($474,300)	$3,920,810	$111,720	$4,032,530		2.85%
	Gas Cost							
12	Test Year Gas Costs	$1,844,753					Income Statement	
13	Normal Weather Adjustment		$29,902				page 5	
14	Non-Weather Related Gas Cost Adjustment		301,565				page 5	
15	Gas Price Adjustment		(536,641)				page 5	
16	Miscellaneous		23,056				page 8	
17	Total Gas Costs	$1,844,753	($182,118)	$1,662,635	$0	$1,662,635		
18	**Gross Margin**	$2,550,357	($292,182)	$2,258,175	$111,720	$2,369,895		
	Other Operating Expenses							
19	Test Year Other Operating Expenses	$1,068,682					Income Statement	
20	Amortized Regulatory Expense		76,667				page 10	(20,683)
21	Net Write-Off Non-Gas Cost		(15,380)		335		page 10 & 14	($748)
22	Payroll		(16,383)				Attachment SEK-2	
23	Payroll Taxes		(995)				Attachment SEK-2	
24	CSS Redistribution		(80,429)				Attachment SEK-2	
25	Distribution Expenses		(28,338)				Attachment SEK-2	
26	Business Insurance Expense		25,764				Attachment SEK-2	
27	Out of Period Expenses		6,226				Attachment SEK-2	
28	Non-Recurring Expenses		(3,293)				Attachment SEK-2	
29	Non-Allowed Expenses		(168)				Attachment SEK-2	
30	IURC Fee		(157)		131		page 11 & 15	366
31	Total Other Operating Expenses	$1,068,682	($36,486)	$1,032,196	$466	$1,032,663		(258)

WESTFIELD GAS, LLC
Summary of Pro Forma Revenue Requirement

Line No.		A Actual per Books	B Pro Forma Adjustments Increase (Decrease)	C Pro Forma Results Based on Current Rates	D Pro Forma Adjustments Increase (Decrease)	E Pro Forma Results Based on Proposed Rates	F Reference	G Change from Case-in Chief
	Depreciation & Amortization							
32	Test Year Depreciation & Amortization	$554,657					Income Statement	
33	Depreciation & Amortization Adjustment		($133,154)				Attachment SEK-2	
34	Pro Forma Depreciation & Amortization	$554,657	($133,154)	$421,503	$0	$421,503		
	Taxes							
35	Test Year Taxes	$172,941					Income Statement	
36	Pro Forma Change in IURT		($29,716)		$1,559		page 12 & 16	($3,479)
37	Pro Forma Change in Property Tax		9,489				Attachment SEK-2	
38	Pro Forma Change in Payroll Tax		(87)				Attachment SEK-2	
39	Pro Forma Taxes	$172,941	($20,313)	$152,628	$1,559	$154,186		
40	**Operating Income**	$754,077	($102,228)	$651,848	$109,696	$761,544		(224,547)

GAS RATE NO. D20

RESIDENTIAL DELIVERY & SUPPLY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for residential domestic and residential space heating purposes by a Customer through one Meter supplying a single Premise, with no more than four (4) individual units.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D20, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

CUSTOMER CHARGE:

$12.00 per Meter per Month

DELIVERY CHARGE:

$0.3641 per Therm for the first 120 Therms delivered each Month

$0.2277 per Therm for the next 380 Therms delivered each Month

$0.2112 per Therm for all usage over 500 Therms delivered each Month

In addition, the Normal Temperature Adjustment from Appendix D, Energy Efficiency Adjustment from Appendix E, and Regulatory Asset Amortization from Appendix F shall apply to all Therms delivered.

GAS SUPPLY CHARGE:

The currently applicable charge for all Gas supplied under this Gas Rate No. D20 is identified on Appendix A as Variable-Rate Supply.

GAS RATE NO. D30

INDUSTRIAL DELIVERY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for year-round industrial processing and incidental general purposes for a single Customer through one Meter supplying a single Premise. This rate is not available for industrial gas loads which are predominately space heating in character.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D30, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

CUSTOMER CHARGE:

$110.73 per Meter per Month

The total Customer Charge will be the sum of all applicable per Meter charges.

DELIVERY CHARGE:

$0.3924 per Therm for the first 500 Therms delivered each Month

$0.1860 per Therm for all usage over 500 Therms delivered each Month

Automated Meter Reading Service charges apply, in accordance with Gas Rate No. A1

GAS SUPPLY:

This rate schedule and the above-stated charges or adjustments do not provide for a supply of Gas. Gas Supply is available from the Company through Variable-Rate Gas Supply Service, under Gas Rate No. S1.

When eligible under the Transportation Program, Customers may also choose to purchase gas supply from a 3rd Party Supplier.

Customers choosing not to make a gas supply selection, either from the Company or from a 3rd Party Supplier, will receive Variable-Rate Supply Service under Gas Rate No. S1.

Gas Rate No. D30 – Industrial Delivery Service (cont'd)

GAS SUPPLY FROM 3RD PARTY SUPPLIERS:

Customers may, when eligible under the Transportation Program, choose a 3rd Party Supplier to furnish a supply of Gas in accordance with the Company's requirements. It is the Customer's responsibility to ensure that the 3rd Party Supplier delivers the directed proportion of gas supplies at delivery points designated by the Company.

The Company also reserves the right to bill the Customer at appropriate Gas Supply Service rates for Gas consumed in excess of Gas Supply Deliveries, following cessation of any agreement with a 3rd Party Supplier.

Following expiration of their contracts with 3rd Party Suppliers, and with appropriate notice, as described in the accompanying Terms and Conditions for Gas Service, Customers may choose to purchase gas supply from the Company under Gas Rate No. S1, with the Company's approval.

Customers who switch from Company Gas Supply Service, switch 3rd Party Suppliers, or return to Company Gas Supply Service will be subject to Switching Charges, under Gas Rate No. A1.

GAS IMBALANCE PROVISIONS:

Delivery Imbalances for Supplier Groups, arising from differences in the level of Daily Gas Supply Nominations compared to the level of Daily Gas Supply Deliveries to the Company's gas system, will be monitored on a daily basis and accumulated monthly for all Customers of a 3rd Party Supplier, in a Supplier Group. Charges for all Delivery Imbalances will be billed, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

Usage Imbalances for Supplier Groups, arising from differences in the level of accumulated Daily Gas Supply Deliveries compared to the level of Gas consumed by Customers in the Supplier Group, will be monitored, combined and netted, on a monthly basis. Unless an Operational Flow Order is issued, all monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Usage Balancing Service, under Gas Rate No. A3. In the event of an Operational Flow Order, monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D30 – Industrial Delivery Service (cont'd)

SUPPLY OF LAST RESORT:

If the 3rd Party Supplier defaults, (as indicated by its failure to nominate and/or deliver gas supplies for three consecutive days) beginning with the fourth day following default, Customers who have contracted for gas supply services from 3rd Party Suppliers, will have access to Supply of Last Resort Service from the Company, under Gas Rate No. S2 if available. Supply of Last Resort Service, if available, will be provided until the first day of the Customer's next billing cycle, at which time Variable Rate Gas Supply Service, under Gas Rate No. S1, will apply for a minimum of one billing cycle, subject to the Company's discretion. If Customers do not have Automated Meter Reading devices, usage applicable to Supply of Last Resort Service will be prorated. A Switching Charge will be assessed, pursuant to Gas Rate No. A1, on the first day of the next billing cycle.

NOMINATIONS:

3rd Party Suppliers of Customers in a Supplier Group, will be required to provide an estimate of Daily Gas Supply Nominations for the following Month to the Company by the required date, as stated in the Terms and Conditions for Gas Service, prior to the beginning of the Month. 3rd Party Suppliers of Customers in a Supplier Group also will be required to provide Daily Gas Supply Nominations to the Company, as stated in the Terms and Conditions for Gas Service. The Company retains the right to refuse Daily Gas Supply Nominations that vary significantly from the estimated daily nomination previously provided to the Company.

NON-ECONOMIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue a Non-Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If a Non-Economic OFO is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Non-Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Non-Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

ECOMONIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue an Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If an Economic Operational Flow Order is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D30 – Industrial Delivery Service (cont'd)

UNACCOUNTED-FOR GAS:

The Company will retain the allowance for Unaccounted-For Gas of the volumes tendered for delivery to the Customer for Company Use Gas as approved by the Indiana Utility Regulatory Commission in Gas Rate No. A2.

CURTAILMENT:

Service under this rate schedule, may be curtailed, as described in Terms and Conditions for Gas Service. If a Curtailment is declared, the Company will notify Customers, and 3rd Party Suppliers, as soon as practical, but not less than 30 minutes prior to the effective time. Customers may be directed to restrict their Gas consumption on an hourly or daily basis. Customers who do not comply with the Company's request may be subject to Non-Performance Charges, under Gas Rate No. A1, for all Gas taken in excess of the Company's order.

GAS RATE NO. D40

COMMERCIAL DELIVERY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for cooking and/or water heating, and/or other commercial use by a single Customer through one Meter supplying a single Premise.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D40, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

CUSTOMER CHARGE:

$37.00 per Meter per Month

The total Customer Charge will be the sum of all applicable per Meter charges.

DELIVERY CHARGE:

$0.2982 per Therm for the first 120 Therms delivered each Month

$0.2162 per Therm for the next 380 Therms delivered each Month

$0.2049 per Therm for all usage over 500 Therms delivered each Month

In addition, the applicable Normal Temperature Adjustment from Appendix D, Energy Efficiency Adjustment from Appendix E, and Regulatory Asset Amortization from Appendix F shall apply to all Therms delivered.

Automated Meter Reading Service charges apply, in accordance with Gas Rate No. A1.

Gas Rate No. D40 – Commercial Delivery Service (cont'd)

GAS SUPPLY:

This rate schedule and the above-stated charges or adjustments do not provide for a supply of Gas. gas supply is available from the Company through Variable-Rate Gas Supply Service, under Gas Rate No. S1.

When eligible under the Transportation Program, Customers may also choose to purchase gas supply from a 3rd Party Supplier.

Customers choosing not to make a gas supply selection, either from the Company or from a 3rd Party Supplier, will receive Variable-Rate Supply Service under Gas Rate No. S1.

GAS SUPPLY FROM 3RD PARTY SUPPLIERS:

Customers may, when eligible under the Transportation Program, choose a 3rd Party Supplier to furnish a supply of Gas in accordance with the Company's requirements. It is the Customer's responsibility to ensure that the 3rd Party Supplier delivers the directed proportion of gas supplies at delivery points designated by the Company.

The Company also reserves the right to bill the Customer at appropriate Gas Supply Service rates for Gas consumed in excess of Gas Supply Deliveries, following cessation of any agreement with a 3rd Party Supplier.

Following expiration of their contracts with 3rd Party Suppliers, and with appropriate notice, as described in the accompanying Terms and Conditions for Gas Service, Customers may choose to purchase gas supply from the Company under Gas Rate No. S1, with the Company's approval.

Customers who switch from Company Gas Supply Service, switch 3rd Party Suppliers, or return to Company Gas Supply Service will be subject to Switching Charges, under Gas Rate No. A1.

GAS IMBALANCE PROVISIONS:

Delivery Imbalances for Supplier Groups, arising from differences in the level of Daily Gas Supply Nominations compared to the level of Daily Gas Supply Deliveries to the Company's gas system, will be monitored on a daily basis and accumulated monthly for all Customers of a 3rd Party Supplier, in a Supplier Group. Charges for all Delivery Imbalances will be billed, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D40 – Commercial Delivery Service (cont'd)

Usage Imbalances for Supplier Groups, arising from differences in the level of accumulated Daily Gas Supply Deliveries compared to the level of Gas consumed by Customers in the Supplier Group, will be monitored, combined and netted, on a monthly basis. Unless an Operational Flow Order is issued, all monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Usage Balancing Service, under Gas Rate No. A3. In the event of an Operational Flow Order, monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

SUPPLY OF LAST RESORT:

If the 3rd Party Supplier defaults, (as indicated by its failure to nominate and/or deliver gas supplies for three consecutive days) beginning with the fourth day following default, Customers who have contracted for gas supply services from 3rd Party Suppliers, will have access to Supply of Last Resort Service from the Company, under Gas Rate No. S2 if available. Supply of Last Resort Service, if available, will be provided until the first day of the Customer's next billing cycle, at which time Variable Rate Gas Supply Service, under Gas Rate No. S1, will apply for a minimum of one billing cycle, subject to the Company's discretion. If Customers do not have Automated Meter Reading devices, usage applicable to Supply of Last Resort Service will be prorated. A Switching Charge will be assessed, pursuant to Gas Rate No. A1, on the first day of the next billing cycle.

NOMINATIONS:

3rd Party Suppliers of Customers in a Supplier Group, will be required to provide an estimate of Daily Gas Supply Nominations for the following Month to the Company by the required date, as stated in the Terms and Conditions for Gas Service, prior to the beginning of the Month. 3rd Party Suppliers of Customers in a Supplier Group also will be required to provide Daily Gas Supply Nominations to the Company, as stated in the Terms and Conditions for Gas Service. The Company retains the right to refuse Daily Gas Supply Nominations that vary significantly from the estimated daily nomination previously provided to the Company.

NON-ECONOMIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue a Non-Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If a Non-Economic OFO is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Non-Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Non-Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D40 – Commercial Delivery Service (cont'd)

ECOMONIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue an Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If an Economic Operational Flow Order is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

UNACCOUNTED-FOR GAS:

The Company will retain the allowance for Unaccounted-For Gas of the volumes tendered for delivery to the Customer for Company Use Gas as approved by the Indiana Utility Regulatory Commission in Gas Rate No. A2.

CURTAILMENT:

Service under this rate schedule, may be curtailed, as described in Terms and Conditions for Gas Service. If a Curtailment is declared, the Company will notify Customers, and 3rd Party Suppliers, as soon as practical, but not less than 30 minutes prior to the effective time. Customers may be directed to restrict their Gas consumption on an hourly or daily basis. Customers who do not comply with the Company's request may be subject to Non-Performance Charges, under Gas Rate No. A1, for all Gas taken in excess of the Company's order.

GAS RATE NO. D50

LARGE VOLUME INTERRUPTIBLE DELIVERY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for space heating and other gas service for a single Customer using in excess of 50,000 dekatherms (dths) per year through one Meter supplying a single Premise. A Customer served under this tariff is required at all times to have alternate fuel capabilities. Equipment must be maintained in operating condition on Customer's Premises to ensure the alternate fuel capability is available during the Curtailment period. From time to time, the Company shall have the right to observe the equipment on Customer's Premises to verify it is in good operating condition and that an inventory of alternate fuels is adequately maintained.

The Company may require, at its sole discretion, that Customers on this Gas Rate No. D50 have Automated Meter Reading Service, provided by the Company through Gas Rate No. A1.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D50, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

CUSTOMER CHARGE:

$ 1,158.56per Meter per Month

The total Customer Charge will be the sum of all applicable per Meter charges.

DELIVERY CHARGE:

$0.1625 per Therm delivered each Month

Automated Meter Reading Service charges apply, in accordance with Gas Rate No. A1.

GAS SUPPLY CHARGE:

This rate schedule and the above-stated charges or adjustments do not provide for a supply of Gas. Gas Supply is available from the Company through Variable-Rate Gas Supply Service, under Gas Rate No. S1.

Gas Rate No. D50 – Large Volume Interruptible Delivery Service (cont'd)

When eligible under the Transportation Program, Customers may also choose to purchase gas supply from a 3rd Party Supplier.

Customers choosing not to make a gas supply selection, either from the Company or from a 3rd Party Supplier, will receive Variable-Rate Supply Service under Gas Rate No. S1.

GAS SUPPLY FROM 3RD PARTY SUPPLIERS:

Customers may, when eligible under the Transportation Program, choose a 3rd Party Supplier to furnish a supply of Gas in accordance with the Company's requirements. It is the Customer's responsibility to ensure that the 3rd Party Supplier delivers the directed proportion of gas supplies at delivery points designated by the Company.

The Company also reserves the right to bill the Customer at appropriate Gas Supply Service rates for Gas consumed in excess of Gas Supply Deliveries, following cessation of any agreement with a 3rd Party Supplier.

Following expiration of their contracts with 3rd Party Suppliers, and with appropriate notice, as described in the accompanying Terms and Conditions for Gas Service, Customers may choose to purchase gas supply from the Company under Gas Rate No. S1, with the Company's approval.

Customers who switch from Company Gas Supply Service, switch 3rd Party Suppliers, or return to Company Gas Supply Service will be subject to Switching Charges, under Gas Rate No. A1.

GAS IMBALANCE PROVISIONS:

Delivery Imbalances for Supplier Groups, arising from differences in the level of Daily Gas Supply Nominations compared to the level of Daily Gas Supply Deliveries to the Company's gas system, will be monitored on a daily basis and accumulated monthly for all Customers of a 3rd Party Supplier, in a Supplier Group. Charges for all Delivery Imbalances will be billed, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

Usage Imbalances for Supplier Groups, arising from differences in the level of accumulated Daily Gas Supply Deliveries compared to the level of Gas consumed by Customers in the Supplier Group, will be monitored, combined and netted, on a monthly basis. Unless an Operational Flow Order is issued, all monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Usage Balancing Service, under Gas Rate No. A3.

Gas Rate No. D50 – Large Volume Interruptible Delivery Service (cont'd)

In the event of an Operational Flow Order, monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

SUPPLY OF LAST RESORT:

If the 3rd Party Supplier defaults, (as indicated by its failure to nominate and/or deliver gas supplies for three consecutive days) beginning with the fourth day following default, Customers who have contracted for gas supply services from 3rd Party Suppliers, will have access to Supply of Last Resort Service from the Company, under Gas Rate No. S2 if available. Supply of Last Resort Service, if available, will be provided until the first day of the Customer's next billing cycle, at which time Variable Rate Gas Supply Service, under Gas Rate No. S1, will apply for a minimum of one billing cycle, subject to the Company's discretion. If Customers do not have Automated Meter Reading devices, usage applicable to Supply of Last Resort Service will be prorated. A Switching Charge will be assessed, pursuant to Gas Rate No. A1, on the first day of the next billing cycle.

NOMINATIONS:

3rd Party Suppliers of Customers in a Supplier Group, will be required to provide an estimate of Daily Gas Supply Nominations for the following Month to the Company by the required date, as stated in the Terms and Conditions for Gas Service, prior to the beginning of the Month. 3rd Party Suppliers of Customers in a Supplier Group also will be required to provide Daily Gas Supply Nominations to the Company, as stated in the Terms and Conditions for Gas Service. The Company retains the right to refuse Daily Gas Supply Nominations that vary significantly from the estimated daily nomination previously provided to the Company.

NON-ECONOMIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue a Non-Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If a Non-Economic OFO is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Non-Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Non-Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D50 – Large Volume Interruptible Delivery Service (cont'd)

ECOMONIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue an Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If an Economic Operational Flow Order is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

UNACCOUNTED-FOR GAS:

The Company will retain the allowance for Unaccounted-For Gas of the volumes tendered for delivery to the Customer for Company Use Gas as approved by the Indiana Utility Regulatory Commission in Gas Rate No. A2.

CURTAILMENT:

Service under this rate schedule, may be curtailed, as described in Terms and Conditions for Gas Service. If a Curtailment is declared, the Company will notify Customers, and 3rd Party Suppliers, as soon as practical, but not less than 30 minutes prior to the effective time. Customers may be directed to restrict their Gas consumption on an hourly or daily basis. Customers who do not comply with the Company's request may be subject to Non-Performance Charges, under Gas Rate No. A1, for all Gas taken in excess of the Company's order.

GAS RATE NO. A1

MISCELLANEOUS CHARGES

AUTOMATED METER READING SERVICE:

The Company will provide Automated Meter Reading Service to 3rd Party Suppliers or to applicable Customers that have requested or are required to have Automated Meter Reading Service. The Automated Meter Reading Service includes installation of an Automated Meter Reading device and access to Meter reads. The following charge for Automated Meter Reading Service will be billed to applicable Customers or 3rd Party Suppliers:

$64 per Month for each Meter transmitting daily Meter readings

NON-PERFORMANCE CHARGE:

The Company shall charge monthly, a 3rd Party Supplier, for any volumes associated with Customers receiving Gas Delivery Service under Gas Rate Nos. D30, D40 and D50 that are considered daily Delivery Imbalances or unauthorized usage during a Curtailment period, or during the first three (3) days of 3rd Party Supplier default. Charges are as follows:

The applicable gas supply charges or credits from Appendix B, plus $6.00 per Therm.

WAIVER OF CHARGE:

In its reasonable discretion, on a case-by-case basis, the Company may waive all or part of any Non-Performance Charge assessable to a Customer pursuant to this Gas Rate No. A1, provided, however, that the waiver of such Non-Performance Charge shall be exercised on a non-discriminating basis.

BILLING:

Non-Performance Charges will be calculated and billed at Month end to the applicable 3rd Party Supplier. Company will purchase amounts from a 3rd Party Supplier that are not offset by other charges.

Gas Rate No. A1 – Miscellaneous Charges (cont'd)

USAGE INFORMATION CHARGE:

The Company shall provide summaries of up to 24 months of Customer's usage by Meter to Customers, and/or 3rd Party Suppliers with the Customer's approval. The information will be provided to 3rd Party Suppliers for the sole purpose of arranging to provide gas supply services. The folllowing charges for those summaries will be billed to requesting 3rd Party Suppliers or Customers, per Meter.

$25 per Customer usage summary, per Meter.

SWITCHING CHARGE:

The Company shall bill a Customer for switching from Company Gas Supply Service, for any changes in the 3rd Party Supplier selected, or for returning to Company Gas Supply Service.

$25 per switch

The changes described above may occur only on the first day of the Customer's billing cycle or as otherwise specified by Company.

GAS RATE NO. A2

UNACCOUNTED-FOR GAS

APPLICABILITY:

This rate schedule is applicable to 3rd Party Suppliers of a Supplier Group in accordance with the Company's requirements.

DESCRIPTION:

1.62% of the quantities received by the Company from 3rd Party Suppliers of a Supplier Group at a point of receipt on the Company's distribution system shall be retained by the Company to compensate for Unaccounted-For Gas. The Unaccounted-For Gas percentage stated above shall be reviewed and adjusted annually by the Company, through updating of this Gas Rate after approval by the Indiana Utility Regulatory Commission, to reflect any changes in the system Unaccounted-For Gas percentage.

GAS RATE NO. A3

USAGE BALANCING SERVICE

APPLICABILITY:

The following provisions shall apply to 3rd Party Suppliers providing gas supply services to a Supplier Group of Customers in accordance with the Company's requirements.

USAGE IMBALANCES:

The Company shall cash out monthly a 3rd Party Supplier with positive or negative monthly net Usage Imbalances associated with a Supplier Group of Customers receiving Gas Delivery Service under Gas Rate Nos. D30, D40 and D50.

Negative monthly net Usage Imbalances reflect situations where a Supplier Group of Customers consumed greater volumes of Gas than accumulated Daily Gas Supply Deliveries for the Month.

Positive monthly net Usage Imbalances reflect situations where a Supplier Group of Customers consumed lesser volumes of Gas than accumulated Daily Gas Supply Deliveries for the Month.

In the event an Operational Flow Order is issued, all Usage Imbalances will be billed in accordance with Rate No. A1 Non-Performance Charges. In all Non-Operational Flow Order periods any net monthly Usage Imbalances will be administered in the following manner:

MONTHLY CASH-OUT:

1. Cash-out charges for net monthly negative Usage Imbalances are as follows (charges posted to bill):

   100% of applicable Gas Supply Charge from Appendix B (including capacity costs) for monthly net Usage Imbalances of greater than 0% up to and including 20%.

   110% of applicable Gas Supply Charge from Appendix B (including capacity costs) for monthly net Usage Imbalances of greater than 20% up to and including 25%.

Gas Rate No. A3 – Usage Balancing Service – (cont'd)

120% of applicable Gas Supply Charge from Appendix B (including capacity costs) for monthly net Usage Imbalances of greater than 25% up to and including 30%.

140% of applicable Gas Supply Charge from Appendix B (including capacity costs) for monthly net Usage Imbalances of greater than 30%.

2. Cash-out credits for net monthly positive Usage Imbalances are as follows (Company will purchase amounts from a 3rd Party Supplier that are not offset by other charges.):

100% of applicable Gas Supply Charge from Appendix B (excluding capacity costs) for monthly net Usage Imbalances of greater than 0% up to and including 20%.

90% of applicable Gas Supply Charge from Appendix B (excluding capacity costs) for monthly net Usage Imbalances of greater than 20% up to and including 25%.

80% of applicable Gas Supply Charge from Appendix B (excluding capacity costs) for monthly net Usage Imbalances of greater than 25% up to and including 30%.

60% of applicable Gas Supply Charge from Appendix B (excluding capacity costs) for monthly net Usage Imbalances of greater than 30%.

BILLING:

Charges and credits for Usage Balancing Service will be calculated monthly and billed at Month end to the applicable 3rd Party Supplier or as otherwise applicable to a Customer. Company will purchase amounts from a 3rd Party Supplier that are not offset by other charges.

GAS RATE NO. A4

SUPPLY ADMINISTRATION SERVICE

APPLICABILITY:

This rate is applicable to 3rd Party Suppliers providing gas supply services to Customers in accordance with the Company's requirements.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. A4, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

APPLICATION:

3rd Party Suppliers are required to apply for approval to provide gas supply services to Customers. Only entities listed as approved bidders on CMS Panhandle Eastern Pipe Line Company or their successors are eligible to apply. Applications must be accompanied by a nonrefundable $1,000 application fee.

SUPPLIER APPLICATIONS:

All 3rd Party Suppliers approved to provide gas supply service to Customers must submit a 3rd Party Supplier Application to Company and comply with Supplier Access Requirements, as defined in the Terms and Conditions for Gas Service. 3rd Party Suppliers are required to comply with all requirements of Gas Delivery Service under Gas Rate Nos. D30, D40 and D50.

ADMINISTRATIVE SERVICE FEES:

The Company shall bill 3rd Party Suppliers the following charges for Supply Administration Services which support Customer-specific supply transactions. Those services include, but are not limited to, nominations, confirmations, scheduling, daily requirements forecasting, imbalance administration, supplier compliance and contract administration. The charges reflect the character of the Customer accounts, and participation in Supplier Groups. Charges to 3rd Party Suppliers include:

> **$100 per Month per Supplier Group plus $5 per Month per Single Account electing Gas Delivery Service**

Gas Rate No. A4 – Supply Administration Service – (cont'd)

BILLING

Charges are billed to 3rd Party Suppliers at Month end.

APPENDIX A

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Company's Gas Supply Services for all Therms delivered on or after December 1, 2016.

Gas Supply Charge: $ Per Therm

Gas Rate D20	Gas Supply Charge	$.3619
Gas Rate D30	Gas Supply Charge	$.3619
Gas Rate D40	Gas Supply Charge	$.3619
Gas Rate D50	Gas Supply Charge	$.3619

APPENDIX B

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Company's Gas Supply services for the month of November 2016.

1. Gas Rate No. A3 Usage Balancing Service – Gas Rate No. A1 Non-Performance Charges – Non-OFO Period (Negative Imbalance): $ Per Therm

(The Gas Supply Charge is equal to the capacity cost, plus the higher of: (1) the month's average commodity cost per Therm for Commercial, Industrial, and Large Volume customers, or (2) the first of the month index price of Panhandle adjusted for appropriate fuel, transportation, and basis.)

Gas Supply Charge - Negative Imbalance $0.3745

2. Gas Rate No. A3 Usage Balancing Service – Gas Rate No. A1 Non-Performance Charges - Non-OFO Period (Positive Imbalance): $ Per Therm

(The Gas Supply Charge is equal to the lower of: (1) the month's average commodity cost per Therm for Commercial, Industrial, and Large Volume customers, or (2) the first of the month index price of Panhandle adjusted for appropriate fuel, transportation, and basis.)

Gas Supply Charge - Positive Imbalance ($0.2673)

3. Gas Rate No. A1 Non-Performance Charges – Economic OFO, Non-Economic OFO, Interruption, or Curtailment Periods (Negative Imbalance): $ Per Therm

(The Gas Supply Charge is equal to the capacity cost, plus the higher of: (1) the first of the month index price of Panhandle adjusted for appropriate fuel, transportation, and basis, or (2) the daily index price of Panhandle adjusted for appropriate fuel, transportation, and basis.)

Day 1	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 2	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 3	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 4	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 5	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 6	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 7	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441

APPENDIX B – CURRENT GAS SUPPLY CHARGES (Cont'd)

Gas Rate No. A1 Non-Performance Charges – Economic OFO, Non-Economic OFO, Interruption, or Curtailment Periods (Negative Imbalance): $ Per Therm

Day 8	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 9	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 10	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 11	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 12	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 13	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 14	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 15	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 16	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 17	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 18	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 19	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 20	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 21	Capacity	$0.0768	Commodity	$0.2673	Gas Supply Charge	$0.3441
Day 22	Capacity	$0.0768	Commodity	$0.2740	Gas Supply Charge	$0.3508
Day 23	Capacity	$0.0768	Commodity	$0.2724	Gas Supply Charge	$0.3492
Day 24	Capacity	$0.0768	Commodity	$0.2693	Gas Supply Charge	$0.3461
Day 25	Capacity	$0.0768	Commodity	$0.2693	Gas Supply Charge	$0.3461
Day 26	Capacity	$0.0768	Commodity	$0.2693	Gas Supply Charge	$0.3461
Day 27	Capacity	$0.0768	Commodity	$0.2693	Gas Supply Charge	$0.3461
Day 28	Capacity	$0.0768	Commodity	$0.2693	Gas Supply Charge	$0.3461
Day 29	Capacity	$0.0768	Commodity	$0.2921	Gas Supply Charge	$0.3689
Day 30	Capacity	$0.0768	Commodity	$0.3096	Gas Supply Charge	$0.3864

APPENDIX B – CURRENT GAS SUPPLY CHARGES (Cont'd)

4. Gas Rate No. A1 Non-Performance Charges – Economic OFO, Non-Economic OFO, Interruption, or Curtailment Periods (Positive Imbalance): $ Per Therm

(The Gas Supply Charge is equal to the lower of: (1) the first of the month index price of Panhandle adjusted for appropriate fuel, transportation, and basis, or (2) the daily index price of Panhandle adjusted for appropriate fuel, transportation, and basis.)

Day 1	Gas Supply Charge	($0.2533)
Day 2	Gas Supply Charge	($0.2296)
Day 3	Gas Supply Charge	($0.2032)
Day 4	Gas Supply Charge	($0.2182)
Day 5	Gas Supply Charge	($0.2048)
Day 6	Gas Supply Charge	($0.2048)
Day 7	Gas Supply Charge	($0.2048)
Day 8	Gas Supply Charge	($0.2239)
Day 9	Gas Supply Charge	($0.2213)
Day 10	Gas Supply Charge	($0.2161)
Day 11	Gas Supply Charge	($0.1981)
Day 12	Gas Supply Charge	($0.1888)
Day 13	Gas Supply Charge	($0.1888)
Day 14	Gas Supply Charge	($0.1888)
Day 15	Gas Supply Charge	($0.2198)
Day 16	Gas Supply Charge	($0.2337)
Day 17	Gas Supply Charge	($0.2409)
Day 18	Gas Supply Charge	($0.2229)
Day 19	Gas Supply Charge	($0.2435)
Day 20	Gas Supply Charge	($0.2435)
Day 21	Gas Supply Charge	($0.2435)
Day 22	Gas Supply Charge	($0.2673)
Day 23	Gas Supply Charge	($0.2673)
Day 24	Gas Supply Charge	($0.2673)
Day 25	Gas Supply Charge	($0.2673)

APPENDIX B – CURRENT GAS SUPPLY CHARGES (Cont'd)

Gas Rate No. A1 Non-Performance Charges – Economic OFO, Non-Economic OFO, Interruption, or Curtailment Periods (Positive Imbalance): $ Per Therm

Day 26	Gas Supply Charge	($0.2673)
Day 27	Gas Supply Charge	($0.2673)
Day 28	Gas Supply Charge	($0.2673)
Day 29	Gas Supply Charge	($0.2673)
Day 30	Gas Supply Charge	($0.2673)

APPENDIX C

NON-RECURRING CHARGES

APPLICABILITY:

Pursuant to the Terms and Conditions, listed below are charges applicable to all Customers in the Company's service area.

CHARGES:

Bad Check Charge (from Section 5.53)	$11.00
Delinquent Account Collection Charge (from Section 5.52)	$14.00
Reconnect/Disconnect Charge (from Section 10.1)	$44.00

APPENDIX D

NORMAL TEMPERATURE ADJUSTMENT

The billed amount for each Rate D20 and D40 Customer shall be subject to a Normal Temperature Adjustment ("NTA") for each bill rendered during the billing months of November through May inclusive.

The NTA adjusts each Customer's Monthly billed amount to reverse the impact on margin recovery caused by non-normal temperatures during the billing period, as measured by actual heating degree day variations from normal heating degree days.

NTA COMPUTATION:

The NTA for each Customer's monthly billing shall be computed as follows:

NTA = NTA Therms x NTA Margin

NTA THERMS:

The NTA Therms usage for each Customer to which the NTA Margin shall be applied is computed as follows:

$$\text{NTA Therms} = \frac{[\text{Actual Therms} - \text{Base Load Therms}]}{\text{Actual Degree Days}} \times [\text{Normal Degree Days} - \text{Actual Degree Days}]$$

NTA MARGIN:

The NTA Margin for Rate D20 shall be the margin (i.e., non-gas cost) component of the second block of the Delivery Charge. The NTA Margin for Rate D40 shall be the margin (i.e., non-gas cost) component of the tail block Delivery Charge.

BASE LOAD THERMS:

Base Load Therms shall be the Customer's average daily Therms usage for the previous summer months (July and August) multiplied by the number of days in the current billing period.

For Customers whose Base Load Therms cannot be accurately determined (e.g., new Customers without two months of summer usage history), estimated average daily Therms shall be used.

Appendix D – Normal Temperature Adjustment (cont'd)

NORMAL AND ACTUAL DEGREE DAYS:

Normal Degree Days for each Customer's billing period shall be as set forth in the tables on the following pages.

Actual Degree Days for each customer's billing period shall be taken from the actual heating degree days reported each day by the National Weather Service.

Normal Degree Days and Actual Degree Days are based on Heating Degree Days as reported for Indianapolis, Indiana.

Citizens Gas of Westfield
2020 N. Meridian Street
Indianapolis, Indiana 46202

Appendix D – Normal Temperature Adjustment (cont'd)

NORMAL DEGREE DAYS (NDD)
NON-LEAP YEAR

Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD
Jul 1	0	Aug 22	0	Oct 13	10	Dec 4	30	Jan 25	37	Mar 18	22	May 9	6
Jul 2	0	Aug 23	0	Oct 14	10	Dec 5	30	Jan 26	37	Mar 19	22	May 10	6
Jul 3	0	Aug 24	0	Oct 15	10	Dec 6	31	Jan 27	37	Mar 20	21	May 11	5
Jul 4	0	Aug 25	0	Oct 16	10	Dec 7	31	Jan 28	37	Mar 21	21	May 12	5
Jul 5	0	Aug 26	0	Oct 17	11	Dec 8	31	Jan 29	37	Mar 22	21	May 13	5
Jul 6	0	Aug 27	0	Oct 18	11	Dec 9	32	Jan 30	36	Mar 23	20	May 14	5
Jul 7	0	Aug 28	0	Oct 19	11	Dec 10	32	Jan 31	36	Mar 24	20	May 15	5
Jul 8	0	Aug 29	0	Oct 20	12	Dec 11	32	Feb 1	36	Mar 25	19	May 16	4
Jul 9	0	Aug 30	0	Oct 21	12	Dec 12	33	Feb 2	36	Mar 26	19	May 17	4
Jul 10	0	Aug 31	0	Oct 22	12	Dec 13	33	Feb 3	36	Mar 27	19	May 18	4
Jul 11	0	Sep 1	0	Oct 23	12	Dec 14	33	Feb 4	36	Mar 28	18	May 19	4
Jul 12	0	Sep 2	0	Oct 24	13	Dec 15	34	Feb 5	35	Mar 29	18	May 20	4
Jul 13	0	Sep 3	0	Oct 25	13	Dec 16	34	Feb 6	35	Mar 30	18	May 21	4
Jul 14	1	Sep 4	0	Oct 26	13	Dec 17	34	Feb 7	35	Mar 31	17	May 22	3
Jul 15	1	Sep 5	1	Oct 27	14	Dec 18	34	Feb 8	35	Apr 1	17	May 23	3
Jul 16	0	Sep 6	1	Oct 28	14	Dec 19	35	Feb 9	35	Apr 2	17	May 24	3
Jul 17	0	Sep 7	1	Oct 29	14	Dec 20	35	Feb 10	34	Apr 3	16	May 25	3
Jul 18	0	Sep 8	1	Oct 30	15	Dec 21	35	Feb 11	34	Apr 4	16	May 26	3
Jul 19	0	Sep 9	1	Oct 31	15	Dec 22	35	Feb 12	34	Apr 5	16	May 27	3
Jul 20	0	Sep 10	1	Nov 1	15	Dec 23	35	Feb 13	34	Apr 6	15	May 28	2
Jul 21	0	Sep 11	1	Nov 2	16	Dec 24	36	Feb 14	33	Apr 7	15	May 29	2
Jul 22	0	Sep 12	1	Nov 3	16	Dec 25	36	Feb 15	33	Apr 8	15	May 30	2
Jul 23	0	Sep 13	1	Nov 4	16	Dec 26	36	Feb 16	33	Apr 9	14	May 31	2
Jul 24	0	Sep 14	2	Nov 5	17	Dec 27	36	Feb 17	32	Apr 10	14	Jun 1	2
Jul 25	0	Sep 15	2	Nov 6	17	Dec 28	36	Feb 18	32	Apr 11	14	Jun 2	2
Jul 26	0	Sep 16	2	Nov 7	18	Dec 29	36	Feb 19	32	Apr 12	13	Jun 3	1
Jul 27	0	Sep 17	2	Nov 8	18	Dec 30	36	Feb 20	32	Apr 13	13	Jun 4	1
Jul 28	0	Sep 18	2	Nov 9	18	Dec 31	36	Feb 21	31	Apr 14	13	Jun 5	1
Jul 29	0	Sep 19	3	Nov 10	19	Jan 1	37	Feb 22	31	Apr 15	12	Jun 6	1
Jul 30	0	Sep 20	3	Nov 11	19	Jan 2	37	Feb 23	31	Apr 16	12	Jun 7	1
Jul 31	0	Sep 21	3	Nov 12	20	Jan 3	37	Feb 24	30	Apr 17	12	Jun 8	1
Aug 1	0	Sep 22	3	Nov 13	20	Jan 4	37	Feb 25	30	Apr 18	12	Jun 9	1
Aug 2	0	Sep 23	4	Nov 14	20	Jan 5	37	Feb 26	29	Apr 19	11	Jun 10	1
Aug 3	0	Sep 24	4	Nov 15	21	Jan 6	37	Feb 27	29	Apr 20	11	Jun 11	1
Aug 4	0	Sep 25	4	Nov 16	21	Jan 7	37	Feb 28	29	Apr 21	11	Jun 12	0
Aug 5	0	Sep 26	5	Nov 17	22	Jan 8	37	Mar 1	28	Apr 22	10	Jun 13	0
Aug 6	0	Sep 27	5	Nov 18	22	Jan 9	37	Mar 2	28	Apr 23	10	Jun 14	0
Aug 7	0	Sep 28	5	Nov 19	23	Jan 10	37	Mar 3	28	Apr 24	10	Jun 15	0
Aug 8	0	Sep 29	6	Nov 20	23	Jan 11	37	Mar 4	27	Apr 25	9	Jun 16	0
Aug 9	0	Sep 30	6	Nov 21	24	Jan 12	37	Mar 5	27	Apr 26	9	Jun 17	0
Aug 10	0	Oct 1	6	Nov 22	24	Jan 13	37	Mar 6	27	Apr 27	9	Jun 18	0
Aug 11	0	Oct 2	7	Nov 23	25	Jan 14	37	Mar 7	26	Apr 28	8	Jun 19	0
Aug 12	0	Oct 3	7	Nov 24	25	Jan 15	37	Mar 8	26	Apr 29	8	Jun 20	0
Aug 13	0	Oct 4	7	Nov 25	26	Jan 16	37	Mar 9	25	Apr 30	8	Jun 21	0
Aug 14	0	Oct 5	7	Nov 26	26	Jan 17	37	Mar 10	25	May 1	8	Jun 22	0
Aug 15	0	Oct 6	8	Nov 27	27	Jan 18	37	Mar 11	25	May 2	7	Jun 23	0
Aug 16	0	Oct 7	8	Nov 28	27	Jan 19	37	Mar 12	24	May 3	7	Jun 24	0
Aug 17	0	Oct 8	8	Nov 29	28	Jan 20	37	Mar 13	24	May 4	7	Jun 25	0
Aug 18	0	Oct 9	9	Nov 30	28	Jan 21	37	Mar 14	23	May 5	7	Jun 26	0
Aug 19	0	Oct 10	9	Dec 1	28	Jan 22	37	Mar 15	23	May 6	6	Jun 27	0
Aug 20	0	Oct 11	9	Dec 2	29	Jan 23	37	Mar 16	23	May 7	6	Jun 28	0
Aug 21	0	Oct 12	9	Dec 3	29	Jan 24	37	Mar 17	22	May 8	6	Jun 29	0
												Jun 30	0

Citizens Gas of Westfield
2020 N. Meridian Street
Indianapolis, Indiana 46202 **Original Page No. 303C**

Appendix D – Normal Temperature Adjustment (cont'd)

NORMAL DEGREE DAYS (NDD)
LEAP YEAR

Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD
Jul 1	0	Aug 22	0	Oct 13	10	Dec 4	30	Jan 25	37	Mar 17	22	May 8	6
Jul 2	0	Aug 23	0	Oct 14	10	Dec 5	30	Jan 26	37	Mar 18	22	May 9	6
Jul 3	0	Aug 24	0	Oct 15	10	Dec 6	31	Jan 27	37	Mar 19	22	May 10	6
Jul 4	0	Aug 25	0	Oct 16	10	Dec 7	31	Jan 28	37	Mar 20	21	May 11	5
Jul 5	0	Aug 26	0	Oct 17	11	Dec 8	31	Jan 29	37	Mar 21	21	May 12	5
Jul 6	0	Aug 27	0	Oct 18	11	Dec 9	32	Jan 30	36	Mar 22	21	May 13	5
Jul 7	0	Aug 28	0	Oct 19	11	Dec 10	32	Jan 31	36	Mar 23	20	May 14	5
Jul 8	0	Aug 29	0	Oct 20	12	Dec 11	32	Feb 1	36	Mar 24	20	May 15	5
Jul 9	0	Aug 30	0	Oct 21	12	Dec 12	33	Feb 2	36	Mar 25	19	May 16	4
Jul 10	0	Aug 31	0	Oct 22	12	Dec 13	33	Feb 3	36	Mar 26	19	May 17	4
Jul 11	0	Sep 1	0	Oct 23	12	Dec 14	33	Feb 4	36	Mar 27	19	May 18	4
Jul 12	0	Sep 2	0	Oct 24	13	Dec 15	34	Feb 5	35	Mar 28	18	May 19	4
Jul 13	0	Sep 3	0	Oct 25	13	Dec 16	34	Feb 6	35	Mar 29	18	May 20	4
Jul 14	1	Sep 4	0	Oct 26	13	Dec 17	34	Feb 7	35	Mar 30	18	May 21	4
Jul 15	1	Sep 5	1	Oct 27	14	Dec 18	34	Feb 8	35	Mar 31	17	May 22	3
Jul 16	0	Sep 6	1	Oct 28	14	Dec 19	35	Feb 9	35	Apr 1	17	May 23	3
Jul 17	0	Sep 7	1	Oct 29	14	Dec 20	35	Feb 10	34	Apr 2	17	May 24	3
Jul 18	0	Sep 8	1	Oct 30	15	Dec 21	35	Feb 11	34	Apr 3	16	May 25	3
Jul 19	0	Sep 9	1	Oct 31	15	Dec 22	35	Feb 12	34	Apr 4	16	May 26	3
Jul 20	0	Sep 10	1	Nov 1	15	Dec 23	35	Feb 13	34	Apr 5	16	May 27	3
Jul 21	0	Sep 11	1	Nov 2	16	Dec 24	36	Feb 14	33	Apr 6	15	May 28	2
Jul 22	0	Sep 12	1	Nov 3	16	Dec 25	36	Feb 15	33	Apr 7	15	May 29	2
Jul 23	0	Sep 13	1	Nov 4	16	Dec 26	36	Feb 16	33	Apr 8	15	May 30	2
Jul 24	0	Sep 14	2	Nov 5	17	Dec 27	36	Feb 17	32	Apr 9	14	May 31	2
Jul 25	0	Sep 15	2	Nov 6	17	Dec 28	36	Feb 18	32	Apr 10	14	Jun 1	2
Jul 26	0	Sep 16	2	Nov 7	18	Dec 29	36	Feb 19	32	Apr 11	14	Jun 2	2
Jul 27	0	Sep 17	2	Nov 8	18	Dec 30	36	Feb 20	32	Apr 12	13	Jun 3	1
Jul 28	0	Sep 18	2	Nov 9	18	Dec 31	36	Feb 21	31	Apr 13	13	Jun 4	1
Jul 29	0	Sep 19	3	Nov 10	19	Jan 1	37	Feb 22	31	Apr 14	13	Jun 5	1
Jul 30	0	Sep 20	3	Nov 11	19	Jan 2	37	Feb 23	31	Apr 15	12	Jun 6	1
Jul 31	0	Sep 21	3	Nov 12	20	Jan 3	37	Feb 24	30	Apr 16	12	Jun 7	1
Aug 1	0	Sep 22	3	Nov 13	20	Jan 4	37	Feb 25	30	Apr 17	12	Jun 8	1
Aug 2	0	Sep 23	4	Nov 14	20	Jan 5	37	Feb 26	29	Apr 18	12	Jun 9	1
Aug 3	0	Sep 24	4	Nov 15	21	Jan 6	37	Feb 27	29	Apr 19	11	Jun 10	1
Aug 4	0	Sep 25	4	Nov 16	21	Jan 7	37	Feb 28	29	Apr 20	11	Jun 11	1
Aug 5	0	Sep 26	5	Nov 17	22	Jan 8	37	Feb 29	29	Apr 21	11	Jun 12	0
Aug 6	0	Sep 27	5	Nov 18	22	Jan 9	37	Mar 1	28	Apr 22	10	Jun 13	0
Aug 7	0	Sep 28	5	Nov 19	23	Jan 10	37	Mar 2	28	Apr 23	10	Jun 14	0
Aug 8	0	Sep 29	6	Nov 20	23	Jan 11	37	Mar 3	28	Apr 24	10	Jun 15	0
Aug 9	0	Sep 30	6	Nov 21	24	Jan 12	37	Mar 4	27	Apr 25	9	Jun 16	0
Aug 10	0	Oct 1	6	Nov 22	24	Jan 13	37	Mar 5	27	Apr 26	9	Jun 17	0
Aug 11	0	Oct 2	7	Nov 23	25	Jan 14	37	Mar 6	27	Apr 27	9	Jun 18	0
Aug 12	0	Oct 3	7	Nov 24	25	Jan 15	37	Mar 7	26	Apr 28	8	Jun 19	0
Aug 13	0	Oct 4	7	Nov 25	26	Jan 16	37	Mar 8	26	Apr 29	8	Jun 20	0
Aug 14	0	Oct 5	7	Nov 26	26	Jan 17	37	Mar 9	25	Apr 30	8	Jun 21	0
Aug 15	0	Oct 6	8	Nov 27	27	Jan 18	37	Mar 10	25	May 1	8	Jun 22	0
Aug 16	0	Oct 7	8	Nov 28	27	Jan 19	37	Mar 11	25	May 2	7	Jun 23	0
Aug 17	0	Oct 8	8	Nov 29	28	Jan 20	37	Mar 12	24	May 3	7	Jun 24	0
Aug 18	0	Oct 9	9	Nov 30	28	Jan 21	37	Mar 13	24	May 4	7	Jun 25	0
Aug 19	0	Oct 10	9	Dec 1	28	Jan 22	37	Mar 14	23	May 5	7	Jun 26	0
Aug 20	0	Oct 11	9	Dec 2	29	Jan 23	37	Mar 15	23	May 6	6	Jun 27	0
Aug 21	0	Oct 12	9	Dec 3	29	Jan 24	37	Mar 16	23	May 7	6	Jun 28	0
												Jun 29	0
												Jun 30	0

Current rates effective pursuant to
I.U.R.C Order in Cause No. 44731 **Effective:**

APPENDIX E

ENERGY EFFICIENCY ADJUSTMENT

The Delivery Charges specified in Gas Rate Nos. D20 and D40 shall be adjusted from time to time in accordance with the Final Order of the Indiana Utility Regulatory Commission in Company's most recent general rate case to reflect an Energy Efficiency Funding Component and a Sales Reconciliation Component.

ENERGY EFFICIENCY FUNDING COMPONENT ("EEFC"):

The EEFC shall recover the costs of funding energy efficiency efforts throughout the Company's service area. These efforts may include, among others, energy efficiency programs, Customer education programs, and weatherization programs designed to benefit Customers under the applicable rate schedules.

The estimated annual costs, plus related revenue taxes, shall be divided by projected sales volumes to determine the applicable EEFC. The actual costs recoverable and the actual costs recovered under the EEFC shall be reconciled, with any under or over recovery being recovered or returned via the EEFC over a subsequent twelve Month period.

SALES RECONCILIATION COMPONENT ("SRC"):

The SRC shall recover the differences between Actual Margins and Adjusted Order Granted Margins for the applicable rate schedules.

Actual Margins are defined as Monthly margins for each rate schedule, prior to the SRC Adjustment. Adjusted Order Granted Margins are defined as the Order granted Monthly margins for each rate schedule, as approved in Company's most recent general rate case, as adjusted to reflect the change in number of Customers from the Order granted Customer levels. To reflect the change in number of Customers, Order granted margin per Customer is multiplied by the change in the number of Customers since the like Month during the test year, with the product being added to the Order granted margins for such Month.

The Company shall defer the calculated differences between Actual Margins and Adjusted Order Granted Margins for subsequent return or recovery via the SRC. Annually, the Company shall reflect in a revised SRC the accumulated Monthly margin differences. Beginning with the twelve-month period ending December 31, 2013, margin differences from Residential Customers

Appendix E – Energy Efficiency Adjustment (cont'd)

receiving Gas Delivery Service under Gas Rate No. D20 eligible for recovery in the SRC annually are capped at 8% of Adjusted Order Granted Margins attributable to Residential Customers applicable to the previous year. Any actual margin differences from Residential Customers in excess of the 8% SRC cap will be deferred for future recovery either in a future SRC filing, with the annual residential SRC amount still subject to the 8% cap, or in a future rate case. The total amount that may be deferred for recovery in a future rate case may not exceed $1 million.

Appendix E – Energy Efficiency Adjustment (cont'd)

The accumulated Monthly margin differences for each rate schedule shall be divided by projected throughput volumes for each rate schedule to determine the applicable SRC. Projected and actual recoveries by rate schedule under the SRC are reconciled, with any under or over recovery being recovered or returned over a subsequent twelve Month period.

ENERGY EFFICIENCY ADJUSTMENT RATE: $ per Therm

The applicable Energy Efficiency Adjustment Rate (the sum of the EEFC and SRC) shall be applied to each Therm of metered Gas usage each Month.

Rate Schedule	A Energy Efficiency Funding Component	B Sales Reconciliation Component	A + B Energy Efficiency Adjustment Rate
Gas Rate D20	**$0.0003**	**$0.0410**	**$0.0413**
Gas Rate D40	**$0.0003**	**$0.1113**	**$0.1116**

APPENDIX F

REGULATORY ASSET AMORTIZATION

APPLICABILITY:

Pursuant to Indiana Utility Regulatory Commission Order in Cause No. 43600, issued, April 1, 2009, the Company was authorized to create a regulatory asset for the purpose of accumulating energy efficiency rebate costs. Pursuant to Indiana Utility Regulatory Commission Order in Cause No. 43624, issued March 10, 2010, the Company was authorized to recover the amortized cost of energy efficiency rebates previously authorized in Cause No. 43600 through this appendix. Appendix F is applicable to Gas Rate Nos. D20 and D40.

RATES AND CHARGES:

The appendix shall be applied to each Therm of metered gas usage each Month. The current charges are set forth below:

$0.0000 per Therm