BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority To Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.	**))))))))**	**Docket No. 09-035-23** **DPU Exhibit No. 3.0**

P U B L I C

Direct Testimony of

Michael J. McGarry, Sr.

REVENUE REQUIREMENT AND NET POWER COSTS RELATED TO HEDGING

For the Division of Public Utilities

Department of Commerce

State of Utah

October 8, 2009

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Direct Testimony of Michael J. McGarry, Sr.

1. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael J. McGarry, Sr. My business address is 2131 Woodruff Road, Suite 2100, PMB 309 Greenville, SC 29607.

Q. By whom are you employed and what is your position?

A. I am employed by Blue Ridge Consulting Services, Inc. located in Greenville, South Carolina, as President and Chief Executive Officer.

Q. On whose behalf are you appearing in these proceedings?

A. I am testifying on behalf of the Utah Division of Public Utilities (Division).

Q. Please describe your educational background and professional experience related to utility regulation.

A. Prior to assuming my present position, I was Vice President of East Coast Operations from July 2003 to June 2004 with Hawks, Giffels & Pullin (HGP), Inc. In that position, I was responsible for developing and overseeing client engagements in utility regulatory affairs, management audit, and rate case management. From August 2001 to July 2003, I was an independent consultant working on a number of different projects, including a renewal/update of delivery service tariffs for Illinois Power and several utility street lighting cost benefit assessment projects. From June 2000 until August 2001, I was a senior consultant with Denali Consulting, Inc., a utility supply chain and e-procurement strategy and implementation firm. From October 1997 through June 2000, I was employed by Navigant Consulting, Inc. and several of its predecessors or acquired firms working on a number of different projects, including a management audit of Southern Connecticut Gas Company and the original delivery service tariff filing for Illinois Power. From July 1985 through October 1997, I was with the New York State Department of Public Service (NYSDPS) in its Utility Operational Audit Section where we conducted focused, operational audits in many facets of utility operations for all sectors of the utility industry including gas, electric, telecommunications, and water. Prior to my employment with the NYSDPS, I was a rate analyst with Orange and Rockland Utilities (1981 to 1983) and then Seminole Electric Cooperative (1983 to 1985). I received my Masters of Business Administration from the State University of New York at Buffalo in 1996 and a Bachelor of Arts in Economics from Potsdam College (SUNY) in 1981.

Q. Have you previously testified before the Public Service Commission (Commission) of Utah?

A. No.

Q. Have you testified before other commissions and were your credentials accepted in those proceedings?

A. Yes. I have testified in regulatory and civil proceedings and my qualifications as an expert in utility ratemaking matters have been accepted. A more complete description of my qualifications and a list of the proceedings in which I have been involved are included as an appendix at the end of my testimony.

2. PURPOSE

Q. What is the purpose of your testimony that you are now filing?

A. My testimony presents the Division's position regarding several rate base and revenue requirement issues in the proposed base rate increase application, testimony and exhibits submitted by Rocky Mountain Power Company (RMP or the Company) in Docket 09-035-23. I address the following adjustments:

- Rate Base – Deferred Transmission Project (DPU Exhibit 3.1 and 3.2)
- Rate Base And Expense – Replacement Asset In-Service And Retirements
- Rate Base – Change In 13-Month Average
- Rate Base – Coal Inventory (DPU Exhibit 3.3 CONFIDENTIAL)
- Expense – CWIP Write-Offs
- Expense – Supplemental Executive Retirement Plan (DPU Exhibit 3.4)
- Expense – Pension And 401(K) Administration (DPU Exhibit 3.5)
- Expense – Property Insurance (DPU Exhibit 3.6)
- Expense – Injuries And Damages (DPU Exhibit 3.7)

My testimony explains the basis for these positions and provides analysis and support for the proposed adjustments and recommendations. I also present the Division's position regarding net power cost as it relates to hedging activities (DPU Exhibit 3.8 CONFIDENTIAL).

Q. What have you reviewed in the preparation of your testimony?

A. I have reviewed the Company's testimony, supporting exhibits and workpapers, responses to data requests, and previous orders of the Commission.

Q. Was this testimony prepared by you or under your direct supervision?

A. Yes.

3. RATE BASE – DEFERRED TRANSMISSION PROJECT

Q. Do you agree with the Company's proposed rate base?

A. No. I have several concerns with the Company's proposed rate base.

Q. Please explain your concerns.

A. My first concern relates to the Company's reclassification of the costs associated with the Herriman 138kv-12.5kv Substation Deferred Transmission Project from a non-rate base account to a rate base account. Company Adjustment 8.13 reclassifies $1,091,392 of the Herriman costs from a non-rate base account, Preliminary Survey and Investigation (PS&I, FERC Account 183), to Plant Held For Future Use (PHFU, FERC Account 105), which is a rate base account. The Company's rationale for the transfer is that the Company has authorized the project and it will be executed in 2014. Therefore, the Company stated that the transfer is appropriate. Company witness McDougal testified that "Preliminary Survey & Investigation charges need to be reflected in results of operations. This adjustment re-allocates the balance as of December 31, 2008, of the Herriman projects costs from FERC Account 183, which is not included in base rates to

FERC account 105, Plant Held for Future Use, to allow for recovery of these costs."[1]

Q. What FERC guidance does the Company use to support the transfer?

A. In response to DPU Data Request 29.6, the Company cited the instructions for FERC Account 183 from the Code of Federal Regulation (CFR 18 Parts 101-142) which states in part, "If construction results, this account shall be credited and the appropriate utility plant account charged."[2] As shown above, witness McDougal indicated construction will result in the future and, based on their interpretation of of CFR 18 Parts 101-142, transferred the project costs to FERC Account 105.

Q. Why was FERC Account 105 used rather than another account that will allow recovery?

A. I believe the Company chose Account 105 because it represents Plant Held for Future Use and is an account that would allow the Company to earn a return on rate base for these costs.

Q. Do you agree that FERC Account 105 is the appropriate account for the charges?

A. No. I do not agree that the charges should have been transferred to FERC Account 105. The charges do not meet the CFR 18 Part 101-142 criteria for inclusion in FERC Account 105.

[1] Company Witness McDougal, page 33, lines 749-753.
[2] Response to DPU Data Request 29.6.

Q. Please explain why.

A. 18 CFR Part 1.101 states, in part, that this account shall include the original cost of Electric Plant owned and held for future use in electric service under a definite plan to include land, land rights, and property acquired. Section E states "The property included in this account shall be classified according to the detail accounts (301 to 399) prescribed for Electric Plant in Service."[3]

The Company provided the cost detail for the $1,091,392 of PS&I charges proposed to be transferred.[4] Those costs in and of themselves do not constitute Electric Plant because they do not contain units of property that can properly be transferred to FERC Account 101 (Electric Plant in Service), categorized in primary plant accounts 301 to 399, and considered used and useful.

The transfer does not meet the criteria for inclusion in FERC Account 105. In order for the project to be considered PHFU, it would require completed construction that also contains one or more units of property that can be transferred in the future to FERC Account 101. Completed construction comes from FERC 107 and is normally transferred directly to FERC Account 101.

Q. What do you recommend?

A. I recommend that the Company transfer the charges back to FERC Account 183 or Construction Work in Progress (CWIP, FERC Account 107) in a non-interest bearing work order and that the charges remain in that account until construction

[3] 18 CFR Part 1.101-142, page 349, FERC 105, Electric Plant Held For Future Use, part E.
[4] Response to DPU Data Request 29.18.

commences. This adjustment will reduce the Utah jurisdiction rate base by $925,284 (DPU Exhibit 3.1).

Q. Do you have any other recommendations concerning this project?

A. Yes. Since the project has been deferred until 2014, some of the preliminary work may be outdated at the time of start up and may require updating or not be applicable at all. Therefore, to the extent that costs are no longer appropriate, I recommend that they be written off to expense at the time the project starts.

In addition, included in the project cost detail is $166,108 of AFUDC. The inclusion of AFUDC, while not specifically precluded by the CFR, is very unusual since AFUDC is generally applied to CWIP. Even though the Company has expended funds to determine whether a project is feasible, it is not in construction and, therefore, should not accrue AFUDC or any other carrying charge. I recommend that the Company reverse the AFUDC of $166,108 (Utah jurisdiction) included in the PS&I and charge it to debt and equity as appropriate (DPU Exhibit 3.2).

4. RATE BASE AND EXPENSE – REPLACEMENT ASSET IN-SERVICE AND RETIREMENTS

Q. Please discuss your next concern.

A. My next potential concern relates to the timing of when plant retirements for replaced assets (retirement units) take place. The Company indicated that "completed projects are generally retired within 90 days of the Technically Complete (TECO) date" and for RCMS (Transmission and Distribution line projects) "the retirement is defined at the time the workorder is set up in RCMS which drives the proper booking of retirements, salvage and removal. The retirement occurs automatically within 90 days of the construction due date."

Q. Why is the timing of when a retirement is booked a concern?

A. Although, the accounting for a retirement does not impact rate base, the timing of when the retirement is recorded is a concern for several reasons. Replaced assets that are not retired and removed from the accounting system at the same time as the new assets are placed in service result in an overstated Electric Utility Plant (FERC 101). As a result, rate base is overstated and depreciation expense and the associated Accumulated Provision for Depreciation, which is an offset to Utility Plant in Service, are overstated because depreciation continues to accrue on the replaced assets.

Q. Does the depreciation reserve reduce rate base?

A. Yes. The offset to depreciation expense is booked to the accumulated provision for depreciation. Therefore, any over-accrual of depreciation expense reduces net plant in service and rate base. The over-accrual of depreciation expense also overstates expense. In addition, since duplicate assets remain in service, net plant, and therefore rate base, is overstated to a greater degree then the offset that depreciation reduces net plant in service.

Q. Have you been able to quantify the potential impact of this issue?

A. No. I have been unable to quantify the impact. Follow-up data requests were submitted to the Company and the response was not received prior to the filing of this testimony. Therefore, I reserve the right to address this issue and possibly recommend adjustments in my rebuttal testimony.

5. RATE BASE – CHANGE IN 13-MONTH AVERAGE

Q. Please explain the next issue you have with the Company proposed rate base?

A. I have a potential issue with the spread of costs included in the 13 month rate base average associated with Steam and Wind Generation construction. The Company has budgeted steam generation outage expenditures in such a manner that these capital expenditures are front-loaded in the test year rather than spread ratably over the 13 month test period.

Q. Please explain your potential issue with the 13-month rate base average for Steam and Wind Generation construction?

A. The Company provided the detail cost estimates for Steam and Wind construction from January 2009 through June 2010 and the 13 month test period average from June 2009 through June 2010.[5] The test period average is based on a formula that takes into consideration when the costs are budgeted during the test period with more weight applied during the early months of the test period and less during the later months. Approximately 44% of the total 13 month average is budgeted in June 2009-November 2009 (months 1 through 6), 39% is budgeted in December 2009 (month 7), and only 17% is budgeted in January 2010 through June 2010

[5] Response to DPU Data Request 25.5.

(months 8-13). Therefore, it appears that an inordinate amount is budgeted in the early months. Since the outage schedule does not necessarily follow the allocation of costs, the costs should be either budgeted in the months the outages would normally take place or ratably in a levelized manner in order not to front load or distort the 13 month average rate base.

Q. Does the allocation of the budget coincide with the outage schedule?

A. No. The outage schedule provided by the Company indicates that for the years 2005 through 2010, outages are scheduled in spring, early summer, and fall, but avoid the winter months and the later summer months.[6]

Q. Wouldn't that be typical for a company to strategically schedule unit outages?

A. Yes. The schedule is very typical of what would be expected, but the outage schedule does not coincide with the budgeted expenditures.

Q. Did the Company explain this since the object of the budget is to "normalize" the costs and it will not necessarily follow the outage schedule?

A. Yes. Company witness Duvall states "the length of the planned outages is based on 48 month historical average and the planned outages are scheduled in a way that all plants are on planned outages during the test year, even though this is not actual practice."[7] The Company has already explained the normalization process and that was approved by the commission in Docket No. 07-035-93.[8]

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[6] Response to DPU Data Request 6.15.
[7] Direct Testimony of Company witness Duvall, page 9-10, lines 202-204.
[8] Direct Testimony of Company witness McDougal, page 18, lines 408-411.

Q. Why is this of potential concern?

A. In spite of the Company's explanation, the potential issue still remains that the budgeted outage expenditures are front-loaded rather than spread ratably over the 13 month test period. To complete our analysis, we have submitted a data request to the Company asking why approximately 39% of the total steam plant expenditures are allocated in December 2009.[9] That response was not received prior to the filing of this testimony. Therefore, I reserve the right to discuss this further and recommend adjustments in rebuttal testimony.

6. RATE BASE – COAL INVENTORY

Q. Have you reviewed the coal inventory included in the Company's proposed rate base?

A. Yes.

Q. Do you have any adjustment to that proposed amount?

A. Yes. I recommend that the Company's Fuel Stock (Acct 151SE) in the amount of $160,345,600 (total Company) be reduced by **[begin confidential]** [redacted] to [redacted] **[end confidential]** (DPU Exhibit 3.3.2). On a Utah-allocated basis that adjustment equates to a reduction of fuel stock of [**begin confidential]** [redacted] **[End Confidential** (See DPU Exhibit 3.3.1).

Q. Please provide an overview of the Company's fuel stock adjustment included in rate base.

[9] Pending receipt of DPU Data Request 48.4.

A. The Company explained its fuel stock adjustment as follows:

> The cost of the Company's coal plant fuel stock is increasing due to increases in the cost of coal and the number of tons stored at each site. This adjustment reflects the increase in the fuel stock balance into results.[10]

The Company's adjustment increases the Company's fuel stock as shown in account 151SE by $34,836,966 for the test year ending June 30, 2010. The total fuel stock that the Company is proposing to include in rate base in Account 151SE is $160,345,600.

Q. Please explain the basis for the Division's adjustment?

A. First, I developed an estimate of the number of days of inventory that are currently at each of the Company's coal plants. The results of that analysis are shown in the following table:

Table 1-PacifiCorp Coal Plants - Analysis of Days Burn Inventory

Line #	Plant	Test Year 13 month average Inventory Balance (tons)	2008 Fuel Burned (tons)	2008 Average Tons Burned per day	Days Burn Inventory
	(A)	(B)	(C)	(D)=(C) ÷ 365	(F)=(B) ÷ (D)
1	Bridger	638,486	5,709,196	15,641.63	41
2	Carbon	44,061	640,585	1,755.03	25
3	Cholla	323,876	1,591,193	4,359.43	74
4	Colstrip	49,664	708,786	1,941.88	26
5	Craig	143,804	667,842	1,829.70	79
6	Hayden	47,796	314,700	862.19	55
7	Hunter	2,033,538	3,779,332	10,354.33	196
8	Huntington	811,214	3,221,777	8,826.79	92
9	Johnston	441,434	3,942,421	10,801.15	41
10	Naughton	419,424	2,772,108	7,594.82	55
11	Wyodak				
12	**Total Plants**	4,953,297	23,347,940	63,966.96	77
13	**Mines/Prep Plant**				
14	Deer Creek	11,566	NA	NA	NA
15	Prep Plant	973,068	NA	NA	NA
16	Rock Garden	95,787	NA	NA	NA
17	**Total Inventory**	6,033,717	23,347,940	63,966.96	94

Notes: Col (B) - Response to DPU 26.1 (13 mth average calculated based on monthly balances (June 2009 through June 2010)
Col (C) - FERC Form 1

[10] Direct Testimony of Steven R. McDougal, page 30, at lines 675 – 677.

Overall, the Company's days of burn coal inventory from all sources is 94 days which means that if the Company were to stop purchases from all sources it would have sufficient supply on hand to continue to generate electricity for approximately 94 days.

To better understand the Rocky Mountain Power Company's fuel stock inventory strategy, the Division requested that the Company provide its coal inventory strategy. The Company provided a confidential document which is titled: "PacifiCorp Energy Coal Inventory Policy – Preliminary Draft.[11] This undated document purports to be the Company's official coal inventory policy. The Company's policy is to limit coal inventory to no more than [**begin confidential]** [redacted] **[end confidential]** and in most cases much shorter.

As shown in the table above, the inventory level overall is greater than the company's stated policies. However, this is being driven by the stock pile levels at the Hunter (196 days) and, to a lesser degree, the Huntington plant (92 days). In addition, the Company states in its policy that coal inventory at the Cottonwood "Prep Plant" is used to feed the Utah generating stations, Carbon, Hunter, and Huntington. The combined inventory for these four inventory sites is 3,861,881 tons or approximately 185 days of supply (based on the 2008 burn rate at these stations).

This level of inventory is more than [**begin confidential]** [redacted] [**end confidential]** what the Company has stated is its inventory strategy for these Utah

[11] Response to DPU Data Request 26.4.

plants and significantly higher than any other station, including the largest station, Bridger. which has only a 41 day supply of coal on hand.

The basis for the Division's adjustment is that these plants' coal inventory stock pile is more than **[begin confidential** [redacted] **[end confidential]** what the Company has indicated is its maximum level for these plants.

Q. Do you know why these stations' coal inventory is so much out of line with the other stations?

A. The Company explained that it was purchasing an additional 500,000 tons from Arch Coal Company to settle a long standing dispute related to Electric Lake in 2008.[12] A review of the changes in the year end levels at Hunter, as shown in the following table, does show the effect of that increase through the end of the test year.

Table 2-Hunter Station Coal Inventory

	2007	**2008**	**June 2009**	**June 2010**
Hunter Inventory Year end (or YTD)	646,905	1,449,523	1,595,900	2,409,078
Change to prior period	NA	802,618	146,377	813,178

With respect to the Huntington Station, the Company claims that it is increasing the level of inventory to compensate for a significant reduction in production from the Deer Creek Mine (the captive mine to Huntington). However, the following table shows that the Company is forecasting a reduction

[12] Response to DPU Data Request 6.11.

in the level of inventory at Huntington, but that the forecast level is still significantly higher than it was at the end of 2007.

Table 3-Huntington Station Coal Inventory

	2007	2008	June 2009	June 2010
Hunter Inventory Year end (or YTD)	647,732	914,355	914,019	862,661
Change to prior period	NA	266,623	-336	-51,358

Q. Is there any indication that a major supply disruption may occur at either of these plants during the test year that would warrant the increase in coal inventory?

A. Nothing in the Company's explanation of the increases[13] indicates any forecasted disruption in its supply for either the Hunter or Huntington Stations.

Q. What is your position concerning ratepayers financing this level of inventory through the Company's rate of return on rate base?

A. Without getting into the merits of the Arch Electric Lake settlement, I believe that it is inappropriate for the Company to expect ratepayers to pay for an investment in a coal inventory stock pile that it does not need. It also seems to me that the Company's policy may also be excessive in that a **[begin confidential]** [redacted] **[end confidential]** is substantially higher than all of the other plants in the PacifiCorp system.

[13] Response to DPU Data Request 6.11.

Q. What do you recommend?

A. I recommend that the Company include in rate base an amount of coal inventory that reflects a more reasonable level of inventory at these stations. I am including the inventory for the Carbon plant as the Company includes it in its strategy for the Utah plants. Therefore, my adjustment is to reduce the allocated portion of the Company's Fuel Stock amount included in Account 151SE by **[begin confidential]** [redacted] **[end confidential]** (Utah allocated). Exhibits 3.3.1 through 3.3.3 show the derivation of this adjustment.

Q. Please explain how you derived your adjustment.

A. As shown in DPU Exhibit 3.3.3, I calculated the Days Burn Inventory for Carbon, Hunter, and Huntington based on each station's individual 2008 burn rates as reported in the FERC Form 1. The results of that analysis showed that these three stations have approximately 185 days of inventory on hand. I then developed the percentage reduction needed to represent a more reasonable level of inventory at these stations based on the Company's stated strategy.[14] To be conservative, I chose the mid-point of that stated strategy which is **[begin confidential]** [redacted] **[end confidential].** Accordingly, in order to bring the Company's inventory in line, they would have to reduce the inventory stock pile by approximately **[begin confidential]** [redacted] **[end confidential].**

[14] Response to DPU Data Request 26.4.

I then applied this percentage to the Company's proposed 13 month inventory balance value for these three stations[15] to arrive at the adjustment amount of **[begin confidential]** [redacted] **[end confidential].**

7. EXPENSE – CWIP WRITE-OFFS

Q. Please explain your concern regarding CWIP write-offs?

A. I have a potential concern of how the Company writes-off Construction Work in Progress (CWIP). The Company explained that the primary reasons for the write-offs are legal, technical, or process risks that are considered significant; work on the project has been stopped and timely resumption is improbable; and funding, budget, or management approval has been withdrawn. The write-offs totaled approximately $2.43 million from January 2008 through May 2009. The Company also cited FERC expense accounts 500-935 as the accounts where the write-offs are expensed. CWIP is reviewed monthly.[16]

Q. Is the process of writing off cancelled projects from CWIP reasonable?

A. Yes. The process is excellent for the timely review of the CWIP. However, not all the reasons the Company cited for cancelling a project support expensing the costs to FERC Accounts 500-935.

Q. What FERC accounts should the cancelled projects be written off to and which reasons support expensing instead of some other accounting?

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[15] Response to in DPU Data Request 26.1.
[16] Responses to MDR Data Requests 2.2 and DPU Data Request 29.11.

A. The CFR instructions for FERC 107 (CWIP) do not indicate to which accounts cancelled or abandoned projects should be written off. However, the instructions for FERC 183 (PS&I), the account from which projects are either transferred to CWIP when authorized, cancelled or abandoned, does have specific instructions. I would use those instructions for guidance as to what should happen to CWIP write-offs since FERC 183 and 107 are closely related.

Projects in which some or all of the reason for cancellation is outside the direct control of the Company should be charged to the customer through expense.[17] Projects cancelled because "funding, budget, or management approval for a project has been withdrawn" are entirely within the direct control of the Company and are more closely related to abandoned projects. Therefore, the stockholder rather than the customer should be charged for a management decision to abandon a project. Those costs should be written off to FERC Account 426.5 (Other Deductions), which is below the line and the same account to which PS&I abandoned projects are written off and charged to the stockholder.

Q. Do the instructions for FERC Account 183 allow the Company to write off projects to either expense or other deductions?

A. Yes. However, it is inappropriate for the customers to bear the burden of the write-offs when the Company had 100% control over the decision to abandon some of the projects. That is why we interpret the CFR to allow either expense or other deductions for project write-offs, depending on the reason for the write off.

[17] 18 CFR Part 1, parts 101-142, page 365, Account 183, paragraph 1, lines 6-8 and lines 9-12.

Q. What adjustment do you propose?

A. For those projects the Company abandoned at its discretion and for no other reason, I would propose that the associated expense write-offs be reclassified to account 426.5 – Other Deductions, which is not included in customer rates. We have issued an additional data request to the Company to quantify the amount of abandoned projects related to this issue.[18] However, a response to the data request was not received prior to filing of this testimony and, therefore, I reserve the right to recommend an adjustment, if appropriate, in my rebuttal testimony.

8. EXPENSE – SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN

Q. Please describe the Supplemental Executive Retirement Plan.

A. According to PacifiCorp's year ended December 31, 2008, Form 10-K, PacifiCorp provides a Supplemental Executive Retirement Plan (SERP) as additional retirement benefits to its executives.[19]

Supplemental retirement plans are provided for highly compensated individuals because benefits under the general pension plans are subject to certain limitations under the Internal Revenue Code. In general, the limitations imposed by the IRS allow for the computation of benefits on annual compensation levels up to $230,000 in 2008 and will increase to $245,000 in 2009.

PacifiCorp's SERP provides monthly retirement benefits of 50% of the final average pay plus 1% of final average pay for each fiscal year that PacifiCorp

[18] Pending receipt of DPU Data Request 48.1.
[19] PacifiCorp Form 10-K, 12/31/08, p. 120.

met certain performance goals set for such fiscal year. The maximum benefit is 65% of final average pay. A participant's final average pay equals the 60 consecutive months of highest pay out of the last 120 months, and pay for this purpose includes salary and annual incentive plan payments.[20]

In 2008, the Company President was the only active executive that participated, and the plan is currently closed to any new participants. The present value of the Company President's SERP accumulated benefits is $1,627,744 as of December 31, 2008. This is in addition to other defined benefit pension plans in which he participates.[21]

Other retirees, beneficiaries, and others with deferred benefits are benefiting from the plan based upon past employment.[22]

Q. How much was included in the pro forma operating expense for SERP?

A. The Company included Supplemental Executive Retirement Plan costs of $2,400,000 on a total company basis.[23]

Q. What do you recommend with regard to executive retirement benefit costs?

A. Executive benefit costs should be shared. The costs of the executive benefits included in the Company's regular pension and 401(k) plans should be included in rates, while the cost of the additional executive benefits paid to the Company

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[20] PacifiCorp Form 10-K, 12/31/08, p. 120.
[21] PacifiCorp Form 10-k, 12/31/08, p. 123.
[22] Response to OCS Data Request 12.8, Confidential Attachment OCS 12.8b. NOTE: specific confidential information was excluded from this testimony.
[23] See Exhibit RMP___(SRM-2), p. 4.2.2.

President and included in the supplemental retirement plan should be excluded from rates and paid for by the shareholders.

These supplemental costs are not necessary for the provision of utility service, but are discretionary costs of the shareholders to attract, retain, and reward its highly compensated employees. Officers of a corporation should be loyal to the corporation and are motivated by the interests of the company and its shareholders first. The award of the SERP each year is tied directly to the Company meeting certain performance goals.[24] The interests of the shareholders and the interests of the ratepayers are not always aligned. I recommend that the SERP costs be removed from rates. The total Company basis is $2,400,000 and $693,744 for the Utah jurisdiction (DPU Exhibit 3.4).

9. EXPENSE – PENSION AND 401(K) ADMINISTRATION

Q. What did the Company include in its pro forma expenses for its retirement plans' administration?

A. The Company included costs for two accounts for its retirement plans' administration pro forma expenses: Account 501102 Pension Administration and Account 501251 401(k) Administration. The table below shows the actual year ended December 2008 and the pro forma 12 months ended June 2010.[25] The Company is requesting ~$1.22 million in pension and 401(k) administration, which is an increase of ~$0.96 million over the Base Year.

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[24] PacifiCorp Form 10-K, 12/31/08, p. 120.
[25] Exhibit RMP____(SRM-2), p. 4.2.2.

Table 4-Pension and 401(k) Administration Expenses

Account	Description	Actual Year End 12/08	Pro Forma 12 Months Ended 6/10	Company's Regulatory Adjustment
501102	Pension Administration	$338,567	$882,597	$544,030
501251	401(k) Administration	$(77,332)	$335,818	$413,150
	Total	$261,235	$1,218,415	$957,180

Q. Did the Company provide an explanation for the significant increase in Pension Administrative expense over the Base Year?

A. Yes. The Company stated that the 2010 budget that was used to derive the 2010 pro forma costs for pension administration assumed there would be a greater need for actuarial work due to the various union negotiations.[26]

Q. What union contracts are being negotiated?

A. The Company stated that modifications to retirement plans were implemented at the beginning of 2008 for IBEW Local 659. All future retirement benefits will be derived from the 401(k) plan. The same approach went into effect on October 1, 2008, for members of IBEW Local 125.[27] During 2009, the Company will be involved in collective bargaining negotiations with three of its unions.[28]

Q. If two unions have already accepted changes to their retirement plans and three unions are involved in negotiations in 2009, is the significant increase in pension administration in 2010 for the reason stated by the Company reasonable?

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[26] Response to DPU Data Request 36.5.
[27] Direct Testimony of Erich Wilson, p. 4, lines 75-79.
[28] Direct Testimony of Erich Wilson, p. 4, lines 88-89.

A. No. The Company stated that its budget was based upon the premise that union negotiations would require additional actuarial work. However, there is no reason to believe that these costs will actually be incurred in 2010.

Q. What do you recommend?

A. The Company's pro forma pension administrative costs should be adjusted to be more reflective of what will actually be incurred in 2010. I recommend that pension administrative costs reflect a slight increase over the 2008 expenditures. During 2008, the Company negotiated retirement changes with two unions. These additional actuarial costs would be included in the Company's 2008 expenses. The other three unions' retirement benefits will be negotiated in 2009. Therefore, the Company's budgeted increase for additional actuarial work due to the various union negotiations will not be realized. If a more realistic pension administrative expense is used for 2010, the result is a reduction of $523,202 on a total company basis and $153,838 in the Utah jurisdiction (DPU Exhibit 3.5).

Q. Did the Company explain the significant increase from the Base Year to its pro forma expense for its 401(k) administrative expense?

A. Yes. The Company stated that the 2008 credit balance for 401(k) administration included a $470,000 refund of fees originally paid in 2007. Removing this credit results in a 2008 expense of $392,768, compared to the $335,818 planned for 2010.[29]

[29] Response to DPU Data Request 36.6.

Q. Has the Company implemented any changes in how administrative expenses are paid?

A. Yes. The Company stated that effective October 2007 it had adjusted its approach to 401(k) administrative fees by having the participants pay a portion of the investment expense to be consistent with the trend in the competitive market data.[30]

A. What is your recommendation?

Q. The Base Year should be adjusted to include the fees refunded, which along with the changes implemented by the Company to have participants share in the cost would actually result in a lower pro forma 2010 401(k) administrative fee than was incurred in the Base Year. The resulting adjustment would reduce 401(k) administration costs by $470,000 on a total company basis and $135,858 in the Utah jurisdiction (DPU Exhibit 3.5).

10. EXPENSE – PROPERTY INSURANCE

Q. How did the Company determine its property insurance expenses?

A. Property insurance was normalized based upon incurred and estimated expenses.[31] The normalized amount was compared to the escalated Base Year and the difference was included as an adjustment.[32]

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[30] Response to DPU Data Request 36.6.
[31] Response to OCS Data Request 5.4, Attachment OCS 5.4, Property Premium-548000.
[32] Exhibit RMP ___(SRM-2), p. 4.17.2.

Q. Was the Base Year adjusted to account for non-recurring items?

A. No. The Base Year included both the 2007 and 2008 low/no claim bonus.[33] The 2007 low/no claim bonus reduced the amount of property insurance and should not have been included in the 2008 Base Year.

Q. How did the Company estimate its normalized property insurance?

A. The Company estimated its normalized property insurance by totaling the various premiums and fees either paid or estimated. It also included a no/low claim bonus of $850,000 that was later removed in a data response with the explanation that the Company's insurance providers would likely not provide the low-claim bonuses in the next couple of years.[34]

Q. Should the Company have removed the no/low claim bonus when it generated its revised estimate for its normalized property insurance?

A. No. The Company had already received the low claim bonus of $858,931.[35] Therefore, the reduction for the Low Claim Bonus should be included in the normalized level. By excluding the low claim bonus in its revised estimate the Company was overstating its normalized property insurance. Actually, the $850,000 that the Company originally used, then removed, should be increased to $858,931.

[33] Response to DPU Data Request 9.2, Attachment DPU 9.2, low/no claims bonus 06/07= $869,677 and 07/08= $869,963.
[34] Response to OCS Data Request 5.4.
[35] Response to MDR Data Request 2.34. Refer to 12 Month YTD May 08 – Apr 09 Actual.

Q. How do you address the Company's statement that low/no claims bonuses received in the past will not likely occur in the next couple of years?

A. Although the Company was notified by its insurance carriers EIM and AEGIS that bonus distributions would not be paid in the current year, both companies indicated that this would be short term to address the losses and reductions in liquidity of the insurance industry in recent months. The insurance companies were exercising due diligence over any surplus capital by suspending the credit distributions for the near term. However, EIM stated that it regarded distributions as an extremely important element of coverage and it intended to reinstate distributions as soon as it is practical.[36] AEGIS also stated that it would review the level of continuity credits next year.[37] The elimination of no/low claim bonuses is short-term and should not be arbitrarily removed, thereby resulting in ratepayers paying overstated property insurance.

Q. What do you recommend?

A. I recommend that the Company reduce its Base Year by $869,677 to remove the 2007 no/low claim bonus booked in 2008. The original reduction in the normalized amount for low claim bonus of $850,000 should be increased to $858,931, the actual amount received. Should the Company present a revised normalized level for property insurance eliminating the July 2009 Update for Low Claims Bonus 10-1-08 to 10-1-09 of $850,000, it should be disallowed. The

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[36] Response to OCS Data Request 11.7, Attachment OCS 11.7a, memo from EIM dated December 2, 2008.
[37] Response to OCS Data Request 11.7, Attachment OCS 11.7a, web page from AEGIS dated May 6, 2009.

result of my recommendations reduces property expense by $904,932 on a total company basis and $373,873 in the Utah jurisdiction (DPU Exhibit 3.6).

11. EXPENSE – INJURIES AND DAMAGES

Q. Did the Company make an adjustment to injuries and damages?

A. Yes. The Company made an adjustment to normalize injuries and damage expenses to reflect a three-year average using the cash method.[38]

Q. What did the Commission order in Docket No. 07-035-93 regarding injuries and damages?

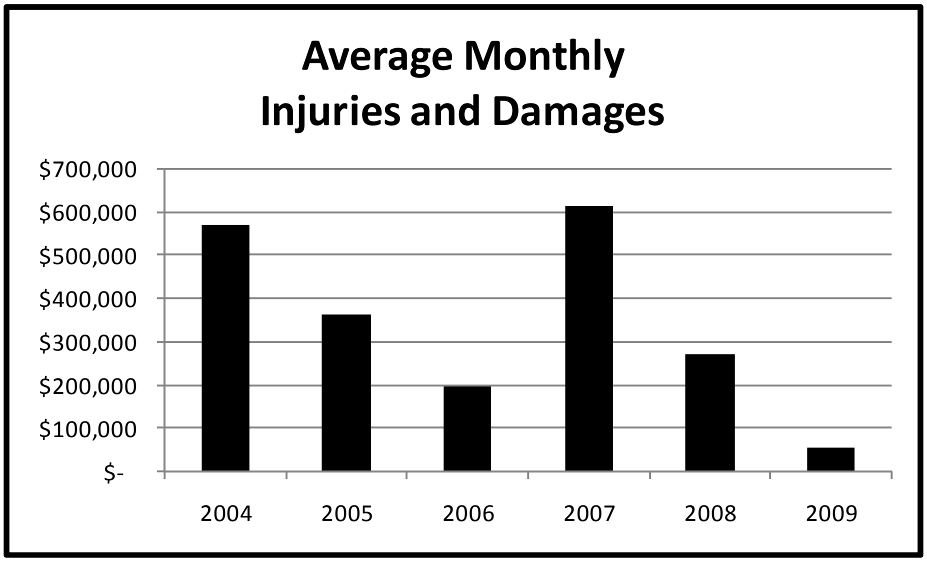
A. In Docket No. 07-035-93, the Commission ordered the Company to use an average of historical expenses rather than using an accrual method for injuries and damages. The Commission adopted a three-year average while stating that a five-year average would be acceptable for this type of account.

Q. Should a five-year average for injuries and damages be used to normalize injuries and damage expense?

A. Yes. The net cash amount for injuries and damages experiences wide variations from one year to then next. The following graphic illustrates average monthly injuries and damages by year.[39]

[38] Exhibit RMP____(SRM-2), p. 4.17.1.
[39] Response to DPU Data Request 22.4.

Figure 1-Average Monthly Historical Injuries and Damages



Q. What do you recommend regarding injuries and damages?

A. Due to the wide variation in the net amount for injuries and damages, I recommend that the Commission adopt a five-year (60 month) average using the most current information available instead of the three-year average used by the Company. Using a 60 month average will smooth out the wide variations and at the same time reflect recent expenditure levels.

Q. Do you recommend any other changes to the Company's calculation of pro forma injuries and damages?

A. Yes. When the Company calculated its Base Year expense it subtracted insurance receivables to convert the Company's accrual injuries and damages to a cash basis. In addition, the Company should also add the cash received during the same period to calculate the net Base Year expense on a cash basis.

Q. How did you account for the charge against injuries and damages for the avian matter that the Company pleaded guilty to and settled?

A. On December 12, 2008, the Company accrued a liability of $500,000 related to 34 violations of the Migratory Bird Treaty Act filed by the US Fish and Wildlife Service. The $500,000 was accrued as a liability in 2008, of which $200,000 was allocated to Utah. This amount was recorded above the line prior to settlement recognizing that the case would result in some liability for restitution.[40]

In July 2009, the Company pleaded guilty and agreed to pay $10.5 million in restitution as follows:

- $900,000 in restitution (apportioned $650,000 above the line and $250,000 below the line)
- $1,700 in special assessments (below the line)
- $510,000 in fines (below the line)
- $9.1 million for compliance with its avian protection plan (capital)

Fines and penalties should not be in rates. In addition, the $500,000 recorded in 2008 is a non-recurring expense and should be disallowed.

However, the Division's adjustment for injuries and damages is based upon an average of historical expenses (cash basis) instead of an accrual method. Since the Company only accrued (recorded on its books, without actual cash outlay) the $500,000 booked as a potential liability, the $500,000 does not impact

[40] Responses to MDR Data Request 2.36 and DPU Data Request 33.7.

the Division's recommended adjustment for injuries and liabilities, which was calculated based on actual cash outlay.

Should the Commission not adopt the Division's recommended adjustment for injuries and damages, all the avian fines and penalties should be disallowed.

Q. What is the impact of your recommended changes?

A. My recommended change to normalize injuries and damages by using a five-year average and to complete the conversion of the Company's accrual of Base Year injuries and damages to a cash basis would result in a reduction of injuries and damages of $3,521,812 on a total company basis and $1,455,036 in the Utah jurisdiction (DPU Exhibit 3.7).

12. NET POWER COST AS IT RELATES TO HEDGING ACTIVITIES

Q. Division Witness Brill indicated that you are proffering testimony on PacifiCorp's Hedging activities. Is that correct?

A. Yes. The Division retained Blue Ridge via a competitive bid process to assist the Division's Staff with the evaluation of Rocky Mountain Power Company's net power costs in the Company's current base rate increase request[41] before the Commission. Blue Ridge's scope included evaluating the reasonableness of RMP's Net Power Costs. Division Witness George Evans of Slater Consulting is testifying to various adjustments to the Company's proposed net power costs.

[41] Docket No. 09-035-23.

Q. What was the scope of the engagement?

A. Blue Ridge's analysis of the Company's hedging and risk management program focused on an evaluation of the following areas:

- Identification of risk tolerance
- Establishment of risk management goals and guidelines
- Definition of risk metrics
- Establishment of procedures and authority for execution of hedges
- Procedures for managing credit risk
- Establishment of measurement and reporting procedures including accounting and compliance

Division Staff also requested that Blue Ridge provide an assessment of how the Company's hedging policies compare to those employed in other states or jurisdictions in the U.S.

Blue Ridge performed a high level review of the Company's commercial trading and risk management hedging procedures and practices and developed a report with findings, conclusions, and recommendations for the Division to consider and suggesting measures that the Company should implement to enhance its commercial trading and risk management functions. Blue Ridge's report to the Division is included as DPU Exhibit 3.8 CONFIDENTIAL.

Q. Please describe your overall findings and recommendation to the Division.

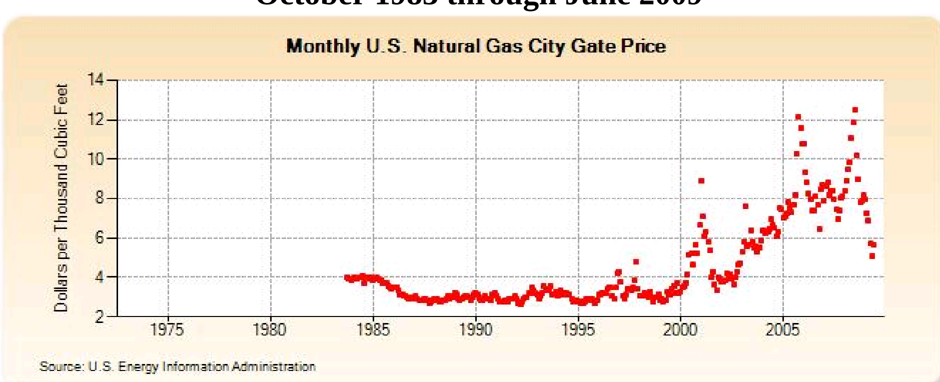
A. Overall, Blue Ridge found that the Company's commercial trading and risk management program procedures (and the related hedging programs) are well-documented and controlled and adhere to generally accepted standards found elsewhere in the industry. The Company has well-stated goals and strategy that are aimed at mitigating price volatility. In addition, our review of the Company's internal documents showed that the Company is self-monitoring compliance with accepted commercial trading and risk management procedures and through its own internal audit function.

In addition, I have recommended, based on my review of other jurisdictions' approaches to hedging and industry-related research and analysis, that the Division should recommend to the Commission that it adopt a "pre-approval" policy of the Company's hedging strategy and implementation plans. The primary benefit of this pre-approval process is that it will (a) provide the Commission with a complete picture and allow all parties the opportunity to review and comment on the Company's strategy and determine whether it is in the best interest of the Company and its customers and (b) help to mitigate the second guessing that is inherent in any hedging program. I believe that this approach will help the Company to act prudently, efficiently, and in the best interest of its customers. The Division's recommendations are contained in the Direct Testimony of Douglas Wheelwright.

Q. What was your overall assessment and findings associated with how other jurisdictions approach hedging?

A. Blue Ridge found that hedging associated with mitigating the price volatility of natural gas for sale to ultimate customers or for use in production of electricity is widespread throughout the utility industry in the U.S. The issue of hedging and risk management has been an issue that regulators have been addressing since the 1990s when physical and financial commodities trading for natural gas were first introduced.[42] Interest by regulatory commissions in the subject has increased significantly since 2000 when natural gas prices experienced significant price volatility and upward movement. Figure 2 below shows a chart of the monthly history of Natural Gas City Gate Prices (as published by the Energy Information Administration). This chart clearly shows that beginning in 2000, monthly prices start a significant upward trend and are highly volatile.

Figure 2-Monthly U.S. Natural Gas City Gate Price
October 1983 through June 2009

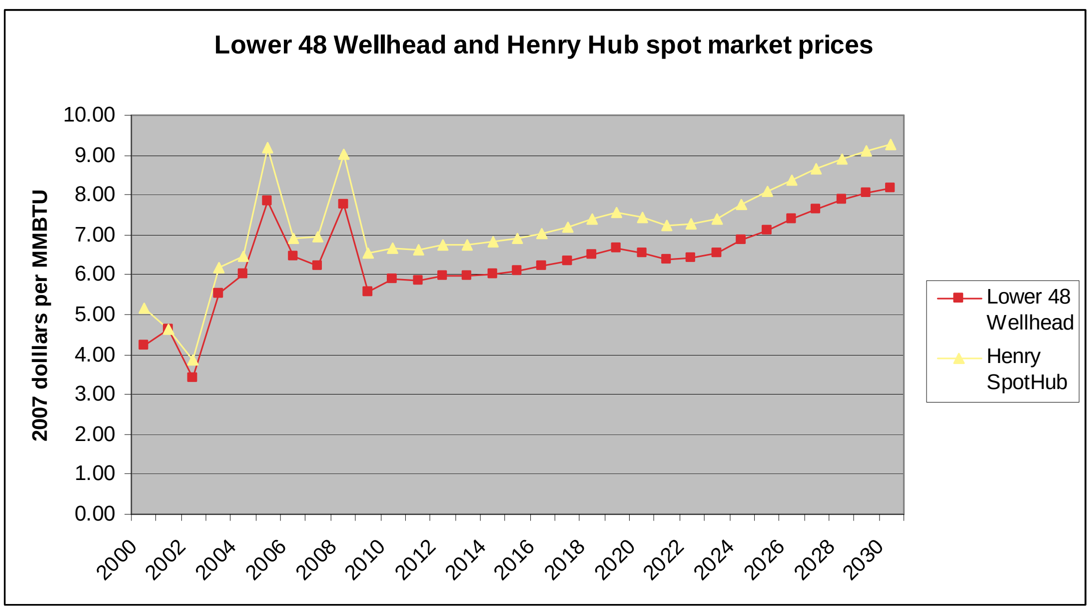


[42] Ken Costello, Regulatory Questions on Hedging: The Case for Natural Gas, *The Electricity Journal*, May 2002, page 44.

However, the way that individual state commissions address the issue of hedging and risk management varies significantly from a complete hands-off approach all the way to review and pre-approval of individual utility hedging and risk management plans. One consistent theme that Blue Ridge found was that all of the jurisdictions reviewed have some level of interest and oversight of its utilities' hedging and price volatility mitigation plans.

As the Commission considers its policy determination related to PacifiCorp's hedging strategies, it is important to keep in mind that despite recent price drops, most forecasts do show natural gas prices increasing and that there will be continued volatility in those prices. Figure 3 shows the well-head price forecast for natural gas for 2000 to 2030.

Figure 3-Natural Gas Prices 2000-2030



Source: Energy Information Administration Figure 64. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030

After reviewing orders and dockets for 27 regulatory commissions, we determined that all but one allows hedging in one form or another.[43] Through our review, Blue Ridge found that there appears to be a consensus among most in the utility industry (from either the utility or regulatory perspective) that commission involvement in the issue of hedging is vital to the success of these types of price risk mitigation programs. This may include pre-approving utility submitted plans to offering guidelines or conducting post-plan implementation reviews. In one form or another, most industry analysts and regulators agree that a hands-off approach from regulators is not sound policy.[44]

Q. How does Pacificorp's hedging strategy look in comparison with other utilities you examine or of which you are aware?

A. As described in my report, PacifiCorp's hedging term of **BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** appears to be longer than most utilities that we have been able to review. The effect of this is to lock in prices for a portion of the Company's needs considerably into the future. While in an increasing and volatile market, this would protect the Company and its customers and provide price "insurance," it also prevents the Company from adjusting that portion that is locked in when markets are declining as we have seen in the recent past. Douglas

[43] Our research encountered one state where we could not determine if hedging in some for or another was permitted. We could not reach a conclusion because of limitations of that state's online documentation system.

[44] Ken Costello, Regulatory Questions on Hedging: The Case for Natural Gas, *The Electricity Journal*, May 2002, page 51.

Wheelwright's Direct Testimony discusses the Company's hedging strategies and their implications in greater detail.

Q. Do you have any other recommendations?

A. Yes. I have made several modest operational and procedural related recommendations related to the Company's commercial trading and risk management. Those recommendations appear in the report.

Q. Does this conclude your direct testimony?

A. Yes.

Appendix A - Qualification of Michael J. McGarry, Sr.

Summary

Mr. McGarry's professional experience spans twenty-seven years within the private and public sectors. He has conducted over twenty five comprehensive management and operational audits of investor-owned energy and telecommunications utilities. These audits have included comprehensive management audits and/or operational audits on most functions with the utility environment including corporate governance, strategic planning, internal auditing, capital and operating budget process and practices, distribution operations and maintenance, fuel procurement, supply chain management, demand side management, crew operations, affiliates transactions, commodity trading and construction program practices.

Project Management

Mr. McGarry's experience includes management of multi-discipline teams for a wide range of client engagements, development and implementation of detailed work plans and project schedules. He has analyzed and planned interdivisional resource utilization, supervised, developed and coached interdivisional team members and created numerous executive reports, briefings, and presentations.

Regulatory and Rate Case Management

Mr. McGarry has worked with clients to manage all aspects of the regulatory and rate case process. He has developed efficient processes to prepare supporting analyses and testimony for submission to the regulatory bodies and interveners. He is a seasoned project manager and has analytical expertise to respond to interrogatories and data requests from all rate case interveners in a timely manner. Mr. McGarry has assisted a number of clients in preparing revenue requirement and cost of service analyses. He has also developed rate structure and billing determinant information analyses, time of day and interruptible rates analyses, fuel and purchased power reports and annual wholesale rates for member cooperatives. He has developed complex revenue requirement models to present alternative positions to a utility's proposed rate request.

Testimony and Witness Preparation

Mr. McGarry has proffered and /or supported testimony in Colorado, Delaware, Illinois, Maine, Michigan, Maryland, New York and Pennsylvania. These proceedings included testimony involving management decision and prudence impacts, operations and maintenance expenses, capital investments, revenue requirements, project management and others.

Utility Management and Operational Audits

Mr. McGarry has conducted over twenty five comprehensive management and operational audits of investor-owned energy and telecommunications utilities. These audits have included comprehensive management audits and/or operational audits on most functions with the utility environment including corporate governance, strategic planning, internal auditing, capital and operating budget process and practices, distribution operations and maintenance, fuel procurement, supply chain management, demand side management, crew operations, affiliates transactions, commodity trading and construction program practices.

Restructuring, Unbundling, and Cost Allocation

Mr. McGarry has developed the supporting analyses and regulatory filing requirements needed to support unbundling rates for utilities. This has included detailed studies where the company's plant-in-service and depreciation reserve was allocated to each unbundled function. He has assessed utility management actions to prepare the company for competition, including the processes and practices used by the utility to prepare to enter new markets and offer new services.

Education

Potsdam College, B.A., Economics, 1981
University at Buffalo School of Management, MBA, 1996

Regulatory Experience

Before the Connecticut Department of Utility Control

Docket 07-07-01 *Diagnostic Management Audit of Connecticut Light and Power Company.*
On behalf of the Staff of the Connecticut Department of Public Utility July 2008-Present
Project Manager. Performed overall day to day project management responsibilities to conduct a diagnostic management audit of the Connecticut Light & Power Company (CL&P). Managed a project team of accountants, engineers and industry specialists who were responsible for evaluating the effectiveness of the management and operations of all aspects of the company. In addition, managed a focused prudency review of Northeast Utilities' (CL&P's parent company) development and implementation of a $122 million customer information system known as CustomerCentral or C2.

Before the District of Columbia Public Service Commission

Formal Case No. 1053 - *Technical consultant for the Commission in the matter of Potomac Electric Power Company's request for a $50.4 million increase in base rates.*
Project Manager. Provide technical expertise to Commission in evaluating the Company's rate case filing. Commission accepted adjustments which reduced the allowed increase by a significant percentage.

Case No. 1032 *In the Matter of the Investigation into Potomac Electric Power Company's Distribution Service Rates*
On Behalf of the DCPSC, January 2005-March 2005
Project Manager and Consultant to Commission and Staff. Review and evaluation of Potomac Electric Power Company compliance filings for class cost of service and revenue requirements for distribution service pursuit to a settlement approved in May 2002. Provided analysis and recommended adjustments to Staff on 23 designated issues and 13 Company proposed adjustments. Proceeding was settled in anticipation of a full rate case for rates to be effective August 8, 2007.

Case No. 1016 *In the Matter of the Application of Washington Gas Light Company, District of Columbia Division, for Authority to Increase Existing Rates and Charges for Gas Service*
On Behalf of the DCPSC, June 2003-December 2003
Project Manager and Consultant to Commissioners and Staff. Project Manager for the analysis of WGL's rate filings. Provided analysis and recommended adjustments to the DCPSC Staff on

WGL's proposed increase to base rates. Advised the Commission during deliberations on party positions and possible recommendations.

<u>Before the Delaware Public Service Commission</u>
Docket No. 07-239F *On behalf of the Staff of the Delaware Public Service Commission in the matter of the application Delmarva Power & Light Company for approval of modifications to its gas cost rates.* Project Manager. Oversaw a review of Delmarva Power and Light's gas hedging program.

Docket No. 06-287 *On behalf of the Staff of the Delaware Public Service Commission in the matter of Chesapeake Gas Corporation's implementation of a Gas Hedging program.*
Project Manager. Provided industry expertise and suggestions to the Commission on a proposal plan to implement a gas hedging procurement program at the Company.

Docket No. 06-284 *On behalf of the Staff of the Delaware Public Service Commission in the matter of Delmarva Power and Light Company's request for a $15 million increase in gas base rates.* Project Manager and testifying witness. Provide expert testimony on several rate base and revenue requirement issues. Recommended Commission reduce proposed rate increase request to $8.4 million (56%).

<u>Before the Illinois Commerce Commission</u>
Case: 05-0597 *On behalf of the Illinois Citizens Utility Board, Cook County States Attorney's Office and City of Chicago*
Project Manager and Testifying Witness. Provided analysis and recommended adjustments in the general rate increase of 20.1% or $320 million filed by ComEd.

Consultant to Illinois Power Company. Conducted mandated compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the Company's Controller.

Consultant to Illinois Power Company. Prepared 2001 required update filing for the Illinois Commerce Commission compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the Company's Controller.

<u>Before the Maryland Public Service Commission</u>
Case No 9092 *On behalf of the Staff of the Commission in Base Rate Proceeding for Potomac Electric Power Company*
Project Manager. Reviewed and analyzed company's base increase request and all pro formas, adjustments to test year revenue requirement and supported witness testimony. Commission approved less than 20% of Company's original request.

Before the Michigan Public Service Commission
Case No. U-15808 and U-15889 *In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for Consumers Energy Company to fully comply with Public Acts 286 and 295 of 2008*
Project Manager and testifying witness. Provided expert testimony on the Company's renewable energy and energy optimization plans

Case No. U-15677 *In the matter of the application of The Detroit Edison Company for authority to implement a power supply cost recovery plan in its rate schedules for 2009 metered jurisdictional sales of electricity.* Project manager and testifying witness. Reviewed power supply cost recovery plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-15415 *In the matter of the application of Consumers Energy Company for approval of a power supply cost recovery plan and for authorization of monthly power supply cost recovery factors for the year 2008.* Project Manager. Reviewed power supply cost recovery plan requirements and provided summary briefing to Michigan Attorney General.

Case No. U-15320 *In the matter of the application of Midland Cogeneration Venture Limited Partnership for the Commission to eliminate the "availability caps" which limit Consumers Energy Company's recovery of capacity payments with respect to its power purchase agreement with Midland Cogeneration Venture Limited Partnership.* Project Manager. Oversaw project to provide industry expertise to evaluate issue in case and recommend alternative arguments.

Case No. U-15245 *In the matter of the application of Consumers Energy Company for authority to increase its rates for the distribution of natural gas and for other relief.*
Project Manager and testifying witness. Provided expert testimony on partial and interim rate relief, Consumers' decision to acquire Zeeland Power Company from Broadway Gen Funding, LLC. Provided testimony in permanent phase to reduce company's net operating income to more closely reflect the expected costs in 2008.

Case No U-15244 *In the matter of the application of Detroit Edison for authority to increase its electric base rates.*
Project Manager and testifying witness. Provided expert testimony on revenue requirements.

Case No U-15190 *On behalf of the Attorney General of the State of Michigan in Base Rate Proceeding for Consumer's Energy*
Project Manager. Reviewed the revenue decoupling proposal and supported the witness testimony.

Case No U-15040 *On behalf of the Attorney General of the State of Michigan in Gas Cost Recovery 2007/08 Plan proceeding*
Project Manager and Testifying Witness. Reviewed gas cost recovery plan requirements and provided analysis of the potential benefits of gas procurement hedging program.

Case No. U-15001 *On behalf of the Attorney General of the State of Michigan in Power Supply Cost Recovery 2007/08 Plan proceeding*
Project Manager and Testifying Witness. Reviewed power supply cost recovery plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-14701-R *On behalf of the Attorney General of the State of Michigan in Power Supply Cost Recovery 2006/07 reconciliation proceeding*
Project Manager and Testifying Witness. Reviewed power supply cost recovery reconciliation.

Case No. U-14547 *In the matter of the application of Consumer Energy Company for authority to increase rates for the distribution of natural gas and for other relief*
Expert Witness and Project Manager. Provided analysis, recommended adjustments and filed testimony for the Michigan Attorney General on Consumers Energy proposed increase to base rates.

<u>Before the Nova Scotia Utility and Review Board</u>
Case No. P-886 *On behalf of the Consumer Advocate of the Province of Nova Scotia in the base rate proceeding of Nova Scotia Power*
Project Manager and testifying witness. Provided an evaluation of a management audit of Nova Scotia Power and that report's usefulness to assess the Company's management performance and operational efficiency within the context of that proceeding.

<u>Before the Public Utilities Commission of Ohio</u>
Case No. 08-917-EL-SSO *On behalf of the Ohio Hospital Association in the matter of the Application of American Electric Power of Ohio for authority to increase rates for distribution of electric service.* (Hired by Ohio Hospital Association's attorney for utility matters, Bricker and Eckler, to provide expertise in negotiating rate with American Electric.) Evaluated revenue and rate impact on member hospitals.

Case No. 08-0072-GA-AIR *On behalf of the Staff of Ohio Public Utilities Commission in the matter of the Application of Columbia Gas of Ohio, Inc. for authority to increase its gas base rate.*
Project Manager. Oversaw multi-discipline team of accountants, auditors, engineers and analysts to conduct a comprehensive rate case audit of Columbia Gas of Ohio's gas base rate filing. Primary goal of project was to validate information in filing, provide findings conclusions and recommendations concerning the reliability of information and data in the filing and support Staff in its evaluation of the reasonableness of the filing.

Case No. 07-829-GA-AIR *On behalf of the Staff of Ohio Public Utilities Commission in the matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for authority to increase its gas base rate.*
Project Manager. Oversaw multi-discipline team of accountants, auditors, engineers and analysts to conduct a comprehensive rate case audit of Dominion East Ohio's gas base rate filing. Primary goal of project was to validate information in filing, provide findings conclusions and recommendations concerning the reliability of information and data in the filing and support Staff in its evaluation of the reasonableness of the filing.

Case No. 07-0589-GA-AIR *On behalf of the Staff of Ohio Public Utilities Commission in the matter of the Application of Duke Energy Ohio, Inc., for an increase in Gas Rates.* Project Manager. Oversaw multi-discipline team of accountants, auditors, engineers and analysts to conduct a comprehensive rate case audit of Duke Energy – Ohio's gas base rate filing. Primary goal of project was to validate information in filing, provide findings conclusions and recommendations concerning the reliability of information and data in the filing and support Staff in its evaluation of the reasonableness of the filing.

Case No. 07-551-EL-UNC *On behalf of the Ohio Schools Council in the matter of the Application of First Energy Ohio (and its operating companies Ohio Edison, Cleveland Electric and Toledo Edison) for authority to Increase rates for distribution service, modify certain accounting practices and for tariff approval.* Project Manager. Hired by Ohio Schools Council's attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing First Energy's application with respect to cost of service and rate design and the resulting impact on Council's member school systems energy costs.

Case No. 06-986-EL-UNC *On behalf of the City of Cincinnati in the matter of the Application of Duke Energy Ohio, Inc., to modify its market-based Standard service over.* Project Manager. Hired by City of Cininnati's Water and Sewer District attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing Duke Energy Ohio's proposal and impact on City's project energy costs.

Oregon Public Utilities Commission

Docket No. UP205 *Examination of NW Natural's Rate Base and Affiliated Interests Issues*
Co-sponsored between NW Natural, Staff, Northwest Industrial Gas Users, Citizens Utility Board. August 2005-January 2006
Project Manager. Led a team that conducted a management audit of NW Natural Gas that included an evaluation of rate base issues for Financial Instruments (gas and financial hedging) Deferred Taxes, Tax Credits, Cost for a Distribution System, Security Issuance Costs and AFUDC calculations as well as Affiliate Transactions for Cost Allocations and Transfer Pricing, Labor Loading, Segregation of Regulated Rate Base and Subsidiary Investments and Properties, and validation of tax paid from / to affiliates are proper. Audit was to ensure Company compliance with orders, rules and regulations of the OPUC, with Company policy and with Generally Accepted Accounting Principles.

Before Maine Public Utilities Commission

Case No 2008-151 *Maine Public Utilities Commission Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities (Phase II)*
On behalf of Maine Public Advocate
Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to follow-up on investigation for the need for the program and the company's management of the repair or replacement of its cast iron facilities.

Case No 2004-813 *Maine Public Utilities Commission Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities*
On behalf of Maine Public Advocate
Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to investigate the need for the program and the company's management of the repair or replacement of its cast iron facilities.

Before the Public Utilities Commission of the State of Colorado
Docket No. 04A-050E *Review of the Electric Commodity Trading Operations of Public Service Company of Colorado*
On behalf of the COPUC Staff, March 2004-September 2004
Project Manager. Focused operational audit within the bounds of a litigated proceeding to determine if ratepayers were subsidizing or negatively impacted by PSCo's energy trading function.

South Carolina State Senator
Advised Senator on regulatory process for requesting States Public Service Commission for a comprehensive review of Duke Power Company's storm and restoration and right of way management. Reviewed and advised Senator of results of report finding.

Before the Missouri Public Service Commission
Consultant to Ameren UE. Conducted revenue requirement analysis in preparation of Missouri Public Service Commission compliance filing to un-bundle utility's rate tariffs. Prepared the filing requirements and all support schedules analysis to justify allocations of generation, transmission and distribution.

Southern Connecticut Gas
Consultant. As part of a team that conducted a comprehensive management audit of the management and operations of the Company, completed the capital budgeting area of the audit.

Before the New York Public Service Commission
Case: 94-C-0657
Commission Staff. Proceeding to evaluate the compliance of NYNEX with Commission rules and orders related to operational support system costs to competitors. Part of staff panel to facilitate discussion between company and potential competitors (i.e., users of operational support systems) and report back to Commission.

Focused review of the preparedness of RG&E and ConEd for competition in the electric industry. Evaluated all aspects of the company's management actions to prepare for competition including strategic planning, goals and objectives and senior management's attention to the company operations in a de-regulated industry

Case: 97-M-0567
Commission Staff. Litigated proceeding to determine the benefits of a proposed merger of LILCO / Brooklyn Union Gas. Analyzed the proposed synergy savings.

Case: 96-E-0132 *Show Cause Proceeding Regarding Rate Relief for Ratepayers of Long Island Lighting Company*
Commission Staff and Testifying Witness. Litigated proceeding where Staff proffered testimony containing a benchmark study showing that Long Island Lighting Company's operations and maintenance expenses were excessive compared to a peer group of 24 utilities. Panel testimony concerning the findings and conclusions resulting from the benchmark study.

Case: 96-M-0858 *Prudence Investigation into the Scrap Handling Practices in the Western Division of Niagara Mohawk Power Company*
Commission Staff and Testifying Witness. Litigated proceeding as a result of allegations of bribery and corruption in company practices related to a specific vendor who purchased company scrap metal. Lead team of 10 staff examiners to quantify the extent to which the Company paid excessive rates to this vendor. Testified to the findings of the analysis. Case settled with ratepayers receiving a credit to bills

Case: 91-C-0613 *Operational Audit of the Outside Plant Construction and Rehabilitation Program of New York Telephone Company*
Commission Staff. Comprehensive operational audit of the company's management and implementation of a $150 million capital program to rehabilitate the outside plant distribution network. Served as Staff Examiner responsible for crew supervision, goals monitoring, contractor oversight, and report preparation.

Case: 91-W-0583 *Prudence Proceeding Regarding the Operations and Management of Jamaica Water*
Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive costs to rate payers. Testified on a Staff panel to the excessive costs associated with management's inattention to sound business practices related to the design, purchase and installation of the Company customer information system.

Case: 92-W-0030 *Operational Audit of Jamaica Water Company Operations and Management*
Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, and specific topics areas including engineering, contracting, and information technology. Findings led to prudence proceeding.

Case: 92-M-0973 *Management Audit of Rochester Gas and Electric*
Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, supervision of staff and specific topics areas including purchasing and internal controls.

Case: 93-E-0918 *Operational Audit of the Demand Side Management Function at Rochester Gas and Electric*
Commission Staff. Comprehensive operational audit of the demand side management function including program planning, management and energy savings verification. Developed and supervised the implementation of the work plan.

Case: 88005 *Operational Audit of the Materials and Supply Function at National Fuel Gas*
Commission Staff. Comprehensive operational audit of the materials and supplies function including warehouse operations, inventory control and procurement. Developed and implemented the work plan for this project.

Operational Audit of the Fuel Procurement and Contracting of Long Island Lighting Company
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project.

Operational Audit of the Fuel Procurement and Contracting of Consolidated Edison Company of New York
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Case: 90007 Operational Audit of the Fuel Procurement and Contracting of Central Hudson Gas and Electric
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Operational Audit of the Fuel Procurement and Contracting of Orange and Rockland Utilities
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Operational Audit of the Fuel Procurement and Contracting of Rochester Gas and Electric
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on nuclear fuel. Provided research and data evaluation expertise to the project

Case: 98-E-115 *Prudence Proceeding to Investigate the Construction Costs Associated with the Homer City Coal Cleaning Plant*
Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive construction charges related to the Homer City Coal Cleaning Plant. Testified on a Staff panel to the fuel price differential costs resulting from the failure of the coal cleaning plant to function as designed as well as surrebuttal testimony on the cost of a flu-gas de-sulfurization plant and ancillary equipment and facilities. Case settled with customers receiving $125 million credit.

Case: 87003 *Operational Audit of the Homer City Coal Cleaning Plant*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on the construction of the Homer City Coal Cleaning Plant jointly owned by NYSEG and Penelec. Responsible for fuel and construction costs analysis, benchmarking costs and alternative methods for meeting EPA Clean air restrictions, contracting practices and report preparation.

Case: 87003 *Operational Audit of the Fuel Procurement and Contracting of New York State Electric and Gas*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis, benchmarking costs, contracting practices and report preparation.

Case: 86007 *Operational Audit of the Field Crew Supervision and Utilization of New York State Electric and Gas Company*
Commission Staff. Comprehensive operational audit to determine effectiveness of field crew utilization and supervision. Staff examiner responsible for verifying supervisor activities, reporting, goals attainment and report preparation.

Case: 86005 *Prudence Proceeding to Investigate the Fuel Procurement and Contracting Practices at Niagara Mohawk Power Company*
Commission Staff. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive fuel charges to customers. Responsible for fuel cost analysis and benchmarking costs, contracting practices and testimony preparation. Case settled with customers receiving $66 million credit.

Case: 86005 *Operational Audit of the Fuel Procurement and Contracting of Niagara Mohawk Power Company.*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis and benchmarking costs, contracting practices and report preparation.

Case: 85001 *Operational Audit of the Research and Development Function of Consolidated Edison Company of New York*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on R&D activities. Staff examiner on the project responsible for reviewing projects documentation and control, outside contracting a report preparation.