STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Liberty Utilities (Midstates Natural Gas) Corp.	)	
d/b/a Liberty Utilities	)	**Docket No. 14-0371**
	)	
Proposed General Increase	)	
In Natural Gas Rates	)	

INITIAL BRIEF OF THE STAFF

OF THE ILLINOIS COMMERCE COMMISSION

(PUBLIC)

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NOW COME the Staff witnesses of the Illinois Commerce Commission ("Staff"), by and through their undersigned counsel, pursuant to Section 200.800 of the Illinois Commerce Commission's Rules of Practice (83 Ill. Adm. Code 200.800), and the direction of the Administrative Law Judge ("ALJ"), respectfully submit their Initial Brief ("Staff IB") in the above-captioned matter.

I. INTRODUCTION

A. Overview

On March 31, 2014, Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities ("Liberty Midstates" or "Company")[1] filed with the Illinois Commerce Commission ("Commission") revised tariff sheets in which they proposed a general increase in gas

[1] Staff uses Liberty Midstates or Company to designate the Illinois operating company.

rates pursuant to Article IX of the Illinois Public Utilities Act ("Act" or "PUA"), 220 ILCS 5/9, to become effective May 15, 2014.

B. Procedural History

On May 7, 2014, the Commission suspended the filing to and including August 27, 2014, for a hearing on the proposed rate increase. On July 30, 2014, the Commission re-suspended the tariffs to and including February 27, 2015.

The following Staff witnesses have submitted testimony in this case: Steven R. Knepler (Staff Exs. 1.0 and 6.0), Mike Ostrander (Staff Exs. 2.0, 5.0 (Suppl. Dir.) and 7.0), Rochelle M. Phipps (Staff Exs. 3.0 and 8.0), and Christopher Boggs (Staff Ex. 4.0). No other parties moved to intervene.

An evidentiary hearing was held in this matter on October 16, 2014. The record was not marked Heard and Taken, but rather left open until a later date to address a potential change in the State of Illinois' corporate income tax rate. A summary of Staff's final revenue related recommendations to the Commission for Liberty Midstates is attached hereto as Appendix A.

C. Nature of Liberty's Operations

Liberty Midstates is a public utility that provides natural gas to approximately 85,000 customers in Illinois, Iowa, and Missouri, 22,000 of which are in Illinois. Liberty Midstates is an indirect subsidiary of Algonquin Power and Utilities Corp, a Canadian corporation consisting of a power generation unit and a utility services unit. Prior to August 1, 2012, Liberty Midstates was not a public utility and did not operate in Illinois. On August 1, 2012, pursuant to ICC Docket 11-0559, Liberty Energy (Midstates) Corp. acquired the natural gas distribution utility operations of Atmos Energy Corporation

("Atmos") in Illinois, Iowa, and Missouri. This is the first rate case filed by Liberty Midstates in Illinois. The last rate case filed for this service territory was filed on February 17, 2000 by United Cities Gas Company, an operating division of Atmos.

D. Test Year

Liberty Midstates proposed to use a future test year for the twelve months ending December 31, 2015. No party objected to the use of this test year.

E. Legal Standard

All rates set by the Commission must be "just and reasonable" and any "unjust or unreasonable" rate is unlawful. In this regard, Section 5/9-101 of the PUA provides, in relevant part, that:

> All rates or other charges made, demanded or received by any product or commodity furnished or to be furnished or for any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge made, demanded or received for such product or commodity or service is hereby prohibited and declared unlawful. All rules and regulations made by a public utility affecting or pertaining to its charges to the public shall be just and reasonable.

220 ILCS 5/9-101.

II. RATE BASE

A. Resolved Issues

1. Interest Synchronization Calculation

Staff witness Steven R. Knepler proposed that the interest synchronization adjustment reflect Staff's rate base, weighted cost of debt, and the 7.75% state income tax rate that is to become effective, January 1, 2015. In particular, the Company objected to Staff's weighted cost of debt and state income tax rate. (Company Ex. 7.0, p. 24 and Company Ex. 6.0, pp. 1-8) In surrebuttal testimony, the Company stated that the Company and Staff agree on the interest synchronization methodology, but disagree on the inputs. However, and in the spirit on compromise, the Company acknowledged that the final order should reflect the capital structure and the state income tax rate approved by the Commission. (Company Ex. 8.0, pp. 9-10)

2. Budget Payment Plans

Staff proposed adjustments to reduce the Company's rate base by the average over-collection associated with the budget payment plans. The over-collection represents a ratepayer funded source of capital and should be deducted from the rate base on which the Company is expected to earn a return. (Staff Ex. 2.0, p. 5) The Company accepted Staff's adjustments in rebuttal testimony. (Company Ex. 5.0, pp. 11-12)

3. Utility Plant – Meters

In rebuttal testimony, the Company proposed additions to utility plant rate base for meters inadvertently omitted from its initial filing. (Company Ex. 5.0, p. 18) In its rebuttal testimony, Staff accepted Liberty Midstates' proposed adjustments to utility plant, accumulated depreciation and depreciation expense. (Staff Ex. 7.0, p. 10)

4. Average Net Plant

Staff proposed adjustments to accumulated depreciation to reclassify allocated accumulated depreciation erroneously netted against utility plant in service and to reflect the impact of the correction of test year depreciation expense. (Staff Ex. 2.0, p. 3) The Company accepted Staff's proposed adjustments in rebuttal testimony. (Company Ex. 5.0, Ex. 5.03)

5. Accumulated Deferred Income Taxes

Staff proposed adjustments to correct the shared plant allocation factor and to include the impact of the proration of accumulated deferred income taxes ("ADIT"). (Staff Ex. 2.0, p. 9) The Company accepted Staff's adjustments in rebuttal testimony. (Company Ex. 5.0, p. 11) Also in rebuttal testimony, the Company proposed additions to rate base for meters inadvertently omitted from its initial filing. (Company Ex. 5.0, p. 18) Liberty Midstates proposed adjustments to utility plant, accumulated depreciation and depreciation expense, but did not propose the related adjustment to ADIT. Staff proposed an adjustment to ADIT due to the additional meters in rebuttal testimony. (Staff Ex. 7.0, p. 7) The Company accepted Staff's adjustment in surrebuttal testimony. (Company Ex. 8.0, p. 2)

6. Original Cost Determination

For purposes of an original cost determination, Staff recommended that the Commission approve Liberty Midstates' utility plant balance as of December 31, 2013 of $52,686,071. (Staff Ex. 7.0, p. 15) Although the Company does not explicitly state its acceptance of Staff's original cost recommendation in its testimony, the Company agreed to include the original cost determination as a "Resolved Issue" in the agreed IB outline.

7. Cash Working Capital

Mr. Knepler proposed, and the Company accepted, an adjustment to remove non-cash expenses (uncollectible expense) from the cash working capital ("CWC") allowance. Thus, Staff and Company agree on the formula methodology to calculate the CWC allowance and further agree that the Order's CWC balance should be based on the level of operating expenses approved by the Commission in this proceeding. (Company Ex. 6.0, p. 10)

B. Contested Issues

1. Average Net Plant

The Commission should adopt Staff's adjustments to compute the rate base components of utility plant in service and accumulated depreciation, or net plant, as an average balance, since Staff's method takes into account the fact that investments are made throughout the test year, rather than the Company's method of year-end net plant valuation which incorrectly assumes, for rate setting purposes, that all investments are made at the beginning of the test year. (Staff Ex. 7.0, Schedule 7.01) The Company chose a future test year ending December 31, 2015. An average rate base derives rates that properly match test year revenues and expenses which will occur throughout 2015 with the level of rate base investment also occurring throughout the year. A year-end rate base would derive revenues and expenses for 2015 which represent a level of investment that would not exist until the end of 2015. (Staff Ex. 2.0, p. 4)

A test year is a time period used to develop costs representative of the first year in which rates being set will be in effect. (*Id.*, p. 3) Under the Commission's rules, utilities may select a historical test year or a future test year. (83 Ill Adm. Code 287.20) As far as Staff is aware, the Commission has only approved the use of a year-end rate base with a historical test year and has rejected proposals to use a year-end rate base with a future test year. (Staff Ex. 2.0, pp. 5-6) The Company selected a future test year which is already forward-looking in that it largely relies upon projected costs. (Staff Ex. 2.0, p. 4)

The Company argues that use of average net plant in a case of increasing plant in service is not forward-looking. (Company Ex. 6.0, p. 14; Company Ex. 9.0, p. 6) The Company's argument is meritless since the selection of a future test year, which is based upon projected costs, is by definition forward-looking. In addition, it is normal for utilities to have increased investments after filing a rate case. As an example, The Peoples Gas Light and Coke Company ("Peoples Gas") and North Shore Gas Company ("North Shore") both showed increasing net plant from 2006 through 2013. Over that same time period, Peoples Gas and North Shore each filed four rate cases that each showed an increase in plant investments. Three of the rate cases utilized a future test year with an average rate base, while the fourth rate case utilized a historical test year with a year-end rate base. (Staff Ex. 7.0, pp. 4-5)

The Company further argues that the use of average net plant is less representative of the net plant in place during the period rates are in effect. (Company Ex. 6.0, pp. 13-15; Company Ex. 9.0, p. 6) The year-end 2015 rate base proposed by the Company reflects the level of rate base investment at the end of the test year, rather than the average level during the test year.

The Company's proposal is deeply flawed. Under the Company's proposal, the revenues and expenses throughout all of 2015 – beginning January 1 - would represent a level of investment that would not exist until the end of the test year. In contrast, using an average rate base, as Staff recommends, would result in revenues and expenses that are expected to occur throughout 2015 and correspond with the level of investment throughout the test year. A year-end rate base is not more representative of the rate base that will exist when the proposed rates will be in effect due to the date on which the proposed tariffs would become effective. The Company has proposed using the projected rate base at December 31, 2015 and the projected revenues and expenses at the end of 2015. However, rates from this case would become effective around March 1, 2015. Thus, under the Company's proposal, ratepayers will be paying a return on plant investments that the Company will not make for ten months after the rates' effective date. Using an average rate base, as Staff proposes, properly derives rates that match the rate base more closely with the associated revenues and expenses. (Staff Ex. 7.0, pp. 6-7)

Staff's position is consistent with recent decisions in rate cases in which the Commission approved an average rate base with a future test year: Docket No. 08-0363, Northern Illinois Gas Company, (March 25, 2009); Docket No. 09-0319, Illinois-American Water Company, (April 13, 2010); Docket No. 11-0282, Ameren Illinois Company, (January 10, 2012); Docket Nos. 11-0280/0281, Peoples Gas and North Shore, (January 10, 2012); Docket No. 11-0767, Illinois-American Water Company, (September 19, 2012); and Docket Nos. 12-0511/0512, Peoples Gas and North Shore, (June 18, 2013). (See Staff Ex. 2.0, p. 8) The Commission's practice with respect to average rate base for future test periods is well established, and the Company has not demonstrated sufficient justification to break from this long-standing precedent.

2. Accumulated Deferred Income Taxes

The Commission should adopt Staff's adjustments to establish ADIT as a prorated average balance that is in compliance with Section 168 (i)(9)(B) of the Internal Revenue Code rather than as a year-end balance as proposed by the Company. The discussion on the basis of using average ADIT as a component of an average rate base is the same as above in Section II. B. 1. Average Net Plant.

3. Incentive Compensation[2]

Please refer to Operating Revenues and Expenses Section III. B. 2. of Staff's IB.

C. Recommended Rate Base

Staff recommends a rate base of $39,418,167 as reflected on page 5 of Appendix A to Staff's IB. Staff's recommendation is $504,232 less than the $39,922,399 rate base requested by Liberty Midstates in rebuttal.

III. OPERATING REVENUES AND EXPENSES

A. Resolved Issues

1. Property Taxes – Test Year Expenses

Liberty Midstates accepted Staff's adjustments to property tax expense. Thus, the parties agree on the amount of test year property taxes to be included in the revenue requirement, but disagree on a related issue, Liberty Midstates' request for deferred accounting treatment for the property taxes on an office building to be constructed in Vandalia, Illinois. (Company Ex. 6.0, pp. 8-9) The full discussion of the property tax issue is presented in Section VII. B. of this IB.

2. Outside Professional Services

In its direct case, Staff proposed a $416,254 adjustment to reduce outside professional services expense for outside consultants because the amount had not been supported. (Staff Ex. 1.0, pp. 10-12 and Sched. 1.12) In rebuttal testimony, Staff

[2] Due to the capital component.

revised its adjustment to disallow an additional $206,194 in outside professional services expense for payments made to the former owner, Atmos, for transition and training services to assist Liberty Midstates in its new ownership and management roles. These payments were not reflective of ongoing, recurring expenses. Furthermore, all payments made to Atmos were made during the first quarter of 2013, which is a further indication that such payments were non-recurring and thus, non-recoverable operating expenses. Staff also opined that if Liberty Midstates' request to enter into an affiliate services agreement with a service company is approved in Docket No. 14-0269[3], then it is possible that certain economies of scale will be achieved, which have not been considered in the instant proceeding. (Staff Ex. 6.0, pp. 9-10 and Sched. 6.09) In its surrebuttal testimony, Liberty Midstates acknowledged the potential for cost savings and, for the purpose of narrowing issues, stated that it would not contest Staff's adjustment to Outside Professional Services expense. (Company Ex. 8.0, pp. 6-7)

3. Rate Case Expense

The Company originally proposed rate case expense of $707,500 to be amortized over three years. (Company Sched. C-10) Staff proposed adjustments to reflect actual amounts recoverable for the ADIT consultant and the initial Part 285 consultant. The Company accepted Staff's adjustments in rebuttal testimony. (Company Ex. 5.0, p. 12) Also in rebuttal testimony, the Company revised its rate case expense estimate to $865,478. (Company Ex. 5.0, p. 13) The increased costs were due

[3] Liberty Utilities (Midstates Natural Gas) Corp, Verified Petition pursuant to Section 7-101 for Consent to and Approval of Affiliate Services Agreements, ICC Docket No. 14-0269, filed March 31, 2014.

to the Company's conservative initial estimate and the number of and complexity of issues subsequently raised in the proceeding. (*Id.*)

Ms. Phipps reviewed invoices for the rate case expense associated with Mr. Hevert's testimony. (Staff Ex. 3.0, p. 38) She noted that the Company increased its estimate of rate case expense for Sussex Economic Advisors ("SEA") by [**begin confidential**] XXXXXX [**end confidential**]. Even more concerning is that SEA has submitted invoices for [**begin confidential**] XXXXX [**end confidential**] to date, which means SEA's [**begin confidential**] XXXXXX [**end confidential**] budget for this rate case is nearly depleted before the surrebuttal or hearings stage begins. (Staff Ex. 8.0, p. 27)

The additional rate case expense reflects tasks not included in SEA's original proposal, including financial forecasts in connection with the requirements of 83 Ill. Adm. Code 285.7075. (Staff Ex. 8.0, Attach. C) SEA billed the Company [**begin confidential**] XXXXXXXXXXXXXX [**end confidential**] of work related to those financial forecasts. Yet, SEA apparently developed those forecasts without any input from the Company regarding Liberty Midstates' projected capital expenditures, revenues, O&M expense, dividends, common stock issuances, debt issuances or retirements. Ms. Phipps explained that even if the Company technically complied with Commission rules regarding information that it must provide to the Commission when requesting a rate increase, it submitted information that does not reflect the Company's own projections and, thus, is not useful (*e.g.*, the Company's projected common equity balances through December 31, 2015, as presented in Company Schedule D-1 do not match the forecasted common equity balances for 2014 and 2015, as provided in Schedule G-16). (Staff Ex. 8.0, p. 28)

According to the Company, "the original proposal did not contemplate the breadth of issues surrounding capital structure addressed in rebuttal testimony, or costs associated with Surrebuttal testimony." (Staff Ex. 8.0, Attach C) Ms. Phipps noted that the invoices from SEA provide little insight into the tasks that SEA performed and the amount of time that SEA billed for seems excessive. Specifically, SEA billed the Company (and ultimately ratepayers) for [**begin confidential**] XXXXXX [**end confidential**] related to rebuttal testimony between August 8th and August 29th. (Staff Ex. 8.0, Attach. C) By comparison, SEA billed the Company for [**begin confidential**] XXXXXXX [**end confidential**] related to direct testimony, over the months of December 2013 through March 2013. This is troublesome considering rebuttal testimony is supposed to be more limited in scope than direct testimony. (Staff Ex. 8.0, pp. 28-29)

Although Ms. Phipps does not propose an adjustment to the rate case expense associated with SEA, she summarized her review of rate case expense associated with SEA in order to make the Commission aware that the Company increased its estimate of rate case expense for SEA substantially during this proceeding, and nearly depleted the higher budget before the surrebuttal stage. (Staff Ex. 8.0, p. 27)

Therefore, Staff recommends that the Order in this proceeding include the following Commission conclusion:

> The Commission has considered the costs expended by the Company to compensate attorneys and technical experts to prepare and litigate this

> rate case proceeding and assesses that such costs in the total amount of $865,478, which is $288,493 amortized over three years, are just and reasonable pursuant to Section 9-229 of the Act (220 ILCS 5/9-229).

Liberty Midstates' revised rate case expense estimate of $865,478 amortized over three years results in a test-year rate case expense of $288,493. (Company Ex. 5.0, Ex. 5.10)

4. Allocation from Shared Services ("LABS")

In direct testimony, Staff proposed an adjustment to reduce the expense Allocation from Shared Services (LABS). Based upon information provided by the Company in its rebuttal testimony, Staff withdrew this adjustment. (Staff Ex. 6.0, p. 11)

5. Depreciation Expense

Staff proposed an adjustment to correct a calculation error in the Company's depreciation expense schedule. (Staff Ex. 2.0, p. 14) The Company accepted Staff's adjustment in rebuttal testimony. (Company Ex. 5.0, p. 14)

B. Contested Issues

1. Gross Revenue Conversion Factor

Staff and Company disagree with respect to two of the inputs to the determination of the Gross Revenue Conversion Factor ("GRCF"): (1) the uncollectible expense rate, and (2) the state income tax rate.

a. Uncollectible Expense Rate

The first disputed input is the Company's proposed uncollectible rate of 0.70% that was based upon the average uncollectible rate for the three historical years 2011-2013 of 0.68% plus .02% for the expected rate impact from the instant proceeding. (Staff Ex 6.0, p. 6 and Company Ex 5.0, pp. 4-5)

Staff proposed an uncollectible rate of 0.51% based upon the average uncollectible rate for the five most recent historical years 2009-2013. In rebuttal, Staff demonstrated the reasonableness of its 0.51% proposed rate by calculating two additional average uncollectible rates that approximate Staff's proposed uncollectible rate of 0.51%: 1) the average for the four most recent years (2010-2013) is 0.48% (Staff Sched. 6.08, Column (i):7) and 2) the average uncollectible rate for the period 2009 through 2013 but excluding the high year of 2013 and the low year of 2010 is 0.54%. (*Id.,* Column (j): 7)

As demonstrated by Staff's analysis, its proposed uncollectible rate of 0.51% is objective, verifiable and reasonable, and should be approved by the Commission.

b. State Income Tax Rate

The second disputed input to the GRCF is the Illinois Income Tax rate. The current rate[4] of 9.50% (the rate which is reflected in the Company's filing) is scheduled to sunset and revert to the pre-2011 rate of 7.75% effective January 1, 2015.[5] The Company provided various financial articles and statements from elected officials to support the retention of the current income tax rate. (Company Ex. 6.0, pp. 1-8; Company Exs. 6.1–6.05)

Staff argued that it could not recommend that the Commission base its order on possible legislative action. Staff stated that the Company's case was based upon conjecture and speculation as what, if any, action the General Assembly may take in the

[4] Combined tax rate of 7.75% (5.25% corporate state income tax rate plus property tax replacement rate of 2.5%)

[5] Illinois Income Tax as Amended Through Public Act 98-496, Section 201 (http://www.revenue.state.il.us/LegalInormation/IITA.pdf; accessed July 24, 2014).

fall 2014 veto session and beyond. At the present, there is no bill awaiting the Governor's signature to extend or make permanent the 9.5% state income tax rate. Therefore, Staff recommends that the revenue requirement reflect the 7.75% income tax rate that is to become effective January 1, 2015. (Staff Ex 1.0, pp. 6-7 and Staff Ex. 6.0, p. 5)

Despite having two proposed state income tax rates (7.75% vs. 9.50%), the parties have reached a mutually agreeable solution to address any post-hearing income tax legislation. Should such legislation be enacted prior to the Commission's Order, the parties are to file briefs addressing the impact of the enacted rate. Accordingly, the record has not been marked heard and taken and has been continued generally. (Tr. 33-34:24-21, Oct. 16, 2014.) Therefore, Staff further believes that the state income rate issue is not in dispute.

2. Incentive Compensation

The Commission should adopt Staff's adjustments to reduce Liberty Midstates' operating expenses and rate base for incentive compensation costs that do not provide tangible benefits to ratepayers. (Staff Ex. 7.0, Schedule 7.03) The adjustments are comprised of the following: (1) Long Term Incentive Plan costs related to shareholder-oriented goals; (2) Short Term Incentive Plan costs related to goals tied to financial performance; and (3) Shared Bonus Pool Program costs related to goals tied to financial performance. (Staff Ex. 7.0, p. 8)

Liberty Midstates argues that incentive compensation costs will be incurred during the test year and in the future; incentive compensation is an important recruiting and retention tool; and financial incentives ultimately benefit ratepayers. (Company Ex.

5.0, p. 15) Staff acknowledges that incentive compensation costs could be incurred in the test year and in the future and that incentive compensation can be an important recruiting/retention tool. However, the Company fails to demonstrate how such incentive plans produce tangible benefits to ratepayers. This criteria for rate recovery – the utility demonstration of tangible benefits to ratepayers – has been established in numerous Commission orders:

- Docket No. 08-0363, Northern Illinois Gas Company (March 25, 2009);
- Docket Nos. 09-0166/0167 (Cons), The Peoples Gas Light and Coke Company and North Shore Gas Company, filed March 25, 2009;
- Docket Nos. 09-0308/0309/0310/0311 (Cons), Ameren Illinois Utilities (March 17, 2010);
- Docket Nos. 11-0280/0281 (Cons), The Peoples Gas Light and Coke Company and North Shore Gas Company (January 10, 2012); and
- Docket Nos. 12-0511/0512 (Cons), The Peoples Gas Light and Coke Company and North Shore Gas Company (June 18, 2013).

(Staff Ex. 5.0, pp. 4-5)

C. Recommended Operating Income / Revenue Requirement

Staff recommends a revenue requirement of $12,021,409, an increase of $4,439,655 or 58.56% in base rates. The above revenue requirement produces an operating income of $2,684,377. Staff's revenue requirement recommendation is presented on page 1 of Appendix A to this IB.

IV. RATE OF RETURN/COST OF CAPITAL

Staff witness Rochelle M. Phipps recommends a 6.81% overall cost of capital for the Company's gas delivery services, which reflects a 9.23% cost of common equity, as shown below.

Liberty Utilities (Midstates Natural Gas) Corp. Weighted Average Cost of Capital (WACC) Summary Summary of Staff Proposal					
Capital Component	Weight	Cost	Weighted Cost	Revenue Conversion Factor	Pre-Tax WACC
Short-Term Debt	0.46%	1.41%	0.01%	1	0.01%
Long-Term Debt	53.95%	4.81%	2.59%	1	2.59%
Common Equity	45.59%	9.23%	4.21%	1.6509	6.95%
Total	100.00%		6.81%		9.55%

(Staff Ex. 8.0, Sch. 8.01)

The overall cost of capital for a public utility equals the sum of the costs of the components of the capital structure (*i.e.*, debt, preferred stock and common equity) after weighting each by its proportion to total capital. Under the traditional regulatory model, ratepayer and shareholder interests are balanced when the Commission authorizes a rate of return on rate base equal to the public utility's overall cost of capital, as long as that overall cost of capital is not unnecessarily expensive. In authorizing a rate of return on rate base equal to the overall cost of capital, all costs of service are assumed reasonable and accurately measured, including the costs and balances of the components of the capital structure. If unreasonable costs continue to be incurred, or if any reasonable cost of service component is measured inaccurately, then the allowed rate of return on rate base will not balance ratepayer and investor interests. (Staff Ex. 3.0, pp. 2-3)

A. Resolved Issues

1. Short-Term Debt Ratio

Ms. Phipps recommends a 0.46% short-term debt ratio that equals its proportion to Liberty Utility Company's ("LUC's") actual December 31, 2013 capital structure including ratemaking adjustments. (Staff Ex. 3.0, p. 6) The Company accepts Staff's recommended 0.46% short-term debt ratio. (Co. Ex. 10.0, p. 4)

2. Cost of Short-Term Debt

Ms. Phipps recommends a 1.41% cost of short-term debt, which equals the average one-month LIBOR rate for the 30 days ending January 31, 2014, plus 1.25%. (Staff Ex. 3.0, p. 9) The Company accepts Staff's recommended cost of short-term debt. (Co. Ex. 10.0, p. 4)

3. Embedded Cost of Long-Term Debt

Ms. Phipps recommends using LUC's cost of debt for Liberty Midstates' cost of debt because, unlike Liberty Midstates, LUC has external debt investors. Therefore, LUC's cost of debt reflects market-determined interest rates and renders imputing a cost of debt unnecessary. (Staff Ex. 3.0, p. 6) The embedded cost of long-term debt equals 4.81%. (Staff Ex. 8.0, p. 2) The Company accepts Staff's recommended embedded cost of long-term debt. (Co. Ex. 10.0, p. 4) Staff also recommends that, in future cases, the Company provide invoices and supporting documentation that clearly identify the debt issues, specify the expenses incurred for each particular debt issue, the date those expenses were incurred, and the method for amortizing expenses. (Staff Ex. 8.0, p. 2, footnote 1)

B. Contested Issues

1. Common Equity and Long-Term Debt Ratios

The capital structure of Liberty Midstates comprises 60.10% common equity. (Co. Ex. 7.0- Rev., p. 12) The common equity ratio of its ultimate parent company, Algonquin Power and Utilities Corp. ("APUC"), is 56.64%. (Co. Ex. 7.0 Rev., p. 12) In addition to utility services, APUC has a power generation unit. (Co. Ex. 1.0, p. 3) The actual capital structure of Liberty Midstates' intermediate parent company, LUC, comprises [**begin confidential**] XXXXX [**end confidential**] common equity. (Staff Ex. 3.0, Sch. 3.02) Section 9-230 of the Public Utilities Act ("Act") states, "In determining a reasonable rate of return upon which investment for any public utility in any proceeding to establish rates or charges, the Commission shall not include any (1) incremental risk, [or] (2) increased cost of capital . . . which is the direct or indirect result of the public utility's affiliation with unregulated or nonutility companies." 220 ILCS 5/9-230.

The costs of debt and common equity are a function of capital structure: the higher the common equity ratio, the lower the cost of debt and common equity, all else equal. Conversely, the lower the common equity ratio, the higher the cost of debt and common equity, all else equal. (Staff Ex. 3.0, pp. 6 & 35; Staff Ex. 8.0, p. 9; Co. Ex. 7.0 Rev., p. 11) To illustrate, assume that Liberty Midstates and LUC are standalone companies rather than subsidiary and parent company. Under this hypothetical scenario, Liberty Midstates' higher common equity ratio would result in Liberty Midstates having lower cost debt and common equity than LUC, all else equal. Conversely, LUC's lower common equity ratio would result in higher cost debt and equity than Liberty Midstates, all else equal.

In reality, LUC is the parent company of Liberty Midstates, and provides Liberty Midstates all of its debt and equity capital such that Liberty Midstates' cost of debt equals LUC's cost of debt. (Staff Ex. 3.0, p. 5) In this proceeding, Liberty Midstates seeks to combine its 60.10% common equity ratio with the higher cost debt resulting from LUC's lower common equity ratio. That is, Liberty Midstates' proposal would clearly increase its rate of return due to the cost of debt resulting from the more leveraged capital structure of its parent company, LUC. That combination of higher equity ratio and higher cost of debt would clearly violate Section 9-230 of the Act.

Since Liberty Midstates' cost of debt is that of LUC, the capital structure for setting Liberty Midstates' rates can contain no more common equity than LUC's capital structure under Section 9-230 of the Act. However, the Company deems the LUC capital structure confidential. To the best of Staff's knowledge, the Commission has never issued a rate Order without disclosing publicly the capital structure used for ratemaking purposes in a contested proceeding. Beyond issues of transparency, long-held Commission precedent holds that although orders of the Commission are not *res judicata*, and the Commission is free to reach a different result in a subsequent case than it reached in an earlier case, it must articulate a rational reason for departing from past practices. *See e.g., Citizens Utility Board v. Commerce Commission*, 166 Ill.2d 111, 125, 132 (1995). The Company has failed to articulate a rational reason why the LUC capital structure must remain confidential.

In Staff's view, the Commission should not rely upon a confidential capital structure for ratemaking purposes since it is a key determinant of overall rate of return and interest synchronization and must be examined for consistency with Section 9-230 of the Act. Thus, Ms. Phipps proposes using an imputed capital structure that comprises 45.59% common equity, 53.95% long-term debt and 0.46% short-term debt. (Staff Ex. 8.0, p. 4) Ms. Phipps' capital structure proposal meets the requirements of Section 9-230 of the Act. Further, as will be shown below, Ms. Phipps' capital structure proposal is reasonable given the average capital structure of the gas sample and LUC's BBB credit ratings.

Beyond Section 9-230 issues, Ms. Phipps recommends an imputed capital structure for ratemaking purposes for two additional reasons. First, the capital structure and cost of debt data for Liberty Midstates is not reliable. For example, the Company could not provide audited financial statements (*e.g.*, income statement, balance sheet, statement of cash flows) for Liberty Midstates; in fact, the Company does not prepare either a statement of cash flows or a statement of retained earnings at the Liberty Midstates level. (Staff Ex. 3.0, pp. 3-4) Furthermore, the Company's balance sheet is not "balanced," meaning the total assets exceed the total liabilities plus shareholders equity. (Staff Ex. 8.0, Attachment C) Second, Liberty Midstates obtains both equity funding and debt through its immediate parent company, LUC. Thus, LUC has the only investor claim on Liberty Midstates' cash flows. Debt investors have a lower exposure of risk than equity investors do when they have a priority claim to an asset's cash flows. A priority claim cannot exist without another investor with a subordinate, residual claim. When the priority and residual investor is the same, there is no splitting of the company's net cash flows, rendering the split between debt and common equity in Liberty Midstates' capital structure financially meaningless. Further, as noted above, the cost of debt for Liberty Midstates is a function of the split between debt and common equity in LUC's capital structure, rather than Liberty Midstates' capital structure. Consequently, it is reasonable to impute a capital structure in order to determine a fair rate of return for Liberty Midstates. (Staff Ex. 3.0, p. 5)

Ms. Phipps derived the imputed capital structure that she recommends for setting rates for Liberty Midstates' gas operations as follows. She started with the average common equity ratio of the gas sample (*i.e.*, 49.91%), and subtracted 6.4 percentage points to reflect the two-notch difference between the average Standard & Poor's ("S&P") credit rating for the gas sample companies (*i.e.*, A-) and LUC's S&P credit rating of BBB. 6.4 percentage points reflects two-thirds of the 9.5 percentage point difference between the midpoints of Moody's Investors Service ("Moody's") debt capitalization benchmark ratios for A and Baa rated utilities.[6] The resulting common equity ratio is 43.51%. (Staff Ex. 3.0, pp. 5-6)

The Commission's net short-term debt calculation removes amounts assigned to calculate the return on construction work in progress ("CWIP"), *i.e.*, allowance for funds used during construction. In contrast, the proxy group's capital structure reflects gross short-term debt balances. Therefore, for consistency, Ms. Phipps imputed the long-term capital structure ratios, then removed the short-term debt assigned to CWIP and recalculated the long-term debt and common equity ratios. She began with the 43.51% common equity ratio and LUC's 4.99% gross short-term debt ratio. The long-term debt ratio equals 100% less the sum of the short-term debt ratio and the imputed common equity ratio, or 51.50%. Next, she subtracted the net short-term debt balance (0.46%) from the gross short-term debt balance (4.99%) and assigned the difference (4.53%) to

[6] Moody's credit rating of Baa is equivalent to S&P's BBB credit rating.

common equity and long-term debt, based on their relative proportions of long-term capital. The resulting capital structure comprises 0.46% short-term debt, 53.95% long-term debt and 45.59% common equity. (Staff Ex. 8.0, pp. 3-4)

The 54.42% total debt ratio in Ms. Phipps' capital structure proposal is at the center of the range for Moody's debt to capitalization benchmark ratio of 50-59% for Baa-rated utilities. Moreover, a 54.42% total debt ratio is consistent with APUC's [**begin confidential**] XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX [**end confidential**]. Based on the foregoing, Staff's proposed capital structure is reasonable in relation to other similar companies and consistent with the target capital structure for LUC. (Staff Ex. 3.0, p. 8; Staff Ex. 8.0, p. 4)

2. Cost of Common Equity

Ms. Phipps' analysis indicates that the cost of common equity for Liberty Midstates' natural gas distribution operations is 9.23%. To estimate the cost of common equity for Liberty Midstates, she began with Mr. Hevert's discounted cash flow ("DCF") and risk premium ("CAPM") analyses and she corrected the most significant flaws in those analyses, as described hereafter. (Staff Ex. 3.0, p. 10)

A. Discounted Cash Flow Analysis

Mr. Hevert's multi-stage DCF analysis (also referred to as non-constant DCF, or "NCDCF") models three stages of dividend growth. The first, a near-term growth stage, is assumed to last five years. The second stage is a transitional growth period lasting from the end of the fifth year to the end of the tenth year. Finally, the third, or "steady-state," growth stage is assumed to begin after the tenth year and continue into perpetuity. An expected stream of dividends is estimated by applying these stages of growth to the current dividend. The discount rate that equates the present value of this expected stream of cash flows to the company's current stock price equals the market-required return on common equity. (Staff Ex. 3.0, pp. 12-13)

Ms. Phipps made the following changes to Mr. Hevert's NCDCF analysis: (1) she removed the SV factor from the retention growth rate estimate, which is included in the first stage growth rate; (2) she assumed the dividend payout ratios for the sample companies remain at Value Line's forecasted 2016 – 2018 level rather than reverting to an historical average payout ratio; and (3) she replaced Mr. Hevert's third stage historical growth rate with a forward-looking estimate.[7] (Staff Ex. 3.0, p. 16)

She estimated the growth rate parameters for the DCF analysis as follows. For the first stage, which is assumed to last five years, she used Mr. Hevert's average Zacks, First Call, Value Line growth rate estimates and a modified version of the retention growth estimate that removes the SV factor. In the intervening five-year transitional stage, the first stage growth rate transitions to the third stage growth rate. For the third "steady state" stage, which begins at the end of the tenth year, Ms. Phipps calculated the nominal overall economic growth rate beginning in 2024 to estimate the long-term growth expectations of investors. That growth rate was calculated using the expected real growth rate (2.4%) based on the average of the Energy Information Administration ("EIA") and Global Insight's forecasts of real GDP, and the expected inflation rate (2.3%) based on the difference in yields on U.S. Treasury bonds and U.S> Treasury Inflation-Protected Securities ("TIPS"). She then combined the resulting

[7] Using the January 31, 2014 stock prices instead of the 30-day average stock prices did not change the NCDCF results. Therefore, to reduce the number of issues in this case, Ms. Phipps adopted Mr. Hevert's 30-day average stock prices for the multi-stage DCF analysis.

4.76% average of the EIA and Global Insight forecasts with the 4.38% average nominal GDP growth forecasted by EIA and Global Insight to derive her estimate of long-term growth of 4.57%. (Staff Ex. 3.0, pp. 17-19)

Ms. Phipps' DCF estimate of the required rate of return on common equity for the gas sample is 8.26%. (Staff Ex. 3.0, Sch. 3.05)

B. Risk Premium Analysis

To estimate the cost of equity for Liberty Midstates using risk premium analysis, Ms. Phipps modified Mr. Hevert's CAPM analysis, a one-factor risk premium model that mathematically depicts the relationship between risk and return as:

$$R_j = R_f + \beta_j \times (R_m - R_f)$$

Where R_j ≡ the required rate of return for security j;

R_f ≡ the risk-free rate;

R_m ≡ the expected rate of return on the market portfolio; and

β_j ≡ the measure of market risk for security j.

In the CAPM, the risk factor is market risk, which is defined as risk that cannot be eliminated through portfolio diversification. To implement the CAPM, one must estimate the risk-free rate of return, the expected rate of return on the market portfolio, and a security or portfolio-specific measure of market risk. (Staff Ex. 3.0, p. 20)

Ms. Phipps explained that the most significant flaws in Mr. Hevert's CAPM analyses are: (1) using a forecasted U.S. Treasury bond yield as a proxy for the risk-free rate of return and (2) his estimates of the investor-required return on the market portfolio. (Staff Ex. 3.0, p. 21; Staff Ex. 8.0, pp. 24-25) Thus, Ms. Phipps relied exclusively on Mr. Hevert's current 30-day average yield on thirty-year U.S. Treasury bonds of 3.81% for the risk-free rate. (Staff Ex. 3.0, p. 23)

To estimate the expected rate of return on the market portfolio, Ms. Phipps relied exclusively on Staff's estimate of the market return of 12.15%. The expected rate of return on the market was estimated by conducting DCF analysis on the firms composing the S&P 500 Index ("S&P 500") as of December 31, 2013. Firms not paying a dividend as of December 31, 2013, or for which neither Zacks nor Reuters growth rates were available, were eliminated from the analysis. That analysis estimated that the expected rate of return on the market equals 12.15%. (Staff Ex. 3.0, p. 24)

To estimate the beta of the gas sample, she supplemented the two five-year beta estimates that Mr. Hevert uses with the following five-year beta estimates: (1) Staff's regression beta; (2) Zacks betas; and (3) a five-year Bloomberg beta estimate provided by Mr. Hevert. (Staff Ex. 3.0, p. 24) Ms. Phipps measured market risk on a security-specific basis using a regression analysis that employs sixty monthly observations of stock and the U.S. Treasury bill return data. She also used a beta published by Zacks, which also employs 60 monthly observations in its beta estimation. (Staff Ex. 3.0, pp. 25-26)

Since the beta estimates from Zacks, Bloomberg, Mr. Hevert's regression analysis and Staff's regression analysis are calculated using monthly returns rather than weekly returns (as Value Line uses), Ms. Phipps averaged the monthly return betas to avoid over-weighting the monthly return-based betas. She then averaged that result with the Value Line beta to obtain a single estimate of beta for the sample. For the gas sample, Zacks beta averages 0.66, the Bloomberg beta estimate is 0.62, Mr. Hevert's regression beta is 0.73 and Staff's regression beta is 0.62. The average of the monthly betas is 0.66. (Staff Ex. 3.0, Sch. 3.06) Averaging this monthly beta with the weekly Value Line beta (0.72), produces a beta for the gas sample of 0.69. (Staff Ex. 3.0, p. 26)

Using those inputs, the risk premium model estimates a required rate of return on common equity of 9.56%. (Staff Ex. 3.0, p. 26, and Sch. 3.06)

C. Cost of Equity Recommendation

To assess the reasonableness of her recommendation, Ms. Phipps considered the observable 5.02% rate of return the market currently requires on less risky Baa-rated long-term debt. Based on her analysis, in her judgment, the investor-required rate of return on common equity equals 9.23% for the Company. (Staff Ex. 3.0, p. 34)

To estimate the investor-required rate of return on common equity for the gas sample, Ms. Phipps averaged the NCDCF-derived results (8.26%) and the risk premium-derived results (9.56%) for the gas sample, which produced an estimate of 8.91%. The models from which the individual company estimates were derived are correctly specified and thus contain no source of bias. Moreover, excepting the use of U.S. Treasury bond yield as a proxy for the long-term risk-free rate, the use of a constant growth DCF analysis for estimating the rate of return on the market portfolio, and the use of nominal GDP growth as a proxy for long-term utility growth, she is unaware of bias in her proxy for investor expectations. In addition, measurement error has been minimized through the use of a sample, since estimates for a sample as a whole are subject to less measurement error than individual company estimates. (Staff Ex. 3.0, pp. 34-35)

Next, Ms. Phipps considered the difference in the yields for A and Baa rated long-term utility bonds. On January 29, 2014, the yield for Baa-rated utility bonds was 5.02% and the yield for A-rated utility bonds was 4.54%, which is 48 basis points lower than the riskier Baa-rated bonds. As explained previously, the S&P credit rating of LUC is two notches lower than the average credit rating of the gas sample – *i.e.*, BBB v. A-. Therefore, Ms. Phipps added two-thirds of the difference in the Baa/A rated bond yields, or 32 basis points (*i.e.*, 48 basis points × 0.67), to the 8.91% cost of equity estimate to reflect the greater risk that LUC's lower credit rating implies. The resulting cost of equity is 9.23%. (Staff Ex. 3.0, p. 35)

The Commission has adopted similar adjustments in the past. Northern Illinois Gas Company d/b/a Nicor Gas Company, ICC Order Docket No. 04-0779, 87-88 (Sept. 20, 2005); Central Illinois Public Service Company (AmerenCIPS) and Union Electric Company (AmerenUE), ICC Order Docket No. 02-0798/03-0008/03-0009 (Cons.), 89-90 (Oct. 22, 2003). In Docket No. 08-0363, Staff assessed the risk level of its sample to the target utility and adjusted the cost of equity downward 25 basis points, which equals the spread between Baa1 and A2 30-year utility debt yields. Northern Illinois Gas Company d/b/a Nicor Gas Company, ICC Order Docket No. 08-0363, 59-60 (March 25, 2009). In that case, the Commission concluded:

> We conclude that it is necessary and appropriate to evaluate whether an adjustment to the cost of common equity model results is necessary, given possible differences in risk between Nicor and the companies that make up the sample… [W]e conclude that Staff's analysis is reasonable and convincing… Thus, the Commission concludes that, in establishing an authorized return on common equity for Nicor, the results of analyses applied to the sample must be reduced by 25 basis points.

Northern Illinois Gas Company d/b/a Nicor Gas Company, ICC Order Docket No. 08-0363, 70-71 (March 25, 2009).

Similarly, in Docket Nos. 09-0306 et al., Staff relied upon the spread between the ratings of the proxy group versus the target utility to adjust its cost of common equity estimate to account for the difference in risk between the proxy group and the target utility. In that case, the Commission concluded, "[T]his adjustment appears reasonable and it will be adopted for calculating the recommended ROE." Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP, ICC Order Docket Nos. 09-0306 through 09-0311 Consol., 187-188 and 219-220 (April 29, 2010).

D. Response to Mr. Hevert

Ms. Phipps identified the following flaws in Mr. Hevert's NCDCF analysis, which lead him to over-estimate the Company's cost of common equity: (1) a retention growth rate estimate (*i.e.*, br + sv) that includes an external growth factor "sv," which is based on an assumption that does not hold true for the proxy group companies; (2) a long-term growth rate that is not sustainable; and (3) a faulty assumption that the payout ratios of the proxy group companies will converge to 69.45%. (Staff Ex. 3.0, p. 11)

Ms. Phipps identified the following flaws in Mr. Hevert's CAPM analysis: (1) using a forecasted U.S. Treasury bond yield as a proxy for the risk-free rate; (2) his expected rate of return on the market portfolio is overstated; and (3) his alternate CAPM analyses rely upon beta estimates for two years or less and incorrect market risk premium estimates. (Staff Ex. 3.0, p. 12) Ms. Phipps also testified that Mr. Hevert's bond yield plus risk premium analysis, which has previously been rejected by the Commission, is flawed for numerous reasons. Finally, Mr. Hevert's flotation cost adjustment, which has previously been rejected by the Commission, is inappropriate and unwarranted. (Staff Ex. 3.0, p. 12)

1. DCF Analysis – SV Factor in the Retention Growth Rate

Mr. Hevert's retention growth rate estimate includes an external growth rate factor, SV, which assumes that a company raises all external capital at the market price. (Co. Ex. 4.0, pp. 21-22, Sch. 4.2) However, the source of Mr. Hevert's external financing forecast, Value Line, forecasts that none of the sample companies will issue new shares at the market price. (Staff Ex. 3.0, p. 13)

The Commission has rejected a DCF analysis that includes a sustainable growth rate estimate with an external growth rate factor in the past. Specifically, the Commission has concluded:

> As the Commission understands it, the only difference between Nicor's DCF cost of equity estimate, 9.83%, and CUB's DCF cost of equity estimate, 9.455% is that CUB's calculation excludes the external growth component (S*V), which Nicor included… Generally, the Commission does not look favorably on the sustainable growth approach; however, in this instance, the Commission finds it is not unreasonable to combine the sustainable growth rates with published growth rates to estimate the cost of common equity. The Commission finds that the criticisms of Nicor's external growth component of sustainable growth to be convincing and that Nicor's DCF results will not be considered.

Northern Illinois Gas Company d/b/a Nicor Gas Company, ICC Order Docket No. 08-0363, 70 (March 25, 2009).

2. DCF Analysis – Long-Term Growth Rate Estimate

Mr. Hevert's long-term growth rate of 5.72% is based on the combination of a historical growth in real GDP of 3.27% from 1929-2013 and a 2.37% inflation rate that is derived from forward U.S. Treasury yields starting in 2024. (Co. Ex. 4.0, p. 23) Staff does not object to Mr. Hevert's 2.37% estimate of expected inflation. However, the record shows that Mr. Hevert's 3.27% estimate of real GDP growth far exceeds the estimates of professional forecasters and, thus, should be rejected. EIA and Global Insight currently forecast real GDP growth will average 2.4% during the 2024-2040 and 2024-2043 periods, respectively. (Staff Ex. 3.0, p. 17) Ms. Phipps noted that those forecasts are in line with the 2.4-2.6% annual percentage GDP growth rates published by numerous forecasters for the 2011-2040 measurement period. (Staff Ex. 3.0, p. 17, fn 33) Thus, the projected growth rates for real GDP from eight sources all indicate that Mr. Hevert's historical real GDP growth estimate overstates the level of real GDP growth expected over the long-term and thereby causes his estimate of the investor-required rate of return for the companies in the proxy group to be too high. (Staff Ex. 3.0, p. 17)

Importantly, the long-term growth rate that Mr. Hevert used in the final stage of his multi-stage DCF analyses for the gas samples is not sustainable. Specifically, in order to sustain 5.72% growth given Mr. Hevert's assumed 30.55% earnings retention rate, the companies in the gas sample would have to indefinitely sustain, on average, an 18.72% return on new common equity investment, which is 78% higher than Mr. Hevert's 10.50% cost of common equity recommendation for Liberty Midstates' gas operations. The implausibility of the proxy group sustaining an average 18.72% ROE indefinitely becomes obvious when one considers the ROE for the proxy group averaged 11.00% during 2003-2013, with no single company achieving an 18.72% ROE during any single year of that measurement period. Furthermore, an 18.72% return on retained earnings would exceed Value Line's projected 11.17% ROE for the proxy group. (Staff Ex. 3.0, pp. 14-15)

Mr. Hevert's multi-stage DCF analysis is also problematic because the assumed dividend growth rate far exceeds the assumed growth in earnings per share. According to Mr. Hevert's analysis, average earnings per share growth rate for the proxy group is 5.3% to 5.7% in years 2014- 2024 while the annual dividend growth rate for the proxy group averages 1.6% in 2014, and rises to a range of 9.4% to 8.8% during the 2018-2024 period, with a 2014-2024 average of 6.6%. (Staff Ex. 3.0, p. 15)

In Docket No. 13-0192, the Commission's Order expressed its concern regarding Mr. Hevert's long-term growth rate estimate, stating:

> [T]he Commission shares to a large degree the concerns expressed by Staff and IIEC witnesses that the growth rate used…by Mr. Hevert in the final stage of his multi-stage model is too high and would imply a return on new common equity investment that is implausible and unsustainable. The Commission also believes there is some merit to Ms. Phipps' concern that Mr. Gorman's estimate of the constant growth includes an external growth rate factor which contains an assumption – which Ms. Phipps contends does not hold true for the sample companies – that a company raises all external capital at the market price.

Ameren Illinois Company d/b/a Ameren Illinois, ICC Order, Docket No. 13-0192, 163 (Dec. 18, 2013). Thus, the Commission should adopt Ms. Phipps' NCDCF analysis, which – unlike Mr. Hevert's NCDCF analysis – properly excludes the SV factor from the retention growth rate estimates and reflects a sustainable long-term growth rate estimate.

3. DCF Analysis – 69.45% Payout Ratio

Ms. Phipps identified a problem with Mr. Hevert's multi-stage DCF modeling an increasing payout ratio with accelerating sustainable growth. She explained that Mr. Hevert's model assumes a sample average 56% dividend payout ratio in 2017, which he increases to 69% by 2024, and a sample average 5.3% growth rate in 2018, which he increases to 5.7% in 2024. (Co. Sch. 4.1, p. 1) This is problematic because Mr. Hevert's model ignores that dividend policy involves a trade off between present and future dividends. That is, a declining dividend payout ratio results in a temporary slowing in near-term dividend growth, which is exactly offset by higher long-term sustainable growth because more earnings are retained for reinvestment. Conversely, an increasing dividend payout ratio results in a temporary acceleration of near term dividend growth that is exactly offset by a reduction in long-term sustainable growth because less earnings are retained for reinvestment. (Staff Ex. 3.0, pp. 15-16)

4. Risk Premium Analysis - Forecasted U.S. Treasury Bond Yield.

Staff opposes the forecasted U.S. Treasury bond yields that Mr. Hevert uses as a proxy for the risk-free rate. Ms. Phipps explained that interest rates are constantly adjusting, and accurately forecasting the movements of interest rates is problematic. (Staff Ex. 3.0, p. 22) To illustrate, Staff notes that the Blue Chip Financial Forecast that Mr. Hevert relied upon for his forecasted risk-free rate estimate (Co. Ex. 4.0, p. 29) predicted 30-year U.S. Treasury bond yields would rise from 3.8% to 3.9% in the first quarter of 2014, 4.0% in the second quarter of 2014 and 4.1% in the third quarter of 2014. (Staff Ex. 3.0, p. 23; Staff Cross Ex. 6) In reality, 30-year U.S. Treasury bond yields over the first nine months of 2014 fell to 3.7% in the first quarter, 3.4% in the second quarter and 3.3% in the third quarter. (Staff Cross Ex. 2) Thus, not only did the forecasters over-estimate the level of 30-year U.S. Treasury bond yields, they did not even correctly guess the trend.

In contrast, current U.S. Treasury bond yields reflect all relevant, available information, including investor expectations regarding future interest rates. Consequently, investor appraisals of the value of forecasts are also reflected in current interest rates. Therefore, if investors believe that the forecasts are valuable, that belief would be reflected in current market interest rates. Conversely, if investors believe the forecasts are not valuable, that belief would also be reflected in current market interest rates. In summary, if one uses current market interest rates in a risk premium analysis, speculation of whether investor expectations of future interest rates equal those from a particular forecast reporting service is unnecessary. Further, it is important to note that U.S. Treasury bond yields reflect market forces, while forecasts do not. The risk free rate is reflected in the return that investors are willing to accept in the market. As of January 31, 2014, investors were willing to accept 3.61% return on U.S. Treasury bonds, which includes an interest rate risk premium associated with its relatively long term to maturity. (Staff Ex. 3.0, p. 22) The Commission recognized this in its Docket No. 02-0798 et al. Order, which states:

> The Commission agrees with Staff that Treasury bond yields reflect market forces, and that as of March 21, 2003 investors were willing to accept a 5.24% return on Treasury bonds, despite the inclusion of a maturity premium in Treasury bond yields. The Commission rejects Ameren's suggestion that a higher risk-free rate should have been used in Staffs' risk premium analysis.

Central Illinois Public Service Company (AmerenCIPS) and Union Electric Company (AmerenUE), ICC Order Docket No. 02-0798/03-0008/03-0009 (Cons.), 89-90 (Oct. 22, 2003). Similarly, in Docket Nos. 09-0306 et al., the Commission rejected a CAPM that relied upon a forecasted U.S. Treasury bond yield as a proxy for the risk-free rate, stating, "The Commission further finds that the current yield on long-term U.S. Treasury bond is a more appropriate proxy for the long-term risk-free rate than forecasts of that rate." Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP, ICC Order Docket Nos. 09-0306 through 09-0311 Consol., 214 (April 29, 2010).

5. Risk Premium Analysis - Market Rate of Return

To estimate the market risk premium ("MRP"), Mr. Hevert used the constant growth DCF model to calculate the market capitalization weighted average return on equity using data from Bloomberg and Value Line. (Co. Ex. 4.0, p. 27) Mr. Hevert's flawed DCF analyses overstate his MRP estimate because each of his analyses includes one or more companies with a growth estimate over 40%, which significantly affects the MRP estimate. Specifically, the Bloomberg analysis includes a company with a growth rate of 144.90%, which adds 0.10% to the market return. For the Value Line analysis, Ms. Phipps identified four companies with growth rates ranging from 72.5% - 129%, which add 0.67% to the market return. Additionally, thirty-five dividend-paying companies are missing growth rates in the Value Line DCF analysis. Furthermore, because a publicly-traded company's market value is observable, it should be the same in both the Bloomberg and Value Line analyses. Nonetheless, Mr. Hevert's Bloomberg and Value Line analyses use different market values for many of the companies. Likewise, dividend yields are observable; yet, Mr. Hevert's Bloomberg and Value Line analyses use the same dividend yield for a given company in only a handful of instances. Thus, the results of Mr. Hevert's market return analyses are questionable at best and thus, should be disregarded. (Staff Ex. 8.0, pp. 25-26)

6. Risk Premium Analysis - Alternate CAPM Analyses

Mr. Hevert also presents "alternate CAPM analyses," which use (1) two-year and eighteen month beta coefficients; and (2) market risk premiums that were calculated using both dividend and non-dividend paying companies. (Co. Ex. 4.0, 31-32) According to the Company, "Mr. Hevert did not make a specific adjustment to his ROE recommendation based on the results of his alternate CAPM analyses. Rather, Mr. Hevert considered those results along with other factors, when determining where the Company's cost of equity fell within the range of his results." (Staff Ex. 3.0, p. 27)

Mr. Hevert relies on beta estimates measured over eighteen to twenty-four months. (Co. Ex. 4.0, pp. 31-32) Betas measured over shorter periods are more prone to measurement error arising from short-term changes in risk and investor risk preferences, which can bias the beta estimate. A *decrease* in a company's systematic risk could *increase* its estimated beta even though generally an increasing beta would be interpreted as signaling an *increase* in a company's systematic risk. Conversely, an *increase* in a company's systematic risk could *lower* its calculated beta even though generally a decreasing beta would be interpreted as signaling a *decrease* in a company's systematic risk. Those counter-intuitive results are a consequence of the inverse relationship between risk and stock values. As the risk of a stock declines, its price rises, all else equal. In a rising stock market, the beta calculated will rise for a stock that is declining in risk, all else equal. Conversely, in a declining market, the beta calculated will decline for a stock that is increasing in risk. Consequently, a longer measurement period should be used as a more complete business cycle will include both rising and falling markets, reducing measurement error. Ms. Phipps calculated beta using only eighteen months of data for three consecutive measurement periods to demonstrate the inherent volatility in using such a short measurement period to measure beta. (Staff Ex. 3.0, pp. 27-29)

Moreover, five-year betas are preferable to betas measured over shorter periods for the reasons explained by Ibbotson Associates:

> Ideally, a beta should be measured over the longest time period possible. With a large number of data points, the statistical precision of the regression equation should be high… The amount of history included in beta calculations done by commercial beta services is fairly consistent at five years. Using five years of data is a rather arbitrary decision that attempts to use as much data as possible without including irrelevant historical data. Using five years of data would ideally cover a number of different economic scenarios such as expansion and contraction in the economy.

(Staff Ex. 3.0, p. 29)

For his alternate CAPM, Mr. Hevert developed two estimates of the market risk premium by calculating the required return on the S&P 500 Index using data from Bloomberg and Value Line. (Co. Ex. 4.0, Sch. 4.6) He used a constant growth DCF on all of the companies in the index with long-term growth projections available, including non-dividend paying companies. Staff witness Phipps explained that Mr. Hevert's inclusion of the non-dividend paying companies in a constant growth DCF analysis upwardly biases his estimate of market return. That is, the dividend growth rate of non-dividend paying companies cannot be both constant and equal to the earnings growth rate as Mr. Hevert's estimation process assumes. If the dividend growth rate is constant, it must remain 0% for a non-divided paying company. In contrast, the average dividend growth rates of the non-dividend paying companies in Mr. Hevert's analyses equal approximately 17%. Including non-dividend paying companies in a DCF analysis of the market overstates the resulting estimated required rate of return on the market and the implied market risk premium. The weighted average growth rate for the dividend paying companies is approximately 10% whereas the weighted average growth rate for the non-dividend paying companies is 18% to 22%. (Staff Ex. 3.0, p. 30)

In Docket No. 13-0192, the Commission rejected Mr. Hevert's CAPM analysis, stating:

> In its Order in Docket No. 11-0282, the Commission expressed "serious concerns" with the betas used by Mr. Hevert. The Commission noted that it has traditionally relied upon betas calculated with five years of data. In the instant case, Staff again used a period of five years. Staff again takes issue with the beta measurement period used by Mr. Hevert, which in the current proceeding was 18 to 24 months. Staff explained why betas measured over shorter time periods, such as those used by Mr. Hevert, are more prone to measurement error arising from short-term changes in risk and investor risk preferences, which can bias the beta estimate. Having reviewed the record, the Commission again finds that the beta estimates provided by Staff are more reliable.
>
> In Docket No. 11-0282, the Commission also expressed "serious concerns" with the market risk premium relied upon by Mr. Hevert. There, as in the current case, Staff objected to Mr. Hevert's inclusion of non-dividend paying companies in the DCF analysis used in the calculation of the expected market return, from which the risk-free rate is subtracted in the calculation of the market risk premium. Staff contends that inclusion of non-dividend paying companies upwardly biases the estimate of the market return, as does IIEC. The Commission again shares this concern, and agrees with Staff that the market risk premium calculated by Staff is more reliable.

<u>Ameren Illinois Company d/b/a Ameren Illinois</u>, ICC Order, Docket No. 13-0192, 164-165 (Dec. 18, 2013). Likewise, in the instant case, the Commission should reject the Company's alternative CAPM analyses.

7. Bond Yield Plus Risk Premium Analysis

Mr. Hevert's risk premium model suffers from the same problems as the risk premium models he presented, and the Commission rejected, in prior cases. Ameren Illinois Company d/b/a Ameren Illinois, ICC Order Docket No. 13-0192, 165 (Dec. 18, 2013); Ameren Illinois Company d/b/a Ameren Illinois, ICC Order Docket No. 11-0282, 125 (Jan. 10, 2012). Specifically, the Commission questioned the validity of the bond yield plus risk premium approach given (1) its reliance on utility authorized returns on equity throughout the U.S.; and (2) its heavy reliance on historical data (1992-2010) and the difficulty in determining an appropriate historical period to rely upon. Ameren Illinois Company d/b/a Ameren Illinois, ICC Order, Docket No. 11-0282, 125 (Jan. 10, 2012).

Staff witness Phipps noted that Mr. Hevert's model, estimated over the period 1980–2014, nonsensically predicts that when the U.S. Treasury bond yield falls to 2.90% or below (which occurred 163 days between December 16, 2008, and December 31, 2013), the cost of common equity for utilities will rise. (Staff Ex. 3.0, pp. 31-32) In rebuttal testimony, Mr. Hevert presented an alternative bond yield plus risk premium analysis, which employs a shorter measurement period (2011 to the present) and includes credit spreads as an additional independent variable. (Co. Ex. 7.0 Rev., pp. 48-49) However, the alternative model is no better than Mr. Hevert's original analysis. Mr. Hevert's alternative model predicts the cost of equity is inversely related to the 30-year U.S. Treasury bond yield when the U.S. Treasury bond yield is 3.73% or lower (vs. a 2.90% inflection point in his original analysis). This is not consistent with the positive relationship that one would reasonably expect to exist between the cost of equity and

U.S. Treasury bond yields – *i.e.*, the cost of equity would increase as the 30-year Treasury bond yield increases. (Staff Ex. 8.0, pp. 26-27)

The counter-intuitive relationship between bond yields and implied risk premiums indicates that Mr. Hevert's risk premium model is not useful for checking, let alone estimating, the cost of common equity for gas utilities. (Staff Ex. 3.0, p. 27)

The Commission has rejected Mr. Hevert's bond yield plus risk premium analysis in prior cases. Specifically, the Commission's Order in Docket No. 13-0192 states:

> Mr. Hevert also performed a Bond Yield Plus Risk Premium analysis. Staff and IIEC disagree with Mr. Hevert's position. The Commission observes it has not relied upon this approach in prior orders, including [Docket No. 11-0282]. The Commission finds that Mr. Hevert's Bond Yield Plus Risk Premium analysis should not be relied upon in the current case for the reasons explained by Staff as summarized above.

<u>Ameren Illinois Company d/b/a Ameren Illinois</u>, ICC Order, Docket No. 13-0192, 165 (Dec. 18, 2013). Likewise, in the instant case, the Commission should reject the Company's Bond Yield plus Risk Premium analysis.

8. <u>Flotation Cost Adjustment</u>

The flotation cost adjustment proposed by Mr. Hevert is contrary to long-standing Commission practice. The Commission Order from Docket No. 94-0065 states, "The Commission has traditionally approved [flotation cost] adjustments only when the utility anticipates it will issue stock in the test year or when it has been demonstrated that costs incurred prior to the test year have not been recovered previously through rates." <u>Commonwealth Edison Co.</u>, ICC Order Docket No. 94-0065, 93-94 (Jan. 9, 1995). Moreover, that Order states, "[the utility] has the burden of proof on this issue." Thus, the Commission should allow recovery of flotation costs only if a utility can verify both that it incurred the specific amount of flotation costs for which it seeks compensation and it has not previously recovered those costs through rates." The Company has done neither. In fact, the Company has no unrecovered cost of common equity issuance costs. (Staff Ex. 3.0, citing Co. Sch. D-5)

Mr. Hevert's flotation cost calculations were based on the costs of issuing equity that were incurred by APUC and his sample group companies in their two most recent common equity issuances. Based on those issuance costs, he calculated a flotation cost of 0.15% (15 basis points) for the gas distribution operations. He did not make a specific flotation cost adjustment, but claims to have considered the effect of flotation costs in determining where the Company's ROE falls within the range of results. (Staff Ex. 3.0, pp. 33-34) Thus, the size of the flotation cost in Mr. Hevert's rate of return on common equity remains a mystery.

The Commission has repeatedly rejected generalized flotation cost adjustments in previous cases as an inappropriate basis for raising utility rates. Ameren Illinois Company d/b/a Ameren Illinois, ICC Order Docket No. 11-0282, 126 (Jan. 10, 2012); MidAmerican Energy Company, ICC Order Docket No. 01-0696, 24 (Sept. 11, 2002); Central Illinois Public Service Company (AmerenCIPS) and Union Electric Company (AmerenUE), ICC Order Docket Nos. 02-0798/03-0008/03-0009 (Cons.), 89 (Oct. 22, 2003); Central Illinois Light Company, ICC Order Docket Nos. 01-0465/01-0530/01-0637 (Cons.), 79 (March 28, 2002); Northern Illinois Gas Company d/b/a Nicor Gas Company, ICC Order Docket No. 04-0779, 94 (Sept. 20, 2005); North Shore Gas Company and The Peoples Gas Light and Coke Company, ICC Order Docket Nos. 07-0241/07-0242, 102 (Feb. 5, 2008). Moreover, the Commission has rejected similar flotation cost proposals by Mr. Hevert (*i.*e., flotation cost calculations that are based on the equity issuance costs of the parent company and the proxy group companies). Specifically, the Commission's Order in Docket No. 13-0192 states:

> The Commission observes that the AIC proposal is essentially the same as was advanced by AIC, and rejected by the Commission, on page 126 of its Order in Docket No. 11-0282. The Commission found, in part, "The Commission concludes that the record in this proceeding does not justify an upward adjustment to the cost of common equity to reflect flotation costs…The Commission, however, is not amenable to approving a flotation cost adjustment based upon an average of flotation costs for other utilities, as Mr. Hevert calculated in his direct testimony." The Commission's rationale in Docket No. 11-0282 is equally applicable to the record in the current case. In the instant proceeding, the Commission finds, as it did in Docket No. 11-0282, that the record does not justify an upward adjustment to the cost of common equity to reflect flotation costs.

Ameren Illinois Company d/b/a Ameren Illinois, ICC Order, Docket No. 13-0192, 165-166 (Dec. 18, 2013). Since Mr. Hevert's calculation is not based on issuance costs that the Company has incurred but has not previously recovered through rates, it should not be considered in setting the investor-required rate of return on common equity.

C. Recommended Overall Rate of Return

For all the foregoing reasons, Staff recommends the Commission adopt a 6.81% overall cost of capital for the Company's gas delivery services, which reflects a 9.23% cost of common equity, as shown below.

Liberty Utilities (Midstates Natural Gas) Corp. Weighted Average Cost of Capital (WACC) Summary Summary of Staff Proposal					
Capital Component	Weight	Cost	Weighted Cost	Revenue Conversion Factor	Pre-Tax WACC
Short-Term Debt	0.46%	1.41%	0.01%	1	0.01%
Long-Term Debt	53.95%	4.81%	2.59%	1	2.59%
Common Equity	45.59%	9.23%	4.21%	1.6509	6.95%
Total	100.00%		6.81%		9.55%

D. Ability to Satisfy Docket No. 11-0559 Condition

In Docket No. 11-0559, the Commission imposed the following condition, which essentially caps the Company's common equity ratio for ratemaking purposes:

> For the next rate proceeding for Liberty Energy Midstates, the pre-tax cost of capital will be set using no higher than the lower of (1) the pre-tax cost of capital that Liberty Energy Midstates would have had if (a) its debt to equity ratio was the same as Atmos' equity ratio as of September 30, 2011 (including short-term debt), and (b) the cost of its debt were the same as the cost of debt held by Atmos on September 30, 2011, and (2) the pre-tax cost of capital based on the actual capital structure of Liberty Energy Midstates.

Liberty Energy Corporation and Liberty Energy (Midstates) Corp., ICC Order, Docket No. 11-0559, 9 and Appendix A (June 27, 2012). Based on the condition set forth in the Commission's Order in Docket No. 11-0559, the upper limit pre-tax cost of capital is 10.47% with a 9.23% cost of common equity. (Staff Ex. 3.0, Sch. 3.07) Ms. Phipps proposes an overall cost of capital of 6.81% for Liberty Midstates, which is 9.55% on a pre-tax basis. (Staff Ex. 8.0, pp. 4-5) Thus, her recommendation satisfies the Commission's condition set forth Docket No. 11-0559.

V. COST OF SERVICE

Staff does not object to the Liberty Midstates Gas Cost of Service ("COS") study. The Company's COS study shows, by customer class, the distribution of revenue responsibility necessary to achieve equalized rates of return on investment at the Company's proposed revenue requirement. The Company's COS study identifies the revenues, costs, and profitability for each customer class. It also serves as a partial basis for the Company's proposed rate design. Generally, the Company prepared the COS study utilizing three major steps: (1) cost functionalization;[8] (2) cost classification; and (3) cost allocation of all the costs of the utility's system to customer classes. (Staff Ex. 4.0, p. 5)

Staff witness Mr. Boggs evaluated whether the Company's COS study assigns costs to the various rate classes appropriately and, thus, whether it would be an acceptable guidance tool for determining rates. To that end, Mr. Boggs analyzed the testimony and exhibits presented by Mr. Long. Mr. Boggs also reviewed data request responses from Liberty Midstates related to the gas COS study. (*Id*)

The Company's functionalization methodology is consistent with the Commission's Uniform System of Accounts which groups plant and expenses into various functions such as production, gas in storage, storage, transmission, or distribution.[9] This methodology was used previously in various natural gas rate cases and Staff has no objections to its use in this proceeding. (*Id.,* pp. 5-6)

[8] "The assignment of plant costs (i.e. investments) and related operation, maintenance, depreciation and tax expenses to the basic functions of production, storage, transmission and distribution." (American Gas Association Rate Committee, American Gas Association Gas Rate Fundamentals, p. 135 (4th edition,1987))

[9] 83 Ill. Adm. Code 505.

Classification divides rate base and expenses into energy (or variable-related), demand or customer components. The Company used a methodology, which classifies the functionalized plant and expenses based on how the expenses are incurred: commodity related, demand related, and customer related. Commodity-related costs are costs that vary with the throughput sold to, or transported for, customers. Demand-related costs service the peak demand of the system. Customer-related costs are incurred by the Company to extend service and attach a customer to the distribution system for gas metering, for usage, and for maintenance of customers' accounts. This methodology reflects cost causation, has been accepted previously by the Commission in various natural gas rate cases, and Staff has no objections to its use in this proceeding. (*Id.,* p. 6)

The Company's COS study used a combination of direct assignment and generic functional allocators to assign costs among the customer classes. For costs that have a direct relationship to a specific customer class, the Company directly assigned those costs to that class. For costs that pertain to more than one customer class, the Company used either external allocators or developed internal allocators that are composites of other allocated costs in the COS study. The Company then allocated the cost to more than one customer class. The Company's combination of direct assignment and generic functional allocators to assign costs among the customer classes is reasonable because it fairly assigns costs to the specific customer classes that cause those costs to be incurred. (*Id.,* p. 7)

The Company used the peak day demand to evaluate service adequacy and the contribution of each class during peak day demand and operating pressure. The peak day demand and peak hourly demand are the primary factors that drive the planning and designing of facilities required to serve customers. Company witness Mr. Long explains that it was necessary to use the peak day demand allocator because no load research data or peak day data was available to provide a better estimate. (Company Ex. 3.0, p. 26) The peak day demand methodology has been commonly used in various natural gas rate cases in which the Commission has approved its use in a COS study. Thus, Staff advocates that the use of the peak day demand methodology in Liberty Midstates' COS study is reasonable. (Staff Ex. 4.0, p. 8)

The Company also determined each rate class's contribution to the total annual energy consumption of the Company. The Company then developed the allocator by determining each class' annual therm consumption in proportion to the total therm consumption by all classes. Staff witness Mr. Boggs had no objections to the Company allocating consumption costs among the classes in proportion to the total therm consumption as the most logical way to allocate consumption costs. (*Id.,* pp. 8-9)

In addition, the Company used a simple pro-rata distribution of revenue by rate class from which a percentage of total revenue for each class is determined. The pro-rata distribution of revenue by rate class as a percentage of total revenue is the most logical way to allocate revenue-related items and Mr. Boggs had no objection to its use. (*Id.,* p. 9)

The Company's meter cost allocator reflects the total cost for meters installed for each customer class. The Company determined a current cost for each type of meter and how many of each type is installed for each rate class. From this information, the

Company then estimated the total cost for the meters installed for each customer class. Staff believes that this methodology is cost based and is the fairest, most logical method to allocate revenues needed to recover those meter costs. (*Id.,* p. 10)

The Company's direct labor costs were categorized by the operating function(s) (labor costs for gas supply, transmission, distribution, etc.) to which they are related and were assigned accordingly. Each labor cost was then classified as either being a fixed labor cost or as being a variable labor cost and then assigned to the appropriate rate class. After all labor costs were allocated, each customer class was assigned the corresponding weighted proportion of labor costs based on how each class contributed to the incurring of those costs. The Company's COS study employed two labor allocators. The one in the study labeled L1G utilized all labor expense accounts whereas the one labeled L2G utilized transmission and distribution functional labor only. Mr. Boggs agreed that this methodology is cost based and assigns to each customer class its portion of labor costs incurred by the Company. (*Id.,* pp. 10-11)

The Company begins the gas plant allocation process by assigning all plant among the customer classes. The results of the various allocated plant functions are added together for each rate class and the respective sums represent the total allocation of plant functions to each class. The Company ends the total gas plant allocation process by assigning various operating expense items to each class based upon plant assignments to those classes. Mr. Boggs determined that this methodology is cost based and did not object to its use. The Company's process of allocating plant-related expenses based on gas plant balances reflects how each class contributes to the operating expense items incurred by the Company. (*Id.,* pp. 11-12)

Mr. Boggs concluded that the data provided by the Company is the most recently available and, therefore, the most reliable. Relying on data from any other source or any other time period would not be pertinent to this proceeding. The Company's COS study appropriately assigns costs to the various functions and rate classes. Thus, it is an acceptable guidance tool for determining rates in this case. (*Id.,* p. 13)

VI. RATE DESIGN

Staff does not object to the Liberty Midstates Gas proposed rate design. Company witness Mr. Long first evaluated customer costs associated with each rate class. He used the customer costs for each rate class to evaluate levels at which the fixed charge could be set. He considered as customer costs only those costs reflected in expense accounts 871, 875, 878, 892, 893, 901, 902.2, 903.2,912, 913 and 916 and in plant accounts 380, 381, 382, 383 and 385. Thus, Mr. Long classified as customer costs only those costs that are customer related. (Company Ex. 3.0, p. 41)

Mr. Long evaluated the customer-related costs for each rate class by adding the amounts of customer related plant accounts allocated to each class and multiplying those totals by the rate of return on rate base. Next, he added in the customer related expense accounts that are allocated to each class. After the completion of this process, Mr. Long applied the gross revenue factor to the amount of return and increased the expense accounts by that result in order to place their value at the revenue level. The result for each rate class is the annual customer related revenue requirement for each class. He then divided each of these annual class cost amounts by the number of customers in each class, and then by twelve months in order to determine the cost per customer per month for each class. (*Id.*)

The calculated results of Mr. Long's customer costs per customer for each customer class included $13.92 for the residential class, $17.82 for the commercial class, and $380.28 for the industrial class. (*Id.*) However, Mr. Long's proposed Customer Charges are a $23 Customer Charge for the residential class, an $80 Customer Charge for the commercial class and a $200 Customer Charge for the industrial class. (Staff Ex. 4.0, p. 16)

Mr. Long evaluated three different approaches to determine the revenue allocation process before he selected the one he used to determine his Customer Charge proposals for each class. Mr. Long calls the revenue allocation approach he selected the "sensitivity allocation" approach and he presents it in Company Ex. 3.0, Schedule 3.3, on lines 26-30. Under this approach, Mr. Long applied the overall 38.54% average revenue increase only to the residential class. The other proposed revenue increases that he applied were 41.32% to the commercial class and 20% to the industrial class. This approach used "both the iterative process as well as [his] professional judgment in order to mitigate extreme results of the other attempts." (Company Ex. 3.0, p. 44) Mr. Long states that this final approach is both "fair and reasonable". (*Id.*) Mr. Long stated that his main consideration for this approach is the very small industrial class that consists of only eight customers. He explained that cost based revenue allocation would produce a large rate increase for this class.

Mr. Long used the class revenue allocations and the billing determinants from the forecasted test year to calculate the amount needed on a monthly basis from each customer in each class to recover the customer-related costs related to providing natural gas service. His results are presented in Company Ex. 3.0, Schedule 3.4.

Mr. Boggs compared Mr. Long's proposed rates with the rates that would result based on the COS study. Mr. Boggs began by using the COS study to determine class revenue allocations. The same revenue requirement by customer class was used that was provided in Company Ex. 3.0, Schedule 3.1, to determine the amounts of revenue needed from each customer class to recover the cost to serve that class. Customer-related costs were targeted from the COS study and the billing determinants of each class to calculate the Customer Charge. All remaining revenue needed was recovered through the Usage Charge (PGA charges were not considered in any of these approaches as they are a pass-through rate and remain equal throughout the process). (Staff Ex. 4.0, pp. 17-22)

Mr. Boggs' approach using the COS study to determine class revenue allocations revealed that under a strictly cost-based approach, residential Customer Charges and Usage Charges would nearly double from their current levels. For commercial customers, the Customer Charge would *decrease*, but the Usage Charges would more than double. For the Industrial class, Customer Charges would have to be increased four fold and Usage Charges would have to more than triple the current level to meet the proposed test year revenue requirement. (*Id.*)

Mr. Boggs determined that cost based-rates shaped by the COS study would produce excessive increases to the industrial class' Customer Charge and Usage Charge such that the needed increases would most likely have an adverse impact on the monthly bills of the eight industrial customers. With the commercial class showing a decline in its monthly Customer Charge, a different rate design could be developed that would more evenly allocate the proposed revenue requirement increase. (*Id.*)

Staff witness Mr. Boggs recommends that the Commission approve the Company's rate design/revenue allocation proposal presented in Mr. Long's direct testimony. This rate design/revenue allocation proposal represents the most fair and balanced scenario at this time. After fifteen years without any rate increases, the cost to serve Liberty Midstates customers has increased considerably and all customers will receive a significant increase. In future rate cases, the Company should have more historical data that will allow for better analysis of how to distribute future increases among the customer classes. (Staff Ex. 4.0, pp. 22-23)

If the Commission approves a different revenue requirement than the one proposed by the Company, Mr. Boggs proposes to keep the Customer Charges for each rate class the same as proposed by Mr. Long in his direct testimony and collect the remainder of the revenue requirement through the Usage Charge. This recommendation would remain consistent with the Company's current proposal to use the Usage Charge as a fall-out to recover any revenue that the Customer Charge does not capture. This recommendation also does not require any adjustment to the PGA charge that the Company proposes. (*Id.,* p. 23)

In addition, the Company states that it does not intend to update or eliminate rates for Optional Gas Service, Contract Service, Negotiated Gas Service and Cogeneration Compressed Natural Gas, Prime Movers, Fuel Cell Service, Large Tonnage Air Conditioning customer classes (Class numbers 150, 190, 191 and 192 respectively) because the Company provides no permanent service to any customers in those classes. The Company intends to keep rates for those four classes open in the event that future customers request service in one of those classes. *See* Att. 4.1. (*Id.,* pp. 23-24)

Since there are no customers in any of the four classes listed above, it is reasonable to maintain the current rates for these classes at this time. However, Mr. Boggs recommends that the Commission in its order in this proceeding require Liberty Midstates to perform and provide a new cost of service study should a new customer begin taking service from Liberty Midstates who is eligible to take service under customer classes 150, 190, 191 or 192. (*Id.,* pp. 24-26)

VII. OTHER

A. Quality of Future Rate Filings and Reports

During the course of this proceeding Staff made several recommendations which can be summarized in the following three categories:

1. Recommendations for improvements in the quality of data submitted in future rate filings;
2. Recommendations for supplemental Information to be submitted with the Form 21 Annual Report; and
3. Recommendation for progress reports on the implementation of Accounting Controls and Procedures.

1. Future Rate Filings Recommendations

In his direct testimony, Mr. Knepler recommended several improvements that Liberty Midstates should make to improve the quality of the data presented in future rate filings. Staff also recommended that the Commission put Liberty Midstates on notice that future rate filings should incorporate Staff's recommendations. (Staff Ex. 1.0, pp. 14-17) In his rebuttal testimony, Company witness Christopher Krygier acknowledged that Liberty Midstates was presented with a set of unique challenges in its initial rate filing before the Commission. He further stated that the Company takes the Commission reporting requirements seriously and that the Company pledges to provide more complete information in its next rate case. (Company Ex. 5.0, p. 23) Staff recommends that the Commission include the following language in its order to put Liberty Midstates on notice that the quality of its future rate filings must improve:

> The Commission recognizes that Liberty Midstates was presented with a set of unique challenges in its initial rate filing. However, the Company determines when to file its rate case and has the burden of proof to support its rate increase. Any future rate filing should reflect the following improvements in its next rate filing:
>
> 1. All Part 285 schedules and workpapers should use line numbers and column headings to provide ease of reference;
> 2. Responses to Staff data requests should include the appropriate supporting calculations, workpapers, and reference sources;
> 3. Responses to Staff data requests should be made in a timely manner;
> 4. Cost should be recorded in the same accounts across historical, budget, and forecasted periods in its filings;
> 5. The 46-deficiencies identified in the Part 285 Deficiency Letter filed on e-docket on May 1, 2014 should not recur in a future rate filing. (Staff Ex 1.0, Attach. D.)
>
> The Commission also recognizes that the use of the acronym, “Liberty”, causes confusion as to whether the Company is being referred to or one of the affiliates of the Company is being referred to. Thus, the Commission puts the Company on notice that the acronyms of affiliated companies and the names of affiliates need to be adequately differentiated and consistently used in all filings with the Commission not just rate filings.
>
> (Staff Ex. 1.0, pp. 15-17)

2. Form 21 ILCC Annual Report Supplemental Information

The Form 21 ILCC submitted annually by Liberty Midstates to the Commission requires the Company to provide “total company data.” Because Liberty Midstates operates in three states (Illinois, Missouri and Iowa), the total company data does not provide the Commission with information on the Illinois jurisdiction of the Company. Thus, Staff has proposed that Liberty Midstates supplement its annual Form 21 ILCC submission with specific Illinois only data. (Staff Ex. 1.0, 18-20)

In surrebuttal testimony, Company witness Krygier expressed concerns that the adoption of Company-specific requirements will subject the Company to a regulatory regime that is not applicable to any other utility. However, the Company does believe that it could use reasonable efforts to comply with making certain otherwise inapplicable requirements applicable to the Company. (Company Ex. 8.0, 12)

Staff recommends that the Commission include in the following finding its order:

> In order to provide the Commission with information on the Illinois jurisdiction of the Company annually in its Form 21 ILCC, the Commission orders Liberty Midstates to supplement its Form 21 ILCC with the following schedules with only Illinois jurisdictional data to be designated by an “a” following the page number, beginning with the 2014 reporting year that is to be submitted to the Commission by March 31, 2015:
>
> 1. Page 2a – Balance Sheet: supplement to also provide Illinois jurisdictional data for lines 29 – 31, Customer Accounts Receivable, Other Accounts Receivable, and Accumulated Provision for Uncollectible Accounts, as included on the associated lines of Page 2, Balance Sheet;
>
> 2. Page 3a – Balance Sheet: provide Illinois jurisdictional data for Deferred Debits reflected on lines 56 - 71 included in the existing page 3, Balance Sheet;
>
> 3. Page 4a – Balance Sheet: provide Illinois jurisdictional data for the Other Non-Current Liabilities reflected on lines 25 - 32 and Customer Deposits reflected on line 38 included in the existing page 4, Balance Sheet;
>
> 4. Page 5a – Balance Sheet: provide Illinois jurisdictional data for the Deferred Debits reflected on lines 51 – 58 included in the existing page 5, Balance Sheet;

5. Page 32a – Employee Data: supplement the existing information for the number of Illinois employees;
6. Page 33a – Charges for Outside, Professional and Other Consultative Services;
7. Pages 42a and 43a – Accumulated Deferred Income Taxes – Accelerated Amortization of Property;
8. Page 47a – Transactions with Associated (Affiliated) Companies;
9. Page 233a – Miscellaneous Deferred Debits;
10. Pages 234a – 235a – Accumulated Deferred Income Tax;
11. Pages 262a - 263a – Taxes Accrued, Prepaid and Charged During Year;
12. Pages 320a - 325a – Gas Operation and Maintenance Expense;
13. Page 335a – Miscellaneous General Expenses;
14. Pages 336a - 338a – Depreciation, Depletion and Amortization of Gas Plant;
15. Pages 350a - 351a – Regulatory Commission Expenses;
16. Page 352a – Employee Pension and Benefits;
17. Pages 354a – 355a – Distribution of Salaries and Wages; and
18. Pages 708a - 709a – Purchased Gas.

In addition, the FERC Form 2 submitted to the Commission should not be hand-written and should be legible.

3. Progress Reports on the Implementation of Accounting Controls

In addition to being a utility company that operates in three states, Liberty Midstates is also a member of Algonquin Power and Light Company, a Canadian based, multi-level corporation. Liberty Midstates is directly assigned or allocated costs from various affiliated companies pursuant to the affiliate agreements that were approved by the Commission in Docket No. 11-0559. The costs charged to Liberty

Midstates are then further jurisdictionalized among its Illinois, Missouri and Iowa operations. To more clearly trace the direct and allocated costs from these affiliated companies, Staff proposed that Liberty Midstates develop certain accounting controls and procedures. (Staff Ex. 6.0, pp. 10-11) Staff believes the details of the accounting controls and procedures can be more fully addressed in a mutually agreeable manner in Docket No. 14-0269, Liberty Midstates' ongoing request for approval of revisions to its existing affiliate services agreements, and recommends that the Commission include the following direction in its order:

> In Docket No. 14-0269, Liberty Midstates' on-going case with the Commission for approval to revise its existing affiliate services agreements, the Commission directs Staff and the Company to develop controls and procedures to be approved by the Commission to ensure that costs charged to Liberty Midstates from its affiliates are being properly allocated and billed pursuant to the affiliate services agreements approved by the Commission. Controls and procedures that shall be developed shall include, but not be limited to, the following:
>
> 1) Costs billed direct from affiliates can be distinguished from costs that are allocated from affiliates within Liberty Midstates' books and records;
> 2) Billings from each affiliate should be able to be ascertained within Liberty Midstates' books and records; and
> 3) All costs billed from affiliates should be supported by source documents that authorize the provided services.

In addition, the Company has agreed to make semi-annual progress reports to the Manager of the Commission's Accounting Department, beginning on October 1, 2015 and continuing such until the accounting controls and procedures are fully implemented. (Staff Cross Ex. 1) However, since Staff is now recommending in this IB, that the Commission direct Staff and the Company to work together to develop accounting controls and procedures in Docket No. 14-0269, the Staff recommendation for semi-annual reporting pursuant to an Order in this proceeding is unnecessary.

B. Property Taxes – Request for Deferred Accounting[10]

Test Year Expense

In his direct testimony, Mr. Knepler proposed a $73,484 adjustment to reduce property taxes comprised of the following;

1. $18,695 for an expense component counted twice;
2. $6,311 reduction to limit the annualized increase to the Company's proposed 3% inflation rate; and
3. $48,478 property taxes on a new office building to constructed in Vandalia, Illinois.

(Staff Ex 1.0, pp. 9-10)

In rebuttal testimony, the Company accepted the removal of the duplicate property tax and the inflation adjustment ($18,695 and $6,311). (Company Ex. 6.0, pp. 8-9) The Company also would not contest the removal of the property tax on the yet to be constructed Vandalia office building that will not be assessed in the Company's 2015 test year but in 2016, with the first tax payment being made in 2017. (*Id.,* 9)

Request for Deferred Accounting Treatment

The Company's rebuttal testimony also included a request for deferred accounting treatment for property taxes paid between now and its next rate case as a regulatory asset. (*Id.,* 9) The Company further proposed in surrebuttal testimony that in its next rate case, the Company would reflect one year's worth of amortization in the operating expenses and the unamortized portion would be included in rate base. (Company Ex. 9.0, p. 4)

[10] No longer an operating expense issue.

Mr. Knepler responded that it would not be permissible for the Commission to approve deferred accounting treatment for the recovery of property taxes for an office building to be built in a future rate case because it would violate test year rules by mismatching expenses and revenues from different periods. (Staff Ex. 6.0, pp. 12-13) In fact, the Commission has ruled against the establishment of a regulatory asset for the future recovery of costs in various proceedings, including a rulemaking to amend the Commission's rule to provide for the recovery of deferred costs (Docket No. 93-0408) and a request by Citizens Utilities Company to defer its costs related to the conversion of microprocessors to accept dates after the turn of the last century ("Y2K") (Docket No. 98-0895).

In *Re Central Illinois Public Service*, ICC Docket No. 93-0408 (Oct. 19, 1994) ("CIPS"), a coalition of utilities sought to initiate a rulemaking for the purpose of:

> The proposed rule would establish specific categories of costs and cost savings which entities subject to regulation ("regulated entities") by the Illinois Commerce Commission ("Commission") would be authorized to defer for future recovery or flow back to customers; establish procedures for obtaining, where necessary, authorization to defer such costs; and authorize the recovery of such deferred costs through tariffs approved by the Commission.

CIPS at 1.

Relying on *Business and Profession People v. Commerce Commission,* 146 Ill.2d 175 (1991) ("BPI II"), the Commission declined to initiate the rulemaking because:

> Because test year rules were viewed as intended to prevent utilities from mismatching revenue and operating expense data and post-in service carrying charges are not operating expenses, they were found not to be test year items.

CIPS at 8.

The Commission also denied deferred accounting treatment in Docket No. 98-0895, the Citizens Utilities Company's request to recover its Y2K costs, because it would violate test year principles:

> The requested deferral would improperly match expenses from a non-test year with revenues from a test year. The requested deferral is contrary to the ratemaking principle requiring that expenses be recognized in the year in which they are incurred. … Therefore, we reject CUCI's Application to allow deferral of its Y2K operating expenses for ratemaking purposes.

Citizens Utilities Company of Illinois, d/b/a Citizens Water Resources, ICC Order Docket No. 98-0895, 3 (March 15, 2000).

Liberty Midstates' proposal would also violate the prohibition against single-issue ratemaking because it would defer selected elements of the revenue requirement formula (i.e., property taxes) and consider changes in them in isolation from changes in the other elements of the revenue requirement formula. All elements of the revenue requirement should be examined contemporaneously so that changes in one element are netted against all the other elements. The Illinois Supreme Court articulated this longstanding principle in *BPI II*, where it explained:

> The rule against single-issue ratemaking recognizes that the revenue formula is designed to determine the revenue requirement based on the *aggregate* costs and demand of the utility. Therefore, it would be improper to consider changes to components of the revenue requirement in isolation. Often times a change in one item of the revenue formula is offset by a corresponding change in another component of the formula. For example, an increase in depreciation expense attributable to a new plant *may* be offset by a decrease in the cost of labor due to increased productivity, or by increased demand for electricity. (Demand for electricity affects the revenue requirement indirectly. The yearly revenue requirement is divided by the expected demand for electricity to arrive at a per kilowatt hour rate. If actual demand is more than the estimated demand used in the formula, the utility's revenues increase.) In such a case, the revenue requirement would be overstated if rates were increased based solely on the higher depreciation expense without first considering changes to other elements of the revenue formula. Conversely the revenue requirement would be understated if rates were reduced based on the higher demand data without considering the effects of higher expenses.

146 Ill. 2d at 43-44.

Thus, the Commission has previously rejected proposals requesting a "regulatory asset" in compliance with the Illinois Supreme Court in BPI II that found that a regulatory asset violates basic test year principles and the prohibition against single issue ratemaking. Therefore, Staff recommends that Liberty Midstates' request to establish a regulatory asset for property taxes on its office building to be constructed in Vandalia, Illinois, be denied.

VIII. CONCLUSION

WHEREFORE, for all of the following reasons, Staff respectfully requests that the Commission's order in this proceeding reflect all of Staff's recommendations regarding the Company's request for a general increase in gas rates.

Respectfully submitted,

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Illinois Commerce Commission

November 7, 2014

Liberty Utilities (Midstates Natural Gas) Corp.
d/b/a Liberty Utilities
Statement of Operating Income with Adjustments
For the Test Year Ending December 31, 2015

Line No.	Description	Company Rebuttal Pro Forma Present (Sch. 6.01, p. 2, col (d)	Staff Adjustments (Source)	Staff Pro Forma Present (Cols. b+c)	Company Proposed Increase (Co. Ex. 5.01	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. d+e+f)	Adjustment To Proposed Increase	Staff Pro Forma Proposed (Cols. g+h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Tariffed Revenues	$ 7,465,402	$ -	$ 7,465,402	$ 5,466,835	$ (76,215)	$ 12,856,022	$ (950,965)	$ 11,905,057
2	Fuel Adjust. Clause Revenues	$ -	$ -	$ -	$ -	$ -	$ -		$ -
3	Other Revenues	$ 116,352	$ -	$ 116,352	$ -	$ -	$ 116,352	$ -	$ 116,352
4	Total Operating Revenue	$ 7,581,754	$ -	$ 7,581,754	$ 5,466,835	$ (76,215)	$ 12,972,374	$ (950,965)	$ 12,021,409
5	Uncollectible Accounts	$ 113,117	$ (37,247)	$ 75,870		$ 27,492	$ 103,362	$ (4,850)	$ 98,512
6	Distribution Expense	$ 1,387,302	$ -	$ 1,387,302	$ -	$ -	$ 1,387,302	$ -	$ 1,387,302
7	Customer Accounts	$ 160,088	$ -	$ 160,088	$ -	$ -	$ 160,088	$ -	$ 160,088
8	Sales Expense	$ 23,664	$ -	$ 23,664	$ -	$ -	$ 23,664	$ -	$ 23,664
9	A&G	$ 2,784,061	$ (32,611)	$ 2,751,450	$ -	$ -	$ 2,751,450	$ -	$ 2,751,450
10	Depreciation & Amortization	$ 3,026,648	$ (1,050)	$ 3,025,598	$ -	$ -	$ 3,025,598	$ -	$ 3,025,598
11	Taxes Other Than Income Taxes	$ 702,697	$ (4,377)	$ 698,320	$ -	$ -	$ 698,320	$ -	$ 698,320
12	Cost of Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Total Operating Expense								
14	Before Income Taxes	$ 8,197,577	$ (75,285)	$ 8,122,292	$ -	$ 27,492	$ 8,149,784	$ (4,850)	$ 8,144,934
							$ -		$ -
15	State Income Tax	$ (114,666)	$ (12,377)	$ (127,043)	$ 519,349	$ (103,705)	$ 288,601	$ (73,324)	$ 215,277
16	Federal Income Tax	$ (358,482)	$ (50,091)	$ (408,573)	$ 1,682,145	$ (2)	$ 1,273,570	$ (296,749)	$ 976,821
17	Deferred Taxes and ITCs Net	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Total Operating Expenses	$ 7,724,429	$ (137,753)	$ 7,586,676	$ 2,201,494	$ (76,215)	$ 9,711,955	$ (374,923)	$ 9,337,032
19	NET OPERATING INCOME	$ (142,675)	$ 137,753	$ (4,922)	$ 3,265,341	$ -	$ 3,260,419	$ (576,042)	$ 2,684,377
20	Staff Rate Base (Appendix A, p. 5, Column (d))								$ 39,418,167
21	Staff Overall Rate of Return (ICC Staff Exhibit 8.0, Schedule 8.01)								6.81%
22	Revenue Change (Col. (i) Line 4 minus Col. (d), Line 4)								$ 4,439,655
23	Percentage Revenue Change (Col. (i), Line 22 divided by Col. (d), Line 4)								58.56%

Liberty Utilities (Midstates Natural Gas) Corp.
d/b/a Liberty Utilities
Statement of Operating Income with Adjustments
For the Test Year Ending December 31, 2015

Line No.	Description	Company Direct Pro Forma Present (Liberty Sch C-1)	Company Rebuttal Adjustments (Liberty Ex 5.02)	Company Rebuttal Pro Forma Present (Cols. b+c)	Company Surrebutal Adjustments (Liberty Ex. 8.0, 6-7)	Company Surrebuttal Pro Forma Present (Cols. d+e)
	(a)	(b)	(c)	(d)	(e)	(f)
1	Tariffed Revenues	$ 7,465,402	$ -	$ 7,465,402	$ -	$ 7,465,402
2	Fuel Adjust. Clause Revenues					
3	Other Revenues	116,352	-	116,352	-	116,352
4	Total Operating Revenue	7,581,754	-	7,581,754	-	7,581,754
5	Uncollectible Accounts	113,117	-	113,117	-	113,117
6	Distribution Expense	1,378,773	8,529	1,387,302	-	1,387,302
7	Customer Accounts	160,088	-	160,088	-	160,088
8	Sales Expense	23,664	-	23,664	-	23,664
9	A&G	2,888,553	101,702	2,990,255	(206,194)	2,784,061
10	Depreciation & Amortization	2,964,329	62,319	3,026,648	-	3,026,648
11	Taxes Other Than Income Taxes	776,181	(73,484)	702,697	-	702,697
12	Cost of Gas	-	-	-	-	-
13	-	-	-	-	-	-
14	-	-	-	-	-	-
15		-	-	-	-	-
16	Total Operating Expense					
17	Before Income Taxes	8,304,705	99,066	8,403,771	(206,194)	8,197,577
18	State Income Tax	(121,235)	(9,411)	(130,646)	15,980	(114,666)
19	Federal Income Tax	(392,672)	(30,483)	(423,155)	64,673	(358,482)
20	Deferred Taxes and ITCs Net	-	-	-	-	-
21	Total Operating Expenses	7,790,798	59,172	7,849,970	(125,541)	7,724,429
22	NET OPERATING INCOME	$ (209,044)	$ (59,172)	$ (268,216)	$ 125,541	$ (142,675)

Liberty Ex. 5.02
Line 15, Column (j)

State Inome Tax:

Operating Income (Loss) Before Taxes	(99,066)
Company State Tax Rate	9.5%
Illinois Inocme Tax	(9,411)

Federal Income Tax:

Operating Income (Loss) Before Taxes	(99,066)
Less: Illinois Icome Tax Expense	(9,411)
Taxable Federal Inocme Tax	(89,655)
Federal Income Tax Rate	34.00%
Federal Income Tax	(30,483)

Company Rebuttal Increase:

(Liberty Schedule 5.01)

	5,466,835
	9.5%
Page 1, Col. (e). line 16	519,349
	5,466,835
	519,349
	4,947,486
	34.00%
Page 1, Col. (e). line 17	1,682,145

Sources:
Column (e); See, Staff Ex. 6.0, Schedule 6.02, Column (e)

Liberty Utilities (Midstates Natural Gas) Corp.

d/b/a Liberty Utilities

Statement of Operating Income with Adjustments

For the Test Year Ending December 31, 2015

				Company Accepted	Co Accepted - SRTTY	Adjustment Withdrawn	Company Accepted	Company Accepted	
Line No.	Description	Interest Synchronization (Sch. 6.06)	Uncollectible Expense at Present Rates (Sch. 1.08	Property Tax Expense (Sch. 1.11)	Outside Professional Services (Sch 6.09)	Allocations from Shared Services (LABS) (Sch 1.13)	Rate Case Expense (Sch. 2.04)	Depreciation Expense (Sch. 2.05)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Tariffed Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Fuel Adjust. Clause Revenues		-						-
3	Other Revenues	-	-	-	-	-	-	-	-
4	Total Operating Revenue	-	-	-	-	-	-	-	-
5	Uncollectible Accounts	-	(37,247)	-	-	-	-	-	(37,247)
6	Distribution Expense	-	-	-	-	-	-	-	-
7	Customer Accounts	-	-	-	-	-	-	-	-
8	Sales Expense	-	-	-	-	-	-	-	-
9	A&G	-	-	-	-	-	-	-	-
10	Depreciation & Amortization	-	-	-	-	-	-	-	-
11	Taxes Other Than Income Taxes	-	-	-	-	-	-	-	-
12	Cost of Gas	-	-	-	-	-	-	-	-
13	Total Operating Expense								
14	Before Income Taxes	-	(37,247)	-	-	-	-	-	(37,247)
								-	
15	State Income Tax	(18,212)	2,887	-	-	-	-	-	(15,325)
16	Federal Income Tax	(73,705)	11,683	-	-	-	-	-	(62,022)
17	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
18	Total Operating Expenses	(91,917)	(22,677)	-	-	-	-	-	(114,594)
19	NET OPERATING INCOME	$ 91,917	$ 22,677	$ -	$ -	$ -	$ -	$ -	$ 114,594

Liberty Utilities (Midstates Natural Gas) Corp.
d/b/a Liberty Utilities
Adjustments to Operating Income
For the Test Year Ending December 31, 2015

Line No.	Description	Subtotal Operating Statement Adjustments (Sch 6.02, p. 1)	Incentive Compensation (Sch. 7.03)	(Source)	(Source)	(Source)	(Source)	(Source)	Total Operating Statement Adjustments
	(a)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Tariffed Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Fuel Adjust. Clause Revenues	-							-
3	Other Revenues	-	-	-	-	-	-	-	-
4	Total Operating Revenue	-	-	-	-	-	-	-	-
5	Uncollectible Accounts	(37,247)	-	-	-	-	-	-	(37,247)
6	Distribution Expense	-	-	-	-	-	-	-	-
7	Customer Accounts	-	-	-	-	-	-	-	-
8	Sales Expense	-	-	-	-	-	-	-	-
9	A&G	-	(32,611)	-	-	-	-	-	(32,611)
10	Depreciation & Amortization	-	(1,050)	-	-	-	-	-	(1,050)
11	Taxes Other Than Income Taxes	-	(4,377)	-	-	-	-	-	(4,377)
12	Cost of Gas	-	-	-	-	-	-	-	-
13	Total Operating Expense								
14	Before Income Taxes	(37,247)	(38,038)	-	-	-	-	-	(75,285)
15	State Income Tax	(15,325)	2,948	-	-	-	-	-	(12,377)
16	Federal Income Tax	(62,022)	11,931	-	-	-	-	-	(50,091)
17	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
18	Total Operating Expenses	(114,594)	(23,159)	-	-	-	-	-	(137,753)
19	NET OPERATING INCOME	$ 114,594	$ 23,159	$ -	$ -	$ -	$ -	$ -	$ 137,753

Liberty Utilities (Midstates Natural Gas) Corp.
d/b/a Liberty Utilities
Rate Base
For the Test Year Ending December 31, 2015

Line No.	Description	Company Pro Forma Rate Base Sch 6.03, p. 2, col (d)	Staff Adjustments (St. Ex. 1.0 Sch 1.2-S&P)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Utility Plant in Service	$ 65,856,245	$ (1,865,627)	$ 63,990,618
2	Less: Accumulated Depreciation	(26,234,473)	1,241,358	(24,993,115)
3		-	-	-
4	Net Utility Plant in Service	39,621,772	(624,269)	38,997,503
5	Additions to Rate Base			
6	Gas Stored Underground & Propane	1,604,364	-	1,604,364
7	Cash Working Capital	570,164	(30,211)	539,953
8	Budget Plan Balances & Customer Deposits	(3,878)	-	(3,878)
9			-	-
10			-	-
11			-	-
12			-	-
13			-	-
14			-	-
15			-	-
16	Deductions From Rate Base			
17	Customer Advances for Construction	(570,958)	-	(570,958)
18	Accumulated Deferred Income Taxes	(1,299,065)	150,248	(1,148,817)
19			-	-
20			-	-
21			-	-
22		-	-	-
23	Rate Base	$ 39,922,399	$ (504,232)	$ 39,418,167

Liberty Utilities (Midstates Natural Gas) Corp.
d/b/a Liberty Utilities
Rate Base
For the Test Year Ending December 31, 2015

Line No.	Description	Company Direct Pro Forma Rate Base Co. Sch. B-1	Company Rebuttal Adjustments (Co. Ex. 5.03)	Company Rebuttal Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Utility Plant in Service	$ 63,916,617	$ 1,939,628	$ 65,856,245
2	Less: Accumulated Depreciation	(24,673,695)	(1,560,778)	(26,234,473)
3		-	-	-
4	Net Utility Plant in Service	39,242,922	378,850	39,621,772
5	Additions to Rate Base			
6	Gas Stored Underground & Propane	1,604,364	-	1,604,364
7	Cash Working Capital	570,524	(360)	570,164
8	Budget Plan Balances & Customer Deposits	22,814	(26,692)	(3,878)
9	-	-	-	-
10		-	-	-
11		-	-	-
12		-	-	-
13		-	-	-
14		-	-	-
15		-	-	-
16	Deductions From Rate Base			
17	Customer Advances for Construction	(570,958)	-	(570,958)
18	Accumulated Deferred Income Taxes	(1,240,930)	(58,135)	(1,299,065)
19	-	-	-	-
20	-	-	-	-
21	-	-	-	-
22	-	-	-	-
23	Rate Base	$ 39,628,736	$ 293,663	$ 39,922,399

Liberty Utilities (Midstates Natural Gas) Corp.
d/b/a Liberty Utilities
Adjustment to Rate Base
For the Test Year Ending December 31, 2015

Line No.	Description	Cash Working Capital (Sch. 1.14)	Average Net Plant Sch. 7.01 & 7.02	Accumulated Deferred Income Tax (Sch. 7.02)	Budget Payment Plans (Sch. 2.03)	(Source)	(Source)	(Source)	Total Rate Base Adjustments
		Company Accepted CWC Methodology	Partially Accepted		Company Accepted				
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Utility Plant in Service	$ -	$ (1,865,627)	$ -	$ -	$ -	$ -	$ -	$ (1,865,627)
2	Less: Accumulated Depreciation	-	1,241,358	-	-	-	-	-	1,241,358
3	-	-	-	-	-	-	-	-	-
4	Net Utility Plant in Service	-	(624,269)	-	-	-	-	-	(624,269)
	-								
5	Additions to Rate Base								-
6	Gas Stored Underground & Propane			-	-	-	-	-	-
7	Cash Working Capital	(30,211)	-	-	-	-	-	-	(30,211)
8	Budget Plan Balances & Customer Deposits	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-
16	Deductions From Rate Base	-	-	-	-	-	-	-	-
17	Customer Advances for Construction	-	-	-	-	-	-	-	-
18	Accumulated Deferred Income Taxes	-	-	150,248	-	-	-	-	150,248
19		-	-	-	-	-	-	-	-
20	-	-	-	-	-	-	-	-	-
21	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
23	Rate Base	$ (30,211)	$ (624,269)	$ 150,248	$ -	$ -	$ -	$ -	$ (504,232)

Liberty Utilities (Midstates Natural Gas) Corp.
d/b/a Liberty Utilities
Revenue Effect of Adjustments
For the Test Year Ending December 31, 2015

Line No.	Description	Per Company	Staff Adjustments	Per Staff
	(a)	(b)	(c)	(d)
1	Present Revenues	$ 7,581,754 [(1)]	$ -	$ 7,581,754 [(2)]
2	Proposed Increase	5,466,835 [(3)]	(1,027,180) [(4)]	4,439,655 [(5)]
3	Proposed Revenues	$ 13,048,589	$ (1,027,180)	$ 12,021,409
4	% Increase	72.11%		58.56%
5	Staff Adjustments:			
6	Rate of Return (Applied to Company Rate Base)		(666,866)	
7	Interest Synchronization		(160,208)	
8	Uncollectible Expense at Present Rates		(37,437)	
9	Property Tax Expense		-	
10	Outside Professional Services		-	
11	Allocations from Shared Services (LABS)		-	
12	Rate Case Expense		-	
13	Depreciation Expense		-	
14	Incentive Compensation		(38,232)	
15	-		-	
16	-		-	
17	Cash Working Capital		(2,889)	
18	Average Net Plant		(59,702)	
19	Accumulated Deferred Income Tax		14,369	
20	Budget Payment Plans		-	
21			-	
22	Gross Revenue Conversion Factor		(76,215)	
23				
24	Rounding		-	
25				
26	Total Revenue Effect of Staff Adjustments		$ (1,027,180)	

Sources:
- (1) Appendix A, page 1, column (b), line 4
- (2) Appendix A, page 1, column (d), line 4
- (3) Appendix A, page 1, column (e), line 4
- (4) Appendix A, page 1, columns (f) + (h), line 4
- (5) Appendix A, page 1, column (i), line 22

Reconciliaton to Appendix A, page 1:

Column (c), line 4 - Staff Adjustments to Revenues	$ -
Column (c), line 4 - GRCF	(76,215)
Column (c), line 4 - Adjustment to Proposed Increase	(950,965)
	$ (1,027,180)

Liberty Utilities (Midstates Natural Gas) Corp.
d/b/a Liberty Utilities
Interest Synchronization Adjustments
For the Test Year Ending December 31, 2015

Line No.	Description	Amount	
	(a)	(b)	
1	Rate Base	$ 39,418,167	(1)
2	Weighted Cost of Debt	2.600%	(2)
3	Synchronized Interest Per Staff	$ 1,024,872	
4	Company Interest Expense	789,882	(3)
5	Increase (Decrease) in Interest Expense	$ 234,990	
6	Increase (Decrease) in State Income Tax Expense		
7	at 7.750%	$ (18,212)	
8	Increase (Decrease) in Federal Income Tax Expense		
9	at 34.000%	$ (73,705)	

(1) Source: Appendix A, p. 5, Column (d).
(2) Source: ICC Staff Exhibit 8.0, Schedule 8.01.
(3) Source: Company Schedule C-5.4, line 3.

Liberty Utilities (Midstates Natural Gas) Corp.
d/b/a Liberty Utilities
Gross Revenue Conversion Factor
For the Test Year Ending December 31, 2015

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	
2	Uncollectibles	0.5100%	0.005100	
3	State Taxable Income		0.994900	1.000000
4	State Income Tax	7.7500%	0.077105	0.077500
5	Federal Taxable Income		0.917795	0.922500
6	Federal Income Tax	34.0000%	0.312050	0.313650
7	Operating Income		0.605745	0.608850
8	Gross Revenue Conversion Factor Per Staff		1.650860	1.642441

Liberty Utilities (Midstates Natural Gas) Corp.
Adjustment to Cash Working Capital
For the Test Year Ending December 31, 2015

Line No.	Description	Amount	Amount
	(a)	(b)	(c)
1	Cash Working Capital - per Staff (Line 11, Column (c))		$ 540,313
2	Cash Working Capital - per Company (Line 11, Column (b))		570,524
3	Staff Adjustment (Line 1 - Line 2)		$ (30,211)

Cash Working Capital Determination:

Line No.	Description	Company Amount	Staff Amount
	(a)	(b)	(c)
4	Distribution Expense	$ 1,378,773	$ 1,387,302
5	Customer Accounts Expense	160,088	160,088
6	Uncollectible Accounts Expense	113,117	-
7	Sales Expense	23,664	23,664
8	Administrative & General Expenses	2,888,553	2,751,450
9	Total Expenses Requiring Cash Working Capital	$ 4,564,195	$ 4,322,504
10	CWC Formula Method (45-days or 1/8 of a year)	8	8
11	CWC Allowance (Line 9 divided by Line 10)	$ 570,524	$ 540,313