BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
SOUTHWESTERN ELECTRIC POWER	)	**DOCKET NO. 09-008-U**
COMPANY FOR APPROVAL OF A GENERAL	)	
CHANGE IN RATES AND TARIFFS	)	

PREPARED DIRECT TESTIMONY OF WILLIAM B. MARCUS

on behalf of

THE ARKANSAS ATTORNEY GENERAL

June 26, 2009

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ARKANSAS PUBLIC SERVICE COMMISSION
DOCKET NO. 09-009-U

PREPARED TESTIMONY OF WILLIAM B. MARCUS
ON BEHALF OF THE ARKANSAS ATTORNEY GENERAL

I. Introduction

Q. Please state your name, business affiliation and address.

A. I am William B. Marcus. I am Principal Economist for JBS Energy, Inc., 311 D Street, West Sacramento, California 95605.

Q. Please provide your qualifications.

A. My qualifications are attached as Exhibit WBM-1. I have over 30 years experience with energy utility issues. I have previously testified or made formal comments before about forty federal, state, provincial, and local utility and environmental regulatory bodies in the U.S. and Canada on issues including utility restructuring and performance-based ratemaking, revenue requirements, resource planning, and cost-of-service and rate design. I have filed testimony at this Commission on a number of occasions, including the recent general rate cases of Entergy Arkansas, Inc. ("EAI"), Oklahoma Gas and Electric ("OG&E"), Arkansas Electric Cooperative Corporation ("AECC"), The Empire District Electric Company ("EDE"), Arkansas Western Gas Company ("AWG"), Arkansas Oklahoma Gas Corporation ("AOG") and CenterPoint Energy Arkla (Dockets No. 06-101-U; 08-103-U and 06-070-U; 04-141-U; 04-100-U; 06-124-U, 04-176-U and 02-227-U ; 07-026-U, 05-006-U and 02-024-U; and 06-161-U, 04-121-U and 01-243-U respectively), several other cases involving EAI (Dockets No. 08-149-U, 07-129-U, 06-152-U, 01-041-U and 01-184-U), the AWG Weatherization case (Docket No. 05-111-P), both the September, 2000 and September, 2001 phases of the Commission's restructuring investigation (Docket No. 00-190-U), Docket No. 98-339-U (the last Southwestern Electric Power Company ("SWEPCO") rate case), and approximately 20 unbundling cases for co-ops and investor-owned utilities, most of which were settled.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arkansas Attorney General. I was retained to review a number of aspects of the general rate application filed by Southwestern Electric Power Company ("SWEPCO" or "the Company").

Q. What is the overall context of this rate case?

A. SWEPCO has requested a rate increase of $26.9 million as well as the approval of a new Generation Recovery Rider ("Rider GR") that provides for the inclusion of Construction Work in Progress ("CWIP") in the rate base for the Turk and Stall plants as well as for automatic recovery of return, taxes and depreciation when these units come into service.

The Attorney General's investigation does not involve the detailed accounting audit provided by the Staff but looks at a number of specific areas. This analysis has identified at least $14.4 million in reductions from SWEPCO's requested rate increase in areas including the capital structure and return on equity, incentive bonuses including stock-based compensation, directors' and officers' ("D&O") liability insurance, working cash assets, Account 907-915 vouchers, and other operating revenue.[1] We expect that the Staff's detailed audit will support additional rate reductions. To the extent that the Commission accepts recommendations of Staff reducing rate base or expenses, or increasing revenues, this would at least further reduce SWEPCO's requested base rate increase.

This testimony also supports rejection of Rider GR (both Phase 1 – CWIP in rate base – and Phase 2). Instead the Attorney General can support the recovery of costs for the Stall combined cycle plant when it comes into service similar to Entergy's Rider CA.

[1] In addition, the Attorney General recommends rejecting $358,000 of increases in tariffed service charges largely paid by renters and other lower income residential customers.

Q. What are your detailed recommendations?

A. With respect to Rider GR, I recommend that the Commission reject Rider GR and instead provide for expeditious recovery of the revenue requirement for the Stall combined cycle plant when it comes into service through a mechanism similar to EAI's Rider CA.

With respect to rate of return and revenue requirements, I recommend that the Commission:

1. Use SWEPCO's initially filed capital structure of about 47% equity and 53% debt (including short-term debt), which is within one percentage point of a a hypothetical capital structure using the Company's comparison group, but updated for other components of the capital structure.[2]

2. Adopt an authorized return on equity ("ROE") of 10.0% rather than adopting SWEPCO's requested 11.5%. (The combination of the two recommendations on capital structure and rate of return creates a $9,500,000 reduction at SWEPCO's proposed rate base).

3. Reduce expenses by a total of $2,563,000 (Arkansas jurisdictional) for incentive programs and executive perquisites. Of this amount $2,431,000 results from sharing the costs of incentive programs for exempt employees, managers, and executives that are related to financial goals on a 45% ratepayer and 55% shareholder basis to reflect that payments are heavily dependent on goals that benefit shareholders. The remaining $132,000 results from removing costs of performance shares and similar long-term incentive programs that are awarded preponderantly to a few top managers using criteria largely based on AEP's share price performance ($120,000) and executive perquisites for tax gross-ups and financial planning ($12,000).

4. Reduce Directors' and Officers' liability insurance by at least $1,000 (Arkansas jurisdictional), by sharing half of the cost with shareholders.[3]

5. Increase late payment charges allocated to Arkansas jurisdiction by $297,000 to reflect actual revenues generated from Arkansas customers.

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[2] It is not clear to the AG what the current request it. SWEPCO revised Schedule D-1 in response to APSC-158 and appears to increase the equity capitalization to 52.20%, with 0.2% preferred stock, and 47.65% debt, as discussed in more detail in Section III.A. below. To the extent that SWEPCO's request has changed from their original filing, the Attorney General's recommendation would be for a hypothetical capital structure of approximately 47% equity and 53% debt instead of the actual structure as reflected in revised Schedule D-1.

[3] This figure is based on AG DR 2-30. Much larger amounts that would be in excess of $100,000 (Arkansas jurisdictional) are consistent with the answer to APSC-055.

6. Include an allowance for late payment charges of 0.472% of revenues to reduce any rate increase arising from this case. The impact is to reduce the rate increase by $4,698 per each million dollars.

7. Reject $283,000 of increased service charges for service connections because those charges disproportionately harm low income individuals and renters and $101,000 in additional charges for collection trips that would make it harder for customers to pay off arrearages and avoid disconnections.

8. Reduce the allocation of tariffed service charge revenue in Account 451 by $28,000 to reflect actual payments made by Arkansas customers on a pro forma basis after the Attorney General's reduction to the company's request for increased revenues.[4]

9. Use a five-year average to normalize fluctuating revenues from sales of emissions allowances, increasing Arkansas jurisdictional revenue by $1,375,000.

10. Remove approximately $51,000 (Arkansas jurisdictional) in vouchers in Accounts 907-910 for expensive business meals, donations, club dues, and for costs paid to the Texas Housing Authority that appear to specifically benefit only Texas.

11. Reduce Arkansas jurisdictional rate base for working capital assets by $7.59 million, comprised of a jurisdictional allocation change of $5.21 million to more accurately assign working capital assets based on the specific costs that comprise these assets and a reduction of $2.39 million Arkansas jurisdictional ($11.79 million total company) for assets not necessary to provide utility service. This rate base reduction reduces the Arkansas revenue requirement by $643,000.

We have also prepared residential weather normalization calculations for the residential class based on the recorded year 2008. A preliminary estimate is that class revenues should be increased by $1,119,000 over recorded 2008 revenues. Because the company's case is based on six months recorded and six months forecast, these figures are not consistent with that case. Our weather normalization estimate is therefore not reflected in the revenue requirement

[4]The $28,000 reduction arises if the Commission rejects the $357,600 in new service charge revenue that the Attorney General opposes. If the Commission increases charges for collection trips and service connections, then any additional revenue from those charges should also be included as part of Arkansas jurisdictional revenue.

figures above. It will be integrated into the total analysis in surrebuttal after reflecting the Staff's updating of the case to recorded test year figures.

We have also prepared a calculation of normalized ordinary storm damage expenses which is $453,000 less than SWEPCO's actual 2008 expenses. This recommendation will be integrated with both the true-up from 6 months actual to 6 month recorded in the Staff testimony and the Company's possible recommendations to implement reserve accounting expected to be addressed in this proceeding.

Additional disallowances are likely to be reasonable, based on our further investigation and information brought forward by Staff and other parties.

With respect to class cost of service, I recommend that the Commission:

1. In general, accept the broad outlines of SWEPCO's cost of service study, and in particular the average and peak allocation for generation and the classification of distribution plant and expenses as demand-related except for meters and services.

2. Make the same adjustments to working cash assets as are made in the jurisdictional allocation.

With regard to residential rate design, I recommend that the Commission take the following steps to encourage conservation and reduce the highly promotional nature of SWEPCO's rates in promoting electric space and water heating, while mitigating customer impacts.

1. Reject SWEPCO's 16% increase to the residential customer charge.

2. Develop a single rate class for residential customers.

3. Close SWEPCO's special rate for electric space heating to new customers effective 3 months after the effective date of this rate case (so that customers with electric heat in the pipeline who have acted in reliance on this rate design are not harmed).

5. Adopt a tiered rate in the summer months, with a second tier for large users 20-25% above the first tier – similar to the recently adopted OG&E rate design.

4. Increase the electric heat second tier rate by 0.8 cents to 1.0 cents/kWh more than the basic residential rate to begin a process of slowly reducing the tier differential.

II. Generation Recovery Rider (Phases I and II)

Q. What new generation is SWEPCO building?

A. It is building three units:

- Mattison peaking plant (332 MW) for $123 million (in service now);
- Stall combined cycle plant (508 MW) for $384 million (in service mid-2010); and
- Turk coal plant (447 MW share of a 600 MW plant) for $1.194 billion (total plant cost $1.628 billion), which is in projected to be in-service in 2012.

The cost of the Turk plant has increased significantly since the plant was approved by the APSC in Docket No. 06-154-U.[5]

Q. Has SWEPCO proposed exceptional ratemaking treatment for these units?

A. Yes. It has proposed to recover through a special rider the financing costs associated with average projected amounts of Construction Work in Progress on an annual basis for both Stall and Turk before the units come into service (Phase I of Rider GR).[6] SWEPCO has also proposed a Phase II formula ratemaking method to place costs of return and depreciation into rates at the onset of commercial operation. The Phase II rates are based on a financial capital structure rather than the Modified Balance Sheet Approach ("MBSA") typically used in Arkansas.

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[5] *See* SWEPCO's Monthly Status Reports filed in Docket No. 06-154-U.

[6] Rider GR Phase I provides recovery of financing costs for Construction Work in Progress associated with generating plants, which is equivalent to placing CWIP in rate base for generating units. Unless specifically referring to a specific term in Rider GR, this testimony will refer to Rider GR and the general concept of CWIP in rate base interchangeably because the concepts are the same.

Q. Is Construction Work in Progress ("CWIP") in rate base generally appropriate for investments in new generation as a matter of policy?

A. No. CWIP is inappropriate for several reasons. It is (a) inconsistent with competitive market processes, (b) essentially blunts incentives associated with Integrated Resource Planning ("IRP"), and (c) has adverse intergenerational impacts. Additionally, if adopted, it reduces the utility's business risk, which should be considered in setting the rate of return and capital structure.

Q. Will you discuss how CWIP is inconsistent with competitive market principles?

It is an artifact of monopoly regulation that is unavailable in the competitive business world. Consider the case of, for example, a new mine. The mine's customers typically do not pay for a mining company to build a mine before it comes into service. The mining company's investors advance the funds to build the mine and the mine gets paid for the metal that the mine produces once it is operating, thereby generating a return for the investors. The construction workers get paid, but they're paid by the mining company's shareholders in advance.

Utilities are similar - except that under rate regulation, they have an explicit method of recovering pre-construction costs over the life of the plant. Standard utility ratemaking gives an Allowance for Funds Used During Construction ("AFUDC") which provides for interest and an equity return on money tied up during construction. This AFUDC is added to the direct capital cost of the plant. Once the plant comes into service and is used and useful and providing (or delivering) electricity, all of this money (direct costs and AFUDC) is recovered over the life of a plant (through depreciation and a rate of return on equity and debt on the undepreciated balance).

SWEPCO's request for cash payment for both interest and their return on equity capital tied up in CWIP before the plant is operational thus provides cost recovery that virtually no other business can achieve and that would be almost impossible in an unregulated setting.

Q. Will you explain how including CWIP in rate base essentially can distort the type of choices that are typically made in an IRP process.

A. There are three ways in which such distortions can occur.

First, CWIP in rate base encourages utilities to build power plants rather than purchase power (by removing one of the disincentives to ownership – the cash flow consequences of financing a plant in-house). We are concerned that when utilities determine their resource plans, they may choose ownership over PPA options based on relatively flimsy grounds. Assurance that the utility would receive rate base treatment of CWIP before the plant comes into service would make ownership *even more* compelling to the utility relative to purchasing power and offloading risk onto other parties.

Second, the inclusion of CWIP in rate base through a mechanism like Rider GR also creates a financial disincentive to energy efficiency. Again, if efficiency can avoid or defer a power plant, it can avoid or defer the cash flow consequences of financing the plant. But if those cash flow consequences are automatically covered by ratepayers with CWIP recovery, there will be even less incentive for utilities to promote efficiency and we may see even greater demands for shareholder incentives.

CWIP in rate base also provides the greatest benefits to investments in long-lead-time power generation technologies (large utility central station plants instead of more modular renewable and combined heat and power plants with shorter lead times).

Q. Can you give an example of the intergenerational impacts of CWIP in rate base?

A. The specific concern regarding the intergenerational inequities of CWIP are most effectively illustrated in the case of an 85-year-old customer of SWEPCO. The life expectancy of this customer is 5.41 years for a male and 6.54 years for a female.[7] On average, this customer could pay for half of his/her remaining life for CWIP for the Turk plant, while only receiving two or three years of service once it is complete. Even if she survives for 10 years, she will pay for about 7 years of Turk's costs under normal accounting, but will pay for the plant for ten years with CWIP in rate base.

Q. Will you discuss business risk?

A. One key business risk facing an electric utility is the construction risk – both the risk that construction projects will be on time and on budget – and that they can be financed over the construction period. CWIP in rate base significantly reduces SWEPCO's business risk associated with construction. First, it removes the finance risk. Second, it reduces the consequences to the utility of being late or over budget because (depending on the specifics of the mechanism) it may cover cost overruns and schedule slippages.

Q. Does this reduction in risk affect the AG's alternative recommendation?

A. While we oppose CWIP in rate base or through the specific mechanism proposed here, Rider GR, if the Commission adopts it, it should recognize this risk reduction by reducing SWEPCO's return on equity at the same time to reflect the lower risk. The extent of this reduction is dicussed in Section III. below.

Q. What arguments are made in favor of CWIP in rate base?

A. The general argument in favor of including CWIP in rate base is that it will improve the utility's financial condition and that it will save consumers money over the long term.

Q. Will you discuss the issue of consumer savings?

A. While including CWIP in rate base will indeed reduce customer costs by large numbers of nominal dollars, on a net present value basis, the smaller number of dollars paid up front are basically equivalent to the larger number of additional

[7] Social Security Online, Actuarial Publications, Period Life Table. http://www.ssa.gov/OACT/STATS/table4c6.html

dollars paid by customers for a return and depreciation on AFUDC over the life of the plant. Therefore, from an economist's point of view, savings are negligible.

While Mr. Brice's Direct Testimony highlights alleged consumer savings, Exhibit TPB-6 tells a different story. On a net present value basis, AFUDC accounting produces a lower present value of revenue requirements for any discount rate above 7.6%.

Mr. Brice erroneously compares the 7.6% rate to relatively low interest rates that customers receive on CDs or pay for home mortgages (p. 22 of his direct testimony). He even claims that some industrial customers can borrow as low as at LIBOR (which he cites as 0.42%).[8] Therefore he claims that customers should be happy, comparatively, to invest up front to get a 7.6% return on their power bills.

But these rates are clearly less than the <u>incremental</u> cost of capital. For residential and small business customers, the marginal cost of capital is likely to be credit card interest for many customers – far higher than 7.6%. In other cases, it is the ability to contribute to a 401k or IRA, which may have a higher opportunity cost of capital both because investments can be expected to make more than 7.6% over the long term and because of foregone tax advantages. Some customers simply cannot access capital at all (many small businesses, residential customers facing foreclosure). Large business may be able to borrow limited amounts of money from banks under stringent conditions, but their hurdle rates (incremental return requirements on productive investments that they make) are nearly always above 7.6%. If a commercial customer requires a three-year payback to make an investment in energy efficiency – one of the key arguments supporting energy efficiency programs - one cannot then also say with a straight face that that the same customer would take a lower return by choosing the CWIP option. If a business actually requires a return on equity of 11.5% - the utility's request in this case - would that business voluntarily sign up to make in investment to prepay

[8] Direct Testimony of Thomas P. Brice, pp. 21-22.

part of its power bill for the next 30 years with a 7.6% rate of return? I submit that most such businesses would not sign up for this kind of program.

Savings from CWIP are thus completely illusory, notwithstanding Mr. Brice's optimism about how easy it is for residential and business customers (except SWEPCO of course) to borrow money cheaply.

Q. Will you discuss SWEPCO's financial condition?

A. While a large construction program will clearly cause financial indicators to worsen, SWEPCO has failed to provide good evidence as to the amount of worsening that is likely to happen without CWIP. Instead, it has provided a worst-case scenario that is both inaccurate and outdated.

Q. What evidence did SWEPCO present?

A. The testimony of Ms. Renee Hawkins shows dramatic reductions in the financial condition of SWEPCO if CWIP is not included in rate base and timely recovery is not otherwise provided (see tables on pp. 10 and 12 of Ms. Hawkins' Direct Testimony, referred to as "Page 10 Table" and "Page 12 Table" respectively).

After reviewing these tables and obtaining workpapers (AG DRs 2-9 and 2-11), I can make several observations without divulging confidential information.

My first observation is that the Page 10 Table (what happens if SWEPCO's request is denied) does not depict reality. According to the titles of the tables, SWEPCO assumes that it either gets everything it requests for construction financing recovery through Rider GR (Page 10 Table) but assumes (Page 12 Table) that if SWEPCO did not receive what it is requesting, it would <u>never</u> receive any rate recovery for the Stall plant from the date when it comes into service in 2010 to the end of 2013, or, for that matter from when the Turk Plant is projected to be completed during 2012 to the end of 2013. These assumptions are simply wrong from the perspective of conventional ratemaking. If the Commission rejected SWEPCO's proposed Rider GR, SWEPCO would be violating its fiduciary duty to its shareholders if it did not file a rate case to recover the cost of each of these plants as it comes into service. As a result, the drastically plummeting financial ratios (starting in 2010 but particularly in 2012 and 2013, after Turk comes on line) in the Page 10 Table are not only unrealistic and alarmist, but materially misrepresent the Company's financial position. This table is simply not credible.

For example in 2013, with both plants included in the rate base, the company assumed that it would lose $40.7 million and would have horrible financial ratios as a result. In actuality, if all of the rest of SWEPCO's underlying analysis were to be correct, a system-wide request for rate relief could generate on the order of $190 million more in system-wide corporate profit than the negative $41 million estimated by SWEPCO in the Page 10 Table, greatly improving financial metrics.[9]

Q. Did SWEPCO provide any information as to the impact of ordinary rate relief?

A. Yes. In response to APSC-166, the Company provided data for three years (2010-2012) assuming that SWEPCO received ordinary rate relief but not Rider GR. (*See* Exhibit WBM-2). It is not clear how the rate relief was calculated (i.e., whether it included non-generation impacts or not). While the company admits that this is not an analysis at the level of detail shown in the responses to AG DRs 2-9 and 2-11, and there appear to be several errors in the analysis,[10] the response to APSC-166 is at least somewhat indicative and is certainly the best analysis the company has given the Commission at the time of the filing of this testimony.

[9] Given a 9.5% return on SWEPCO's system-wide $1,607 million at the end of 2012, equity in 2013 would be $152.6 million, which, when added to the $40.7 million loss in SWEPCO's Page 10 Table is a difference of $193.3 million. This figure is likely too low because the end-of-2012 equity fails to include any equity increase resulting from rate changes when the Stall plant comes into service.

[10] The company did not change interest payments to reflect changing amounts of debt, did not change depreciation expense in EBITDA to reflect AFUDC accounting, and made an error in calculating the amount of equity for the debt-equity ratio (subtracting before-tax rather than after-tax amounts). The amount of rate relief without the riders appears to exclude anything for non-generation costs. Finally, the Company's analysis has not been updated for the cash flow from the extension of federal bonus depreciation through 2009 in the stimulus bill, which would reduce debt by about $15-$30 million.

The table below compares the results for 2010-2012 with (a) the company's proposed extraordinary rate relief, and (b) ordinary rate relief when plants become used and useful from APSC-166; and (c) the incorrect analysis conducted by SWEPCO with the assumption that there would be no rate relief of any kind. It shows that before 2012, the allegedly large differences in financial statistics are much smaller than SWEPCO has alleged, and by 2012, the existence of rate relief greatly reduces the impact.

Table 1: Comparison of SWEPCO Financial Ratios in Hawkins' Testimony and APSC-166

	2010	2011	2012
Funds from Operation Interest coverage (ratio - higher is better)			
Company Page 12 Table (with rate relief)	2.73	2.53	3.71
APSC-166 no GR Rider, ordinary rate relief	2.29	2.12	3.44
Company Page 10 Table (no rate change at all)	*1.98*	*1.77*	*2.07*
Total Debt to Earnings before Interest Taxes Depreciation and Amortization (lower is better)			
Company Page 12 Table (with rate relief)	4.49	4.61	3.52
APSC-166 no GR Rider, ordinary rate relief	5.28	5.42	3.84
Company Page 10 Table (no rate change at all)	*6.70*	*7.30*	*8.10*
Funds from Operation as % of Total Debt (higher is better)			
Company Page 12 Table (with rate relief)	11.0%	10.3%	18.5%
APSC-166 no GR Rider, ordinary rate relief	8.0%	7.4%	16.3%
Company Page 10 Table (no rate change at all)	*6.2%*	*5.1%*	*7.1%*
Funds from Operation as % of Capital Expenditures (lower is better)			
Company Page 12 Table (with rate relief)	41.1%	57.9%	121.1%
APSC-166 no GR Rider, ordinary rate relief	30.6%	42.5%	109.1%
Company Page 10 Table (no rate change at all)	*24.2%*	*31.2%*	*59.3%*
Total Debt as % of Total Capital (lower is better)			
Company Page 12 Table (with rate relief)	56.3%	55.8%	50.0%
APSC-166 no GR Rider, ordinary rate relief	58.4%	57.9%	51.2%
APSC-166 no GR Rider, ordinary rate relief CORRECTED EQUITY (after tax not before tax)	57.9%	57.4%	51.0%
Company Page 10 Table (no rate change at all)	*58.2%*	*59.5%*	*61.6%*

Q. Aside from the issue of rate relief, are there any other problematic assumptions in Ms. Hawkins' analysis of SWEPCO's financial condition?

A. Yes. The debt-equity ratios are incorrect and outdated. Not only are the debt and equity ratios wrong because SWEPCO measures net income incorrectly (because of the lack of rate relief discussed above), but SWEPCO assumes that its parent company would let it develop an unbalanced capital structure and incur downgrades without any additional equity contributions after 2009 even though the period of time when the company would face financial stress is relatively limited.

In fact, more recent information, provided by the Company in APSC-157, contradicts this assumption in Ms. Hawkins' tables. The data response indicates that AEP has actually paid an additional $72.5 million of equity to SWEPCO above its initial 2009 forecast of $70 million, due to AEP's equity issuance earlier this spring. As a result of this equity infusion and stronger recent SWEPCO cash flow than projected, SWEPCO has been able to cancel or delay a $275 million debt issue that was originally projected. Thus, the analysis conducted by Ms. Hawkins is both outdated and based on unrealistic assumptions and cannot be relied upon.

In addition, there is a further update required because the 2009 economic stimulus act extended 50% bonus depreciation into 2009. This will increase SWEPCO's cash flow by as much as several tens of millions of dollars, and may be one of the reasons for the cancellation or delay of the $275 million debt issue.

Q. Has SWEPCO reduced its spending other than on the Turk and Stall plants?

A. Yes. SWEPCO has cut its capital budget twice – once in 2009, which was factored into the analysis presented by the Company's testimony (AG DR 2-16), and again in 2010-11, where $270 million has been cut from spending over the two-year period.[11] These additional spending cuts, which are not included in the analysis presented by Ms. Hawkins, would also improve coverage ratios and reduce the need to raise debt.

Q. Do you have any comments on rating agencies' views of a construction program like SWEPCO's?

[11] Details supporting the aggregate cuts are given in the confidential response to AG DR 2-8(d).

A. Yes. The rating agencies have been ratcheting down credit standards for the last 25 years. Those higher standards are only now coming home to roost with the resumption of significant amounts of regulated construction in recent years.

When the utility industry was last in a large generation construction boom in the 1980s, SWEPCO's measure of funds from operations to capital expenditures without CWIP in the 30% range (Page 10 Table) would have placed it easily in the A to BBB range under Standard and Poor's ratings.[12] Now it is virtually impossible for any utility that is building a large generating plant relative to its initial size to obtain an A rating – even with CWIP in rate base. The SWEPCO 2011 Funds from Operations ("FFO") to capital spending ratio of 57.9% <u>with CWIP</u> could have supported an AA rating in 1983. Now it would barely clear the Moody's "low" threshold. Relative to 25 years ago, bondholders and their rating agencies thus now appear to have much more fear of a large utility construction program, particularly a program involving large volumes of generation assets that take years to construct.

Rating agencies also changed the calculation of interest coverage ratios to exclude AFUDC from income in the early 1990s – a further upward ratchet in credit quality for utilities with a significant generation construction program.

Essentially, the rating agencies, which represent one stakeholder in the whole regulatory process – bondholders – have created the whole scare over SWEPCO's poor financial performance. Their actions to ratchet up credit standards to protect their clientele over the last quarter century have created the allegedly poor financial performance that SWEPCO now claims requires extraordinary measures such as CWIP in rate base just so that it can build powerplants.

Q. Is SWEPCO's CWIP request unusual for American Electric Power?

A. No. American Electric Power ("AEP") has made its policy clear in its 2008 10-K filing:

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[12] Standard and Poor's Credit Overview 1983, "Utilities Criteria Rating Methodology Profile," page 41.

> Public utilities have traditionally financed capital investments until the new asset was placed in service. Provided the asset was found to be a prudent investment, it was then added to rate base and entitled to a return through rate recovery. Given long lead times in construction, the high costs of plant and equipment and difficult capital markets, we are actively pursuing strategies to accelerate rate recognition of investments and cash flow. AEP representatives are leading the dialogue with our state commissioners and legislators on alternative ratemaking options to reduce regulatory lag and enhance certainty in the process. These options include pre-approvals, a return on construction work in progress, rider/trackers, securitization, formula rates and the inclusion of future test-year projections into rates.[13]

Exhibit WBM-3 shows the same policy. It contains an excerpt (page 54) from the AEP 2008 Edison Electric Institute Factbook, where AEP specifically says that it is attempting to reduce regulatory lag, among other things with a return on CWIP across its system.

Q. What is the AG's recommendation regarding SWEPCO's requested Rider GR?

A. The AG recommends against adoption of both Phases I and II of Rider GR and suggests disparate regulatory treatments for the construction costs of the Stall Plant and the Turk Plant based upon the specific circumstances of each construction project.

Q. What regulatory treatment do you recommend for the Stall plant?

A. The Stall gas-fired plant is relatively close to completion (only a few months beyond the end of the pro forma period and beyond the time when rates become effective in this case). It also does not have as significant a set of cost and prudence issues as the Turk coal-fired plant.

While the Attorney General does not support either Phase I or Phase II of the AEP recovery mechanisms, in this specific case, we could support a mechanism like EAI's Rider CA for Stall once it comes into service. As the Commission will recall, the AG opposed the use of Rider CA for the Ouachita Plant, and despite the AG's objections, the Commission allowed EAI to use the mechanism. The

[13] American Electric Power Company, 2008 Form 10-K, p. 15.

AG's objections to the Rider CA in the Entergy Case were based in large part on its contention that an Annual Earnings Review ("AER") could produce the same type of rate relief for Entergy while providing more comprehensive protection to ratepayers.

The Stall Plant presents a similar set of circumstances as the Ouachita Plant and given the Commission's prior approval of Rider CA for Ouachita, the AG believes that this might be a more reasonable approach to address the need for recovery of the costs of Stall beginning in 2010 without the need to bring an entirely new rate case so close upon the heels of this matter, while at the same time maintaining the integrity of Arkansas' traditional treatment of not including construction costs in rate base if they are not used and useful in the near term. This mechanism would provide a lower rate of return (based on the MBSA) but would also include O&M costs.[14] Rider CA treatment of the plant would allow SWEPCO to obtain timely rate recovery for this plant without immediately filing another rate case after the decision is made in the current case. Notwithstanding the rider, a prudence review of the costs of the Stall plant should be pursued in a later General Rate Case. The Rider CA treatment for Stall would be removed when rates from the next rate case are put in place.

Q. What regulatory treatment do you recommend for the Turk Plant?

A. I would recommend that SWEPCO be required to file a general rate case for recovery of the cost of the Turk plant and review of its prudence when the plant comes into service.[15] There are several reasons why the AG does not see either Rider GR or a Rider CA-like treatment as appropriate for the Turk Plant. First,

[14] We would propose one change to Rider CA starting in the first full year the plant comes into service. A mid-year rate base should be calculated instead of using the beginning-of-year rate base like EAI's Rider CA.

[15] On Wednesday, June 24, 2009, two days prior to the filing of this testimony, the Arkansas Court of Appeals ruled upon Case No. CA08-128, the Hempstead County Hunting Club's appeal of the PSC grant of a CECPN to SWEPCO for the construction of the Turk Plant. The Court reversed the grant of the CECPN application. This recent development will potentially impact the Company's request for Rider GR as well as the Attorney General's recommendations. However, the AG is not addressing, in this filing, the ramifications of the Court of Appeals decision and provides recommendations to the Commission consistent with the Company's application herein for a Rider GR.

the costs of the plant have increased well above the budget presented to the Arkansas Commission in the certification proceeding due to permitting delays and other reasons.[16] Second, the timing of Turk's in-service date is several years down the road instead of mere months from the end of the pro forma year. Third, there are potentially prudence issues involved with the construction and amount of the Turk Plant that are not present in the case of the Stall Plant.

In the event the Commission sees fit to allow some type of interim rate relief prior to a prudence review, the interim relief should in no circumstances be for any more than the initial budget presented by SWEPCO in APSC Docket No. 06-154-U and as the Commission approved that application.[17]

Q. **If the Commission is considering anything similar to Phase I and II of SWEPCO's Rider GR, contrary to the Attorney General's recommendation, do you have any further comments?**

A. Yes. While we oppose CWIP in rate base as a general policy and Rider GR specifically, for the reasons discussed above and believe that the Turk plant's costs need to be dealt with in a general rate case, there is clearly a series of intermediate steps that the Commission could take that would be less bad than the Company's proposal.

First, if the Commission believed that it needed to provide CWIP for SWEPCO to improve its financial condition, the first step to consider would be to allow Phase I of Rider GR for the Stall plant for the limited period of time until that plant comes into service. CWIP for Stall would effectively be targeted for a short period of time, limited in dollar terms, and could be justified as an exceptional

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[16] *See* SWEPCO's Monthly Status Reports filed in Docket No. 06-154-U.

[17] APSC Docket No. 06-154-U, Order No. 11, p. 59, "The total estimated direct capital cost of the plant is approximately $1.344 billion, of which SWEPCO's 73% share is approximately $986 million. SWEPCO estimates $136 million of transmission investment will be necessary to bring the plant on line, resulting in a total investment by SWEPCO of $1.122 billion. The estimated amount of allowance for funds used during construction (AFUDC) on SWEPCO's investment is approximately $231 million for the generating plant, and approximately $21 million for the transmission facilities, for an overall total cost to SWEPCO of approximately $1.374 billion. (R. Hawkins Direct Testimony, pp. 6,7; J. Kobyra Supplemental Testimony, p. 4.)"

case on the theory that the plant will be in service outside the pro forma year but still not long after the rate effective period of this case. It would provide a well defined (limited but clearly significant) amount of cash flow to the Company.

CWIP for Stall would not be as open-ended as CWIP for Turk (which under the company's proposal could last for two years or more on hundreds of millions of dollars) and would not largely relieve SWEPCO of the business risks of needing to control costs and schedules at the Turk plant.

Second, if the Commission believes that further cash flow relief is necessary beyond Stall, then it should provide an amount of CWIP defined in advance and locked in for Turk – a fixed number of dollars in each of 2010, 2011, and the first half of 2012 until the plant comes into service. A fixed dollar amount well below the total cost of the plant would be better than SWEPCO's proposal for an open-ended amount based on its future forecast of whatever the plant costs, because it would leave the company with incremental incentives to control cost and schedule and the accompanying business risk if it does not control these items.

While the Attorney General believes that CWIP for Turk should be minimized even more than CWIP for Stall, it is critical for the regulatory process that the maximum amount granted should not exceed as an upper bound the total budget for Turk presented to the Commission in the certification case. The Company should not be insulated from the risk of budget increases just because it has proposed a rider to collect CWIP financing costs. Increases above the budget are likely to be controversial from the perspective of reasonableness and prudence, should not be given automatic approval in a rider, and if granted, should therefore be subject to refund – even before the plant is operational. Making amounts above the initial budget subject to refund, while necessary to maintain the integrity of the regulatory process, may also defeat some of the purpose of the rate relief by not allowing the cash to flow to the income statement (at least without heavy footnoting from the corporate auditor).

III. Rate of Return

A. Capital Structure

Q. What capital structure has SWEPCO proposed?

A. It is not clear. The original testimony and the request for Rider GR provide for a financial capital structure (excluding deposits and no-cost capital) of 46.9% common equity, 0.2% preferred stock, and 52.9% debt.

However, SWEPCO revised Schedule D-1 in response to APSC-158 and appears to increase the equity capitalization to 52.20%, with 0.2% preferred stock, and 47.65% debt. This schedule reflects changes arising from SWEPCO's issuance of additional equity and postponement or cancellation of 2009 debt issues (discussed above).

Q. What is your evaluation of SWEPCO's request?

A. I first examined the capital structures of the companies in SWEPCO's ROE comparison group. These structures are useful benchmarks which to compare the capital structure that the applicant is requesting.

Table 2 below presents the capital structures of Dr. Hadaway's proxy group from his ROE analysis—excluding Edison International ("Edison"), Entergy Corp. ("Entergy"), and FPL Group, Inc. ("FPL") because they are more than 30% unregulated, based on income, not revenue.

Table 2: Capital Structure Data

Proxy Company	STD**	LTD	Preferred	Common (with STD)	Common (w/o STD)
Allete	1.4%	40.9%	0.0%	57.7%	58.5%
Alliant Energy, Co.	7.4%	30.7%	0.0%	61.9%	66.9%
Con. Edison	5.4%	45.9%	1.0%	47.7%	50.4%
DTE Energy Co.	7.2%	51.6%	0.0%	41.3%	44.5%
IdaCORP	9.2%	44.2%	0.0%	46.6%	51.3%
Nstar	15.5%	47.5%	0.0%	37.0%	43.8%
PG&E Corp.	6.5%	49.2%	0.0%	44.3%	47.4%
Portland General	7.3%	42.7%	0.0%	50.0%	54.0%
Progress Energy	6.3%	51.9%	0.0%	41.8%	44.6%
Southern Co.	6.0%	50.4%	3.3%	40.3%	42.8%
Vectren Corp.	12.1%	43.2%	0.0%	44.8%	50.9%
Wisconsin Energy	12.7%	45.3%	0.4%	41.6%	47.7%
Xcel Energy Inc.	7.8%	49.0%	0.7%	42.5%	46.1%
Average	8.1%	45.6%	0.4%	46.0%	49.9%
Adjusted avg.*	8.1%	45.8%	0.0%	46.2%	50.1%

* Assigning 50% of preferred stock to debt and 50% to equity

** Includes current maturity of long-term debt

Source: Google Finance (average of quarterly balance statements, four quarters ending March 31, 2009)

Q. What do you recommend?

A. The average capital structure of the 10 comparison companies is 46.2% equity and 53.8% debt after adjusting for preferred stock, which is relatively close to the initial actual capital structure requested by SWEPCO. It contains considerably less equity than the SWEPCO's updated calculations.

Pending review of the Staff's analysis of the Staff comparison group, I can at this time support SWEPCO's original financial capitalization request, as it is not very different from the results for its comparison group. I do not believe that the current actual capital structure of 52% equity should be used because the equity percentage is likely to decline over the rate effective period as additional plant is constructed, particularly at Turk. I therefore believe that 46.9% equity capitalization, in addition to being generally in line with other companies, is likely to be generally representative of the debt-equity ratio during the rate-effective period.

Q. Do you have any adjustments to SWEPCO's capital structure and cost other than the financial capital structure?

A. Yes. I recommend that the Commission use the current customer deposit interest rate of 2.80% for Arkansas instead of the 3.90% blended rate for all jurisdictions used by SWEPCO in its original schedule (updated to 3.60% in APSC-158). The use of the Arkansas rate reflects that the Commissions in both Louisiana and Texas calculate customer deposits in ratemaking based solely on their own state's amount of deposits and interest rates.[18] Therefore, SWEPCO will over-recover its customer deposit costs if Arkansas uses a blended rate while the other states use their own rates.

I also update the non-financial capital to reflect amounts in APSC-158. This update is particularly important because it significantly increases accumulated deferred income taxes, apparently to reflect the extension of bonus depreciation from 2008 to 2009 as part of the 2009 stimulus act.[19] Updating the capital structure and making no other changes to the cost of equity and debt reduces the before-tax rate of return by 28 basis points (from 7.00% to 6.72%) and the after-tax rate of return by 29 basis points (from 9.63% to 9.34%).

B. Return on Equity

1. <u>Current and Expected Future Economic Conditions and their Potential Effect on SWEPCO Going Forward</u>

Q. What is your assessment of Dr. Hadaway's description of the economic environment, SWEPCO's risk profile, and the interplay between the two?

A. Dr. Hadaway's describes the economic environment as "being more turbulent than at any time since the 1930s" on p. 24, indicating that the Dow Jones Industrial Average has "fluctuated by 50% in the past year."

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[18] To show that Louisiana costs are retained in Louisiana, see SWEPCO, Comments in APSC Docket No. 08-137-U, Attachment 2, p. 14 of 32.

[19] "2009 Stimulus Act" refers to the American Recovery and Reinvestment Act of 2009.

The AG agrees that these have been turbulent economic and financial times, though there appears to be some improvement in credit market conditions since earlier this winter.

Since the fall, the interest rate for long-term treasury bonds has declined. This phenomenon results from shakiness in the credit markets and diminished confidence in corporate earnings and solvency. Meanwhile, the market is treating the corporate bond market as unusually risky. Indeed, one of the biggest indicators of a topsy-turvy market is the spread between long-term Federal bond rates and corporate bond rates. The two figures below illustrate this spread (between the 20-year Treasury bond and both the (Moody's 'seasoned') Aaa- and Bbb-rated corporate bonds for the last 10 years (monthly basis).

Figure 1: Comparison of Corporate and Government Bond Yields 1998-April, 2009

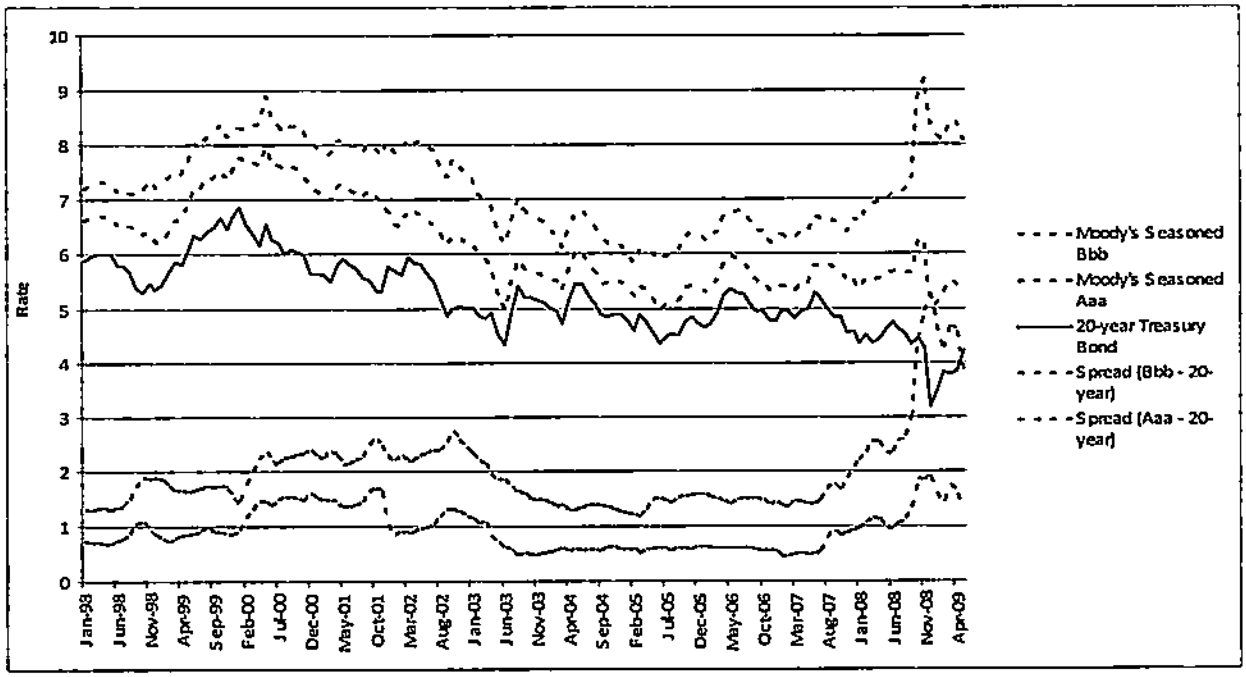
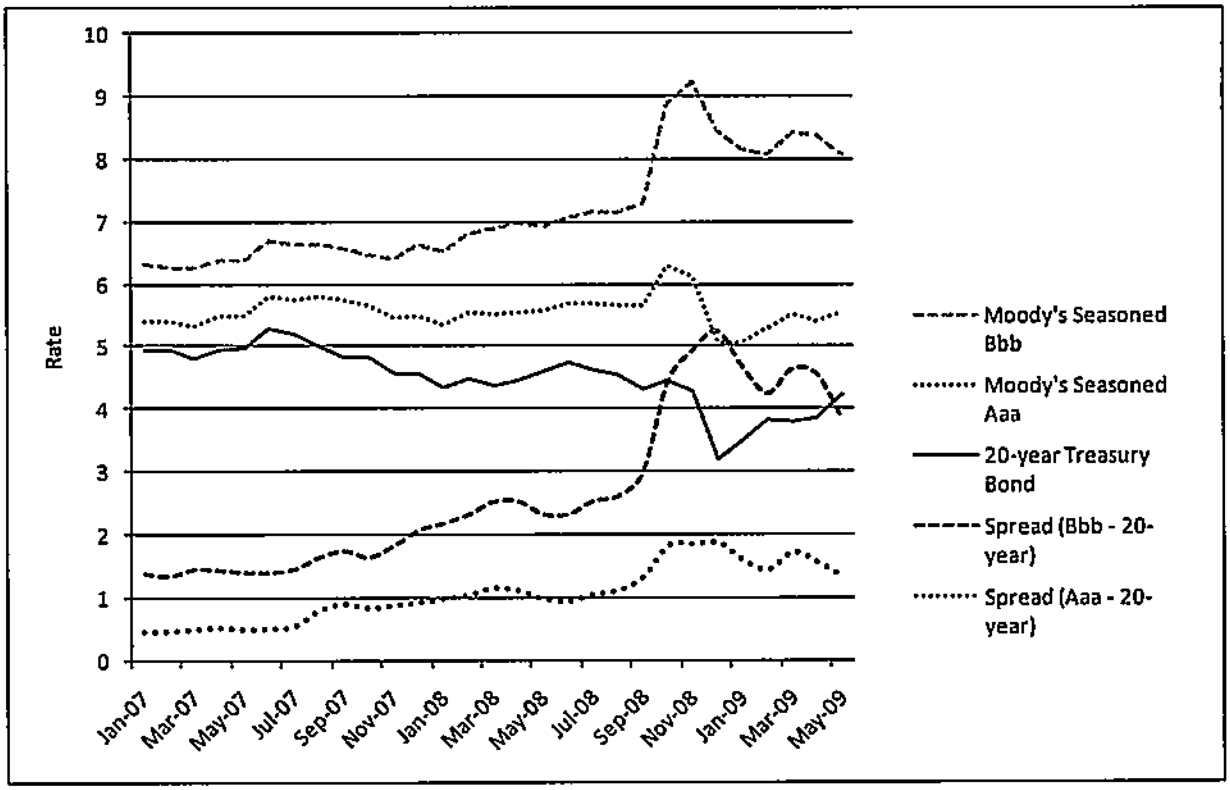


Figure 2: Comparison of Corporate and Government Bond Yields 2007-April, 2009



Figures 1 and 2 indicate a spread between Treasury bonds and Aaa and Bbb bonds of about 1.3% and 3.8%, respectively. This is an improvement from the 500 basis point spread on Bbb bonds at the end of December but is still abnormally high. Compare these spreads with the spreads observed in the last recession (1.7% in October of 2001 for Aaa bonds, and 2.7% in October of 2002 for Bbb bonds). The spread against Aaa bonds is about the same, presently, as it was during the last recession. The spread against Bbb bonds is clearly and substantially higher now (a full 42% higher for Bbb bonds) than it was in the last recession.

The question that a regulatory agency must answer is the appropriate long-term response to this spike in riskiness of corporate debt and the "flight to quality" that reduced interest rates on treasury bonds. While it now appears that the worst of the financial crisis, and its attendant fallout, seem to have passed, there are still significant residual effects.

Q. Would you put these conditions into context for this rate case?

A. Yes, I would. First, the conditions in place have been and continue to be problematic. It is obvious just from looking at the corporate bond spread (against the Treasury bonds); that the spread is, in fact, a *symptom* that something is out of whack and the system is not working properly. However, as is well known, the Federal government has taken aggressive steps to turn the system around, with the recent financial bailout package and the Federal Reserve Board's ("the Fed") December interest rate cuts to the lowest recorded rates being the most obvious examples of the Federal government's activist stance. And the Federal government gives every indication that it will continue its aggressive interventions. Although the Fed stated in its most recent Open Market Committee meeting statement (June 24, 2009) "economic activity is likely to remain weak for a time, the Committee continues to anticipate that policy actions to stabilize financial markets and institutions, fiscal and monetary stimulus, and market forces will contribute to a gradual resumption of sustainable economic growth in a context of price stability."[20] In fact, the Committee also stated that "conditions in financial markets have generally improved in recent months. The Fed also announced its intension to keep the federal funds rate at 0 to ¼ percent and anticipates keeping such rates for an extended period. Additionally, the Fed indicated the following:

> As previously announced, to provide support to mortgage lending and housing markets and to improve overall conditions in private credit markets, the Federal Reserve will purchase a total of up to $1.25 trillion of agency mortgage-backed securities and up to $200 billion of agency debt by the end of the year. In addition, the Federal Reserve will buy up to $300 billion of Treasury securities by autumn. The Committee will continue to evaluate the timing and overall amounts of its purchases of securities in light of the evolving economic outlook and conditions in financial markets.[21]

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[20] Federal Reserve Press Release, June 24, 2009, Page 9. Available: www.federalreserve.gov/newsevents/press/monetary/20090624a.htm .

[21] Federal Reserve, April 28-29, 2009.

President Obama signed a Federal stimulus bill worth $789 billion on February 17, 2009. For context, $789 billion is about double what the Federal government spent on the interstate highway system, in today's dollars[22]. In any case, it will include the biggest investment in infrastructure since the 1950s[23].

The information contained in such citations illustrates that the government is taking strong and multi-faceted to steps to ease credit and stimulate growth and jobs. It is important to keep in mind as we move through the following analysis that economic conditions we are experiencing right now are part of a cycle that should reverse itself (and is even beginning to show signs of doing so, already) during the rate-effective period; the government interventions only serve to speed up this process and make the recovery more robust.

There is a subtler point, however, and one that rate makers should keenly understand: *if economic and financial conditions persist, or get worse, then all companies will have difficulty obtaining capital and making profits for investors*. If the advent of the "doom and gloom" scenario is at hand, SWEPCO's regulated business will look like a safe haven to investors, compared to the alternatives in other industries with no similar regulatory protection of returns in a howling recession.

Moreover, when the market does return from this recession, SWEPCO shareholders will earn a tidy return on their outstanding shares as the market gains steam. Essentially SWEPCO could be paid for "doom and gloom" through a higher than appropriate return on equity but not have to face the regulators to reduce rates when the "doom and gloom" ultimately lifts.

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[22] CBS News. 12/22/08. *Obama Stimulus Package Could Grow To $850 Billion.* Available: www.cbsnews.com/blogs/2008/12/22/politics/politicalhotsheet/entry4683490.shtml

[23] Newsday. 12/08/08. *Economic stimulus package could reach $1.2 Trillion.* Available: www.newsday.com/news/printedition/nation/ny-usstim085956982dec08,0,5280976.story

Q. Has the financial and economic outlook improved during 2009?

A. Yes. As seen in Figures 1 and 2 regarding spreads between corporate and Federal bonds, the spread against the Aaa-rated bond has narrowed to 1.3%, down from 1.9%, and the spread against the Bbb-rated corporate bond is down to 3.8%, as of May 31, 2009, down from a high of 5.3% on December 31, 2008. Part of the reason for the narrowing of these spreads is that corporate bond rates have come down from their heights in March. This indicates that it has become easier and cheaper to obtain financing, which is a result of a decline in the risk that investors perceive. The other reason for the decline in the spreads is the increase in long-term Treasury rates. Usually when this occurs during a recession, it is an indication that investors are anticipating an economic rebound and the accompanying inflation that could be associated.

There also signs of improved conditions for utilities, in particular. For example, Kansas Gas & Electric—which Fitch Ratings has rated as 'BBB-'—recently issued 10-year, BBB+-rated first mortgage bonds at a rate of 6.7%[24], which is substantially below the rates that Dr. Hadaway cited on pp. 29 of his testimony, and indicate a spread against 10-year Treasury notes of 3.41. Dr. Hadaway identified 30-year utility bonds that had spreads against 30-year Treasury bonds of over 425 basis points in October and November. He also cited a 10-year, 10%-yield issuance with a spread of more than 600 basis points against 10-year Treasury notes. The terms that Kansas Gas & Electric is issuing under are far more favorable, reflecting the improved economic and financial outlook.

Overall, the performance of the stock market since March 2009 is further evidence suggesting that conditions have improved. The S&P 500, for example, has improved to 923 (as of market close on June 15, 2009) from 676 (as of March 9, 2009), a 36.5% rise.

[24] Morningstar, 6/9/09. *Fitch Rates Kansas Gas & Electric's $300MM 6.7% FMBs 'BBB+'; Outlook Stable.* http://news.morningstar.com/newsnet/ViewNews.aspx?article=/BW/20090609006106_univ.xml

Q. Please explain how the rest of your analysis is organized in light of your previous comments.

A. The main focus of the rest of my analysis is on providing an alternative to Dr. Hadaway's calculations and conclusions, as they relate to SWEPCO specifically. However, I will return to the key issues of the economic and financial environment throughout the rest of the testimony to place Dr. Hadaway's and my results in context and to support my conclusions and recommendation.

2. <u>Equity Returns from Pension and Decommissioning Funds</u>

Q. Do you have any comments on the analysis of the return on equity ("ROE") that Dr. Hadaway conducted?

A. Yes. I have two general comments. First, the Commission should reject inflated estimates of investors' alleged expectations and unjustified methodologies that inflate the rate of return.

Second, the Commission must not forget that the purpose of this case is to set a return on equity for the <u>regulated</u> operations of an electric and gas utility, and must prevent higher returns from unregulated activities from influencing its decisions.

Q. Have you developed some additional information to examine the requested return on equity?

A. Yes. It is valuable for the Commission to look beyond the calculation of competing mathematical models when considering the return on equity and look at what utilities and analysts are saying about the stock market when they are **<u>not</u>** trying to convince regulatory commissions to give them a specific return on equity.

There are several sources of this kind of information, including data presented by utilities in their roles as multi-billion-dollar investors in nuclear decommissioning funds and as pension fund managers. In the context of investing in these funds, many utilities are, in fact, trying to convince regulatory commissions to give them more money by providing very low estimates of equity returns on their own investments.

Q. Can you provide an example?

A. Yes, Pacific Gas and Electric Company ("PG&E") conducted a survey of 10 actuarial firms, to inform the California Public Utilities Commission that its expectation of an 8.3% equity return and a 7.0% overall return was reasonable. The study showed expectations of average US stock market equity returns of only <u>7.51%</u> in early 2006. This is one of the lowest market return estimates in recent times. Exhibit WBM-4 contains this document. PG&E increased the figure to a still-low 9% equity return in 2008 but reduced it again in 2009 to the 8% range.

Q. Have you looked at equity return estimates in the pension field?

A. Yes, I have analyzed the equity return estimates made by actuaries when setting parameters for the rate of return on assets used in calculating funding for pensions and other post retirement benefits ("OPEBs").

Utility annual reports now contain the data that are used to make these assumptions, including (1) the expected return on assets invested in the pension plan, and (2) the target and actual percentages of debt and equity investments. Even though many of the annual reports do not state expected earnings by asset class, they do provide the overall fund earnings expectation in addition to the allocation the fund managers accord each of the funds' asset classes. AEP's pension forecasts provides an example.[25] AEP expects a pension return of 8.0% with an allocation of 60% equity, 39% debt, and 1% cash. This is consistent with a return of 9.5% on equity assets using the Company's pension fund discount rate assumption of 6.0%. These forecasts are provided in AG DR 3-34, which is attached as Exhibit WBM-5.

[25] AEP SEC Form 10-K Filing for year ending December 31, 2008, Filed on 2/27/09. P. 72 & 77. Available at: ccbn.10kwizard.com/xml/download.php?repo=tenk&ipage=5497096&format=PDF.

Q. Does an examination of pension fund returns for other utility companies have any applicability in this case, in particular?

A. Yes. I have calculated the implicit equity return on the pension funds of all of Dr. Hadaway's comparison companies. One can look at other companies by making the simplifying assumption that the returns on US stocks, international stocks, and real estate are similar over the long run (an assumption that will not have a large impact on the results because of relatively small quantities in international stocks and real estate). Based on this assumption, one can estimate the stock market return that would result with a bond return of, for example, 5% or 6%. In this analysis, for each utility I set the bond return equal to the discount rate that the pension actuary uses (generally the actuary uses the corporate bond rate).[26] This method also calculates the equity risk premium (over corporate debt) for each company by using their own debt return estimates. The estimates of the comparison group's pension actuaries yield an average equity return of 9.56% with an implied risk premium relative to corporate bonds of 3.26%. Table 3 shows this comparison and the average return.

[26] This rate is the pre-mortgage crisis rate. Additionally, as noted above, Kansas Gas & Electric recently made an issuance at 6.7%.

Table 3: Pension Return Assumptions for Comparison Companies

Proxy Company	Discount Rate (or fixed income return if stated)	Pension Return	% equity	% debt	% cash if stated	Equity return (debt @ discount rate, cash @ 3%)	10-K Reference
Allete	0.0625	0.09	0.68	0.32	0	10.29%	pp. 79-80
Alliant Energy, Co.	0.062	0.085	0.7	0.3	0	9.49%	pp. 121, 123
Con. Edison	0.06	0.085	0.67	0.33	0	9.73%	pp. 99
DTE Energy Co.	0.065	0.0875	0.76	0.24	0	9.46%	pp. 130-131
Edison International	0.0625	0.075	0.67	0.33	0	8.12%	pp. 153-154
Entergy Corp.	0.065	0.085	0.65	0.35	0	9.58%	pp. 156, 160
FPL Group, Inc. (1)	0.0625	0.075	0.415	0.585	0	9.26%	pp. 72-73
IdaCORP	0.064	0.085	0.7	0.28	0.02	9.50%	pp. 110-111
Nstar	0.061	0.09	0.71	0.29	0	10.18%	pp. 71-72
PG&E Corp.	0.0631	0.073	0.6	0.4	0	7.96%	pp. 90
Portland General	0.065	0.09	0.68	0.32	0	10.18%	pp. 64, 105
Progress Energy (2)	0.062	0.09	0.665	0.335	0	10.41%	pp. 198, 204
Southern Co.	0.0675	0.085	0.85	0.15	0	8.81%	pp. II-72, II-68
Vectren Corp.	0.0625	0.0825	0.63	0.37	0	9.42%	pp. 82, 84
Wisconsin Energy	0.0605	0.085	0.54	0.46	0	10.59%	pp. 109-110
Xcel Energy Inc.	0.0625	0.0875	0.71	0.26	0.03	9.91%	pp. 47, 49
average	0.0630	0.0844	0.6644	0.3325	0.0031	9.56%	
risk premium relative to corporate bonds						3.26%	

Source: Data taken from utility 2008 10-Ks

(1) FPL Group, Inc. has 9% of its investments in Convertible Bonds. We divided these 50%-50% between Equity and Debt.

(2) Progress Energy has 15% of its investments listed as 'Other'. We divided these 50%-50% between Equity and Debt.

In addition, we prepared an "Arkansas Group" of utilities with data from company 10-K statements. The spread in equity return estimates was from 8.94% to 10.26% (average 9.54%). Table 4, detailing the Arkansas Group comparison, shows results similar to those of the comparison companies.

Table 4: Pension Return Assumptions for Other Arkansas Utilities

	OG&E	Entergy	CenterPoint	Average of Arkansas group
Year	2008	2008	2008	
Equity, Real Estate, etc.	47%	65.0%	54%	55.33%
Debt	53%	35.0%	46%	44.67%
Cash	0.0%	0%	0%	0.00%
Return	8.00%	8.50%	8.00%	8.17%
Discount Rate	6.00%	6.5%	6.90%	6.47%
Equity Return (Fixed income @ disc rate)	10.26%	9.58%	8.94%	9.54%
10-K reference	pp. 122, 126	pp. 156, 160	pp. 76, 78	

Q. Are these implicit estimates of stock market returns by utility pension actuaries consistent with other information provided by utilities in their role as investors?

A. Yes. In their role as managers of decommissioning trust funds, utilities also must project stock and bond market returns to assure the adequacy of funds. We provide some recent examples from filings by Entergy Arkansas, Inc. ("EAI") and Southern California Edison Company ("Edison").

EAI's workpapers on future decommissioning fund returns filed in the November 1, 2006 Rider 26 update in Docket No. 87-166-TF show an expected equity return of 7.1% in excess of the CPI inflation rate or an average of 9.3% from 2007-2011.[27] (*See* Exhibit WBM-6).

As for Edison, its consultant (Global Insight) provided an arithmetic average estimate of stock market returns of 8.13% over the next 30 years (*see* Exhibit WBM-7). The risk premium of stocks relative to bonds over the last 20 years of the period (2019-2037) is assumed to be less than the dividend yield on stocks, as price appreciation is less than the yield on 10-year treasury bonds. Even more importantly, Global Insight assumed a yield of 5.36% on the 10-year Treasury bond, which is consistent with a stock market risk premium of only 277 basis points. Similarly, PG&E used a Russell and Associates long-run equity market return estimate of 8.5%. These figures are generally consistent with the equity return estimates that Edison and PG&E used when setting returns for their pension funds.

Q. Please comment on how the expected return of pension and nuclear decommissioning funds relates to the return that prospective investors in utilities "require."

[27] It is interesting that this analysis uses historical data from Ibbotson to reach this conclusion. Ibbotson data are used by many utility rate of return analysts to claim that stock market returns are 7.1% above long-term treasury bond returns, even though treasury bond returns exceed inflation.

A. Explicitly defining the two terms is helpful:

- "Expected" return is the weighted-average most likely outcome of an investment in a particular security or portfolio of securities.
- "Required" return is the minimum return that an investor requires to compensate him for assuming a given level of risk.

Pension and decommissioning funds' stated expectations for returns from equities in which they have invested must be greater than or equal to their required returns for the stock market or the individual stocks they hold. Otherwise, their managers would not have invested in those individual stocks. If they did not like the "expected" return for the market as a whole, the managers would theoretically shift to a portfolio with more fixed-income securities—all the way up to a ratio of 100% if they did not like the expected return of a single available stock. Despite the possibility of more heavily-weighted fixed-income portfolios, these funds vote with their dollars to stay heavily invested in the stock market because the expected return is at least as great as the minimum return that they require to assume for the level of risk they are assuming. These managers make such decisions notwithstanding returns that are lower than those which Dr. Hadaway believes are "required."

In essence, fund investors are matching their "requirements" to their "expectations." They simply do not "require" a minimum return of 11.5% (even without the company's request for CWIP in ratebase) when the 30-year federal bond rate was 4.43%[28], as Dr. Hadaway recommends, given that this corresponds to a risk premium of 7.07%.

Instead, pension funds can provide dollars to retired workers with fewer contributions by corporations and governments by staying in the market despite their stated (average) mid-financial crisis "expectations" of 9.56% equity returns

[28] Averaged over 5/13/09 to 6/12/09. Accessed: http://www.federalreserve.gov/releases/h15/data/Business_day/H15_TCMNOM_Y20.txt, on June 14, 2009.

and 6.3% corporate bond returns, which corresponds to a risk premium (geometric mean) of 3.26%.

Moreover, because of the standards written into the Employee Retirement Income Security Act of 1974[29] (ERISA), we can reasonably assume that pension fund managers are providing those returns at a level of risk that they deem prudent. Pension fund behavior in the face of current expectations of relatively low equity returns shows that those low returns meet or exceed their "required return" on equity investments.

All we have to do in order to uncover the required return is look at what market participants are actually doing with their own money in the face of current expectations.

Q. **Do you have an example of a pension fund's holdings?**

A. Yes. While utilities do not generally publically identify their pension funds' holdings, the California Public Employees' Retirement System ("CalPERS") does. Of CalPERS's investments, only 26.4% were in fixed income; the rest were in public equity (52.8%), real estate (9.4%), alternative equity (7.3%; mostly private equity), and cash (4.1%).[30] Of the fixed income investments CalPERS held as of June 20, 2008, only 14.0% was in US Treasuries and similar low-risk, low-return equities. CapPERS's other fixed income is in (as percent of total fixed income) asset-backed securities (1.6%), commercial mortgages (26.9%), corporate bonds (29.5%), direct loans (2.2%), distressed securities (2.2%), high yield securities (0.7%), international debt (6.9%), mortgage-backed securities (14.2%), mortgage loans (0.6%), sovereign securities (1.8%), and credit swaps (negative equity position). Clearly, CalPERS is not stodgy when it comes to the risk it will accept even in its fixed-income securities.

[29] ERISA is a Federal law that establishes minimum standards for pension plans in private industry and provides for extensive rules on the federal income tax effects of transactions associated with employee benefit plans.

[30] CalPERS, Annual Investment Report, June 30, 2008. Available: https://www.calpers.ca.gov/mss-pub/SearchController?viewpackage=action&PageId=SearchCatalog&package_code=1420. Cash includes international currency and inflation-linked assets..

As of June 30, 2008, it held 13.4% of the total market value of its $100.6 billion in equity holdings in 10 stocks, nine of which are publicly traded; they are shown in the following Table 5.

Table 5: Statistics on CalPERS Top 10 Domestic Equity Holdings

Company	Market Value of Shares	% of Total Invested in Equity[a]	Google Beta[b]	Value Line Beta[c]
EXXON MOBIL CORP	1,886,860,567.97	2.6%	0.5	0.75
GENERAL ELEC CO	1,043,608,252.24	1.4%	1.44	1.15
MICROSOFT CORP	995,545,855.08	1.3%	1.01	0.8
WAL MART STORES INC	905,645,859.00	1.2%	0.19	0.6
CHEVRON CORP	890,223,285.06	1.2%	0.68	0.9
AT+T INC	843,554,139.90	1.1%	0.64	0.75
BERKSHIRE HATHAWAY INC DEL	740,894,140.00	1.0%	0.59	0.75
PROCTER AND GAMBLE CO	727,206,601.08	1.0%	0.57	0.6
RELATIONAL INVESTORS LP	706,077,122.16	1.0%	NA	
JOHNSON + JOHNSON	682,401,942.90	0.9%	0.53	0.6
Total of Top 10 Holdings	**9,422,017,765.39**	**12.8%**		
Average of Top 10 Holdings	**942,201,776.54**	**1.3%**	**0.68**	**0.77**

[a]Based on total holdings market value on June 30, 2008, which was about $73.8 billion.
[b]From Google Finance, accessed June 22, 2009.
[c]From ValueLine, accessed June 22, 2009.

The data in the paragraph above and in Table 5 above confirm that pension funds are heavily invested in the stock market and their expectations on equity return should be given far more weight than the "expectations" divined by utility witnesses in order to convince the utility commissions that they should be awarded an ROE that is above those utilities' true cost of capital. Furthermore, CalPERS choice of fixed-income securities illustrates that pension funds are so conservative that they are not good proxies for market expectations on a range of investment vehicles. In other words, pensions are not unduly more conservative than utility stocks, and one could make the case that utilities would actually be defensive items in a portfolio that is otherwise relatively more risky.

Q. Do you have any more evidence that supports the use of pension funds as one indicator for the risk premium associated with the stock market?

A. More evidence supporting the use of pension funds when analyzing equity risk premiums is available by inspecting the composition of the funds that respected multi-manager investment firms, such as Russell, offer to their ERISA-qualified purchasers (i.e., companies with federally-regulated pension funds). These funds have myriad levels of risk from which to choose. Exhibit WBM-8 shows the funds that the Russell Investment Group offers to its pension fund clients. These funds are available in virtually all risk levels—from target-date and conservative funds to growth funds, small cap funds, and aggressive funds.

Q. Does the Russell Investment Group use the same types of mathematical techniques that Dr. Hadaway and other analysts use to estimate future stock market returns?

A. Yes. In particular, Russell uses a modified discounted cash flow methodology, which it calls the dividend discount model, to derive an equity risk premium. *See* Exhibit WBM-9. Russell's analysis suggests a stock market return of 9%, composed of 3% inflation, a 3% real return on government bonds, and a 3% equity premium. The real equity return is divided into two components, an average long-term dividend yield of 2.3% and real earnings growth of 3.9% - components that are very similar to those used in a DCF method.

3. <u>Other Information on Stock Market Returns</u>

Q. What information can you bring to bear from other market participants on future stock market returns?

A. There is a considerable amount of information—both in the popular press and the academic literature—suggesting that stock market returns are likely to be less now than in the past.

To give a rather frightening statistic from the recent market meltdown, the S&P 500 closed at 903 at the end of December 2008. It was 897 at the end of August, 1997. In eleven years and four months, a buy-and-hold investor in the broad market would have received virtually nothing except the benefits of reinvested dividends.

Q. What information have you found in the popular press addressed to individual investors?

A. In the popular financial press:

- Warren Buffett has been projecting long-term stock market returns in the same range as, or even below, the pension actuaries for over five years,

  In May, 2008, Mr. Buffett stated that he would be happy to generate gains of 10% a year from common stocks over the long-term but questioned whether that will happen. The Berkshire Vice Chairman, Charlie Munger, said that Berkshire Hathaway is "very happy to make money at a rate in the future that's way less than we have in the past <u>and I suggest that you adopt the same attitude</u>."[31] [emphasis added]

  This position is consistent with his 2005 letter to Berkshire Hathaway shareholders, discussing the company's stock portfolio, he stated:

  > Expect no miracles from our equity portfolio. Though we own major interests in a number of strong, highly-profitable businesses, they are not selling at anything like bargain prices. As a group, they may double in value in ten years. The likelihood is that their per-share earnings, in aggregate, will grow 6-8% per year over the decade and that their stock prices will more or less match that growth. (Their managers, of course, think my expectations are too modest – and I hope they're right.)[32]

  Mr. Buffett also made a similar statement in 2003.[33]

- *Seeking Alpha* finds that from the end of 1968 through October 2008, the dividend-reinvested S&P 500 has earned a 1.5% premium over corporate bonds and just a 1.10% premium over government bonds. Through

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[31] "Buffett Cautions on Long-term Returns". MarketWatch (May 3, 2008). Available: www.marketwatch.com/news/story/buffett-warns-long-term-stock-returns/story.aspx?guid=%7BF74E5BEC-FBFC-4C72-93EE-9DB987BCB1B7%7D

[32] Warren Buffett, Letter to the Shareholders of Berkshire Hathaway, Inc., 2005, page 15. http://www.berkshirehathaway.com/letters/2005ltr.pdf

[33] "Stock Investors Should Expect 6-7 Percent Annual Return, Buffett Says." Bloomberg News Service (May 3, 2003). http://quote.bloomberg.com/apps/news?pid=10000103&sid=a1.neDMy8DEU&refer=us

October 2008, the long-term Treasury bond has *outperformed* stocks since the summer of 1987 and have come in just behind stocks since late 1980 (Exhibit WBM-10).[34]

- Long before the current meltdown, on July 11, 2005, *Fortune* magazine published an article entitled "Get Real About Your Future" where a panel of five experts all suggest returns in the overall equity market of less than 10%[35]
- Similarly, the August 29, 2005 *Barron's* magazine contained an article entitled "Preparing for Low Returns" by Keith Wibel. Mr. Wibel suggests that over the next ten years, S&P 500 returns will be in the vicinity of 6% including dividends (although with a relatively wide range); with historical earnings growth plus dividends, the return would be closer to 8%.[36]).

Q. What information has been developed in recent academic literature that relates to the rate of return?

A. In the academic literature, there has been considerable focus on the "risk premium"—the difference in returns between stocks and bonds. This is a key input into the Capital Asset Pricing Model ("CAPM") used to analyze the rate of return.

Arnott and Bernstein's[37] paper (Exhibit WBM-11) specifically states that "observed" excess returns to stocks and the "prospective" or expected risk premium are two different concepts and that the Ibbotson method of looking at historical data does not provide a risk premium. Their paper suggests that stock

[34] *Seeking Alpha*. "What Equity Risk Premium?". Available: www.seekingalpha.com/article/98784-what-equity-risk-premium .

[35] "Get Real About Your Future," Fortune, July 11, 2005.

[36] Keith Wibel, "Preparing for Low Returns," Barrons, August 29 2005.

[37] Robert D. Arnott and Peter L. Bernstein, "What Risk Premium Is 'Normal'?" *Financial Analysts Journal*, Vol. 58, No. 2 64-85. (March-April 2002).

prices increase in real terms approximately equally to the real per capita GDP growth over the long term.

- "The consensus that a normal risk premium is about 5 percent was shaped by deeply rooted naiveté in the investment community."[38]
- "The observed real stock returns and the excess returns for stocks relative to bonds in the past 75 years have been extraordinary, largely as a result of important nonrecurring developments."[39]
- "The historical average equity risk premium measured relative to 10-year government bonds as the risk premium investors might objectively have expected on their equity investments is about 2.4 percent, half what most investors believe."[40]

Clark and da Silva[41] (Exhibit WBM-12) suggest that the equity risk premium as observed in the marketplace can be decomposed into several components – the dividend yield on stocks, plus the real earnings growth associated with stocks, plus changes in the price/earnings ratio of the market, minus the real return on government bonds. One of those components – changes in the price/earnings ratio – caused a large increase in stock prices through the 1980s and 1990s, but is estimated to be near zero going forward. These analysts therefore estimate a long-run risk premium (without P/E effects) in the vicinity of 4% and cite a number of other studies in the 2.4% to 4.5% range (with one outlier of 7%).

Harvey and Graham have conducted extensive empirical studies of the equity risk premium, by interviewing CFOs of large companies and asking them what they expect as a risk premium.[42] They have found a 10-year equity risk premium

[38] *Id.*, p. 81.

[39] *Id.*, p. 80.

[40] *Id.*, p. 81.

[41] Roger G. Clarke and Harindra de Silva, "Reasonable Expectations for the Long-Run U.S. Equity Risk Premium," *Analytic Investors, Risk Management Perspectives* (April, 2003).

[42] Graham, John R. and Harvey, Campbell R., The Equity Risk Premium Amid a Global Financial Crisis(May 14, 2009). Available at SSRN: http://ssrn.com/abstract=1405459

(relative to 10-year treasury bonds) declining from about 4.5% in 2000 to the 3.8% range prior to the crisis and then rising to about 4.7% in recent months (Exhibit WBM-13 contains the most recent report). However, the 4.7% risk premium is associated with a 10-year treasury bond rate below 3% and yields an equity return barely over 7%. The average from 2000-2009 is 3.46%. Graham and Harvey state, based on interviews with CFOs, that it is an expected return over 10 years based on a buy-and-hold strategy. The equity risk premium was found to be significantly, though relatively weakly correlated to the <u>real</u> rate of interest, as paid on Treasury Inflation Indexed Notes (not to be confused with nominal rates including inflation). They found the equity risk premium to be higher with higher real rates, rising by about 21 basis points for every 100 basis points in the real rate of interest. It is also correlated positively with the spread between treasury and corporate bonds and with the stock market volatility index, increasing as these indicators of stock and bond market risk increase. Graham and Harvey also asked the CFOs to assess a one-in-ten chance that the market would exceed or fall below a certain level. The **90^{th} percentile return** for the entire market estimated by these CFOs averaged 11.50% from 2002 to the present. The risk premium associated with this 90^{th} percentile return was 7.06%.

Donaldson, Kamstra, and Kramer claim that it is simplistic to estimate the *ex ante* risk premium expected by investors solely using historical data on *ex post* returns without considering other aspects of the data related to market returns.[43] This information specifically includes dividend yields, Sharpe ratios (measuring the riskiness of a portfolio based on the portfolio return minus the risk free rate divided by the standard deviation of portfolio returns), and return volatility. When all of this information is used to simulate the performance of the US markets over the past 50 years, these authors compute an *ex ante* risk premium of 3.5%. Exhibit WBM-14 contains the abstract of this paper.

[43] Donaldson, Glen, Kamstra, Mark J. and Kramer, Lisa A., "Estimating the Equity Premium" (November 2008). Rotman School of Management Working Paper Available at SSRN: http://ssrn.com/abstract=945192

Ivo Welch's 2007 "Welch Survey" (published in 2008)[44] is a survey of 400 finance professors. It indicates a one-year equity premium and a 30-year geometrically-averaged equity premium of between about 5%, or in the interquartile range of between 4% and 6%. Participants in the Welch Survey estimate a 30-year arithmetic equity premium at about 75 basis points above the geometric equivalent, and they estimate that the 30-year geometric expected rate of return on the stock market at about 9%. While higher than some of the other estimates, the arithmetic mean is still 1.35% below Dr. Hadaway's figure of 7.1%. Please see the 2007 Welch Survey's abstract in Exhibit WBM-15.

As a final example, E. Dimson, P.R. Marsh, and M. Stanton, in an article that focuses on how big the equity risk premium has been, historically, and what risk premium investors, corporate managers, and regulators can expect going forward conclude that "(a) plausible, forward-looking risk premium for the world's major markets would be on the order of 3% on a geometric mean basis, while the corresponding arithmetic mean risk premium would be around 5%."[45]

4. <u>The Effect of Unregulated Operations on Proxy Group Earnings</u>

Q. Will you comment further on the need to set a return for regulated operations only?

A. It should be self-evident that the Commission is estimating the rate of return for a regulated utility. SWEPCO's evidence does not follow this principle adequately, however, and therefore overstates the return on equity required by the utility operations of electric companies.

Dr. Hadaway's proxy company selection criteria were based on 70% of <u>revenue</u> from electricity operations.

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[44] Available at: Welch, Ivo, "The Consensus Estimate for the Equity Premium by Academic Financial Economists in December 2007" (January 2008). Cowles Foundation Discussion Paper No. 1325. Available at SSRN: http://ssrn.com/abstract=285169.

[45] E. Dimson, P.R. Marsh, M. Stanton, "Global Evidence of the Equity Risk Premium", Journal of Applied Corporate Finance, Vol.15, No.4 (2003).

I believe that a better method for analyzing the impacts of unregulated activities on utility returns would use income or assets rather than revenue to determine the extent of unregulated activities. After all, the DCF and CAPM or risk premium methods are measuring growth in income and stock market risks based on earnings, not revenues. In addition, revenues are an arbitrary way of measuring activities, because revenues for utilities include significant amounts of (largely pass-through) fuel costs, so two utilities with largely identical profiles – one with more coal and nuclear generation and the other with more gas generation would have different percentages of unregulated revenues. When I analyzed the utility's capital structure, I removed Edison International, Entergy, and FPL Group in his proxy group, because they have more than 30% unregulated activities, based on income, I may have further comments and explicit adjustments regarding proxy companies after reviewing the Staff's comparison group.[46]

In any event, although I understand that in this day and age it is difficult to find a pure regulated utility to which to compare return for return when setting the regulated rate of return, we recommend that the Commission recognize the impact of unregulated activities on utility earnings growth at least judgmentally by using the lower end of ranges, particularly when considering "betas" for the capital asset pricing model and when considering the results of the comparable earnings and discounted cash flow ("DCF") analysis.

5. <u>Risk Premium methods: Critique of Dr. Hadaway's Analysis</u>

Q. What is the risk premium method of determining cost of capital?

A. As Dr. Hadaway testifies, risk premium methods are one of the methods used to estimate utilities' cost of capital. Risk premium methods are used to determine the return on a particular asset or portfolio of assets, using historical returns on

[46] Even within utilities, new incentive ratemaking programs may render the calculation of the rate of return for a pure wires utility problematic. For example, Pacific Gas and Electric Company and Southern California Edison Company were granted very generous Energy Efficiency incentives by the California regulators. Those incentives will leak into growth rates used to analyze the ROE for utilities without comparable energy efficiency programs in states without comparable energy efficiency incentives, thus biasing upward the plain vanilla return on ordinary regulated operations.

risk-free asset and add an increment to account for additional equity risk. Once the premium is determined, one can use it in combination with the risk-free rate to estimate the regulated return on equity. The Capital Asset Pricing Model (CAPM) is one form of risk premium method, although Dr. Hadaway uses a different risk premium method.

Q. Will you discuss how the Capital Asset Pricing Model ("CAPM") is generally implemented to provide some background?

A. The Capital Asset Pricing Model ("CAPM") relates the required return to two components – the risk free rate of return, and the market risk premium (amount by which typical stock market returns exceed the risk-free rate of return) – using a measure called "beta" that quantifies the riskiness of the individual stock or investment as compared to the market risk. Beta is also viewed as the

Return = Risk Free Rate + Beta X Market Risk Premium

The risk free rate for purposes of analyzing a utility return is typically a long-term government bond rate, although short-term government bill rates are often used in other contexts.

As the equation indicates, the essence of CAPM is that it calculates the "required" return by adding an adjusted market risk premium to the risk free rate. The standard risk free proxy used in utility regulation is long-term government bonds. The market risk premium is the return of the market above the risk-free rate. The quantification of the market risk premium is a point of controversy in many rate of return analyses. We addressed this issue above at some length, suggesting that the market risk premium is relatively low, as compared to the average returns achieved historically by stocks and bonds over the last 80+ years.

The adjustment to the market risk premium is "beta". "Beta," or the risk of individual stock or stocks, is calculated by comparing the returns on individual stocks to the market return over a period of time. A beta of less than one indicates that a stock will tend to increase at a rate that is less than the market return when the market goes up and decrease at a rate that is less than the market decline when it drops. Conversely, a beta greater than one means that a stock will increase or decrease more rapidly than the rate at which an increasing or decreasing market would. Again, the further beta is from one, the greater this effect.

Theoretically, beta is the portion of systematic or non-diversifiable risk associated with a given stock. The source of "beta" traditionally used in utility rate cases comes from Value Line, which has made such calculations for over 30 years. However, new sources of beta, calculated in different ways, have become available in the Internet age (from Google, Yahoo!, and Reuters). These betas at the moment are considerably lower than Value Line betas.

Q. Does Dr. Hadaway use CAPM?

A. No, Dr. Hadaway does not subscribe to the CAPM method for determining regulated cost of capital. He testifies on p. 15 that CAPM's "additional data requirements and potentially questionable underlying assumptions have detracted from their use in most regulatory jurisdictions." While I agree that there are some issues surrounding the use of CAPM for setting regulated equity return, and that practitioners have tended to use a variety of methods in combination in order to deal with issues that arise in all methods used to derive an applicant's cost of capital, it is unusual to see a utility witness take this stance. A number of utility witnesses who have testified in Arkansas have claimed that CAPM (of course with very high estimates of the market risk premium) would yield higher returns than the Discounted Cash Flow ("DCF") method commonly used in Arkansas.[47]

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[47] Footnote 33 in the Attorney General's Comments in Docket 08-137-U (pages 26-27) catalogued a number of uses of CAPM by utility witnesses with extremely high risk premiums. Analysis using data starting in 1926 is found in a number of recent cases including Direct Testimony of Donald A. Murry for OG&E in Docket 08-103-U, Schedule DAM-21. Direct Testimony of Robert B. Hevert on behalf of CenterPoint Energy Arkansas Gas in Docket 06-161-U, page 26. Direct Testimony of Roger A. Morin for Entergy Arkansas, Inc. in Docket 06-101-U, pages 37-38. The use of even higher short-term rates as an input into CAPM is also found in some utility testimony. In the EAI case, Dr. Morin also used a prospective estimate from Value Line with a future market risk premium of 7.9%. Id. He used an 8.8% prospective CAPM estimate from Value Line in Docket 04-176-U, based on a model that assumed a 13.5% to 16.7% growth rate in corporate earnings. . Direct Testimony of Roger A. Morin for Arkansas Western Gas Company. in Docket 04-176-U, pages 27-28, AWG witness Frank Hanley used a future market risk premium based on an 18.4% stock market return in a CAPM analysis. Prepared Testimony of Frank J. Hanley on Behalf of Arkansas Western Gas Company in docket 02-024-U, pp. 47-48, Exhibit FJH-13.

Q. Does Dr. Hadaway use a form of risk premium analysis that is different from CAPM?

A. Yes. Dr. Hadaway relies on a number of sources in his risk premium conclusions. The first source is an analysis that Dr. Hadaway, himself, performs. This analysis uses utilities' authorized utility returns and utility cost of debt in order to calculate the "indicated" risk premium that prevails in the market for utility equities[48]. Dr. Hadaway calculates the difference between authorized utility returns (but neglects to report which utilities he uses) and Moody's average public utility bond yields for the years 1980 to 2008, which averaged yields a so-called "basic risk premium" of 3.19%. Dr. Hadaway then adjusts this basic risk premium using a statistical relationship he calculates between authorized utility equity risk premiums and average utility interest rates, and then uses a) the projected single-A utility bond yield and b) the current single-A utility bond yield to calculate the so-called "indicated equity return;" this indicated equity return is what he cites in the table on p. 42 to show the range of his ROE analysis results.

Specifically, using the "projected" single-A utility bond yield, Dr. Hadaway calculates an equity risk premium of 4.1%, to which he adds the projected single-A utility bond yield, itself, which his testimony indicates is 6.95%, to get an "indicated equity return" of 11.05%. Similarly, using the "current" single-A utility bond yield, Dr. Hadaway calculates an equity risk premium of 3.98%, to which he adds the projected single-A utility bond yield, itself, which his testimony indicates is 7.23%, to get an "indicated equity return" of 11.21%.[49]

In addition to his own analysis, Dr. Hadaway relies on published risk premium studies, although he provides neither the studies nor any specific citation to the studies. The study Dr. Hadaway relies on is published by Morningstar/Ibbotson, which apparently indicates a risk premium over corporate bonds of 4.5% (calculated by geometrically averaging risk premium for common stocks versus

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[48] APSC Docket No. 09-008-U Dr. Hadaway's Direct Testimony, p. 35.

[49] *See* APSC Docket No. 09-008-U, Exh. SCH-6 and 7 to Dr. Hadaway's Direct Testimony.

long-term corporate bonds from 1926-2007). This narrow review of the literature, indicates an ROE of 11.73% (7.23% debt cost + 4.5% risk premium = 11.73%) using the geometric mean.[50]

Q. What is your evaluation of Dr. Hadaway's risk premium method?

A. There are several key problems that I will expand upon in more detail. The most important issue is that he uses authorized returns from other state Commissions as a proxy for returns that the market might "expect," which is both circular and requires the Commission to abdicate its responsibility. For this reason alone, Dr. Hadaway's risk premium analysis lacks merit.

Q. Does Dr. Hadaway's risk premium method suffer from additional flaws?

A. Yes, Dr. Hadaway's method suffers from its use of calculating risk premiums based on corporate bond rates and subsequently deducing the current utility cost of capital by adding his calculated risk premium to current and projected corporate bonds yields (as of the filing of his testimony on February 19, 2009). Dr. Hadaway appears to use corporate bonds, in part, in order to solve the problem of the influence that a "flight-to-safety" might have had on government securities, which he writes about on page 23..

The problem with substituting corporate bonds for government bonds as a means of dealing with the influence of "flight-to-safety" is that corporate bonds have an equally-powerful "flight from risk" phenomenon, which in this economic and financial environment tends to elevate corporate bond rates by raising the premium of corporate bonds over treasuries to abnormally high levels. The latter will produce an overestimate of ROE.

Additionally, we are already seeing a easing of the corporate bond rates from those that Dr. Hadaway supplied in his original testimony. Whereas, Dr. Hadaway supplied a "current" utility corporate (single-A) bond rate of 7.23%,

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[50] Dr. Hadaway's use of the geometric mean places him at variance with many other utility rate of return witnesses who use the higher arithmetic mean.

Kansas Gas & Electric, as stated above, just issued debt at 6.7% with a BBB+ rating.

Q. What is your evaluation of Dr. Hadaway's use of the Morningstar/Ibbotson review?

A. Although Dr. Hadaway provides neither the citation to nor the data and analysis of Morningstar/Ibbotson, I am familiar with the likely source of this dataset and analysis. Dr. Hadaway indicates that the historical data are from 1926-2007, and provides the arithmetic and geometric average risk premium from the study.

A constant risk premium—which is what is derived from an average over a set of years, 1926-2007 in this case—can only be justified from the narrow perspective of pure statistics. Because returns on stocks and bonds are volatile from year to year, it is impossible to discern trends in highly aggregated data on returns using standard statistical techniques without analyzing other information (for example, the information analyzed in a more sophisticated way by Donaldson, Kamstra, and Kramer, provided in Exhibit WBM-14.) However, the statistical perspective is a narrow one. It states that statistical methods cannot discern a trend in data, not that such a trend is absent.

While investors do not necessarily believe that every year will be economically rosy, by using data beginning from 1926, Dr. Hadaway is assuming—by relying on the Morningstar/Ibbotson data—that investors today give significant weight to a recurrence of the economic conditions of 60-80 years ago (the Great Depression, World War II, and Federal Reserve Board monetary policy designed to keep interest rates down for the purpose of financing government war debt cheaply).[51] The Federal Reserve Board itself recently rejected use of data all the way back to 1927 when calculating the return on equity capital used to estimate returns on Federal Reserve Bank priced services. It made the determination to use only 40 years of historical data, not over 80 years.[52]

[51] Donaldson, Kamstra, and Kramer, op. cit., p. 9 stated that "modern monetary policy" began in 1951.

[52] 70 Federal Register, 60341-60347, October 17, 2005. Notice in Docket OP-1229.

As discussed above, considerable amounts of the academic literature are identifying a risk premium (with respect to government bonds) in the range of 3.5 to 5%. Corporate CFOs are identifying a risk premium of 3.6% and are stating that a risk premium above 7.21% would only be observed with a 10% probability. Most utilities' own pension actuaries and decommissioning fund managers are showing 9-10% stock market returns with fixed income returns in the 6% range.

In addition, as noted above, if current economic and financial conditions continue or worsen, then investors are going to be lucky to get a return on their capital anywhere near what regulated utilities are allowed even allowing that these conditions are currently making capital more expensive.

Therefore, the Morningstar/Ibbotson estimate of the long run risk premium based on an average going back to 1926 is not a reasonable predictor of investors' expectations or requirements over the long-term, regardless of long-ago history or statistical niceties or the difficult climate we presently face—even granting current special circumstances with the current financial and economic climate that may push short-term risk-premiums to abnormally high levels.

6. <u>Analysis of the Effect of Lower Equity Return Estimates from Pension and Literature Sources</u>

Q. Have you prepared any comparisons of historical stock market returns, returns on utility stocks, and bond returns over a long period of time (i.e., a period of time that could be used in a historical CAPM)?

A. Yes. I have prepared a comparison of returns for electric utilities, gas utilities, the S&P 500 and bonds (using electric and gas utility return and bond return data presented by Dr. Roger Morin)[53] and S&P 500 data developed by Dr. James

[53] Electric utility and bond return from Exhibit RAM-3 of his testimony in APSC Docket No. 06-101-U (Entergy Arkansas, Inc. General Rate Case), available: http://www.apscservices.info/PDF/06/06-101-u_16_1.pdf; gas utility return from Exhibit RAM-3 of APSC Docket No. 04-176-U (Arkansas Western Gas Company rate case), available: http://www.apscservices.info/efilings/Docket_Search_Documents.asp?Docket=04%2D176%2DU&DocNumVal=9.

Vander Weil, a utility witness in a recent Pacific Gas & Electric Company cost of capital case, shown in Table 6 below.

I used the period 1955-2001. I purposely chose the beginning of the period to start after the end of the Korean War and the ensuing 1954 recession, as well as after the beginning of "modern monetary policy." The period of time that includes the Great Depression and World War II and its aftermath does <u>not</u> reflect conditions that current investors believe hold today or are likely to recur in the future, even though reaching farther back in history produces higher risk premium numbers that utility rate of return analysts like to use. The end of the period (2001) was the last year for which Dr. Morin presented data in his recent rate case filings.[54]

<u>Table 6: Returns and Risk Premiums for Electric Utilities, Gas Utilities, the S&P 500, and Long-Term Treasury Bonds</u>

	1955-2001	1960-2001	1967-2001	1983-2001	1955-1966	1967-1982
S&P 500 return	11.86%	11.77%	12.31%	15.33%	10.57%	8.73%
Electric Utility Return	11.53%	11.47%	11.53%	15.30%	11.52%	7.05%
Gas Utility return	12.16%	11.79%	12.25%	15.07%	11.91%	8.91%
Bond Return	6.33%	7.27%	7.90%	11.17%	1.73%	4.02%
Electric Utility risk premium	5.20%	4.20%	3.62%	4.13%	9.79%	3.03%
Gas Utility risk premium	5.84%	4.52%	4.35%	3.89%	10.18%	4.89%
S&P 500 risk premium	5.54%	4.51%	4.41%	4.15%	8.84%	4.71%
Electric utility return as % of S&P 500	97.1%	97.4%	93.6%	99.8%	109.0%	80.8%
Gas utility return as % of S&P 500	102.5%	100.1%	99.5%	98.3%	112.7%	102.1%

Over the 46 years from 1955-2001, the S&P 500 had a return that averaged 5.54% above long-term treasury bonds. This is approximately 56 basis points below the arithmetically-derived risk premium of corporate stocks against long-term corporate bonds.

[54] In APSC Docket No. 06-101-U, Dr. Morin responded to a data request by the Attorney General that the data series on which he relied to do this analysis were discontinued after 2001. It is also difficult to update this analysis because the prevalence of deregulation this decade means that fewer and fewer utilities are close to being purely regulated. However, the point regarding the bias that pre-modern monetary policy returns (those that include the Depression, WWII, and the Korean War) introduce to 2009 *ex ante* expectations remains robust and relevant to our discussion regardless of the lack of a dataset that does not go past 2001.

Q. Will you compare the returns on utility stocks versus the S&P 500 in the Table above?

A. The rest of this chart is even more interesting than the risk premium estimate. Over the 46 years ending in 2001, electric utilities underperformed the S&P 500 by only 32 basis points (2.9%) despite being considerably less risky (with betas less than 1). Over sub-periods, the return ranged from 81% to 109% of the S&P 500. The lowest return was experienced in the 1967-1982 period, a time when electric utilities in particular faced depressed prices due to the lack of fuel adjustment clauses in the 1974 oil shock coupled with dramatic reductions in demand growth, massive capital spending programs, and burgeoning interest rates. In the 1983-2001 period, electric utilities provided a return virtually identical to the S&P 500.

Gas utilities had even better performance. Gas utilities <u>outperformed</u> the S&P 500 by 30 basis points (2.5%) despite being less risky (with betas less than 1 over the vast portion of the historical period). Over sub-periods, the return ranged from 98% to 113% of the S&P 500 – a return virtually identical to the market as a whole.

This finding needs to be compared with a principle cited in key court cases on rate of return—that the authorized return on common equity should be the same as returns on investments in other firms with similar risks. For a group of less risky, low-beta regulated utility stocks to perform equivalent to the market as whole violates this risk principle.

This may even suggest there has been some kind of long term "free lunch" for utility investors, which the market may not yet have fully recognized. The "free lunch" may potentially arise from the circular nature of the setting of utility returns – high returns in the past beget requests by utilities for high returns in the future,[55] which in turn begets stock performance equal to the S&P 500 over the long run with considerably less risk (particularly in the past) than the S&P 500.

Q. Have you been able to update this information beyond 2001?

A. The specific data series used in this analysis essentially stopped in 2001. However, other information comparing the electric and gas utility sub-indices of the S&P 500 and the S&P 500 in the US has recently been developed by Professors Lawrence Kryzanowski and Gordon Roberts for 1989-2008.[56] These data indicate that utilities have outperformed the S&P 500 over this 20 year period as well as the last decade (where utility performance has been positive and S&P 500 performance has been negative).

Q. Are you providing any additional quantitative information as a check on the information presented by Dr. Hadaway?

A. Yes. Table 7 depicts our CAPM calculations over a range of market return assumptions, using the current risk-free rate (4.43%, the average 20-year Federal bond rate from May 13 to June 12, 2009) in all cases except Case 8, the California decommissioning fund estimate, where the higher risk-free rate of 5.36% contained in that analysis was used), and the average beta (0.68[57]) for Dr. Hadaway's proxy companies.

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[55] A prime example of such circularity is Dr. Hadaway's use of authorized returns by other state Commission to derive his recommended risk premium.

[56] Lawrence Kryzanowski and Gordon Roberts, Prepared Testimony on behalf of the Office of the Utilities Consumer Advocate in Alberta Utilities Commission Docket 1578571/Proceeding No. 85 (March 2, 2009), pp. 288-289 and Schedules 5.3 and 5.4 (pages 412-413).

[57] Average of proxy company betas, as calculated by Value Line. We note that utility betas have been highly volatile in the last three years. As recently as a year and a half ago, Value Line was publishing utility betas in the vicinity of 1.0, whereas, other sources, such as Google, Yahoo!, and Reuters were publishing utility betas in the vicinity of 0.7. Utilities were never risky enough to merit a beta of 1.0. On the other hand, the likes of Google, Yahoo!, and Reuters are now publishing betas on the order of 0.5, which is low, and appears to be caused by the effects of precipitous recent drop of stocks from certain sectors, such as the financial sector.

Table 7: Range of Capital Asset Pricing Method Results

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Average
Risk-free rate (current[1])	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	5.36%	
Market equity return		9.60%	9.30%	10.39%			8.13%	
Risk premium	5.54%	5.17%	4.87%	5.96%	4.00%	3.59%	2.77%	4.56%
Beta[2]	67.81%	67.81%	67.81%	67.81%	67.81%	67.81%	67.81%	
Return on equity	8.19%	7.94%	7.73%	8.47%	7.14%	6.86%	7.24%	7.65%

Case 1 -Historical Risk Premium - 1955-2001 average S&P risk premium
Case 2 - Pension equity returns 10 comparison electricity companies
Case 3 - Entergy nuclear decommissioning return - geometric mean with current inflation
Case 4 - Entergy nuclear decommissioning return - approximate arithmetic mean with current inflation *
Case 5 - Clark and da Silva risk premium estimate
Case 6 - Graham and Harvey average risk premium 2000-2005 (close to Donaldson, Kamstra and Kramer estimate)
Case 7 - California utilities' equity and debt market estimates (decommissioning funds)

* added 109 basis points for difference between geometric and arithmetic means for S&P-500 minus GDP implicit price deflator for 1955-2001. Note that I do not accept the contention that the arithmetic mean is the only appropriate measurement of equity returns but am providing this figure to show the impact.

[1] 20-year Treasury Bond rate, average from May 13, 2009 to June 12, 2009 (US Federal Reserve, accessed: www.federalreserve.gov/releases/h15/data/Business_day/H15_TCMNOM_Y20.txt on June 13th 2009)

[2] Value Line's beta (accessed January 13, 2008).

The average returns in Table 7 range widely, from 6.86% in Case 6 to 8.47% in Case 4.

While I do not think that returns at the top end of this range are unreasonable, the returns on the low end are certainly unreasonable. I point them out, however, to illustrate that the recession is responsible for creating the low return numbers by creating the low risk-free rate. But, as I stated above, if the recession is leading us toward lower returns going forward, then investors are going to be scrambling to realize returns comparable to those on the high end of this CAPM range for comparably risky assets.

I would also point out that **the highest possible number calculated using the highest risk premium (8.47%) is well below the current authorized rate of return for SWEPCO (10.75%), which is again below the 11.5% SWEPCO is requesting in this case.** Also, figures at or below 9% are not unheard of, and have previously been adopted. The Alberta Energy and Utilities Board's current formula for setting the utility cost of capital, based on a risk premium method, which started out at 9.6% in 2004, was indexed at 8.51% in 2007 and 8.75% in 2008. *See* Exhibit WBM-16. A figure of 8.56% would flow from the Alberta formula applied to the current 4.43% risk-free rate.

Finally, betas for electric utilities have been declining recently from about 0.9 in 2007 to 0.7 or lower now. As could be expected, a market meltdown that spread to the broad market but was concentrated in financial and natural resource stocks has resulted in a decline in the systematic risk of utilities relative to the market as a whole. All else being equal such a decline in beta <u>should</u> cause the expected return on equity to decline.

Q. **Do low Treasury bond rates present a challenge to classical CAPM analysis?**

A. Yes, just as high corporate bonds present a problem with Dr. Hadaway's risk premium method, low Treasury bond rate (with a larger spread between Treasuries and corporate bonds than is generally seen, historically) is an indicator of relatively high risk as discussed above, but the CAPM model is not specifically designed to capture that risk. Although Treasury bonds have increased recently from their extreme lows in February and March of this year, they remain below historic averages.

Recognizing that the risk-free rate may be unusually low due to the continuing "flight to quality" and relatively easy monetary policy, and the market risk premium may have moved up temporarily (as noted by Graham and Harvey), it would be necessary not to rely on a raw CAPM analysis without using judgment.

On the other hand, using historical corporate bond rates, as Dr. Hadaway has done in his risk premium analysis, to estimate risk premium, and then adding those historically-based risk premia to abnormally elevated corporate bond rates resulting from the current economic and financial environment is also wrong under current market conditions for the opposite reason. It does not reflect the fact that it is virtually impossible to obtain the long-term average differential return between stocks and bonds in a market that is subject to the present short-term risk shown by the current differential between treasury and corporate bonds.

Recognizing the difficulties with both of these approaches, I am recommending a middle ground between the results of the unreasonably high and low results that Dr. Hadaway's risk premium method and the CAPM method produce.

Q. Have any recent tax changes affected utilities' cost of capital?

A. Yes. The new lower tax rates on both dividends and capital gains have increased the after-tax returns for at least some investors in the market, which all else being equal, should lower the cost of equity capital relative to the period before 2003.

7. <u>Discounted Cash Flow Models</u>

Q. Is there a problem with the Discounted Cash Flow model that Dr. Hadaway used?

A. In addition to the issues that I discussed above regarding companies involved in unregulated activities (or companies with growth in returns and dividends as a result of incentives for non-core operations such as energy efficiency or FERC transmission that should not be included in a state commission's rate of return on rate base), there is a problem with the DCF models inasmuch as Dr. Hadaway relies entirely on forward-looking forecasts of future cash flows. While forward-looking forecasts have some value they need to be tempered with historical and fundamentally based analyses. Given the current down market, analysts' predictions are weighed heavily with expectations the market will turn around, which produces larger growth estimates of dividends and earnings than is sustainable over the long-term. Market analysts never predicted the original drop when calculating the rate of return, but would not hesitate to use the abnormally high rebound from that drop. It is important to understand regarding this point that even Dr. Hadaway's second and third DCF model runs[58], which are not labeled using analysts' projected growth rates, have this infirmity, albeit to a lesser degree. His second model relies on analysts' projections of long-term GDP growth, and the third relies on three- to five-year dividend projections plus long-term projected growth in GDP. All three models use Value Line projections of dividend for the coming year.

Conversely, an alternative fundamental, or "earnings retention," method measures the sustainable increase in book value (related to ROE for an electric utility under rate base regulation), which is a way of indicating a utility's long-run ability to increase its earnings, and hence dividends. It is based on the earned rate of return, multiplied by the retention ratio (the percentage of earnings not paid out in dividends), plus an adder for the accretion to book value that arises when a utility finances construction by selling stock at a price above book value. This fundamentals method would take out the short-term volatility of this down market, giving a more realistic view of what we could expect of the long-term.

Additionally, I would note that current market conditions and the drop in utility stock prices have caused the dividend yield of utility stocks to increase significantly. To the extent that the credit crisis and the associated risk aversion is

[58] Dr. Hadaway performed three DCF model runs, per p. 36 of his direct testimony: constant growth with analysts' growth rate projections, constant growth with long-term GDP growth projections, and low near-term growth.

ameliorated, one could expect the dividend yield component of the DCF method to fall over the next year or two.

Therefore, this discussion, as well as conclusions drawn from the pension fund and CAPM discussions, above, indicate that the Commission should give little weight to the range of values Dr. Hadaway presents in his table on p. 42, which is 10.9%-11.73%.

8. <u>ROEs approved by Other Commissions</u>

Q. Are there other commissions that have approved rates of return that are on the order of what your results suggest?

A. Yes, in addition to the Alberta decision that we provided above, there are a number of state commissions in the U.S. that have approved ROEs of less than 10% in recent years. (These are meant to be illustrative; we do not mean to imply that other examples do not exist.)

- <u>In 2008</u>, the New York Public Service Commission approved a return of 9.1% for electric distribution service (Consolidated Edison Company of New York, Inc., Case 07-E-0523[59]). In 2006, it approved 9.8% (Orange and Rockland Case 05-G-1494),[60] and 9.6% (Central Hudson, Cases 05-E-0934 & 05-G-0935, and St. Lawrence Gas, Case 05-G-1635[61]).

[59] New York Public Service Commission, Order Establishing Rates for Electric Service in Case 07-E-0523 (March 25, 2008), slip op. p. 126. http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/27823125130A3E38852574170067DDB4/$File/301_07e0523ORDER_FINAL.pdf?OpenElement

[60] New York Public Service Commission, Order Making Temporary Rates Subject to Refund in Case 06-E-1433—Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

[61] New York Public Service Commission. Press Release on 11/8/06: PSC Approves Three-year Rate Plan for St. Lawrence Gas. Available: http://www.stlawrencegas.com/pressrel/Press%20Release%20-%20November%202006.pdf.

- The New Mexico Public Regulation Commission approved an ROE of 9.5% in June, 2007 (Public Service Company of New Mexico)[62].

- The New Hampshire Public Utilities Commission approved a rate of return of 9.63% on generation (Public Service Company of New Hampshire, Docket DE 04-177)[63] in 2005.

In sum, other commissions have authorized single-digit rates of return in the recent past. We grant that this past does not include the current financial meltdown, but as we have stated above, if financial and economic conditions stay as they are, any guaranteed return in the high single-digits will be welcome news to potential and current investors.

C. *Summary of Rate of Return*

Q. Will you summarize your position regarding the rate of return?

A. The requested 11.5% return on equity for a utility like SWEPCO is simply not reasonable under the circumstances.

1. SWEPCO's parent company, AEP itself, expects that the broad equity market will earn 10.06% when making pension fund projections.

2. The average equity return expected by the pension actuaries of the 16 utilities identified by Dr. Hadaway as a comparison group to SWEPCO is 9.56%, given an average discount rate (high grade long-term corporate bond rate) of 6.3%.

3. The 90th percentile return for the entire market from Graham and Harvey's CFO survey averaged 11.5% from 2002 to the present. The CFOs' average

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[62] New Mexico Public Regulation Commission. Press Release on 6/29/07: PRC Reduces Proposed PNM Rate Hike. Available: http://www.nmprc.state.nm.us/news/pdf/062907pnm_ratehick.pdf.

[63] New Hampshire Public Utilities Commission. Order No. 24,473, Transition and Default Service Rates, Order Following Hearing Regarding Return on Equity. The order indicated that the appropriate rate of return on a diversified utility would be 9.42% and added 21 basis points for risks of regulated generation

expected return was around 8% (risk premium of 3.5%). The current elevated risk premium of 4.74% on a sub-3% treasury bond is still below 8%.

4. Other academic literature, as well as the analysis by the Russell Investment Group suggests a risk premium of 3% to 5%, which corresponds to an overall stock market return below 10%.

5. Historical data that does not reach back to the Depression and World War II supports equity returns of 10% or less.

In addition to these factors, we must look carefully at the context. Current market conditions are both abnormal and unsustainable and also cause models typically used when analyzing the rate of return to yield results that are unreasonable or difficult to interpret.

The spread between corporate bonds and government bonds has increased relative to more normal past conditions, as investors' appetite for risk is reduced. The very low rate on government bonds renders some of the results of a classical capital asset pricing model ("CAPM:) formulation to be unrepresentative of anything except the results that would be likely to occur in a deep credit-based recession (returns in the 7-8% range).

On the other hand, Dr. Hadaway's risk premium method has the opposite infirmity under current market conditions that could tend to overstate long-term equity returns. Applying some kind of "normal" risk premium to abnormally high corporate bond rates is likely to overstate the required return.

Similarly, one must be cautious when applying a DCF model in this market. Temporarily depressed stock prices can result in unusually high current stock dividend yields that are coupled with growth estimates that are both unsustainable long-term and are consistent with falling dividend yields in the future.

Either this risk aversion (marked by large spreads between government and corporate bonds) will continue for a significant period of time, or it will return to more normal levels, which we are seeing to some degree even in the short time since Dr. Hadaway filed his testimony.

If the spread continues to return to more normal levels, it would be a mistake to give utilities a rate of return that could be in place for several years on the basis of transitory market conditions.

If, on the other hand, the outsized spreads between government and corporate bonds stops improving, or reverts to the even higher spreads we saw earlier this year, the resulting credit crisis (spread far beyond the housing sector) will contribute to an extremely deep recession. Under such recessionary conditions, investors might *desire* high returns to compensate for risks, but those high returns will simply not be realized. In essence, a high rate of return does not flow from a prediction of a continuing high risk premium. The credit conditions and real economic conditions that would flow from forecasting a continued high risk premium would ensure that stock market investors are unlikely to realize the returns that they would allegedly "require". Under these conditions, utilities would be a relatively safe haven compared to many other investment choices and should be priced accordingly with lower returns than are in place today.

While we do not know what will happen, we can state that using current dysfunctional market conditions as the basis for adopting large upward changes to investors' required returns on utility equity is likely to be the wrong answer – either because the conditions generating such "required" returns will be transitory or because, if not transitory, the conditions generating such "required" returns will make it impossible for the returns to be achieved in the real world.

Faced with a highly uncertain economy and a situation where standard rate of return models do not provide terribly good forecasts, I recommend that the Commission find middle ground between the various competing model results. As noted above, a high return such as that proposed by Dr. Hadaway is not reasonably justifiable based on an appeal to current market conditions. A lower return could be justified by the type of analysis that is presented in this testimony under normal economic conditions.

A reasonable interpretation of CAPM results today would be to focus on the top end of the range at this time (8.0% to 8.5%) and to add 50-100 basis points to estimate the potential for a relatively low risk free rate and an elevated risk premium in the near term, yielding a range of 8.5% to 9.5%. This result is below the minimum of a DCF-based analysis (though the top end is close to the minimum point). However, this fact in isolation should point the Commission directionally lower than the midpoint of a DCF range given its traditional reliance on the DCF.

In addition, one must take into account firm-specific aspects of business and financial risk. Specifically considering (1) that AEP (close to a pure play electric utility) is near a market-to-book ratio of 1.0 as a result of the stock market decline in early 2009 (after being well over 1.0 for many years in the past); (2) that there is still some fear in the credit markets that should not be exacerbated; and (3) SWEPCO's heavy construction program, I recommend an ROE of 10.0% in this case for SWEPCO at this time.

Q. Would your recommendation change if the Commission were to largely adopt SWEPCO's proposal for Construction Work in Progress in the Rate Base as part of its Generation Rider?

A. Yes. If SWEPCO's proposal for current recovery of CWIP costs from ratepayers is largely adopted, I would recommend a further 25 basis point reduction in ROE to 9.75% to take into account the significant reduction in business and cash flow risk.

Q. How should the return on equity be changed if the Commission were to grant a rate rider to recover the costs of Turk when it becomes commercially operational?

A. If SWEPCO is provided a rate rider such that it does not need to file a rate case to recover the costs of Turk when it comes into service, the rider should reflect a reduced rate of return on the Turk investment at the time of commercial operation (e.g., a 9.5% return on equity for the Turk investment) to reflect the major reduction in the Company's risk and improvement in cash flow that would occur when rate recovery is available for the Turk plant.

Q. Will you confirm the rate of return that you are recommending?

A. Given financial market and economic conditions, I am recommending that the Commission adopt an ROE of 10.0%. The Commission should adopt a return on equity of 9.75% to reflect reductions in the company's business and financial risk if the Commission provides current recovery in rate base of substantial amounts of CWIP.

Q. Have you prepared a summary showing your proposed rate of return on rate base?

A. Yes, it is provided below in Table 8, including the AG's capital structure, ROE and customer deposit rate.

Table 8: AG's Capital Structure and Rate of Return

			As Adjusted (with 53-47 Debt-Equity)				
Line No.	Description		Amount	Proportion	Rate	Weighted Cost	After Tax Cost
1	Long Term Debt	(a)	1,549,298,550	40.13%	6.22%	2.50%	2.50%
2	Preferred Stock	(b)	4,700,221	0.12%	4.67%	0.01%	0.01%
3	Common Equity	(c)	1,373,906,262	35.59%	10.00%	3.56%	5.62%
4	Accumulated Deferred Income Taxes	(d)	390,733,860	10.12%	0.00%	0.00%	
5	Pre-1971 ADITC		-				
7.	Post-1970 ADITC	(d)	15,351,902	0.40%	7.99%	0.03%	0.04%
8	Customer Deposits	(d)	38,190,904	0.99%	2.60%	0.03%	0.03%
9	Short Term/Interim Debt	(d)	-	0.00%	1.22%	0.00%	0.00%
10	Current, Accrued and Other Liabilities	(d)	374,142,805	9.69%	0.00%	0.00%	0.00%
11	Other Capital Items	(d)	114,337,786	2.96%	1.74%	0.05%	0.05%
12	Totals		3,860,662,290	100.00%		6.174%	8.456%

Q. **Will you compare your rate of return with SWEPCO's?**

A. SWEPCO proposes a rate of return of 7.00% before tax and 10.02% after tax. We recommend 6.17% before tax and 8.46% after-tax. The differences between us can be disaggregated into 28 basis points befor tax (68 basis points after tax) for the updating of other assets, 1 basis point for customer deposits, and 54 basis points before tax (89 basis points after tax) for the AG's 10.0% rate of return;

With SWEPCO's requested rate base of $608,966,000 (Arkansas jurisdiction), the Attorney General's capital structure and rate of return reduce the required rate increase by $9,500,000 or 37.6% of the proposed increase.

IV. Expenses and Rate Base

A. Incentive Compensation

1. Short-Term Incentive Programs

Q. **What are SWEPCO's recorded test year short-term incentive ("STI") program expenses?**

A. Based on SWEPCO's Response to AG DR 3-15[64], attachments 1 and 2, SWEPCO's test year STI program expenses were $9,880,287, and AEP's test year STI program expenses allocated to SWEPCO were $9,304,659. SWEPCO's total allocated test year STI expenses were $19,184,946.

Q. **Have you analyzed AEP's STI programs, as they apply to SWEPCO employees and shared service employees.**

A. The payment of incentives is detailed in documentation provided in SWEPCO's response to APSC-028. An incentive percentage is computed for individual work groups based on a series of performance expectations—some of which are financial (e.g., meeting budgets) and some of which are not financial. The

[64] This data response was labeled confidential but counsel for SWEPCO cleared our use of aggregate figures from it.

performance, relative to average of all of the groups in SWEPCO and in the shared services function, are separately computed.

However, the amount of the total incentive payment for the company is entirely based on earnings per share—with a floor of 20% with earnings at or below the low end of guidance ($3.10 in 2008) and a ceiling of 200% with earnings at or above the high end of guidance ($3.30 in 2008). In the end, each group's incentive payment is scaled to match the company's overall incentive based on Earnings Per Share ("EPS"), based on the individual incentive multiplied by the ratio of the corporate EPS incentive to the total group's incentives.

Additionally, between 20% and 35% of each group's incentives are based on financial measures, such as spending below budget.[65]

Q. What do you recommend?

A. Following the Arkansas Commission's past practice, I recommend sharing the financial metrics 50-50 between ratepayers and shareholders, and allowing 100% of the incentives associated with non-financial metrics. Because the total amount paid out is based on Earnings Per Share, I recommend the Commission disallow 50% of total allocated STIs off the top to reflect such sharing. I also recommend that the Commission disallow an additional 5% of STIs to reflect a sharing of the minimum 20%[66] of STIs that are financial in nature (e.g., groups spending less than budgets). Therefore, the total disallowance would be 55% of SWEPCO's test year expense.

My recommendation reduces total AEP STI expenses by $5,117,562 and SWEPCO STI expenses by $5,434,158, for a total SWEPCO-allocated STI reduction of $10,551,720. Using the Arkansas retail total payroll allocation factor (21.535%, per SWEPCO's Response to AG DR 3-16), the corresponding

[65] *See* SWEPCO's Response to APSC-144.

[66] The 5% recommendation is consistent with sharing STIs 50-50 with shareholders because I have already taken 50% of the total incentives to reflect the 50-50 sharing based on the total STI amount depending on Earnings per Share.

Arkansas jurisdictional reduction is $2,272,313. I also reduce payroll taxes by $159,062 (Arkansas jurisdictional) using a 7% ratio for FICA to payroll, for a total reduction of $2,431,375.

2. Stock-Based Compensation

Q. What is the amount of long-term stock-based incentive compensation requested for rate recovery in the test year?

A. SWEPCO is requesting $360,440 of SWEPCO's long-term incentives for inclusion in rates and $198,217 of American Electric Power Service Company ("AEPSC"), according to the response to AG DR 2-18. Using the Arkansas retail total payroll allocation factor (21.535%, according to AG DR 3-16), the Arkansas jurisdictional portions are $77,621 and $42,686, respectively for SWEPCO and AEPSC employees, for a total of $120,307. Long-term incentive compensation paid to SWEPCO's employees increased by a factor of 3.6 between 2007 and 2008, based on total payout information in SWEPCO's Response to APSC-028.

Q. Is it reasonable to pay for stock-based long-term incentive compensation?

A. No. Long-term incentive compensation is tied largely to stock prices and has very little benefit to ratepayers. For AEP, according to the response to AG DR 2-18, long-term incentive compensation is tied to two measurement criteria—AEP's stock price and a so-called "Performance Share Incentive" score, which is made up of two equally-weighted components—Earnings per Share targets, and Total Shareholder Return of AEP's peer companies.[67] If SWEPCO's stock prices go up, shareholders can provide the compensation to the executives.

Moreover, if stock prices drop, shareholders would be cushioned by the provision of cash to cover the cost of performance stock. Long-term incentive compensation also fluctuates dramatically in value over time depending on the performance of the stock market. In AG DR 2-18(d) we asked, "Please provide a narrative explanation of how the recent decline in the stock market has affected

[67] SWEPCO, proxy statement for 2008 Annual Shareholders meeting, page 22.

the valuation of long-term incentives issued prior to the decline[, and] explain how this change in valuation affects the income statement and balance sheet of the company," in order to gain an understanding of how poor stock market performance would affect the fair value of long-term incentive compensation. SWEPCO responded:

> At the start of 2008, the 20 day average stock price was $47.74 and the [Performance Share Incentive] performance scores averaged 1.454. By year's end those two measurements had fallen to $30.874 and 0.945 respectively. **This drop in valuation resulted in expense on the income statement being reversed and the liability on the balance sheet being reduced.**" (Emphasis added.)

This response shows that any decline in AEP's valuation in the rate-effective period will result in a reversal of the income state entry and a liability on the balance sheet being reduced even though the amount ratepayers are paying for such stock would have been set in the general rate case. In other words, the Company will pay out less than it was awarded in the rate case, based simply on the fact that its stock price went south, and shareholders will pocket the rest.

In sum, long-term incentive compensation (a) is not a cash expense, (b) fluctuates in value based on options value calculations, (c) is concentrated in a few executives, and (d) does not provide significant ratepayer benefits with its focus on stock prices and earnings per share. In fact, all else being equal, larger rate increases from the utility's regulators would increase the value of stock and increase the value of executive compensation.

The Commission should adopt the same outcome for SWEPCO as for Entergy in Docket No. 06-101-U. There, the Commission found:

> The Commission, however, does not find substantive evidence of any material benefit to ratepayers attributable to those programs strictly tied to the stock prices of Entergy Corp. Although EAI witnesses testify to some general benefits ratepayers may enjoy, EAI offers no substantial evidence of ratepayer benefit which would justify including these stock-driven incentives in rates.[68]

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[68] APSC Docket No. 06-101-U, Order No. 10 (June 15,2007), p. 68. The Public Utilities Commission of Nevada, California Public Utilities Commission and Public Utility Commission of Texas also both recently

The rejection of stock-based long-term incentive compensation would reduce SWEPCO's rate request in Arkansas by $120,307.

3. Executive Perquisites

Q. What the type and amounts of executive perquisites?

A. While the Company has excluded costs of any personal or family use of corporate aircraft, country club dues, and similar perquisites, it does ask for ratepayer money for financial planning and tax gross-ups for the executives identified as having a base salary of at least $200,000 (*See* the response to AG DR 2-19, Attachment 3). For financial planning, SWEPCO has identified AEP expenses of $203,699[69] and for tax gross-ups it has identified AEP expenses of $191,194. The total AEP test year expense for these perquisites is $394,893. SWEPCO's allocation is $27,184.[70] Additionally, SWEPCO identified perquisite costs in the test year for SWEPCO employees with salaries of at least $200,000 for tax gross-ups in the amount of $26,956 (*See* the response to AG DR 2-19, Attachment 4).

Q. Should ratepayers be responsible for paying for these perquisites?

A. No, neither of these perquisites should be provided at ratepayer expense. Executives at AEP and SWEPCO are highly compensated and can certainly afford to pay their own taxes and for their own financial planning. The preponderance of utility customers do not generally receive financial planning service as a fringe benefit from their employers. They should not have to pay for this perquisite. The disallowance from AEP's executives is $394,893, or $27,184 to SWEPCO. The disallowance from SWEPCO's executives is $26,956. The

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disallowed long-term incentive plans and stock-based compensation. *See* Public Utilities Commission of Nevada, Order in Docket No. 08-12002, page 139. (June 24, 2009); California Public Utilities Commission Decision No. 09-03-025, pp. 134-135; and Public Utility Commission of Texas, *Application of AEP Texas Central Company For Authority To Change Rates*, Docket No. 33309, Final Order at FOF No. 82 (March 4, 2008).

[69] This includes a trivial amount for the perquisite "personal services".

[70] This amount was determined by applying the allocation factors in the response to AG 2-19, Attachment 1.

total disallowance allocated to SWEPCO is $54,000. The disallowance allocated to Arkansas would be $11,659.[71]

B. Directors' and Officers' Liability Insurance

Q. What has SWEPCO requested for the Directors' and Officers' ("D&O") liability insurance?

A. It is not clear what SWEPCO has requested in rates for D&O insurance. The response to AG DR 2-30 indicates that the 2008 premium for AEPSC is $65,269, of which SWEPCO is allocated $7,346. However, the response to ASPC-055, Attachment 2 contains the invoices for D&O insurance paid by AEP (not AEPSC) in 2008. The invoices in the response to ASPC-055 sum to $4,140,779.[72] The SWEPCO allocation from AEPSC of $4.1 million would be approximately $500,000, not $7,346. The AG has sent AG DR 5-5 to the Company to resolve this issue. In the interim, I am submitting my testimony, here, assuming that the value from the response to AG DR 2-30 ($7,346) is the correct value. Once the company has answered AG DR 5-5, our review may produce a different disallowance. I reserve the right to update my recommendation, once this difference is resolved, given that the underlying philosophy does not depend on the amount SWEPCO is being charged for D&O insurance.

Also, once the amount SWEPCO customers are being charged is clarified, and the method for calculating this method is known, I may have further recommendations regarding the amount that is charged to SWEPCO customers.

Q. Do you recommend sharing the cost of the D&O liability insurance policy between ratepayers and shareholders?

A. Yes. It is not appropriate to assign 100% of the cost of D&O insurance to utility ratepayers. Instead, it is reasonable to share the cost of this insurance on a 50-50

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[71] Based on the Arkansas retail allocation factor identified in the response to AG DR 3-16, 21.535%.

[72] SWEPCO has agreed that the total amount of D&O insurance premiums stated on the invoices in ASPC-055 HS-Confidential does not need to be designated as confidential (Email from Stephen Cuffman, SWEPCO, to Shawn McMurray, AG, on June 23, 2009.)

basis between ratepayers and shareholders, since D&O insurance is often called into play when shareholders of publicly traded companies sue company management.

Ratepayers should pay a portion of D&O insurance because the existence of the insurance does improve the ability to attract and retain qualified directors and enables them to make decisions without fear of personal liability. However, proceeds of insurance payouts do not flow to ratepayers, but only to shareholders.

At the same time, D&O insurance provides a mechanism for aggrieved shareholders to collect funds under certain circumstances. The policies reduce the risk of common equity investment in the event of a bad decision by management or directors. Moreover, in the absence of such insurance, many of the cases in which shareholders could collect funds (related to inadequate or misleading disclosures to shareholders of material company activities), would be below the line from the perspective of ratepayers.

I thus recommend that shareholders share in the cost of the policy because not only do shareholders get the payoff from the insurance policy when something goes wrong, but without the insurance, ratepayers would not be liable in any event for any portion of the payment to shareholders.

Q. Has the Commission shared D&O insurance between ratepayers and shareholders in the past?

A. Yes. The Commission has adopted 50-50 sharing of such expenses, based on this rationale. In its Orders in four contested cases,[73] the APSC adopted the 50-50 sharing of these expenses based on the rationale given above. Excerpts from two decisions are quoted below:

> The news (T. 1040) is replete with stories about companies experiencing lawsuits by shareholders. The Commission agrees with the AG that more often than not it is the current shareholders who sue management and who receive a large portion of the

[73] APSC Docket Nos. 02-227-U, 04-121-U, 04-176-U, and 06-101-U.

> proceeds from the D&O insurance payouts. Accordingly, the Commission finds that Arkla's existing asset-based allocation for D&O insurance should be maintained and that the expense for D&O insurance should be shared on a 50-50 basis between shareholders and ratepayers.[74]

> The Commission agrees that ratepayers, as well as shareholders, benefit from good utility management, which D&O Insurance helps secure. However, as found in prior dockets, the direct monetary benefits of D&O Insurance flow to shareholders as recipients of any payment made under these policies. That monetary protection is not enjoyed by ratepayers. The Commission therefore finds that, because shareholders materially benefit from this insurance, the costs of D&O Insurance should be equally shared between shareholder and ratepayer. [75]

Q. Have other state commissions shared D&O insurance between ratepayers and shareholders?

A. Yes. The California Public Utilities Commission ("CPUC") has similarly required a 50-50 sharing of this cost since 1996.[76] The 1996 decision specifically cited information brought forward by the Commission's Division of Ratepayer Advocates that the bulk of lawsuits using this insurance were brought by shareholders and that the one such shareholder suit that Southern California Edison settled resulted in a below-the-line payment of amounts less than the policy deductible. The Commission concluded:

> In D. 87-12-066, 26 CPUC 2d 392,422, we permitted these types of premiums to be recovered in rates. However, the statistics provided by DRA [Division of Ratepayer Advocates] from 1986-1993, which were not available in 1987 when we decided D. 87-12-066, illustrate that shareholders also benefit from this insurance. Therefore, we will allow half of the expenses requested by Edison for this item. By making this allocation, we are not implying that it is not necessary for

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[74] (Arkansas PSC Docket No. 04-121-U, Order No. 16, page 40, September 19, 2005 http://www.apscservices.info/pdf/04/04-121-u_286_1.pdf)

[75] Arkansas PSC Docket No. 06-101-U Order No. 10, Page 70, June 15, 2007, footnote omitted, http://www.apscservices.info/pdf/06/06-101-u_303_1.pdf

[76] CPUC Decision No. 96-01-011 in Application No. 93-12-025 slip. op. at 140-141, January 15, 1996, regarding Southern California Edison Company; and California PUC Decision No. 00-02-046 in Application No.. 97-12-020, slip op. at 309, February 17, 2000, regarding Pacific Gas and Electric Company.

> Edison to maintain such insurance. To the contrary, we are funding half of the premium with ratepayer funds. However, to the extent that shareholders also benefit from this insurance, they should also share in the expense.[77]

The Connecticut Department of Public Utility Control has gone a step further by requiring ratepayers to pay just 25% of the cost of D&O insurance cost since 2006. Its January 27, 2006 Decision in Docket 05-06-04 (for United Illuminating) stated:

> The Department partially agrees with the OCC, the AG and the Company. In the 03-07-02 Decision, the Department allowed a portion of that company's proposed expense and stated that "the Department has historically allowed some level of expense for D&O Insurance in rates to assure some level of ratepayer protection from catastrophic lawsuits." 03-07-02 Decision, p. 49. The Department also notes that the annual gross DOL premium (before credits and allocations) was $134,430 in years 2001 and 2002, increasing to $1,029,516 in years 2007 through 2009, lending credence to the OCC's assertion regarding corporate scandals, above. The Department agrees with the OCC that the shareholders should bear the weight of their decisions in appointing directors (who appoint the officers of the Company). Accordingly, the Department allows $140,000 of DOL expense, or approximately ¼ of the total company expense, to be collected in rates as the customers' responsibility. The Department, therefore, disallows DOL expenses of $393,879 in 2006, and $419,612 in each of 2007, 2008 and 2009.[78]

Q. Do you have any evidence specific to SWEPCO to support your contention that D&O Insurance benefits shareholders?

A. Yes. The AG asked SWEPCO to identify any lawsuits and claims filed since 2003 where D&O liability insurance could have been called upon to pay some or all of the claims had it been found meritorious (AG DR 2-31). SWEPCO's response identified a number of actions. There were two sets of actions that were on behalf of shareholders. The first was a series of 14 lawsuits, which sought class action certification, against AEP, certain AEP executives, and in some of the lawsuits, members of the AEP Board of Directors and certain investment banking

[77] CPUC Decision No. 96-01-011, p. 141.

[78] Connecticut DPUC Decision in Docket 05-06-04 (United Illuminating Company) January 27, 2006, p. 47. The DPUC reconfirmed its precedent of allowing only 25% of D&O liability insurance in rates in its Decision in Docket 08-07-04 (United Illuminating Company) February 4, 2009 at page 43.

firms. These lawsuits alleged a number of grievances related to AEP's alleged failure to disclose "round trip" trades at its unregulated trading arm. The second was a set of 2 lawsuits where shareholder derivative actions against AEP and its Board of Directors alleging a breach of fiduciary duty for failure to establish and maintain adequate internal controls over unregulated gas trading operations. Both of these sets of actions were dismissed, but it is clear that AEP would have made a claim against its D&O insurer had they been found meritorious. It is also clear that both of these items related to unregulated activities and should not have been allocated to SWEPCO. As it stands, AEP would have made a claim against the carrier for merely the costs it incurred to defend itself against the suit had they been over the deductible for such claims, as indicated in the response to AG DR 2-31.

It is clear from this information that SWEPCO's shareholders are large potential beneficiaries of D&O liability coverage.

Q. **What is the effect of your proposed 50-50 sharing of D&O insurance?**

A. My current recommendation is to charge SWEPCO ratepayers for $3,673 for D&O insurance, which is 50% of the 2008 figure of $7,346. This corresponds to an Arkansas allocation of $782.[79] Again, once SWEPCO tells us which of its two different numbers is actually right, this recommendation may change.

C. Late Payment Charges (FERC Account 450)

Q. **Have you conducted an analysis of SWEPCO's late payment charges?**

A. Yes. In the response to AG DR 3-60, SWEPCO provided late payment revenues for the past five years. Calculations of the relationship of uncollectibles and late payment revenues by customer class are given in Exhibit WBM-17. As a percentage of revenues, late payment revenues have been very stable in the vicinity of 0.46% of total revenues. Therefore, we are willing to accept the 2008 figure ($1,211,595) as representative of long-term costs. However, an additional

[79] This allocation is based on the "LABORT" allocator, with an Arkansas allocation of 0.212957.

change needs to be made to reflect the increase in late payment charges as a result of the rate increase.

Q. Does this change affect the jurisdictional allocation?

A. Yes, it does. Apparently SWEPCO has either higher late payment interest rates (likely, since Arkansas has one of the highest late payment charges in the country) or more late payers in Arkansas than in other states, because the actual amount of late payment charges is considerably higher than the allocation used by SWEPCO based on number of customers. I therefore directly assign $1,211,595 actually paid by the Arkansas jurisdiction for late payment charges in Account 450, which increases revenue at present rates by $297,201 from the $914,394 assigned by SWEPCO.

Q. How does the amount of late payment charge revenue need to be increased as a result of the rate increase proposed in this case?

A. The Company's calculations of the impact of the rate increase include a revenue conversion factor for uncollectibles at 0.377% of rates but do not include any allowance for late payment charges. Late payment charges are 0.472% of revenues in the test year and very close to that amount in earlier years. The Attorney General recommends including the late payment charge in the revenue conversion factor, as has been done for AWG and EAI. We have done so in the Company's cost of service model by including a line item for the increase in late payment charge revenue equal to 0.472% of the increase in present rate revenue. The effect is to reduce the rate increase by $4,698 per each million dollars of increase in the required revenue to reflect the late payment revenues that will be collected due to the rise in base rates.

D. Other Tariffed Service Charges Revenue (FERC Account 451)

1. <u>Evaluation of Proposed Increases to Charges</u>

Q. What has SWEPCO proposed for other tariffed service charges?

A. SWEPCO has proposed to institute a new service connection charge of $25 and to raise several other charges.

Q. Is the Attorney General concerned with any of the proposed increases in service charges?

A. Yes. There are two proposed increases that are of concern, the collection charge, which is being raised from $10 to $20, and the new service connection charge.

Q. Why are you concerned about the collection charge increase?

A. There are two key policy reasons that warrant keeping this charge at a level below cost. First, disconnections are not cost-effective to the Company (by extending the time until the Company is paid, thus increasing its need for working capital, and by increasing the risk of uncollectibles). Thus, to the extent that increasing the field collection charge makes it harder for customers to pay and creates additional disconnections, it may actually cost the company more than the revenue it raises. By being penny-wise and raising this charge to reflect "costs", the Company may be being pound-foolish. In sum, the Company should work with the customer to avoid disconnection, because disconnection is bad for both the customer and the Company. Working with the customer to avoid disconnection means not making the customer come up with large amounts of money above and beyond their past-due electric bill, such as an increased field collection charge.

Second, even if this <u>particular</u> charge for field collections does not reflect cost, the Commission should remember that the late payment charge (which is assessed against all customers receiving a field collection call) exceeds the company's cost of capital and thus generates surplus money that can be considered to fund a portion of the Company's collection activities.

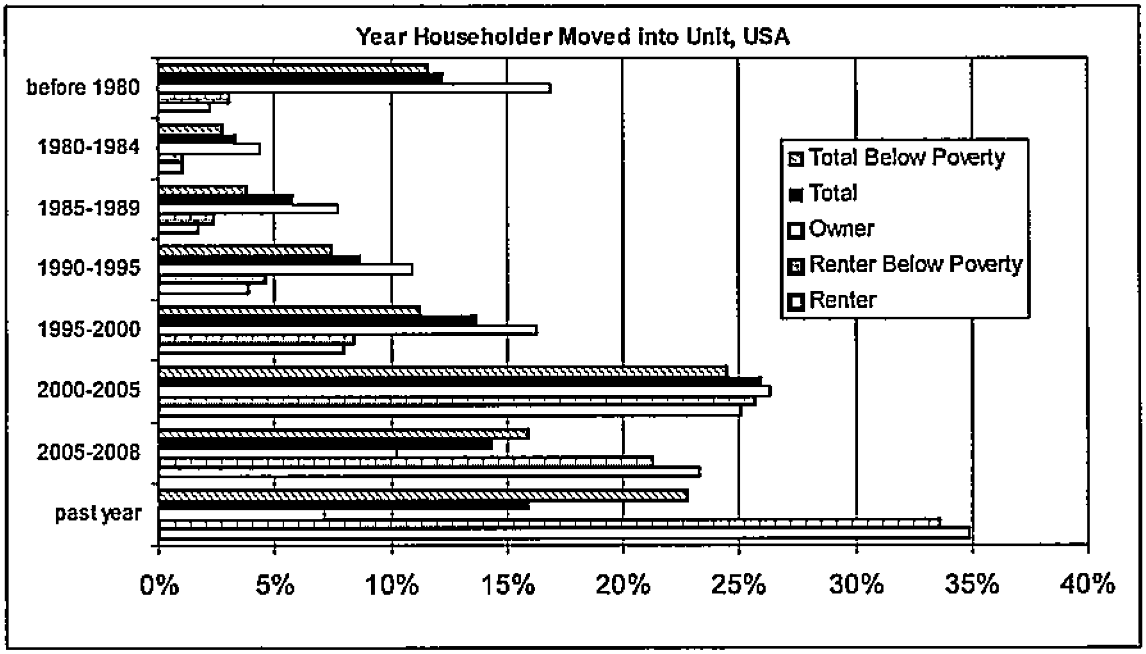
Q. Will you discuss the service connection or establishment charge?

A service connection fee is aimed at recovering the cost of establishing service from customers who move. As a result, it has highly disproportionate impacts on renters and lower income ratepayers because these customers move more often than homeowners and the more affluent.

The 2000 census shows that 21.6% of households in the state of Arkansas moved in the year prior to the census.[80]

The people who do move are disproportionately renters, who have disproportionately lower incomes, as shown in more detailed data from the American Housing Survey. The survey is not conducted for any metropolitan areas served by SWEPCO. Therefore, we provide 2007 data from the US as a whole. If anything, our previous review of southern cities (e.g., Memphis) reveals a more transitory population than in the US as a whole. As shown in Figure 1, 35% of renters (and 34% of renters below the poverty line) moved in the past year, while only 7% of homeowners moved in the past year.

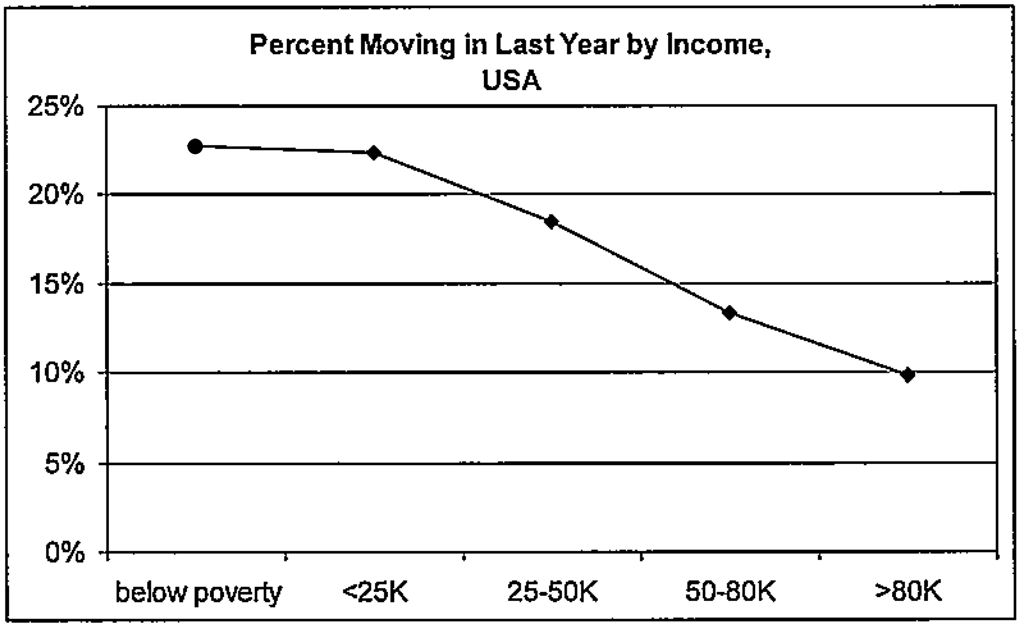
Figure 3: Year Householder Moved into Unit, United States



Because renters have lower average incomes than homeowners, the percentage of households moving in the past year is strongly related to income. (Figure 4)

[80] http://factfinder.census.gov/servlet/QTTable?_bm=y&-geo_id=04000US05&-qr_name=DEC_2000_SF3_U_DP4&-ds_name=DEC_2000_SF3_U

<u>**Figure 4: Percent Moving in Last Year by Income Level**</u>



Even though lower income people pay this charge disproportionately, the existence of this charge does not reduce the utility's costs. It does not alter customers' behavior by causing customers not to move (unless the charge becomes one of many burdens to be overcome for a homeless household or a motel-dweller to get an apartment). One cannot argue that the charge might provide incentives to reduce the utility's costs (as might be argued for a late payment or reconnection charge).

Q. Are you aware of other utilities that do not charge full cost for this service?

A. Yes. In California, the charges are generally below cost, with Pacific Gas and Electric having no service connection charge at all and Southern California Edison and San Diego Gas and Electric each charging $15.

Q. What is your recommendation?

A. There are other goals besides adherence to cost incurrence for charges such as this one. The Attorney General would recommend that the Commission either not impose this new charge at all or set a charge at a lower level such as $10 that recovers only part of the cost in light of the disproportionate impact on low-income ratepayers and renters.

Q. What is the impact of these recommendations on the revenue requirement?

A. Based on Exhibit JLJ-5, the recommendation to impose a service connection charge would reduce pro forma revenue by $282,375.[81] The recommendation not to increase the service connection charge would reduce revenue by $75,245, for a total reduction of $357,620. The increase in customer service charges would be $86,831 instead of the $444,451 recommended by SWEPCO.

While these costs would end up in rates paid by the general body of ratepayers the alternative is worse – to increase service connection charges disproportionately to renters and low income customers and to make it more difficult for customers to keep their electric service when trying to pay to avoid a disconnection. Therefore, we recommend leaving these costs in rates instead of instituting or raising the charges.

2. Jurisdictional Allocation of Tariffed Service Charges

Q. Given SWEPCO's request to increase tariffed other operating revenue in Arkansas, are there any problems with the jurisdictional allocation of tariffed operating revenue in Account 451?

A. Yes. SWEPCO has used jurisdictional allocation factors rather than directly assigning costs by state for tariffed revenues in Accounts 450 (late payment charges) and 451 (miscellaneous service revenue). Thus, as an extreme case, SWEPCO proposes to increase tariffed service charges in Arkansas by $444,451, but then allows most of that money to be siphoned off to Texas and Louisiana by SWEPCO's allocation method, which provides a total of $443,873 to the Arkansas jurisdiction – *less than SWEPCO's proposed increase in charges*, even though SWEPCO is requesting $773,407 in charges.

Q. Is this method reasonable?

[81] For illustration, a $10 charge would raise $112,950 in revenue, reducing the pro forma revenue in Account 451 by $169,425.

A. No. The costs paid by Arkansas ratepayers are higher than the allocated amounts, as shown by comparing SWEPCO's jurisdictional cost of service study with the response to AG DR 3-54.

Q. What do you recommend for Arkansas jurisdictional tariffed service charges?

A. I directly assign Arkansas tariffed charges to Arkansas in Accounts 451. This amount is $773,407, increasing revenue by $329,534 with the Company's proposed charges. With the AG's recommendation to reject the increases to the collection trip charge and the service connection charge, we would recommend that Arkansas be allocated $415,787 in revenues, which is only $28,086 less than SWEPCO's allocation including the higher charges.

E. Other Operating Revenue: Emissions Allowances

Q. What has SWEPCO proposed for emissions allowances?

A. SWEPCO has proposed to include emissions allowances costs or revenues going forward as part of the Energy Cost Rate ("ECR"), while retaining in test year rates a nominal amount of profits from the sales of allowances ($565,828 total company). Apparently, now that SWEPCO is becoming a net buyer of allowances, it wants to recover those costs from ratepayers, while in its role as a net seller, it had no impetus to put revenues in the ECR to enable ratepayers to recoup them.

Q. What is your evaluation of SWEPCO's proposal?

A. SWEPCO's asymmetrical ratemaking proposal is made worse because emissions allowance revenues have fluctuated significantly over the past five years, with two years of sales revenues in excess of $10 million (total company). The figures from the response to AG DR 3-33 show the following results.

Table 9: SWEPCO Gain on Disposition of Allowances 2004-2008

	Disposition of Allowances Gain	Loss	Net Gain
2004	$ 2,640,601	$ 939	$ 2,639,662
2005	$ 1,053,816	$ 196	$ 1,053,620
2006	$ 20,865,270	$ -	$ 20,865,270
2007	$ 12,497,919	$ 11	$ 12,497,908
2008	$ 550,556	$ -	$ 550,556
Five year average	$ 7,521,632	$ 229	$ 7,521,403
SWEPCO			$ 565,828

Q. What is your recommendation?

A. To normalize this greatly fluctuating revenue source, I recommend that the revenues be based on the five year average. As part of this recommendation, which contains a much larger base rate revenue from allowances, I would recommend, for this rate case only, that any net loss on allowances calculated on an annual basis should be booked to the ECR but net gains calculated on an annual basis be retained in base rates.

Thus $7,521,403 of revenue should be assumed, an increase of $6,955,575 over SWEPCO's amount. The additional Arkansas jurisdictional revenue would be $1,375,597.

F. Weather Normalization

Q. Have you conducted any analysis of the relationship of 2008 company loads to weather?

A. Yes. We conducted a regression analysis that relates loads per customer from 2003-2008 separately in the two subclasses of the residential class (with and without electric space heating) to heating degree-days, cooling degree-days, time trends and monthly dummy variables.

We found that total kWh sales for residential customers were understated, although because the weather in 2008 was cooler than average in both the summer and the winter.

However, sales increased in the summer months when the rates are higher, while normalization reduced sales in the winter months largely in the space heating rate schedule where the tailblock rate is extremely low (1.75 cents/kWh base rate). As a result, we calculate a weather normalization adjustment to increase residential class base rate revenue for the recorded year 2008 by about $1,119,000.

We have not yet incorporated these results in our cost of service study, either in revenues or billing determinants, because they are based on actual 2008 sales instead of 6 months actual and 6 months projected. We will integrate our results with those of the Staff in surrebuttal testimony, as we understand that Staff will be updating the entire company cost of service to the year ending December 31, 2008.

The equations we found and our results in terms of revenue are included in Exhibit WBM-23.

G. Storm Damage

Q. Did SWEPCO propose any adjustments for normalized storm damage expense in its rate case filing?

A. No, not in its original filing. However, on May 29, 2009, SWEPCO filed an application with Commission requesting approval to defer "extraordinary storm-related [O&M] expenses" as a result of the January 2009 ice storm ("Deferral Application").[82] The Deferral Application "further requests that the Commission address recovery of the extraordinary storm-related expenses as part of" this rate case.[83] It is not clear to the Attorney General whether or not the Deferral Application, and its request to be addressed herein is intended, by the Company,

[82] APSC Docket No. 09-050-U, Application, p. 2.

[83] *Id.*, p. 3

to impact the setting of a normalized storm damage expense for the purposes of inclusion in rates. It is also unclear to the Attorney General whether or not the recently adopted Act 434 of 2009 (codified at Ark. Code Ann. § 23-4-112) is part of SWEPCO's Deferral Application or should be considered as part of this rate proceeding. As such, the Attorney General is making recommendations in direct testimony which solely address the setting of a normalized storm damage amount excluding the 2009 ice storm for the purpose of inclusion in rates.[84] After the filing of this testimony, ideally SWEPCO will indicate the exact nature of the request in the Deferral Application and the method by which it proposes to address that issue here. The Attorney General will offer a more detailed recommendation regarding the Deferral Application in response in Surrebuttal Testimony.

Q. What was SWEPCO's storm damage expense in 2008?

A. SWEPCO spent $1,031,465, of which $110,422 was for straight-time labor (which presumably was diverted from other non-storm activities), leaving $921,043 of other costs. All of these costs were booked to Arkansas, so all of the costs are already jurisdictionalized.

Q. Were SWEPCO's storm damages higher in 2008 than in earlier years?

A. Yes. The year 2008 was the highest of the five previous years. (SWEPCO's Response to APSC-042). The table below shows the information.

[84] The AG would note that the analysis undertaken herein with regard to setting a normalized storm damage amount would be the identical analysis required to set the appropriate level of storm cost reserve account as specified by Ark. Code Ann. § 23-4-112(c)(1)(B) should the Company, either herein or in Docket No. 09-050-U request reserve accounting treatment for all storm expenses for 2009 and on a going-forward basis.

Table 10: SWEPCO's Arkansas Storm Damage Expenses, 2004-2008

	2004	2005	2006	2007	2008	Average
raw total expenses (SWEPCO)	122,666	430,287	449,833	373,047	1,031,465	481,460
remove						
straight-time labor and fringes	14,899	35,737	43,033	51,496	110,422	51,117
55% STIP	639	16,349	7,231	18,064	21,137	12,684
stock based compensation	0	1,321	6,611	14,739	-10,586	2,417
subtotal	15,538	53,407	56,875	84,299	120,973	66,218
remainder (allowed)	107,128	376,880	392,958	288,748	910,493	415,241

Q. What do you propose for ordinary storm damage for SWEPCO?

A. I would recommend $456,765, which is the five-year average of $415,241 plus 10% to approximately account for inflation over the five year period. The calculation excludes straight-time labor and fringe benefits, which the Company would have to pay in any event, and costs disallowed for incentive compensation elsewhere in the case). These costs should not be recovered through the reserve. This would constitute an adjustment of $453,727 from recorded 2008 test year costs in the same categories of $910,493.[85]

H. Customer Service and Information Accounts 907-915

Q. Has the company reclassified any expenses in Accounts 907-916 as below the line?

A. Yes, but only very limited amounts. In its adjustment 9 it removed $5,804 from Account 907 and $1,132 from Account 908. Adjustment 10 (for civic activities) removed no costs from any of these accounts.

Q. Have you investigated the spending in Account 907-916?

A. Yes. In AG DR 3-46, we requested a list of vouchers in excess of $250. The vouchers totaled $2,630,386. Upon review of this list, we highlighted every business entertainment expense in excess of $250, a series of entries for dues to the Petroleum Club in Shreveport as well as other entries for dues, and a number

[85] This adjustment, if necessary, could be integrated with the Staff's filing that will update test year costs to the end of 2009. The correct number at the end of the process is given above, but how that number differs from the 6 months actual and 6 months projected costs initially filed by the company is unknown.

of obvious contributions (Razorbacks Foundation and local childrens' homes and other organizations). Our preliminary recommended disallowance is $77,831. Because there is $1,895 of overlap with costs that SWEPCO removed, the net additional disallowance is $75,936 (total company). We have also noted $183,477 in payments to the Texas Department of Housing which appear on their face to be of questionable benefit to Arkansas ratepayers and no similar expenditures in Arkansas. We have also disallowed these costs in lieu of directly assigning them to the Texas jurisdiction. The total additional reduction over the Company's proposal is $251,872 in Account 907 and $7,540 in Account 908, or $55,966 Arkansas jurisdictional.

Q. Are you still investigating these accounts?

A. Yes. We have requested every individual voucher in excess of $5,000 but have not received them yet. It is our intention to update this recommendation in Surrebuttal Testimony, after we have received the additional information.

I. Working Capital Assets

1. <u>Adjustments to Specific Assets</u>

Q. Do you have any adjustments to working cash assets?

A. Yes. After reviewing the response to APSC-063, I have determined that $11,785,509 of the items requested (12 month balance through December 31, 2008) are unrelated to SWEPCO's provision of utility service, and another $1,770,385 is unrelated to providing utility service to Arkansas customers.[86] The descriptions of the items that I am adjusting out are given below as extracted from the response to APSC-063. The rationale for excluding each is then provided in slightly more detail.

[86] If updated to a later date by Staff, the same balance sheet items should be removed or reassigned.

Table 11: Attorney General's Adjustments to Working Capital Assets

Account		Description	Total	
Revenue Requirement Adjustments				
124	1240002	Oth Investments-Nonassociated	693,635	For example, includes investments in the National Rural Utilities Cooperative Finance Corporation and the BIDCO Red River Valley Business & Development
124	1240044	Spec Allowances Inv SO2	34,090	Related to Coal Activities
124	1240050	Spec Allowance Inventory CO2	32,764	Related to Coal Activities
143	1430001	Other Accounts Rec-Regular	1,649,968	Charges for Turk, Pirkey, Flint Creek, and Dolet Hills until they are billed out (jointly owned power plants)
143	1430080	Jointly Owned Unit O&M Billing	8,819,193	Receivable from AECC for Flint Creek, NTEC and OMPA for Pirkey and Dolet Hills (jointly owned power plants)
146	1460006	A/R Assoc Co - Intercompany	326,468	These are receivables from intercompany transactions. For example when SWEPCO worked on PSO's ice storm.
146	1460025	Fleet - M4 - A/R	29,391	A/R related to utility fleet usage such as work by SWEPCO fleet group for an affiliate
		TOTAL	11,785,509	
Jurisdictional Items				
165	1650009	Prepaid Carry Cost-Factored AR	238,886	Arkansas factoring costs - direct assign
165	165000208	Prepaid Taxes	287,082	TX State Gross Receipts Tax - direct assign
186	1860108	RER OVER/UNDERRECOVERY	1,483,202	Texas renewable energy under recovery - direct assign
		Total direct assign	2,009,169	

- Account 1240002 involves costs that are unrelated to utility service including owning a piece of a Business Investment Development Company ("BIDCO") and investing in the financing of Rural Electrification Co-operatives.

- Accounts 1240044 and 1240050 are inventories of emissions allowances that SWEPCO admits were purchased for the purpose of "speculation" (Attachment to the response to APSC-110). Ratepayers are not speculators.

- Accounts 1430001 and 1430080 involve unbilled work and receivables from other utilities for jointly owned powerplants. These unbilled and billed receivables are related to the partial ownership of the plants by these other utilities, <u>not</u> to the provision of service to SWEPCO ratepayers from these plants.

- Account 1460006 contains receivables from intercompany transactions. Again, these are not costs related to provision of service to SWEPCO customers but to recovery of costs used to provide service to other AEP affiliated utility customers such as Public Service Company of Oklahoma.

- Account 14600025 is similar, involving receivables for fleet service costs charged to affiliates to provide service to those affiliates, not to provide service to SWEPCO ratepayers.

There are also three items where adjustments need to be made to the jurisdictional allocation, one directly assignable to Arkansas and two to Texas.

- Account 1650009 contains factoring costs specific to Arkansas. I have directly assigned these costs to Arkansas in my jurisdictional allocation of working capital below.
- Account 1650001208 contains prepaid Texas gross receipts taxes. Each state pays its own state income and gross receipts taxes; therefore this cost should be assigned to Texas in the jurisdictional allocation.
- Account 1860108 involves deferred charges related to renewable energy in Texas. While these are indeed costs related to SWEPCO's role as a utility, they should be allocated 100% to Texas in the jurisdictional allocation. Otherwise, Arkansas ratepayers would be charged for costs arising from the Texas statutes and regulations requiring the purchase of renewable energy for Texas customers.

2. <u>Jurisdictional Allocation of Working Capital Assets</u>

Q. Do you have any adjustments to the jurisdictional allocation of working capital assets?

A. Yes. SWEPCO allocates these costs entirely by the total rate base. Essentially this allocation method throws away specific information regarding the nature of these costs. It is clear from reviewing the structure of SWEPCO's cost of service model that in other jurisdictions, it allocates the costs by type (e.g., fuel inventory, materials and supplies, prepayments, etc.). However, it ignores this information in Arkansas.

I divide the costs into six functions, into working capital related as

- energy-related (fuel inventory, emissions allowances, prepayments for lignite, and various costs associated with energy trading, as well as 50% of system sales accounts receivable);
- production-related (costs specifically identified as related to production plant, such as deposits for jointly owned plant, and 50% of system sales accounts receivable);
- plant-related (largely materials and supplies);
- revenue-related (accounts receivable and unbilled revenue from customers);
- direct assigned (three small items - factoring and tax assets specifically tied to Arkansas and Texas and a Texas renewable energy cost); and
- miscellaneous working capital (the remainder).

Each of these items is jurisdictionalized and then allocated to customer classes using the relevant allocation method. Like SWEPCO, I assign the miscellaneous (residual) cost by total rate base.

Q. **Have you prepared an analysis of the differences in working capital arising from these differences in the jurisdictional allocation?**

A. Yes. They are provided in Table 12 below.

Table 12: Comparison of SWEPCO and AG Jurisdictional Allocation of Working Capital

SWEPCO JURISDICTIONAL ALLOCATION	442,550,701	96,713,383
AG JURISDICTIONAL ALLOCATION		
ENERGY RELATED WORKING CAPITAL	107,250,136	20,861,244
PRODUCTION RELATED WORKING CAPITAL	20,802,403	4,114,077
PLANT RELATED WORKING CAPITAL (m/s)	67,296,168	14,366,100
REVENUE RELATED WORKING CAPITAL	50,082,967	9,671,928
DIRECT ASSIGNED WORKING CAPITAL	2,009,170	238,886
MISCELLANEOUS WORKING CAP	195,109,856	42,251,328
TOTAL BEFORE AG ADJUSTMENTS	442,550,701	91,503,563
ALLOCATION DIFFERENCE FROM COMPANY	-	(5,209,819)
AG ADJUSTMENTS TO COMPANY WORKING CAPITAL		
AG ADJUST ENERGY-RELATED	(66,854)	(13,004)
AG ADJUST PRODUCTION RELATED	(8,819,193)	(1,744,166)
AG ADJUST PLANT RELATED	-	0
AG ADJUST REVENUE RELATED	-	0
AG ADJUST MISCELLANEOUS	(2,899,462)	(627,883)
TOTAL AG ADJUSTMENTS	(11,785,509)	(2,385,052)
TOTAL AG WORKING CAPITAL	430,765,191	89,118,511
DIFFERENCE FROM COMPANY	(11,785,509)	(7,594,872)

My more disaggregated and more accurate analysis allocates $5,209,819 less to Arkansas of working capital at the company's proposed revenue requirement. The proposed adjustment to the total revenue requirement discussed above reduces working capital rate base by a further $2,385,052 (Arkansas jurisdiction), for a total reduction of $7,594,872.

V. Cost of Service and Rate Design

A. Cost of Service Study

Q. Will you discuss the SWEPCO cost of service study in general terms?

A. SWEPCO's cost of service study for Arkansas follows past regulatory practice in Arkansas to a great degree. I specifically agree with two major aspects of its study; (1) the use of the "average and peak" method for generation costs and (2) the assignment of all distribution costs in Accounts 364-368 as demand-related.

The average and peak method reflects that the amount of generation required is related to the peak demand, but the type of generation that is built is dependent on the economics of sustained energy use. The reasonableness of the average and peak method is exemplified by the decision to construct the expensive Turk powerplant (and other coal-fired generators in past years) to fill a specific need for baseload power, which has high capital costs and low fuel costs. If SWEPCO had only needed power for a few hours at peak, it would have proposed and built more combustion turbine generation similar to the Mattison plant that it recently completed.

I also agree with SWEPCO's assignment of revenues from late payment charges and tariffed service charges according to the number of customers; as these assignments generally follow both the reason for the charges and the differential amounts paid by each customer class.

As a result, I recommend only one relatively small change, which follows from my recommendation to the jurisdictional allocation of working capital assets. I recommend that the Commission allocate the various types of working capital assets to customer classes using the same methodology that I propose in the jurisdictional allocation.

Q. Have you prepared a cost of service study with the Attorney General's recommendations?

A. Yes. The jurisdictional allocation is summarized in Exhibit WBM-18, and the class cost allocation at an equalized rate of return is summarized in Exhibit WBM-19.

Q. Would any rate classes require mitigation of rate shock given the results of the cost of service study as proposed by SWEPCO and as modified by you?

A. Yes. The lighting classes would receive relatively large decreases, while the municipal service classes and some industrial and TOU classes have significant increases.

Within the municipal group, streetlighting has a large decrease and other municipal functions have a large increase, but the average across the group (including municipal services and public highway lighting) is almost zero rate change, I would propose to cap the municipal non-streetlighting costs at a capped rate increase (along with public highway lighting) and to allow the remainder of the decrease to flow to municipal lighting. This would assure that as a whole, municipalities are treated on a cost basis (approximately zero net increase) in this period of tight budgets, while individual municipal functions (lighting, pumping, and other services) would see mitigated increases or decreases moving toward cost.

For the remaining customers with a system-wide rate increase of 10.89% resulting from the AG's analysis to date, I would propose a floor of no decrease for any customer class (mainly applicable to private area lighting, though there is one small commercial class that would hit the floor) and a cap (to equalize the revenue), which amounts to 10.89% above the system average rate of 10.81% or 21.70%. Since there is no fuel rate increase in this case, the total increases are far less than the base rate increases. If the total rate increase were to be less than 5%, I would recommend providing some decrease to classes capped at zero in this analysis.

In addition, as discussed below, I am developing a rate design for the residential class as a whole rather than for the subcomponents identified by SWEPCO, so that the entire class average of 5.89% will be my target for residential rate design.

Exhibit WBM-20 shows revenues at an equalized rate of return down to the schedule level data for the jurisdictional and class cost allocation. Exhibit WBM-20 also shows our proposal for rate design mitigation.

B. Residential Rate Design

1. <u>SWEPCO's Proposal</u>

Q. Will you describe SWEPCO's current rate design?

A. SWEPCO currently has a rate structure with a customer charge of $6.88, a flat rate in the summer time (3.96 cents/kWh base rate), a flat rate in the winter months that is about 14% below the summer rate for customers without space heating (3.4 cents/kWh), and a declining block rate that is extremely promotional for space heating. The first block (up to 500 kWh per month) is the same as the winter non-space-heating block. The second block (in excess of 500 kWh per month) is reduced by 49% from the summer block and is less than 2 cents per kWh plus the fuel adjustment clause

Q. What has SWEPCO proposed in this case?

A. In the context of its proposed increase, it proposes increases to the customer charge and summer and winter rates (including the first block in non-space heating) by the class average rate increase of 16% rounded to the nearest 0.5 cents/kWh or 5 cents per month. Because SWEPCO (and we) observed that the winter space heating rate has a lower rate of return than the summer space heating rate, SWEPCO proposed a 29% increase for the winter second block in that rate. However, the 29% rate increase in the much lower winter rate is the same increase in cents per kWh as the 16% increase in the first block rate.

Q. Should the customer charge be raised in this case?

A. No, for reasons discussed below. A higher customer charge is inimical to the efficient use of energy, as well as providing disproportionate increases to lower income people, who on average are likely to use less energy than higher income people.

2. SWEPCO's Residential Customers

Q. Do you have any information on the composition of SWEPCO's residential customers?

A. Yes. In AG DR 3-2, we requested information on the number of customers in both the ordinary residential rate and the rate with electric space heating. We found that approximately a third of SWEPCO's customers are on the residential space heating rate. This is confirmed by the responses to AG DRs 3-11 and 3-12 (data from SWEPCO's energy efficiency potential study).[87]

Of the electric heat customers in SWEPCO's service area, an extremely high 56.5% use electric resistance heat, the least energy efficient form of space heating, including 44% of electric heat customers in single-family homes, 68% in apartments and 94% in mobile homes. Only 43.5% use heat pumps. Controlling for the type of dwelling, resistance heating uses from 68% to 90% more than a heat pump.

3. <u>Policy Considerations</u>

Q. Will you describe the Attorney General's long-term policy for residential rate design?

A. In the long term, residential rate design should have as a significant goal the encouragement of conservation of energy (including encouraging the use of natural gas where it is more efficient than electricity). To do this, we have an ultimate goal to minimize reliance on fixed charges (customer charges) and declining block rates. We recognize that gradualism is important so that existing customers who have installed equipment in reliance on certain types of rate structures are not harmed. A flat or inverted summer rate, a moderately lower flat winter rate, and limited reliance on customer charges would satisfy this long-term goal. Inverted rates in the summer months also tend to reflect costs for residential customers, since base levels of use relate to non-weather-sensitive use such as refrigeration, lighting, etc. The weather-sensitive use creates the system peak and therefore should be charged more.

Q. Will you comment on the impact of customer charges and declining block rates on energy efficiency?

A. All else being equal, an increased residential customer charge will decrease the cost-effectiveness of measures that save electricity. Moreover, a high customer

[87] Exhibit WBM-21 contains responses to AG DRs 3-9, 3-11, and 3-12 relating to electric heat usage.

charge decreases the effectiveness of energy efficiency programs operated by the utility by making it less cost-effective for customers to conserve. The end result of having rate design compete with efficiency programs is either higher rebates raising program costs or lower penetration of the programs or both. Given the Commission's move toward the development of significant energy efficiency programs it should not be driving with one foot on the gas (efficiency programs) and the other foot on the brake (promotional rate design). Rate design and efficiency policy should be harmonized, not at cross-purposes with each other.

Q. Have you analyzed the relative use of energy by gas and electric end uses?

A. The table below (with supporting data in the workpapers) shows the energy efficiency of gas versus electric use for space heating, water heating, and clothes drying.[88] For electric heat, the issue is whether the customer uses a heat pump or electric resistance heating. The resistance heating is far less efficient than burning gas directly in the residence. While a gas combined cycle fueling a heat pump is slightly more energy efficient than a gas furnace. However, a heat pump generally does not stand alone but comes with other electric appliances. When these appliances are brought along into the all-electric home, they dramatically reduce the efficiency of total energy use. Moreover, when coal-fired electric generation is at the margin, the amount of both energy use and greenhouse gas emissions burgeons due to electric heat, even with a heat pump.

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[88] Propane heat would have similar efficiency to gas at the end use, but may have somewhat more energy losses in delivery to the customer.

Table 13: Total Energy Efficiency of Natural Gas vs. Electric Service for Residential End Uses, Modern Energy Efficient Equipment

	gas	electric combined cycle	coal steam
gas vs. electric resistance heat			
end-use efficiency	90%	100%	100%
conversion and delivery efficiency *	98%	45%	31%
implicit heat rate Btu/kWh	3,870	7,630	10,900
efficiency	88%	45%	31%
energy required for end-use electricity relative to gas		197%	282%
CO2 per MMBtu of heat input (pounds)	115	115	210
CO2 for same useful output as 1 MMBtu of gas heat input	115	227	592
additional CO2 for electric option		97%	414%
gas vs.air-source heat pump (Heating Seasonal Performance Factor = 8.2)			
end-use efficiency	90%	240%	240%
conversion and delivery efficiency	98%	45%	31%
implicit heat rate Btu/kWh	3,870	3,176	4,537
efficiency	88%	107%	75%
energy required for end-use electricity relative to gas		82%	117%
CO2 per MMBtu of heat input (pounds)	115	115	210
CO2 for same useful output as 1 MMBtu of gas heat input	115	94	246
additional CO2 for electric option		-18%	114%
water heater			
end-use efficiency	63%	93%	93%
conversion and delivery efficiency	98%	45%	31%
implicit heat rate Btu/kWh	5,528	8,204	11,720
efficiency	62%	42%	29%
energy required for end-use electricity relative to gas		148%	212%
CO2 per MMBtu of heat input (pounds)	115	115	210
CO2 for same useful output as 1 MMBtu of gas heat input	115	171	445
additional CO2 for electric option		48%	287%
clothes dryer			
end-use efficiency (relative to electricity to dry same amount of clothes)	89%	100%	100%
conversion and delivery efficiency	98%	45%	31%
implicit heat rate Btu/kWh (adjusted for slightly lower gas end-use drying efficiency)	3,926	7,630	10,900
efficiency	87%	45%	31%
energy required for end-use electricity relative to gas		194%	278%
CO2 per MMBtu of heat input (pounds)	115	115	210
CO2 for same useful output as 1 MMBtu of gas heat input	115	223	583
additional CO2 for electric option		94%	407%

* Gas delivery losses between the site of a powerplant and a residence. Electric efficiency based on combined cycle heat rate of 7000 Btu/kWh, coal heat rate of 10000 Btu/kWh, 9% line loss.

Q. What policy concerns does the Commission face in light of this information?

A. The Commission needs to balance two concerns: (1) the need to price electricity to support energy efficiency and reduce the increased use of energy that arises from the unwise promotion of electric heat; and (2) the need to avoid potential harm to existing customers who have relied on existing and past promotional rates.

Q. How can the Commission balance these competing concerns?

A. In this particular case, the first and foremost step that the Commission needs to take is to close the electric space heating rate to new customers. The number of customers choosing electric heat is extremely high in this utility, and the rate is so strongly promotional that it will take a significant amount of gradual change over several rate cases to make the rate design for existing space heat customers less promotional (by decreasing the absolute difference between first block and tailblock rates).

The Commission should also continue in the direction it began in the Oklahoma Gas and Electric rate case and adopt an inverted summer rate.

4. <u>**Recommended Rate Design (Block Rates and Customer Charges)**</u>

Q. What is your rate design recommendation in this case?

A. I recommend that rates be designed on the following principles if there is a significant increase:

- No increase to the customer charge for the reasons discussed above.
- In a case with a significant rate increase, rates should be increased in both seasons, but the average increase in the summer (measured in cents per kWh, not percentage of the bill) should be greater than in the winter.
- We specifically support an inverted block summer rate. However, we believe that gradualism is needed and would propose base rate tiering of 20-25% in this case for usage over 1000 kWh. This results in a

differential of 0.8 to 1 cent per kWh. This is only a starting point. Further increases in the second tier inverted block relative to the base rate are reasonable in the longer term but should not be adopted all at once.

- The winter declining block rate differential for electric space heating is 1.65 cents per kWh. A goal for this case (with a closed rate) should be to cut that differential by about 25% to 1.0 to 1.3 cents/kWh. A larger tier reduction is possible without undue bill impacts with a limited rate increase, such as that proposed by the Attorney General, while a larger rate increase such as that proposed by the Company might require smaller moves toward tier reduction.

I have prepared two alternative rate designs showing the application of the rate design principles above. The first assumes that the Company's revenue requirement is adopted. It is presented only as a comparison to the Company's rate design, as I do not expect a 16.8% residential base rate increase to be adopted. The second rate design shows the application of these principles assuming the Attorney General's estimated base rate increase of 5.9% for residential customers.

The table on the next page compares current rates, SWEPCO's proposal, and the alternative rate designs.

Table 14: Comparison of SWEPCO's Rate Design and Alternatives Based on Attorney General's Principles

		Present Rates		SWEPCO Proposal				AG Alternative - SWEPCO Rev Req.				AG Alternative - AG Rev. Req.			
	billing determinants	rate	revenue	rate	revenue	c/kWh increase	% increase	rate	revenue	c/kWh increase	% increase	rate	revenue	c/kWh increase	% increase
No space heat															
customer cSharge	774,264	6.88	5,326,936	8.00	6,194,112	1.12	16.3%	6.88	5,326,936	-	0.0%	6.88	5,326,936	-	0.0%
Summer	341,667,008														
up to 1000 kWh	262,865,651	0.0396	10,410,272	0.0459	12,068,451	0.0063	15.9%	0.045	11,829,854	0.0054	13.6%	0.0408	10,725,735	0.0012	3.0%
>1000 kWh	78,801,356	0.0396	3,120,534	0.0459	3,616,982	0.0063	15.9%	0.0564	4,444,396	0.0168	42.4%	0.0489	3,853,386	0.0093	23.5%
winter all	358,705,190	0.034	12,195,976	0.0396	14,204,726	0.0056	16.5%	0.0394	14,132,984	0.0054	15.9%	0.0343	12,303,588	0.0003	0.9%
			31,053,718		36,082,271				35,734,172				32,209,645		
Space heat															
customer charge	377,388	6.88	2,596,429	8.00	3,019,104	1.12	16.3%	6.88	2,596,429	-	0.0%	6.88	2,596,429	-	0.0%
Summer	179,444,088														
up to 1000 kWh	139,676,661	0.0396	5,531,196	0.0459	6,411,159	0.0063	15.9%	0.045	6,285,450	0.0054	13.6%	0.0408	5,698,608	0.0012	3.0%
>1000 kWh	39,767,427	0.0396	1,574,790	0.0459	1,825,325	0.0063	15.9%	0.0564	2,242,863	0.0168	42.4%	0.0489	1,944,627	0.0093	23.5%
Winter															
up to 500 kWh	95,944,396	0.034	3,262,109	0.0396	3,799,398	0.0056	16.5%	0.0394	3,780,209	0.0054	15.9%	0.0343	3,290,893	0.0003	0.9%
>500 kWh	148,823,916	0.0175	2,604,419	0.0226	3,363,420	0.0051	29.1%	0.026	3,869,422	0.0085	48.6%	0.0245	3,646,186	0.0070	40.0%
			15,568,943		18,418,406				18,774,393				17,176,943		
Total revenue			46,622,662		54,500,677				54,508,565				49,386,588		
Total adjusted for book-to-bill			46,744,666		54,638,035				54,637,442				49,499,345		

Exhibit WBM-22 provides a bill impact analysis of the various proposals. In this analysis, the impacts include not only base rates but ECR rates from Schedule H.

The bill impact analysis shows that in an unrealistic worst case scenario, with the Company's revenue requirement, the Attorney General's proposed rate design does not cause consistent customer harm, even while promoting conservation. Summer rate increases are lower than the Company's proposal for the 69% of SWEPCO customer bills that are less than 1200 kWh per month. Rate increases are 5% higher than the Company's proposal for less than 10% of SWEPCO's largest residential bills using over 2000 kWh per month. Winter electric heat rate increases are less than the Company's for the 47% of the electric heat bills under 800 kWh per month and top out about 4% more than the Company's proposal for the very largest customers. Winter rates for customers without electric heat are lower than the Company's at all usage levels, further reducing rate impacts.

With a lower rate increase such as the Attorney General's revenue requirement, conservation incentive can be implemented with very limited bill impacts. Summer bills are higher with the Attorney General's revenue requirement and rate design than with the Company's revenue requirement and rate design for the 2.1% of customers who use over 3000 kWh per month – nearly 4 times the median use. Winter electric heat rate increases are at or below the Company's proposed level for all but the 9.6% of customers using over 2500 kWh per month and top out at less than 10%. Winter rate increases for customers without electric heat are negligible, reducing overall bill impacts.

The rate design proposed above would encourage the efficient use of energy, reduce the promotion of electric heat, and would not have undue bill impacts. The Commission should adopt it, while also closing the electric heat rate to new customers.

Q. **Does this complete your testimony, Mr. Marcus?**

A. Yes, it does. Thank you.

CERTIFICATE OF SERVICE

I, Sarah R. Tacker, do hereby certify that on this 26th day of June, 2009, a copy of the above and foregoing Direct Testimony was emailed to the following persons at the indicated email address:

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