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MIKE GLEASON
CHAIRMAN
WILLIAM A. MUNDELL
COMMISSIONER
JEFF HATCH-MILLER
COMMISSIONER
KRISTIN K. MAYES
COMMISSIONER
GARY PIERCE
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	Docket No. E-01933A-07-0402
IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	Docket No. E-01933A-05-0650

NOTICE OF FILING DIRECT TESTIMONY

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimonies of Marylee Diaz, Cortez, CPA, William A. Rigsby, CRRA, Rodney L. Moore and Dr. Ben Johnson, in the above-referenced matter.

RESPECTFULLY SUBMITTED this 29th day of February 2008

Arizona Corporation Commission
DOCKETED
FEB 29 2008
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Scott S. Wakefield
Chief Counsel

AN ORIGINAL AND FIFTEEN COPIES
of the foregoing filed this 29th day
of February 2008 with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

COPIES of the foregoing hand delivered/
Mailed/*emailed this 29th day of February 2008 to:

Jane L. Rodda
Administrative Law Judge
Arizona Corporation Commission
400 West Congress
Tucson, Arizona 85701

Lyn Farmer
Chief Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Christopher Kempley, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Ernest Johnson, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

*Gary Yaquinto, President & CEO
Arizona Investment Council
2100 N. Central Avenue, Suite 210
Phoenix, Arizona 85004

*C. Webb Crockett
Fennemore Craig, P.C.
3003 North Central Avenue
Suite 2600
Phoenix, Arizona 85012-2913

*Raymond S. Heyman
*Michelle Livengood
Tucson Electric Power Company
One South Church Street, Suite 200
Tucson, Arizona 85701

*Michael W. Patten
*J. Matthew Derstine
Roshka DeWulf & Patten,PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

*Nicholas J. Enoch
Lubin & Enoch, P.C.
349 North Fourth Avenue
Phoenix, Arizona 85003

*Timothy Hogan
Arizona Center for Law in the
Public Interest
202 East McDowell Road, Suite 153
Phoenix, Arizona 85004

*Michael M. Grant
Gallagher & Kennedy, P.A.
2575 East Camelback Road
Phoenix, Arizona 85016-9225

*Greg Patterson, Director
Arizona Competitive Power Alliance
916 West Adams, Suite 3
Phoenix, Arizona 85007

*Barbara Klemstine
*Brian Brumfield
Arizona Public Service
P. O. Box 53999
Mail Station 9708
Phoenix, Arizona 85072-3999

*Thomas L. Mumaw
*Deborah R. Scott
Pinnacle West Capital Corporation
P. O. Box 53999
Mail Station 8695
Phoenix, Arizona 85072

*Robert J. Metli
Snell & Wilmer L.L.P.
One Arizona Center
400 East Van Buren
Phoenix, Arizona 85004-2202

Daniel D. Haws
OSJA
Attn: ATZS-JAD
USA Intelligence Center & Fort Huachuca
Fort Huachuca, AZ 857613-6000

*Peter Q. Nyce, Jr.
Regulatory Law Office
U.S. Army Legal Services Agency
901 N. Stuart Street, Suite 713
Arlington, VA 22203-1837

*Christopher Hitchcock
Law Offices of Christopher Hitchcock
P. O. Box AT
Bisbee, AZ 85603-0115

*David Berry
Western Resource Advocates
P. O. Box 1064
Scottsdale, AZ 85252-1064

*Jeff Schlegel
SWEEP
1167 W. Samalayuca Dr.
Tucson, AZ 85704-3224

*Lawrence V. Robertson, Jr.
Theodore Roberts
P. O. Box 1448
Tubac, Arizona 85646

*S. David Childers
Low & Childers PC
2999 N. 44th Street, Suite 250
Phoenix, Arizona 85018

*Dan Neidlinger
Neidlinger & Assoc.
3020 N. 17th Drive
Phoenix, AZ 85015

Michael J. Kurtz
Kurt J. Boehm
Boehm, Kurtz & Lowry
36 E. Seventh Street, Suite 1510
Cincinnati, Ohio 45202

Billy L. Burtnett, P.E.
3351 N. Riverbend Circle East
Tucson, AZ 85750-2509

John E. O'Hare
3865 North Tucson blvd.
Tucson, AZ 95716

By Ernestine Gamble
Ernestine Gamble
Secretary to Scott Wakefield

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-07-0402
DOCKET NO. E-01933A-05-0650

DIRECT TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 29, 2008

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APPENDIX 1 – Marylee Diaz Cortez, CPA

ATTACHMENT MDC-A

ATTACHMENT MDC-B

SCHEDULES MDC-1 Through MDC-2

INTRODUCTION

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

A. My name is Marylee Diaz Cortez. I am a Certified Public Accountant. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office (RUCO) located at 1110 W. Washington, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix I, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present the recommendations that result from my audit and review of Tucson Electric Power Company's ("TEP" or "Company") requested rate increase. TEP filed its rate application with the Arizona Corporation Commission ("ACC" or "Commission") on July 2, 2007. RUCO is recommending that rates in this docket be set based on the cost-of-service model, as set forth by the Company and as adjusted by RUCO. My testimony, as well as Rodney L. Moore's testimony, addresses the various adjustments RUCO recommends to the cost-of-service model. RUCO witness William A. Rigsby will address the cost of capital issues associated with the case.

The testimony of RUCO witness Ben Johnson addresses the two other models proposed by the Company and explains why they should be rejected. The testimony of Glen Gregory addresses RUCO's proposed rate design and cost of service analysis.

Q. Please describe your work effort on this project?

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's application as it relates to operating income, rate base, and the Company's overall revenue requirements. This included the issuance of data requests, review of prior commission decisions, and discussions with Company personnel.

Q. Please identify the Exhibits you are sponsoring.

A. I am sponsoring Schedules MDC-1 through MDC-2.

Q. Please provide a summary of the issues you address in your direct testimony.

A. I address the following issues in my direct testimony:

RATE BASE

<u>Accumulated Depreciation</u> This adjustment restates the Company's recorded accumulated depreciation balance from 2004 through the end of the test year. The adjustment is necessary because during this time

period the Company failed to use the Commission-authorized depreciation rates for accruing depreciation on its generation assets.

Springerville Unit I This adjustment restates the cost of the Springerville Unit I generating station from market to book.

Luna Plant This adjustment restates the cost of the Luna generating plant from market to book.

Implementation Regulatory Asset This adjustment decreases rate base to remove certain prior period expenses, which the Company has written off and for which the Commission never granted regulatory asset accounting authority.

OPERATING INCOME

Springerville Unit I Expenses This adjustment restates the cost of operating the Springerville Unit I plant from market cost to test year actual cost.

Luna Plant This adjustment restates the cost of operating the Luna plant from market cost to test year actual cost.

Implementation Regulatory Asset This adjustment removes the proposed amortization of financing costs that TEP has already written off and for which it does not have a deferral accounting order authorizing future recovery.

Bad Debt Expense This adjustment corrects an error the Company made in its calculation of the bad debt ratio.

Navajo Coal Prices This adjustment corrects an error the Company made in its calculation of the incremental cost increase per ton of Navajo coal.

Gain on Sale of SO_2 Allowances This adjustment credits the ratepayers with the revenue realized during the test-year from the sale of excess SO_2 credits from Springerville Unit 1 and 2.

Lime Usage Costs This adjustment removes the cost of extra lime usage during the test year at Springerville Unit I, as it is non-recurring.

Short-term Sales This adjustment credits ratepayers with 100% of the margins realized from short-term power sales.

Generating Facilities – Operating Lease This adjustment removes the capital lease cost associated with the Springerville Unit I Coal Handling capital lease and replaces it with a levelized lease cost in accordance with Decision No. 58497.

Miscellaneous Service Revenues This adjustment corrects an error the Company made in its calculation of the additional revenue that it will derive from the proposed increase in its Miscellaneous Service fees. Specifically, the error had the effect of understating the revenue related to late fee charges.

Wholesale Trading This adjustment includes the revenue and expenses associated with wholesale trading activities in test year operating income. RUCO recommends recovery of these wholesale margins through base rates as opposed to a PPFAC, as was recommended by the Company.

Rate Case Expense – Docket No. E-01933A-05-0650 This adjustment amortizes the test year cost of Docket No. E-01933A-05-0650 over four years.

Gain on Land Sales This adjustment reflects a 50/50 sharing of gains realized on the sales of land between ratepayers and shareholders.

OTHER ISSUES

Purchased Power and Fuel Adjustor Clause RUCO recommends rejection of the Company proposed Purchased Power and Fuel Adjustor Clause ("PPFAC"), and instead recommends a power supply adjustor that would be applicable solely to load that is incremental to that incurred in the test year.

Termination Cost Regulatory Asset – RUCO recommends rejection of the Company's proposed Termination Cost Regulatory Asset. No such asset exists and the notion of such an asset is illusory.

RATE BASE

Rate Base Adjustment #1 – Accumulated Depreciation

Q. Did RUCO perform a reconciliation of TEP's plant balances from the 2003 test year utilized in the 2004 Rate Check to the year end balances included in the test year ended December 31, 2006?

A. Yes. RUCO witness Rodney L. Moore performed this analysis and reconciliation.

Q. Were there any differences between the balances claimed by the Company in its application and RUCO's analysis?

A. Yes. As discussed in Mr. Moore's testimony, while RUCO was able to reconcile with the Company's plant-in-service balances, there was a large discrepancy between the accumulated depreciation balances computed by RUCO and the amounts recorded on the Company's books.

Q. Was RUCO able to ascertain the source of these large discrepancies?

A. Yes. While there were some differences in the Company's calculation methodology and RUCO's these accounted for a minor amount of the total discrepancy of $68 million. The majority of the discrepancy was attributable to the fact that in 2004 the Company began accruing depreciation on its generation assets at rates that were significantly lower than those that had been authorized by the Commission .

Q. Is the Company allowed to change its depreciation rates at its own discretion?

A. No. Under Arizona Administrative Code section R14-2-102(C)4, a Company cannot put new depreciation rates into effect until the Commission authorizes the changes.

Q. Did the Company offer any explanation for changing the depreciation rates on its generation assets without proper authorization from the Commission?

A. Yes. As was discussed at length in Docket No. E-01933A-05-0650, the Company continues to operate under the misconception that the ACC no longer has jurisdiction over its generation assets. While this may have become the case had the Commission not halted divestiture by its Track A Decision[1], the fact is divestiture *was* halted and the ACC continues to regulate and have jurisdiction of all of TEP's assets and operations. Accordingly, TEP must continue to adhere to the Commission rules and regulations, which includes the requirement for Commission authorization in order for TEP to change its depreciation rates.

Q. Besides failing to obtain Commission authorization to change its depreciation rates, are there any other reasons why such changes were inappropriate?

A. Yes. The depreciation rates on which TEP's current rates are based were significantly higher than those that TEP has been using to accrue depreciation expense since 2004. Thus, while ratepayers are paying the higher authorized depreciation expense through their current rates, the rate base is not being reduced by these payments because TEP is accruing accumulated depreciation at the lower, unauthorized, rates. This

[1] Decision No. 65154

is unfair because it results in ratepayers having to pay a return on plant that they have already paid for. Thus, it is necessary to increase the accumulated depreciation account by $49.504 million to ameliorate this inequity. This adjustment also has an impact of decreasing the Accumulated Deferred Income Tax balance by $19.554 million, for a net adjustment of $29.949 million.

Rate Base Adjustment #2 – Springerville Unit I

Q. Have you reviewed the Company's proposed ratemaking treatment for its Springerville Unit I generating plant?

A. Yes. The Company has made a proforma adjustment to remove the actual test year cost of Springerville Unit I, both capital and operating, and replace these actual costs with market price estimates. The overall affect of the adjustment is to increase the revenue requirement for the Springerville Unit I generating station.

Q. How does the Company justify using estimated market costs for rate setting purposes when the actual costs are not only lower, but are also known and measurable?

A. The Company relies on similar ratemaking treatment that was authorized in Decision No. 56659, dated October 1989 and again in Decision No. 57586 in 1991.

Q. Are the circumstances in the instant case the same as they were in 1989 and 1991 in regards to Springerville Unit I?

A. No. In those cases, the plant was owned by a third party which had recently purchased the plant from Alamito Company.[2] At that time TEP had a contract that required it to lease back the Springerville plant at $220 million in excess of its book value. When Decision No. 56659 was issued, TEP did not own the Springerville plant and was paying lease payments that incorporated the inflated cost of plant. The Commission's use of market based rates in that case had the effect of lowering the then-inflated lease payments to a price that was in line with similar arm's length transactions. In contrast, in the instant case TEP now owns a portion of the Springerville Unit 1 plant and the embedded cost of that plant is less than the market price estimations the Company has utilized in its currently proposed adjustment.

Q. Given the current circumstances of the Springerville plant, is a market price estimation adjustment appropriate?

A. No. It's clear that the Commission authorized the market price adjustment in Decision No. 56659 to recognize that the lease cost of the Unit 1 plant was not negotiated at arms-length and was significantly inflated. This is no longer the case and the plant's embedded costs are known and

[2] Pursuant to Decision No. 53815, TEP transferred its Springerville Unit No. 1 and San Juan Unit No. 3 to a newly formed subsidiary called Alamito Company. In 1984 the then-officers of TEP spun-off Alamito as an independent wholesale power company. Alamito was sold to a third party in 1986 at price that was $232 million in excess of the spin-off price.

measurable. The embedded costs do not appear to be inflated since they are lower than TEP's estimates of the prevailing market price. Thus, an adjustment from the embedded costs is neither appropriate nor warranted. Further, the notion that actual costs could be replaced with higher market estimated costs is contrary to even the most basic ratemaking principles. In this instance the Company continues to blindly adhere to a decades-old Commission decision that makes no sense under the current circumstances.

Q. What adjustment have you made?

A. As shown on Schedule RLM-4, Adjustment #2, I have reinstated the actual embedded cost of the Springerville Unit 1 plant in rate base. This adjustment also has impacts on TEP's test year operating income, which will be discussed later in that section of my testimony.

Rate Base Adjustment #3 - Luna Plant

Q. What ratemaking treatment is the Company requesting for its recently purchased Luna Plant?

A. TEP is requesting that this plant be excluded from rate base and that instead a market-based price for the output of this plant be included in operating expenses. The requested ratemaking treatment for the Luna Plant mirrors the ratemaking treatment requested for the Springerville Unit 1 plant, as just discussed.

Q. Does TEP own the Luna Plant?

A. Yes. TEP purchased this plant on November 12, 2004 and the plant entered service on April 4, 2006.

Q. Given that TEP owns this plant, why is the Company requesting that for ratemaking purposes it be treated as power purchased in the market?

A. According to a response to a RUCO data request, TEP believes that since it purchased this plant after its stranded cost settlement in Decision No. 62103 the plant is "deregulated" and the stockholders should be allowed to realize market-based profits from power sales from this plant to TEP's customers.

Q. Do you agree?

A. No. This flawed logic appears to have its roots in TEP's theory that Decision No. 62103 granted the Company market-indexed rates after 2008, which was the subject of Docket No. 01933A-05-0650. In that docket RUCO strongly disagreed with that position and provided substantial evidence and legal argument that TEP's market-indexed theory was incorrect. The Commission continues to have jurisdiction over TEP's operations, including generation. Accordingly market-indexed rates are inappropriate for a plant which the Company owns and uses to provide service to its captive customers. Instead, the Luna Plant should be priced at cost-of-service, as are all of TEP's other assets.

Q. What adjustment have you made?

A. As shown on Schedule RLM-, Adjustment #3, I have reinstated the actual embedded cost of the Luna plant in rate base. This adjustment also has impacts on TEP's test year operating income, which will be discussed later in that section of my testimony.

Rate Base Adjustment #4 - Implementation Cost Regulatory Asset

Q. Please discuss the Implementation Cost Regulatory Asset that TEP is proposing in rate base.

A. The Company is requesting a $47.5 million regulatory asset, referred to as the Implementation Cost Regulatory Asset ("ICRA"), to be included in rate base. Of this amount $14.2 million is related to certain expenses the Company incurred related to its efforts toward restructuring to retail access. Regulatory asset accounting was authorized for these costs pursuant to Decision No. 62103 ("the 1999 Settlement Agreement").

Q. Has TEP included any costs in its proposed regulatory asset for which Decision No. 62103 did not authorize regulatory asset accounting?

A. Yes. Under Generally Accepted Accounting Principles ("GAAP"), when TEP incurred certain debt financing costs and expenses related to amending and terminating certain coal contracts, the Company was required to write them off as expenses. TEP did not seek, nor was it granted, a deferral accounting order from the Commission that would

allow the Company to capitalize these expenses as regulatory assets. Thus, these costs were expensed when incurred, in periods prior to the test year. Therefore, the Company has no asset related to these costs for which rate base recovery is warranted. Accordingly, my adjustment decreases rate base by $33.242 million to remove these prior-period expenses. There is also a companion adjustment discussed in the Operating Income section of my testimony related to amortization of these prior-period expenses.

Q. Has the Commission previously denied recovery of prior-period expenses for which a utility failed to obtain an accounting order?

A. Yes. In a recent UNS Gas rate case the Commission agreed with Staff and RUCO regarding the unrecoverability of prior-period expenses for which the utility never obtained regulatory asset accounting authority. In Decision No. 70011, dated November 27, 2007, the Commission stated:

> [T]he Company's failure to seek an accounting order from the Commission when the costs were incurred renders them unrecoverable as a regulatory asset.

Rate Base Adjustment #5 – FAS 143 Accumulated Depreciation Write-off

Q. Did TEP recently write-off a significant portion of its Accumulated Depreciation reserve?

A. Yes. The Financial Accounting Standards Board ("FASB") issued Statement No. 143, which modified the manner in which asset retirement obligations are to be accounted for under GAAP. The Statement requires

companies to recognize the fair value of future retirement obligations (i.e. costs) at the point in time they are incurred as a liability. Prior to issuance of Statement No. 143, utilities accounted for retirement costs on a pro-rata basis over the life of the asset through their depreciation accruals. Accordingly, TEP's existing Accumulated Depreciation balance contained accruals for the retirement of assets. In order to comply with Statement No. 143, TEP, on January 1, 2003, wrote-off that portion of its Accumulated Depreciation balance that was related to retirement costs and transferred them to a liability account.

Q. Do you agree with TEP's method of accounting for Statement No. 143?

A. Yes. However, I do not agree the accounting required under Statement No. 143 for GAAP purposes is also appropriate for ratemaking purposes.

Q. Please explain.

A. While a change in accounting practice may be desirable from an accounting perspective, it may impact rates in a biased or unfair manner. Because the starting point from which the regulatory body determines a utility's rates is its GAAP-compliant financial statements, any change in GAAP accounting practice must be carefully analyzed and its impact on the resultant rates fully understood before a determination can be made if such accounting change is appropriate for ratemaking treatment.

Q. Have you done such an analysis?

A. Yes. As just discussed, utilities have historically recognized the cost of asset retirement through annual depreciation accruals. These retirement costs, prior to Statement No. 143, resided in TEP's Accumulated Depreciation account, which under the ratemaking formula serves to reduce rate base. The account serves as a rate base reduction because it represents the portion of TEP's plant investment that it has already recovered through its depreciation accruals. Depreciation accruals (expenses) are included in the ratemaking formula, thus, by definition the Accumulated Depreciation account is comprised of amounts paid for by ratepayers. As just mentioned this account reduces rate base, thereby ensuring that ratepayers do not continue to pay a return on that portion of TEP's rate base investment for which ratepayers have already provided reimbursement. Statement No. 143, however, has upset the equity of depreciation accounting because it requires TEP to write-off a portion of the accumulated depreciation balance that ratepayers have already paid for. This write-off decreases the Accumulated Depreciation balance, which in turn increases rate base. The overall result of this accounting is that ratepayers will have to pay a return on portions of the Company's plant investment that ratepayers have already paid for through their utility rates. Thus, while Statement No. 143 may be appropriate from a financial accounting standpoint it has unintended consequences on regulated

companies, and if recognized for ratemaking purposes will result in double recovery of the previously accrued asset retirement costs.

Q. What adjustment have you made?

A. I have reversed TEP's $112.8 million write-off of its Accumulated Depreciation balance. My adjustment is necessary to prevent ratepayers from having to pay again for assets that they have already paid for.

OPERATING INCOME

Operating Adjustment #1 - Springerville Unit 1 Operating Expenses

Q. What adjustment are you recommending for the Springerville Unit 1 expenses?

A. As previously discussed in the Rate Base section of my testimony, the Company has proposed an adjustment that would replace the actual test year embedded costs of the Springerville Unit 1 plant with market-indexed estimated costs. I have recommended that the Company's adjustment be rejected and instead the actual test year embedded costs be reflected for ratemaking purposes. Operating Adjustment #1 simply reflects the operating income impacts of recognizing the actual test year expenses associated with Unit 1 as opposed to the Company's proposed market estimated costs. As shown on Schedule RLM-8, Operating Adjustment #1, this decreases operating expenses by $32.7 million.

Operating Adjustment #10 - Luna Plant Expenses

Q. What adjustment are you recommending for the Luna plant expenses?

A. As previously discussed in the Rate Base section of my testimony, the Company has proposed an adjustment that would replace the actual test year embedded costs of the Luna plant with market-indexed estimated costs. I have recommended that the Company's adjustment be rejected and instead the actual test year embedded costs be reflected for ratemaking purposes. Operating Adjustment #10 simply reflects the operating income impacts of recognizing the actual test year expenses associated with the Luna plant as opposed to the Company's proposed market-index estimated costs. As shown on Schedule RLM-8, Operating Adjustment #10, this decreases operating expenses by $15.96 million.

Operating Adjustment #11 – Implementation Cost Regulatory Asset

Q. Please discuss your adjustment to remove the amortization expense associated with prior-period expenses.

A. As was discussed previously in the rate base section of my testimony, the Company is proposing regulatory asset accounting for certain expenses it incurred in prior periods for which it never obtained authorization from the Commission. I have removed these prior-period expenses from rate base and likewise have decreased operating expenses by $8.311 million to remove the proposed amortization of these prior-period expenses.

Operating Adjustment #15 – Bad Debt Expense

Q. Are you making an adjustment to the Company's proposed bad debt expense?

A. Yes. Pursuant to a data request, the Company acknowledged that it had incorrectly computed the bad debt ratio and provided a revised ratio. My adjustment restates bad debt expense based on the Company's correction to its bad debt ratio. As shown on Schedule MDC-1, this adjustment reduces bad debt expense by $520,078.

Operating Adjustment #16 – Navajo Coal Prices

Q. Has the Company proposed an adjustment for an increased cost of Navajo coal?

A. Yes. The Company made a calculation where it compared its test year Navajo coal costs per ton with a forecasted 2007 cost of coal per ton and determined a $4.85 cost increase per ton. TEP then multiplied the cost increase by the number of tons used in the test year to derive a total cost increase of $2.780 million.

Q. Do you agree with this calculation?

A. No. The Company's calculation understates the actual test year cost of coal per ton and overstates the 2007 forecast. As a result, the incremental cost of $4.85 per ton is erroneous. Using the actual cost per ton in the test year of $30.23 and the actual 2007 cost per ton of $31.28

the incremental increase is only $1.05 not $4.85 as calculated by the Company. When multiplied by the number of tons burned in the test year the corrected calculation indicates a $585,765 increase in Navajo coal costs as opposed to the $2.780 million calculated by the Company. My corrected calculations are shown on Schedule MDC-2 and result in a $2.194 million decrease in operating expenses.

Operating Adjustment #18 – Gain on Sale of SO_2 Allowances

Q. During the test year did the Company generate any revenue pursuant to sales of its SO_2 allowances?

A. Yes. During the test year TEP realized $6.716 million in revenues from the sale of SO_2 allowances. The Company has made a proforma adjustment in this case to remove this test year revenue from its operating income.

Q. Do you agree with this treatment?

A. No. As was explained in the response to RUCO data request 5.10, the revenue that was realized from the sale of excess SO_2 credits was generated as a result of improved equipment and operation at Springerville Units 1 and 2. Since ratepayers bear the cost of these plants they should also realize any benefits received from these plants. As shown on Schedule RLM-8, I have increased revenues by $6.716 million

to credit ratepayers with the test year revenues realized from the sales of SO_2 allowances.

Operating Adjustment #21 - Lime Usage Costs

Q. Please discuss the Company's proposed adjustment for extra lime usage costs.

A. During the test year TEP performed additional scrubbing of Springerville Units 1 and 2 by using more lime than normal to reduce emissions so that Unit III could operate. Since these costs are abnormal and non-recurring the Company removed these costs for Springerville Unit II.

Q. Why didn't TEP also remove the extra lime usage costs for Unit I?

A. Since the Company removed all of the Unit I operating costs from the test year and replaced those actual costs with market costs, the extra lime usage was also removed as part of that adjustment. As discussed earlier in my testimony, I have reversed that adjustment to include the actual test year cost of operating Springerville Unit I. As result of this earlier adjustment it is now necessary to remove the non-recurring lime costs from the test year Springerville Unit I expenses. This adjustment reduces test year Springerville Unit I expenses by a net amount of $295,482.

Operating Adjustment #22 - Short-term Sales

Q. What ratemaking treatment is the Company proposing for its short-term sales revenues and expenses?

A. The Company has removed the test year revenues and expenses generated through short-term sales. TEP proposes that 90% of the net margin associated with short-term power sales be credited to ratepayers via the proposed PPFAC.

Q. Do you agree with the Company's proposed treatment of the revenues and expenses associated with short-term sales?

A. No. As was discussed previously in my testimony, RUCO is recommending that TEP's proposed PPFAC be rejected. Thus, the margins realized from these sales need to be credited to ratepayers through base rates. Further, RUCO does not agree that TEP shareholders should be allowed to retain 10% of these margins. Ratepayers pay all the costs associated with generation of the power that is sold through short-term sales and should, therefore, should be credited with 100% of the margins realized from those sales.

...

Operating Adjustment #23 – Generating Facilities – Operating Lease

Q. Please explain the Company's proposed adjustment related to the Sundt and Springerville Common Facilities and the Springerville Coal Handling Facilities.

A. For ratemaking purposes, pursuant to Decision No. 58497, the Company accounts for these facilities as levelized lease payments, whereas for book purposes these facilities are accounted for as capital leases. The Company adjustment converts the recorded capital lease accounting to the ratemaking levelized lease expense accounting. The net result is a decrease in operating expenses of approximately $21 million.

Q. Do agree with this adjustment?

A. Yes. Decision No. 58497 does require this adjustment. However, I do not agree with the portion of the adjustment that pertains to the Springerville Coal Handling facilities.

Q. Please explain.

A. As discussed earlier the Company has treated the Springerville Unit I on a market-based rate, therefore removing the test year actual expenses associated with that plant. Because the Company has already removed the expenses associated with 50% of the Springerville Coal Handling facility as part of that adjustment, TEP argues that it is unnecessary in this adjustment.

Q. Do you agree?

A. Yes, that would the case if one where to accept the Company's adjustment to treat Springerville Unit I at market rates. RUCO, however, has rejected this treatment and reinstated the actual test year Springerville Unit I expense. Thus, it is necessary to now remove 100% of the Unit I and II Coal Handling expense as part of the leased facilities adjustment required by Decision No. 58497. This adjustment decreases operating expenses by $9.407 million to restate the capital lease expense of 100% of the Springerville Coal Handling facilities to the required levelized lease expense for these facilities.

Operating Adjustment #24 – Miscellaneous Service Revenue

Q. Has the Company proposed any changes in its Miscellaneous Service Fees?

A. Yes. The Company is proposing to increase the tariffs for some of its Miscellaneous Service Fees[3] to more closely match the current cost of providing these services. The Company then calculated a pro forma adjustment to reflect the additional revenues that will be generated by these increased service fees.

...

[3] Service Connect and Reconnect Fees, Meter Reread, Meter Testing, and Late Fees.

Q. Do you agree with the Company's quantification of the additional revenue that will be generated as a result of these increased fees?

A. The Company in its supplemental response to data request RUCO 3.14 acknowledged that it made an error in its calculation of the additional revenue that will be generated by its proposed late fee tariff (see Attachment MDC-A). An adjustment to increase proforma Miscellaneous Service Fee by $1.161 million is necessary to correct this error.

Operating Adjustment #25 – Wholesale Trading

Q. Has the Company proposed an adjustment to its wholesale trading revenues and expenses?

A. Yes. The Company is proposing to remove the revenues and expenses associated with TEP's wholesale trading activity from test year operating income.

Q. What is TEP's rationale for this adjustment?

A. TEP claims that the margins that are realized through the Company's wholesale trading activities should be credited to TEP's proposed PPFAC.

Q. Does the Company therefore recognize that these margins should be credited to ratepayers?

A. Yes. The administrative costs of these activities (i.e. payroll, office expenses, etc.) remain embedded in test year expenses. Thus, since

ratepayers are bearing the cost of these activities they should be credited with the margins realized from wholesale trading. The Company is not arguing this point, but rather agues that these credits should flow back to the ratepayer through the PPFAC.

Q. Do you agree?

A. Yes, I agree that these margins should be credited to ratepayers. However, since RUCO is not recommending approval of the company-proposed PPFAC I have made an adjustment to include these wholesale revenues and expenses on the test year income statement, for recovery through base rates. This adjustment increases test year operating income by $1.7 million.

Operating Adjustment #26 – Rate Case Expense – Docket No. E-01933A-05-0650

Q. Does TEP's test year expenses include any costs related to its Motion to Amend Decision No. 62103?

A. Yes. TEP's test year operating expenses include $481,447 in expenditures related to its Motion to Amend.

Q. For ratemaking purposes is this a recurring cost?

A. No. The expenditures in Docket No. E-01933A-05-0650 relate to a unique rate litigation, and accordingly should be amortized. I am recommending a four year amortization, which reduces test year expenses by $361,085.

Operating Adjustment #27 – Gain on Land Sales

Q. Has TEP realized gains on sales of its land holdings over past several years?

A. Yes. TEP has realized over $2 million in gains on the sale of land over the past several years.

Q. Should ratepayers be credited with a portion of these gains?

A. Yes. The Commission has typically supported the 50/50 sharing of gains on sales of utility property between ratepayers and shareholders. My adjustment therefore credits ratepayers with approximately $1 million in gains, and amortizes this amount over four years, for an expense reduction of approximately $250,000 per year.

OTHER ISSUES

Purchased Power and Fuel Adjustment Clause

Q. Is TEP proposing a Purchased Power and Fuel Adjustment Clause in this case?

A. Yes. Currently the Company does not have a Purchased Power and Fuel Adjustment Clause ("PPFAC") and claims that such an adjustor is warranted because TEP "relies on natural gas and purchased power to meet a growing percentage of its customer demand"[4]. TEP's proposed

[4] Direct Testimony of David G. Hutchens at page 30, lines 20-21.

adjustor is patterned after the power supply adjustor authorized for APS in Decision No. 69663.

Q. What criteria must a utility meet to warrant the authorization of an automatic adjustor mechanism?

A. The Arizona Court of Appeals addressed the eligibility requirements of automatic adjustment mechanisms in Scates v. Arizona Corporation Commission. The court indicated that such mechanisms are restricted to certain narrowly defined operating expenses that are characterized by fluctuations. The Arizona Corporation Commission also defined automatic adjustor mechanisms as applying to expenses that routinely, or widely, fluctuate. The ACC stated the following regarding automatic adjustor mechanisms:

> The principal justification for a fuel adjustor is volatility in fuel prices. A fuel adjustor allows the Commission to approve changes in rates for a utility in response to volatile changes in fuel or purchased power prices without having to conduct a rate case. (Arizona Public Service Company, Decision No. 56450, at page 6, dated April 13, 1989)

Q. Do you believe that the characteristics of TEP's fuel and purchased power mix meet this criteria?

A. No. The primary source of TEP's power sales is from its coal fired plants[5]. Historically, prices of delivered coal have not been volatile or widely fluctuating, as would be required by Scates for automatic adjustment. As

[5] During the test year TEP generated 81% of its sales from its coal fired plants.

shown in the response to data request RUCO 8.5 (see Attachment MDC-B), the delivered price of coal has increased by approximately 8% over the past three years. This is less than inflation for the same period, and thus, hardly qualifies as a volatile expense that justifies extraordinary ratemaking treatment. Further, TEP has made proforma adjustments to its test year delivered coal prices to reflect the increases it anticipates post-test year. Given these adjustments, and the lack of any demonstrated volatility in coal prices, a mechanism for automatic adjustment simply isn't warranted.

Q. What are the characteristics of TEP's other sources of power?

A. During the test year, TEP supplied 6.3% of its power sales via gas generation and 12.6% with market purchases. Both of these sources have historically been somewhat less stable than coal prices, however, again, these sources are relied on for less than 20% of TEP's power sales.

Q. Given the overall characteristics of TEP's power sources does RUCO recommend approval of the Company's proposed PPFAC?

A. No. The proposed PPFAC would allow TEP to automatically flow through the cost of its power to ratepayers outside of a traditional rate case where otherwise all ratemaking elements would be analyzed and rates set on a comprehensive examination of the Company's financial status. Instead

fuel and purchased power would be afforded single ratemaking issue status under TEP's proposed PPFAC. In effect, under this proposal TEP would be held harmless not only from cost increases in fuel and purchased power, but also be held harmless from management and operation of its own generation resources, which comprise over 80% of its power sales.

Q. Without the proposed PPFAC will TEP be required to bear an unacceptable level of risk?

A. No. Based on the Company's test year sources of power, I do not believe TEP is subject to an unacceptable level of risk that would not be adequately compensated through its return on equity. However, RUCO is aware that the percentage of power that TEP supplies through market purchases has continued to grow each year (see Attachment MDC-B). While coal continues to generate approximately the same number of MWh sales each year, purchases continue to increase, thus annually becoming a greater percentage of sales. This trend indicates that TEP is relying primarily on purchases to serve any load growth. Since TEP has not indicated any plans for the purchase of new plants, it appears that purchases will continue to supply TEP's growth into the near term future.

...

Q. Could this pose potential higher levels of risk in the future for TEP?

A. Yes. Potentially the risk of volatility in the market will rise, as long as TEP has annual load growth and continues to rely on the market to serve this growth.

Q. How does RUCO propose to protect TEP from its growing reliance on sources of power that have less price stability than its coal resources?

A. Again, because of the relative price stability of the majority of TEP's power, and the proforma adjustments the Company has made to increase the test year prices of delivered coal to projected 2009 price levels, TEP's current risk exposure is limited to future load growth that will be subject to market purchases. Thus, RUCO is proposing a power supply adjustor that would be applicable only to incremental load above the test year level. RUCO's proposed power supply adjustor would protect TEP from market price volatility related to load growth, while at the same time will not shift the operational risk of TEP's own generating facilities to ratepayers.

Q. How would RUCO's proposed power supply adjustor work?

A. The power supply adjustor would be initially set at zero, and would not be eligible for resetting until December 2010. In December 2010 TEP would compare its actual purchased power expenses with the amount embedded in base rates in this case and multiply the incremental difference (whether negative or positive) by the increase in retail MWh sales from the 2006

test year until the 2009 calendar year. The product of this calculation would be divided by the total 2009 retail MWh sales to yield the annual amount of the power supply adjustor per kWh for the ensuing year.

Q. Does RUCO's proposal include a forward looking component to the power supply adjustor?

A. No. RUCO does not believe the characteristics of TEP's fuel and purchased power supplies warrant the use of estimations or projections of purchased power costs. Such a methodology would only serve to complicate TEP's rate structure and require further adjustment when actual prices became known.

Q. Didn't the Company itself propose a similar adjustor mechanism in Docket E-01933A-05-0650?

A. Yes. Witness James Pignatelli proposed an Energy Cost Adjustment Clause ("ECAC") mechanism in the testimony he filed in Docket No. E-1933A-05-0650. The proposed ECAC was very similar to the mechanism that RUCO is recommending in this docket. The Company proposed ECAC also would have been applicable only to that portion of TEP's load that was incremental to the test year level. In support of the ECAC Mr. Pignatelli observed the following:

> The proposed ECAC is an adjustment clause that allows the portion of retail load above the cost-of-service test year sales to be recovered at market-based prices. It differs from some other purchase power and fuel clauses in that it does not shift any

> operational risk of TEP's generating facilities to the Company's customers and does not include and fuel cost risks associated with the Test Year Retail Sales portion of the load.
>
> and
>
> Although TEP serves the majority of its load with company-owned generating resources, it relies on purchased power to meet a growing percentage of its customer demand. Because this power is purchased at market prices, TEP should be allowed to recover market prices for a portion of its load.[6]

Thus, the Company also recognized the merits of the type of power adjustor that RUCO is now also recommending.

Termination Cost Recovery Asset

Q. What is the Termination Cost Recovery Asset?

A. The Company claims that the Termination Cost Recovery Asset ("TCRA") is a regulatory asset "that represents the economic harm that will have been suffered by TEP if the 1999 Settlement Agreement is not honored and generation service rates are based solely on cost-of-service principles."[7]

...

[6] Direct testimony of James Pignatelli, Docket No. E-0133A-05-0650, pages 20, 21

[7] Testimony of James Pignatelli, Docket No. E-01933A-07-0402, page 20, lines 3-5.

Q. Has the Commission issued an accounting order or a prior decision establishing this "regulatory asset"?

A. No. This "regulatory asset" is merely something that the Company has invented in this docket and has not in any way previously been afforded regulatory asset status by this Commission.

Q. What is your understanding of TEP's logic in inventing the TCRA?

A. TEP appears to believe that the Company was somehow guaranteed market generation rates in 2009 pursuant to the 1999 Settlement Agreement, and that if, as a result of this docket TEP is permitted to charge those market rates, the Company should be compensated for the rate decreases and rate freeze that were part of that Settlement Agreement. This issue was thoroughly vetted in the hearing in Docket No. E-01933A-05-0650, and none of the parties to that docket, other than TEP, agreed with this interpretation of the 1999 Settlement Agreement. No Commission decision was rendered on this issue in Docket No. E-01933A-05-0650, but the matter was consolidated with the instant docket. RUCO's position on this issue has not changed since that hearing, and RUCO refers the reader to the testimonies filed in that docket for a full record of the parties' positions. Further, the rate decreases that TEP implemented in 1999 and 2000 were merely reaffirmed in the 1999

Settlement Agreement and had actually been previously authorized by the Commission in Decision No. 61104, dated August 28, 1998[8].

Q. Setting aside the disagreement on whether the 1999 Settlement Agreement granted TEP market rates in 2009, do you agree with the Company's quantification of this so called "regulatory asset"?

A. No. The Company claims that this so called "regulatory asset" has a value of $788 million as of May 2008 which will increase to $921 million by December 2006? This amount is based on the $111 million annual revenue deficiency that the Company claimed in its 2004 Rate Check, accumulated through 2008, plus interest and return.

Q. Did the Commission issue a decision on the 2004 Rate Check and make a finding of fair value and a revenue deficiency amount?

A. No. The terms of the Settlement Agreement provided that the Rate Check was to be filed in June 2004 to ensure that TEP was not overearning as a result of the stranded cost recovery estimates in the Settlement Agreement. According to Decision No. 62103 the 2004 Rate Check could only result in a rate decrease, not a rate increase. None of the parties to the 2004 Rate Check found that TEP was overearning, thus the question of a rate decrease was moot. Because any rate increase was precluded under the 1999 Settlement Agreement, no hearings were held and there

[8] Decision No. 61104 authorized a settlement agreement between TEP, Staff, RUCO, and other intervenors in TEP's Application for Implementation of a Shared-Savings Proposal.

was no Commission finding of fair value or any specific revenue deficiency.

Q. So the $111 million revenue deficiency that forms the basis of TEP's proposed TCRA is not a finding of the Commission?

A. No. The $111 million is merely the amount of deficiency that TEP represented in its filing, which was comprised of a large number of proforma adjustments, with which the parties in large part disagreed. RUCO represented the deficiency was approximately $30 million; Staff calculated a revenue deficiency of approximately $66 million. The Commission never established a revenue deficiency in any amount since it issued no decision in the 2004 Rate Check, thus, there is no basis of TEP's claim of an annual $111 million "harm" it has born since the Rate Check.

Q. So RUCO disagrees with TEP regarding the existence and justification of a "regulatory asset" as well as to the amount of the so-called "regulatory asset"?

A. Yes. RUCO recommends the Company proposed TCRA be rejected for the above discussed reasons as well as those set forth in RUCO's testimony and briefs filed in Docket No. E-01933A-05-0650.

True-up Revenues

Q. What does TEP mean by the term "true-up revenues"?

A. In the 1999 Settlement Agreement, TEP was permitted to collect a portion of its stranded costs through a fixed Competitive Transition Charge ("CTC"). The Settlement Agreement provided that TEP would collect the fixed CTC of 0.93 cents/kWh (average), until it had collected $450 million, or through the end of 2008, which ever occurred first. At that time, the fixed CTC would terminate. In 2007, TEP projected that it would meet the $450 million target in early 2008. However, in Decision No. 69568, the Commission permitted TEP to continue collecting the fixed CTC until further order of the Commission, and instructed that the amount of fixed CTC that TEP collects above the $450 million target would be considered "True Up Revenue" and would be subject to refund, credit or another mechanism to protect customers.

Q. Has TEP proposed a method of refunding or crediting customers with the true-up revenue?

A. Yes. TEP proposes a slightly lower TCRA than it otherwise believes it is entitled to in recognition of the true-up revenue.

...

Q. Does RUCO believe that is an appropriate method to compensate customers for their overpayment of the Fixed CTC?

A. No. As discussed above, RUCO does not believe TEP is entitled to a TCRA in any amount. Therefore, RUCO proposes that the true-up revenue be credited back to customers through a different mechanism.

Q. What is RUCO's recommended mechanism to refund the over collection?

A. RUCO recommends that customers receive bill credits, based on their individual usage during the over collection period. Until the magnitude of the over collections is actually known, an appropriate refunding period cannot be determined.

Q. Does this conclude your direct testimony?

A. Yes.

APPENDIX I

Qualifications of Marylee Diaz Cortez

EDUCATION: University of Michigan, Dearborn
B.S.A., Accounting 1989

CERTIFICATION: Certified Public Accountant - Michigan
Certified Public Accountant – Arizona

EXPERIENCE: Audit Manager
Residential Utility Consumer Office
Phoenix, Arizona 85007
July 1994 - Present

Responsibilities include the audit, review and analysis of public utility companies. Prepare written testimony, schedules, financial statements and spreadsheet models and analyses. Testify and stand cross-examination before Arizona Corporation Commission. Advise and work with outside consultants. Work with attorneys to achieve a coordination between technical issues and policy and legal concerns. Supervise, teach, provide guidance and review the work of subordinate accounting staff.

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona 85004
October 1992 - June 1994

Responsibilities included the audit, review and analysis of public utility companies. Prepare written testimony and exhibits. Testify and stand cross-examination before Arizona Corporation Commission. Extensive use of Lotus 123, spreadsheet modeling and financial statement analysis.

Auditor/Regulatory Analyst
Larkin & Associates - Certified Public Accountants
Livonia, Michigan
August 1989 - October 1992

Performed on-site audits and regulatory reviews of public utility companies including gas, electric, telephone, water and sewer throughout the continental United States.

Prepared integrated proforma financial statements and rate models for some of the largest public utilities in the United States. Rate models consisted of anywhere from twenty to one hundred fully integrated schedules. Analyzed financial statements, accounting detail, and identified and developed rate case issues based on this analysis. Prepared written testimony, reports, and briefs. Worked closely with outside legal counsel to achieve coordination of technical accounting issues with policy, procedural and legal concerns. Provided technical assistance to legal counsel at hearings and depositions. Served in a teaching and supervisory capacity to junior members of the firm.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Client
Potomac Electric Power Co.	Formal Case No. 889	Peoples Counsel of District of Columbia
Puget Sound Power & Light Co.	Cause No. U-89-2688-T	U.S. Department of Defense - Navy
Northwestern Bell-Minnesota	P-421/EI-89-860	Minnesota Department of Public Service
Florida Power & Light Co.	890319-EI	Florida Office of Public Counsel
Gulf Power Company	890324-EI	Florida Office of Public Counsel
Consumers Power Company	Case No. U-9372	Michigan Coalition Against Unfair Utility Practices
Equitable Gas Company	R-911966	Pennsylvania Public Utilities Commission
Gulf Power Company	891345-EI	Florida Office of Public Counsel

Utility Company	Docket No.	Client
Jersey Central Power & Light	ER881109RJ	New Jersey Department of Public Advocate Division of Rate Counsel
Green Mountain Power Corp.	5428	Vermont Department of Public Service
Systems Energy Resources	ER89-678-000 & EL90-16-000	Mississippi Public Service Commission
El Paso Electric Company	9165	City of El Paso
Long Island Lighting Co.	90-E-1185	New York Consumer Protection Board
Pennsylvania Gas & Water Co.	R-911966	Pennsylvania Office of Consumer Advocate
Southern States Utilities	900329-WS	Florida Office of Public Counsel
Central Vermont Public Service Co.	5491	Vermont Department of Public Service
Detroit Edison Company	Case No. U-9499	City of Novi
Systems Energy Resources	FA-89-28-000	Mississippi Public Service Commission
Green Mountain Power Corp.	5532	Vermont Department of Public Service

Utility Company	Docket No.	Client
United Cities Gas Company	176-717-U	Kansas Corporation Commission
General Development Utilities	911030-WS & 911067-WS	Florida Office of Public Counsel
Hawaiian Electric Company	6998	U.S. Department of Defense - Navy
Indiana Gas Company	Cause No. 39353	Indiana Office of Consumer Counselor
Pennsylvania American Water Co.	R-00922428	Pennsylvania Office of Consumer Advocate
Wheeling Power Co.	Case No. 90-243-E-42T	West Virginia Public Service Commission Consumer Advocate Division
Jersey Central Power & Light Co.	EM89110888	New Jersey Department of Public Advocate Division of Rate Counsel
Golden Shores Water Co.	U-1815-92-200	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-92-135	Residential Utility Consumer Office
Sulphur Springs Valley Electric Cooperative	U-1575-92-220	Residential Utility Consumer Office
North Mohave Valley Corporation	U-2259-92-318	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Graham County Electric Cooperative	U-1749-92-298	Residential Utility Consumer Office
Graham County Utilities	U-2527-92-303	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-93-110	Residential Utility Consumer Office
Litchfield Park Service Co.	U-1427-93-156 & U-1428-93-156	Residential Utility Consumer Office
Pima Utility Company	U-2199-93-221 & U-2199-93-222	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-94-306	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-182	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-310 & U-1303-94-401	Residential Utility Consumer Office
Pima Utility Company	U-2199-94-439	Residential Utility Consumer Office
SaddleBrooke Development Co.	U-2492-94-448	Residential Utility Consumer Office
Boulders Carefree Sewer Corp.	U-2361-95-007	Residential Utility Consumer Office
Rio Rico Utilities	U-2676-95-262	Residential Utility Consumer Office
Rancho Vistoso Water	U-2342-95-334	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-95-491	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-473	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Citizens Utilities Co.	E-1032-95-417 et al.	Residential Utility Consumer Office
Paradise Valley Water	U-1303-96-283 & U-1303-95-493	Residential Utility Consumer Office
Far West Water	U-2073-96-531	Residential Utility Consumer Office
Southwest Gas Corporation	U-1551-96-596	Residential Utility Consumer Office
Arizona Telephone Company	T-2063A-97-329	Residential Utility Consumer Office
Far West Water Rehearing	W-0273A-96-0531	Residential Utility Consumer Office
SaddleBrooke Utility Company	W-02849A-97-0383	Residential Utility Consumer Office
Vail Water Company	W-01651A-97-0539 & W-01651B-97-0676	Residential Utility Consumer Office
Black Mountain Gas Company & Northern States Power Company	G-01970A-98-0017 & G-03493A-98-0017	Residential Utility Consumer Office
Paradise Valley Water Company & Mummy Mountain Water Company	W-01303A-98-0678 & W-01342A-98-0678	Residential Utility Consumer Office
Bermuda Water Company	W-01812A-98-0390	Residential Utility Consumer Office
Bella Vista Water Company & Nicksville Water Company	W-02465A-98-0458 & W-01602A-98-0458	Residential Utility Consumer Office
Paradise Valley Water Company	W-01303A-98-0507	Residential Utility Consumer Office
Pima Utility Company	SW-02199A-98-0578	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144 Interim Rates	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Vail Water Company	W-01651B-99-0355 Interim Rates	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144	Residential Utility Consumer Office
Sun City Water and Sun City West	W-01656A-98-0577 & SW-02334A-98-0577	Residential Utility Consumer Office
Southwest Gas Corporation & ONEOK, Inc.	G-01551A-99-0112 & G-03713A-99-0112	Residential Utility Consumer Office
Table Top Telephone	T-02724A-99-0595	Residential Utility Consumer Office
U S West Communications & Citizens Utilities Company	T-01051B-99-0737 & T-01954B-99-0737	Residential Utility Consumer Office
Citizens Utilities Company	E-01032C-98-0474	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-00-0309 & G-01551A-00-0127	Residential Utility Consumer Office
Southwestern Telephone Company	T-01072B-00-0379	Residential Utility Consumer Office
Arizona Water Company	W-01445A-00-0962	Residential Utility Consumer Office
Litchfield Park Service Company	W-01427A-01-0487 & SW-01428A-01-0487	Residential Utility Consumer Office
Bella Vista Water Co., Inc.	W-02465A-01-0776	Residential Utility Consumer Office
Generic Proceedings Concerning Electric Restructuring Issues	E-00000A-02-0051	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-02-0707	Residential Utility Consumer Office
Qwest Corporation	RT-00000F-02-0271	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Arizona Public Service Company	E-01345A-02-0403	Residential Utility Consumer Office
Citizens/UniSource	G-01032A-02-0598 E-01032C-00-0751 E-01933A-02-0914 E-01302C-02-0914 G-01302C-02-0914	Residential Utility Consumer Office
Arizona-American Water Company	WS-01303A-02-0867	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-03-0437	Residential Utility Consumer Office
UniSource	E-04230A-03-0933	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-04-0407	Residential Utility Consumer Office
Qwest Corporation	T-01051B-03-0454 & T-00000D-00-0672	Residential Utility Consumer Office
Tucson Electric Power Company	E-01933A-04-0408	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0280	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-04-0876	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0405	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0718	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-06-0009	Residential Utility Consumer Office
Black Mountain Sewer Corporation	SW-02361A-05-0657	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Arizona Public Service Company	E-01345A-05-0816	Residential Utility Consumer Office
Arizona-American Water Company	WS-1303A-06-0014	Residential Utility Consumer Office
Tucson Electric Power Company	E-01933A-05-0650	Residential Utility Consumer Office
UNS Gas, Inc.	G-04204A-06-0463 et al.	Residential Utility Consumer Office
UNS Electric, Inc.	E-04204A-06-0783	Residential Utility Consumer Office
Arizona-American Water Company	WS-1303A-06-0491	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-07-0209	Residential Utility Consumer Office

ATTACHMENT MDC-A

TUCSON ELECTRIC POWER COMPANY'S
SUPPLEMENTAL RESPONSES TO
RUCO'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-01933A-07-0402 et al.
January 4,2008

3.14 Please provide an estimate of the revenue to be obtained by the new late payment fees by each customer class of service.

RESPONSE: In the process of compiling this response it was discovered that the late payment fees adjustment proposed by the Company contains errors. The Company is attempting to compile the revised adjustment, which will impact the response to this question. The Company will provide the revised adjustment and the response to this question subsequently.

RESPONDENT: Dallas Dukes

WITNESS: D. Bentley Erdwurm

SUPPLEMENTAL RESPONSE: The pro forma adjustment "Mise Service Revenues - Service & Late Fees" contained an error and has been revised. The original adjustment was an increase to test year revenues of $1,308,077. That amount should be revised to $2,469,342. Please see RUCO 3.14 on the enclosed CD for the workpaper for the revised adjustment.. The original "estimate" of new late fee revenue has increased from $363,721 to $1,524,986. TEP estimates that the new late fee revenue will be obtained by each customer class of service as such:

Residential -	36%
Commercial -	13%
Industrial -	22%
Other/ Public Authority -	29%

The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

RESPONDENT: Dallas Dukes

WITNESS: D. Bentley Erdwurm

ATTACHMENT MDC-B

TUCSON ELECTRIC POWER COMPANY'S
RESPONSES TO
RUCO'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. E-01933A-07-0402 et al.
December 17, 2007

8.5 Generation For each year 2004 - 2007 please provide the following information:

a) The percentage of the total annual electricity generated that was generated by each fuel source (i.e. coal, gas, nuclear, etc.)

b) The total annual mwh produced by each fuel source; and

c) The average annual price per mwh produced for each fuel source.

RESPONSE: a) Please see the percentage of the total annual electricity generated by each fuel source (i.e., coal, gas, nuclear, etc.) for the years 2004 - 2007 below:

	2004	2005	2006	2007
Coal	86.1%	84.3%	81.0%	75.7%
Gas	3.4%	2.9%	6.3%	7.8%
Solar	0.1%	0.1%	0.1%	0.1%
Purchases	10.4%	12.7%	12.6%	16.4%
Total	100%	100%	100%	100%

b) Please see the total annual MWh produced by each fuel source for the years 2004 - 2007 below:

	2004	2005	2006	2007
Coal	10,894,000	10,847,000	10,962,000	8,163,000
Gas	432,000	368,000	850,000	841,000
Solar	8,000	9,000	9,000	6,000
Purchases	1,322,000	1,639,000	1,707,000	1,772,000
Total	12,656,000	12,863,000	13,528,000	10,782,000

TUCSON ELECTRIC POWER COMPANY'S
RESPONSES TO
RUCO'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. E-01933A-07-0402 et al.
December 17,2007

c) Please see the average annual price per MWh produced for each fuel source for the years 2004 - 2007 below:

	2004	2005	2006	2007
Coal	$ 16.43	$ 17.52	$ 17.79	$ 19.36
Gas	78.70	97.83	64.71	73.72
Purchases	55.22	79.93	60.34	64.90
Average Total	$ 22.61	$ 27.77	$ 26.11	$ 31.09

RESPONDENT: Kevin Battaglia

WITNESS: David Hutchens

TUCSON ELECTRIC POWER COMPANY
DOCKET NO. 01933A-07-0402
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SCHEDULE #	
MDC - 1	OPERATING ADJ#15 - BAD DEBT EXPENSE
MDC - 2	OPERATING ADJ #16 - NAVAJO COAL

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
OPERATING ADJ#15 - BAD DEBT EXPENSE

DOCKET NO. 01933A-07-0402
SCHEDULE MDC-1

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	NET SALES	$774,470,361	STF 1.85
2	MISCELLANEOUS REVENUES	2,780,909	STF 1.85
3	SUBTOTAL	777,251,270	LINE 1 + LINE 2
4	REVENUE ANNUALIZATION	5,044,631	STF 1.85
5	WEATHER NORMALIZATION	4,572,055	STF 1.85
6	SERVICE & LATE FEES	1,308,077	STF 1.85
7	TOTAL REVENUES	788,176,033	STF 1.85
8	BAD DEBT % WRTITE-OFF	0.25006%	STF 1.85
9	BAD DEBT EXPENSE	1,970,913	LINE 7 x LINE 8
10	BAD DEBT EXPENSE PER TEP	2,490,991	COMPANY W/P
11	ADJUSTMENT	(520,078)	LINE 9 - LINE 10

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
OPERATING ADJ #16 - NAVAJO COAL

DOCKET NO. 01933A-07-0402
SCHEDULE MDC-2

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	T/Y COST PER TON OF NAVAJO COAL	$30.23	RUCO DR# 2.9
2	ACTUAL 2007 COST PER TON	31.28	RUCO DR# 2.10
3	INCREASE IN COAL COST	1.05	LINE 2 - LINE 1
4	T/Y TONS	557,871	RUCO DR# 2.9
5	PROFORMA COST INCREASE	585,765	LINE 3 x LINE 4
6	PROFORMA COST INCREASE PER COMPANY	2,780,000	COMPANY SCHEDULE C-2
7	ADJUSTMENT	($2,194,235)	LINE 5 - LINE 6

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-07-0402
DOCKET NO. E-01933A-05-0650

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 29, 2008

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SCHEDULES WAR-1 Through WAR-9

INTRODUCTION

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

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utility regulation and your educational background.

A. I have been involved with utility regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have also been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to this testimony, further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Tucson Electric Power Company's ("TEP" or "the Company") application for a permanent rate increase ("Application") for the Company's electric service operations in Southern Arizona. TEP filed the Application with the ACC on July 2, 2007. The Company has chosen the calendar year ended December 31, 2006 for the test year in this proceeding.

Q. Briefly describe TEP.

A. TEP is based in Tucson, Arizona and is the second largest investor-owned electric utility in the state of Arizona. The Company provides electric generation, transmission and distribution services to customers in and around the Tucson metropolitan area in Pima County. TEP is a wholly owned subsidiary of UniSource Energy Corporation ("UniSource" or "Parent"), an Arizona corporation, also based in Tucson, that is publicly traded on the New York Stock Exchange ("NYSE")[1]. UniSource also provides natural gas and electric distribution services through two other Arizona subsidiaries: UNS Gas, Inc. ("UNS Gas"), which serves customers in Northern Arizona and Santa Cruz County; and UNS Electric, Inc. ("UNS Electric"), which serves customers in Mohave and Santa Cruz Counties.

[1] NYSE ticker symbol UNS.

Q. Please explain your role in RUCO's analysis of TEP's Application.

A. I reviewed TEP's Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity and my recommended cost of debt (the Company has no preferred stock). The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Application and from market-based research that I conducted during my analysis.

Q. Is this your first case involving UniSource or TEP?

A. No. In 2003 I was involved with UniSource's acquisition of the gas and electric assets of Citizens' Utilities Company. The aforementioned UNS Gas and UNS Electric subsidiaries of UniSource were the result of that acquisition. During 2005 I provided cost of capital recommendations on TEP's general rate case information filing.[2] The filing was required under the 1999 TEP settlement agreement, approved in Decision No. 62103, and served as a rate check on the Company.[3] More recently I testified on

[2] E-01933A-04-0408

[3] Decision No. 62103 resolved pending litigation on the Commission's Retail Electric Competition Rules and provided TEP with the opportunity to recover stranded costs associated with electric restructuring. The decision also implemented two rate reductions and froze the Company's rates through 2008. TEP entered into the settlement agreement on June 9, 1999 with RUCO, members of Arizonans for Electric Choice and Competition, and the Arizona Community Action Association.

cost of capital issues in rate case proceedings that involved both UNS Gas[4] and UNS Electric[5].

Q. Were you also responsible for conducting an analysis on the Company proposed revenue level, rate base and rate design?

A. No. RUCO Chief of Accounting and Rates Marylee Diaz Cortez, CPA and RUCO analyst Rodney L. Moore will provide testimony on the revenue and rate base aspects of the Company's Application. In addition to RUCO's in-house staff, RUCO has also retained the services of two outside consultants. Glen Gregory, of Garrett Group, LLC, will testify on RUCO's rate design and cost of service recommendations and Ben Johnson, Ph.D. of Ben Johnson Associates, will present RUCO's positions on the various competitive scenarios that TEP is proposing in this case.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

[4] Docket No. G-04204A-06-0463

[5] Docket No. E-04204A-06-0783

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into seven sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of returns for utilities that operate in the Arizona jurisdiction. In this second section I will also provide a brief overview of the current economic climate that TEP is operating in. Fourth, I will discuss my recommended cost of debt. Fifth, I will compare my recommended capital structure with the Company-proposed capital structure. Sixth, I will explain my weighted cost of capital recommendation and seventh, I will comment on TEP' cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of TEP, I am making the following recommendations:

Cost of Equity Capital – I am recommending a 9.44 percent cost of equity capital. This 9.44 percent figure is based on the results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies.

Cost of Debt – I am recommending that the Commission adopt the Company-proposed 6.39 percent cost of long-term debt. This is based on my review of the costs associated with the various debt instruments issued by TEP to finance the Company's plant-in-service.

Capital Structure – I am recommending that the Company-proposed pro forma capital structure, which is comprised of 55.0 percent long-term debt and 45.0 percent common equity, be adopted by the Commission.

Cost of Capital – Based on the results of my recommended capital structure, cost of common equity, and cost of debt analyses, I am recommending a 7.76 percent cost of capital for TEP. This figure represents the weighted cost of my recommended cost of common equity and my recommended costs of short and long-term debt.

...

Q. Why do you believe that your recommended 7.76 percent cost of capital is an appropriate rate of return for TEP to earn on its invested capital?

A. The 7.76 percent cost of capital figure that I have recommended meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

...

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as TEP, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your recommended cost of equity capital for TEP?

A. Based on the results of my DCF and CAPM analyses, which ranged from 8.63 percent to 11.08 percent for a sample of electric providers, I am recommending a 9.44 percent cost of equity capital for TEP. My recommended 9.44 percent figure represents a mean average of the results of my DCF and CAPM analyses, which utilized a sample of publicly traded electric companies.

...

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate TEP's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the

stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = (D_1 \div P_0) + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$D_1 \div P_0$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth.

This formula is the basis for the standard growth valuation model that I used to determine TEP's cost of equity capital. It is similar to one of the models used by the Company.

Q. In determining the rate of future dividend growth for TEP, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's

earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as g = b x r.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[6]

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

[6] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony of Stephen G. Hill, dated December 10, 1993, pages 25 - 32.

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as g = b x r, is also referred to as the internal or sustainable growth rate.

...

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[7] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[8] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rates for earnings and dividends, displayed in the last column, are 16.20 percent. If this rate were to be

[7] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[8] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change only in the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

...

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings

expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[9] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where: g = DCF expected growth rate,

b = the earnings retention ratio,

r = the return on common equity,

s = the fraction of new common stock sold that

[9] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

accrues to a current shareholder, and

v = funds raised from the sale of stock as a fraction of existing equity.

and v = 1 - [(BV) ÷ (MP)]

where: BV = book value per share of common stock, and

MP = the market price per share of common stock.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M ÷ B) + 1] ÷ 2.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M ÷ B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In the most recent Southwest Gas Corporation rate case[10], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case, Mr. Hill used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a proxy group consisting of eight electric utility companies that have similar operating characteristics to TEP.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of TEP?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company, as is the case with TEP itself. Although shares of TEP's parent company, UniSource, are traded on the NYSE, there is no financial data available on dividends paid on *publicly held* shares of TEP. Consequently it was

[10] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

necessary to create a proxy by analyzing publicly traded electric companies with similar risk characteristics.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the companies that make up your proxy for TEP?

A. With the exception of two electric companies, I chose the same sample of electric providers that were used by TEP's cost of capital witness, Samuel C. Hadaway, Ph. D. All of the electric utility companies in my sample, with the exception of MG Energy Inc., are publicly traded on the NYSE and are followed by The Value Line Investment Survey's ("Value Line") electric utility (east, central and west) industry segments. MG Energy Inc. is traded on the NASDAQ[11] which is also a major U.S. stock exchange. Each of the companies in the proxy are engaged in the provision of

[11] National Association of Securities Dealers Automated Quotation system

regulated electric utility services. Attachment A of my testimony contains Value Line's most recent evaluation of the regional electric utility proxy group that I used for my cost of common equity analysis.

Q. What companies are included your proxy?

A. Schedule WAR-2 lists the twenty-six electric service providers included in my proxy and their NYSE/NASDAQ ticker symbols.

Q. Did the Company's witness also perform a similar analysis using electric utility companies?

A. Yes. As I noted earlier, the Company's witness, Dr. Hadaway, performed a similar analysis that used all but two of the publicly traded electric utility companies included in my sample.

Q. What two electric companies did you exclude from your sample?

A. My sample excludes Energy East Corporation (NYSE symbol EAS), and Puget Energy, Inc. (NYSE symbol PSD).

Q. Why did you exclude these two electric service providers from your sample?

A. Both of these electric service providers have accepted takeover offers from other firms. On November 20, 2007, Energy East Corporation shareholders agreed to be acquired by Iberdrola, S.A., a large utility

holding company based in Spain. Puget Energy, Inc. announced the acceptance of an offer from a consortium formed by Macquarie Infrastructure Partners and Diversified Utility and Energy Trusts on October 26, 2007. Because the stock prices of these two companies are now being driven by the offers of their respective buyers, they are no longer suitable for my sample of electric providers.

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the sample for the historical observation period 2002 to 2006. Schedule WAR-5 also includes Value Line's projected 2007, 2008 and 2010-12 values for the retention ratio, return on book equity, book value per share growth rate, and number of shares outstanding for the electric utility companies in my sample.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use Hawaiian Electric Industries, Inc., (NYSE symbol HE) as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula

(described on pages 9 and 10 of my testimony) to multiply HE's earned return on common equity by its earnings retention ratio for each year in the 2002 to 2006 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, Page 1, HE's sustainable internal growth rate ranged from 2.65% in 2002 to 0.67% in 2006. The company's growth rates experienced a declining pattern during the majority of the observation period, which resulted in a 1.58 percent average over the 2002 to 2006 time frame. Value Line's analysts are forecasting a negative retention ratio for 2007 before HE's sustainable growth rate falls to 0.07% during 2008. Value Line's analysts are also projecting that the declining trend will reverse and expects a sustainable growth rate of 1.91% during the 2010-12 period. Value Line has also revised its book value growth projection upward from negative 1.00% in November 2007 to negative 0.50%. Based on the aforementioned projections and estimates, I believe that a 1.75% rate of internal sustainable growth is reasonable for HE.

...

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 demonstrates that HE's share growth averaged 2.56% over the 2002 - 2006 observation period. However, Value Line expects future outstanding shares to increase modestly from 83.50 million in 2006 to 87.00 million by the end of 2012. Taking this data into consideration, I am estimating a 2.00 percent rate of share growth for HE.

My final dividend growth rate estimate for HE is 2.41 percent (1.75 percent internal + 0.66 percent external) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average dividend growth rate estimate using the DCF model for the sample electric utilities?

A. Based on the DCF model, my average dividend growth rate estimate is 4.30 percent, which is also displayed on page 1 of Schedule WAR-4.

Q. How do your average dividend growth rate estimates compare with the growth rate data published by Value Line and other analysts?

A. As can be seen in Schedule WAR-6, my 4.30 percent estimate is 133 basis points higher than the 2.97 percent average of Value Line's and Zacks Investment Research's ("Zacks") projected and historic averages of earnings per share, dividends per share and book value per share. My 4.30 percent estimate is also 223 basis points higher than Value Line's

2.07 percent 5-year historic compound history. Both the Value Line and Zacks earnings projections (Attachment B) indicate that investors are expecting increased performance from electric utility companies in the future. Based on the information presented in Schedule WAR-6, I would say that my 4.30 percent estimate, which is very close to Value Line's projected growth estimate (also based on an average of earnings per share, dividends per share and book value per share) is a fair representation of the growth projections presented by securities analysts at this point in time.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's most recent (i.e. February 8, 2008, December 28, 2007 and November 30, 2007) Ratings and Reports for the Electric Utility (West, Central and East) Industry updates. I then divided those figures by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the companies in my proxies for the period December 10, 2007 to February 8, 2008.

...

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the electric utilities included in your sample?

A. As shown in Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 8.62 percent.

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind the capital asset pricing model ("CAPM") and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[12], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[13] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that

[12] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[13] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification. Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

where:

k	=	cost of capital of a given security,
r_f	=	risk-free rate of return,
$ß$	=	beta coefficient, a statistical measurement of a security's systematic risk,
r_m	=	average market return (e.g. S&P 500), and
$r_m - r_f$	=	market risk premium.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used a six-week average on a 91-day Treasury Bill ("T-Bill") rate.[14] This resulted in a risk-free (r_f) rate of return of 2.68 percent.

Q. Why did you use the short-term T-Bill rate as opposed to the yield on an intermediate 5-year Treasury note or a long-term 30-year Treasury bond?

A. Because a 91-day T-Bill presents the lowest possible total risk to an investor. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of the historical yields of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[15] a true rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the true rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor.

[14] A six-week average was computed for the current rate using 91-day T-Bill quotes listed in Value Line's Selection and Opinion newsletter from January 11, 2008 to February 15, 2008.

[15] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the true rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my testimony, this compensation translates into higher rates of returns to the investor. Since a 91-day T-Bill presents the lowest possible total risk to an investor, it more closely meets the definition of a risk-free rate of return and is the more appropriate instrument to use in a CAPM analysis.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical returns on the S&P 500 index from 1926 to 2006 as the proxy for the market rate of return (r_m). The information was obtained from Morningstar's SBBI Yearbook, which publishes historical data on stock returns, U.S. Treasury yields and rates of inflation. The risk premium (r_m - r_f) that results by using the geometric mean calculation for r_m is equal to 7.72 percent (10.40% - 2.68% = 7.72%). The risk premium that results by using the arithmetic mean calculation for r_m is 9.62 percent (12.30% - 2.68% = 9.62%).

Q. How did you select the beta coefficients that were used in your CAPM model?

A. The beta coefficients (ß), for the electric utilities used in my proxy, were calculated by Value Line and were published in the most recent updates (i.e. February 8, 2008, December 28, 2007 and November 30, 2007) for the West, Central and East regional electric providers in my sample. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the LDC's included in my sample ranged from 0.70 to 1.15 with an average beta of 0.87.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean for r_m results in an average expected return of 9.42 percent. My calculation using an arithmetic mean results in an average expected return of 11.08 percent.

...

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF	8.62%
CAPM	9.42% – 11.08%

Based on these results, my best estimate of an appropriate range for a cost of common equity for TEP is 8.62 percent to 11.08 percent. My final recommendation for TEP is 9.44 percent.

Q How did you arrive at your recommended 9.44 percent cost of common equity?

A. My recommended 9.44 percent cost of common equity is the average of my DCF and CAPM results. The calculation can be seen on Page 3 of Schedule WAR-1.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. Dr. Hadaway is recommending an 11.75 percent cost of equity for TEP's actual test year capital structure and a 10.75 percent cost of equity for the Company-proposed pro forma (i.e. hypothetical) capital structure. Dr.

Hadaway's 11.75 percent cost of equity capital, for TEP's actual test year capital structure, is 231 basis points higher than the 9.44 percent cost of equity capital that I am recommending. Dr. Hadaway's 10.75 percent cost of equity capital, for the Company-proposed pro forma capital structure, is 131 basis points higher than the 9.44 percent cost of equity capital that I am recommending.

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic

indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board ("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[16] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

[16] The interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance,"

pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy since 2001?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve was cutting rates in the hope of avoiding a recession.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates – moves which indicated that the worst may be over and that the current recession

might have bottomed out during the last quarter of 2001 – a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in 45 years.

Even though some signs of economic strength, that were mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC announced "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.[17]"

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25

[17] Wolk, Martin, "Fed holds interest rates steady," MSNBC, January 28, 2004.

percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent.

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief.

As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates.

Q. What was the reaction in the financial community to the Fed's decision not to raise interest rates?

A. As in the past, banks followed the Fed's lead once again and held the prime rate to a level of 8.25 percent, or 300 basis points higher than the federal funds rate of 5.25 percent established on June 29, 2006.

Q. How did analysts view the Fed's actions between January 2001 and August 2006?

A. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy.[18] In other words, the Fed was trying to head off inflation *before* it became a problem. During the period following the August 8, 2006 FOMC meeting, the Fed's decisions not to raise rates were viewed as a gamble that a slower U.S. economy would help to cap growing inflationary pressures.[19]

Q. Was the Fed attempting to engineer another "soft landing", as it did in the mid-nineties, by holding interest rates steady?

A. Yes, however, as pointed out in an August 2006 article in The Wall Street Journal by E.S. Browning, soft landings – like the one that the Fed managed to pull off during the 1994-95 time frame, in which a recession or a bear market were avoided – rarely happen[20]. Since it began increasing the federal funds rate in June 2004, the Fed has assured investors that it

[18] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

[19] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

[20] Browning, E.S, "Not Too Fast, Not Too Slow...," The Wall Street Journal Online Edition, August 21, 2006.

would increase rates at a "measured" pace. Many analysts and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[21]. According to Mr. Browning, at the time that his article was published, the hope was that Chairman Bernanke would succeed in slowing the economy "just enough to prevent serious inflation, but not enough to choke off growth." In other words, "a 'Goldilocks economy,' in which growth is not too hot and not too cold."

Q. Was the Fed's attempt to engineer a soft landing successful during this period?

A. It would appear so. Articles published in the mainstream financial press were generally upbeat on the economy during that period. An example of this is an article written by Nell Henderson that appeared in the January 30, 2007 edition of The Washington Post. According to Ms. Henderson, "a year into [Fed Chairman] Bernanke's tenure, the [economic] picture has turned considerably brighter. Inflation is falling; unemployment is low;

[21] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

wages are rising; and the economy, despite continued problems in housing, is growing at a brisk clip."[22]

Q. What has been the state of the economy over the past year?

A. Reports in the mainstream financial press during the majority of 2007 reflected the view that the U.S. economy was slowing as a result of a worsening situation in the housing market and higher oil prices. The overall outlook for the economy was one of only moderate growth at best. Also during this period the Fed's key measure of inflation began to exceed the rate setting body's comfort level.

On August 7, 2007, the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate unchanged at 5.25 percent.[23] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible recession were beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crises, rooted in a deterioration of the market for U.S. subprime mortgages and securities linked to them, forced the Fed to inject $24 billion in funds (raised through open market

[22] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

[23] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

operations) into the credit markets.[24] By Friday, August 17, 2007, after a turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal,[25] the Fed had used all of its tools to restore normalcy to the financial markets. If the markets failed to settle down, the Fed's only weapon left was to cut the Federal Funds rate – possibly before the next FOMC meeting scheduled on September 18, 2007.

Q. Did the Fed cut rates as a result of the subprime mortgage borrowing crises?

A. Yes. At its regularly scheduled meeting on September 18, 2007, the FOMC surprised the investment community and cut both the federal funds rate and the discount rate by 50 basis points or 25 basis points more than what was anticipated. This brought the federal funds rate down to a level of 4.75 percent. The Feds action was seen as an effort to curb the aforementioned slowdown in the economy. Over the course of the next four months, the FOMC reduced the Federal funds rate by a total 175

[24] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

[25] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007

basis points to its current level of 3.00 percent – mainly as a result of concerns that the economy was slipping into a recession. This included a 75 basis point reduction that occurred one week prior to the FOMC's last meeting on January 29, 2008.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected benchmark rates?

A. Despite the increases (prior to June 2006) by the FOMC, interest rates and yields on U.S. Treasury instruments are for the most part still at historically low levels. The Fed's actions have also had the overall effect of reducing the cost of many types of business and consumer loans. As can be seen in Schedule WAR-8, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has fallen to 3.50 percent from 5.73 percent in 2000.

Q. What has been the trend in other leading interest rates over the last year?

A. As of February 15, 2008, the leading interest rates have all dropped from the levels that existed a year ago (Attachment C). The prime rate has fallen from 8.25 percent a year ago to its current level of 6.00 percent. The benchmark federal funds rate, just discussed, has decreased from 5.25 percent, in February 2007, to its current level of 3.00 percent (the result of the Fed's recent series of interest rate cuts described earlier). The yields on several maturities of U.S. Treasury instruments have also

decreased over the past year. A previous trend, described by former Chairman Greenspan as a "conundrum"[26], in which long-term rates fell as short-term rates increased, thus creating a somewhat inverted yield curve that existed as late as June 2007, appears to have ended and a more traditional yield curve (one where yields increase as maturity dates lengthen) presently exists (Attachment C). The 91-day T-bill rate, used in my CAPM analysis, has fallen from 5.15 percent, in February 2007, to 2.09 percent as of February 6, 2008. The 1-Year Treasury constant maturity rate also decreased from 5.07 percent over the past year to 2.06 percent. Again, for the most part, these current yields are considerably lower than corresponding yields that existed during the early nineties (as can be seen on Schedule WAR-8).

Q. What is the current outlook for interest rates, inflation, and the economy?

A. According to The Wall Street Journal's current February 2008 Economic Forecasting Survey, the federal funds rate is expected to fall from its current level of 3.00 percent to approximately 2.64 percent by December 2008. The change in the consumer price index, a key measure of inflation, is also expected to fall from the December 2007 level of 4.10 percent to 2.30 percent by December 2008.

[26] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005.

Value Line's analysts had this to say in their Economic and Stock Market Commentary that appeared in the February 15, 2008 edition of Value Line's Selection and Opinion publication:

> **The economic weakness might continue for a while.** Unfortunately, the likely further deterioration in the employment and housing outlooks may push back the timetable for even a mild economic recovery until late in the year. For now, we think there is a good chance that we will see either no growth in the U.S. gross domestic product during the first quarter or, more likely, a modest decline. (By comparison, the nation's GDP posted a negligible gain of 0.6% in last year's fourth quarter.) Another tepid showing is likely in the second quarter, when economic growth might resume, but on a nominal basis. Thereafter, we would expect to see some benefits from recent and likely future moves by the Federal Reserve to cut interest rates. However, a resumption of the strong economic growth that we saw earlier in this decade may not take hold until 2009 or, more likely, 2010.

Q. How has the current economic environment of lower interest rates affected the electric utility industry as a whole?

A. Value Line analyst Nils C. Van Liew took note of the environment of low interest rates that existed in the early part of 2007. In Value Line's Electric Utility (East) Industry update dated March 2, 2007, Mr. Van Liew had this to say:

> **Low Interest Rates.** Several factors are, no doubt, driving the electric utilities' strong share-price performance. Perhaps most important is a benign interest-rate environment. Utilities frequently tap the credit markets to fund their operations. (Low interest rates mean they can cost effectively build new power plants and maintain existing ones.) "Cheap money" also tends to drive economic expansion, thereby increasing electricity demand. That said, interest rates should remain relatively low, though the likelihood that the Federal Reserve eases (monetary) policy is small, given persistent inflation concerns.

Given the fact that interest rates are even lower now than they were at the time of Mr. Van Liew's writing, and utility bond rates are currently lower than their 2007 averages, I believe that his views are still valid.

Q. What are the current dividend yields of electric utility stocks followed by Value Line?

A. In the February 8, 2008 Electric Utility (West) Industry update, Value Line analyst Paul E. Debbas, CFA, observed that, following a recent decline in electric utility stock prices, the average yield of the fifty-eight stocks in the Electric Utility Industry, followed by Value Line, is now 3.90 percent which is still low by historical standards but is higher than the group's 3.50 percent to 3.60 percent average yield for most of the past two to three years. Mr. Debbas went on to state that there are some stocks of solid utilities that now have yields of nearly 5.00 percent which offer good dividend-growth potential.

Q. How does the 3.90 percent average yield on the fifty-eight electric utility stocks noted above compare with the average dividend yield of your sample electric utility companies?

A. As can be seen in Schedule WAR-3, my sample electric utility companies have an average dividend yield of 4.32 percent which is 42 basis points higher than the 3.90 percent average yield on electric utility stocks reported by Value Line's Mr. Debbas.

...

Q. After weighing the economic information that you've just discussed, do you believe that the 9.44 percent cost of equity capital that you have estimated is reasonable for TEP?

A. I believe that my recommended 9.44 percent cost of equity will provide TEP with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are low by historical standards), a possible rebound in growth in new housing construction (attributed to the recent cuts in interest rates), and the Fed's ability to keep inflation in check are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my DCF analysis has produced such a return.

COST OF DEBT

Q. Have you reviewed TEP's testimony on the Company-proposed cost of debt?

A. Yes, I have reviewed the testimony prepared by Kevin P. Larson, Senior Vice President, Chief Financial Officer and Treasurer of UniSource Energy ad TEP.

...

Q. Do you agree with Mr. Larson's inclusion of the amortized debt discount and expenses and losses attributed to reacquired debt and the credit facility fees to arrive at his final cost of long-term debt figure of 8.22 percent?

A. Yes.

Q. What is your recommended cost of long-term debt?

A. I am recommending the Company-proposed cost of long-tem debt of 6.39 percent.

CAPITAL STRUCTURE

Q. Have you reviewed TEP's testimony regarding the Company's proposed capital structure?

A. Yes, I have reviewed the direct testimony of Company witness Larson, who also testified on TEP's proposed capital structure.

Q. What was TEP's actual capital structure during the test year?

A. TEP's actual capital structure during the test year was comprised of 60.1 percent debt and 39.9 percent equity.

...

Q. What capital structure is the Company proposing in this proceeding?

A. The Company is proposing a pro forma, or hypothetical, capital structure comprised of 55.0 percent long-term debt and 45.0 percent common equity.

Q. What capital structure are you proposing for TEP?

A. I am recommending the same hypothetical capital structure being proposed by TEP.

Q. Is the capital structure proposed by TEP in line with industry averages?

A. No. As can be seen in Schedule WAR-9, the capital structure proposed by TEP is higher in debt than the average capital structure of the electric utility companies included in my sample. The companies in my sample have capital structures comprised of approximately 50.0 percent debt and 50.0 percent equity.

Q. In terms of risk, how does your recommended capital structure compare to the electric utility companies in your sample?

A. The electric utility companies in my sample would be considered as having a slightly lower level of financial risk (i.e. the risk associated with debt repayment) because of their lower levels of debt. The lower financial risk due to debt leverage is embedded in the cost of equities derived for those companies through the DCF analysis. Thus, the cost of equity

derived in my DCF analysis is applicable to companies that are not as leveraged and, theoretically speaking, not as risky as a utility with a level of debt similar to TEP's. In the case of a publicly traded company, such as those included in my proxy, a company with TEP's level of debt would be perceived as having a slightly higher level of financial risk and would therefore also have a slightly higher expected return on common equity.

Q. Have you made any upward adjustment to your recommended cost of equity that takes TEP's higher level of financial risk into consideration?

A. No. I believe that my recommended hypothetical capital structure which increases TEP's percentage of equity from 39.9 percent to 45.0 percent will provide the Company with additional cash flows to mitigate any concerns regarding financial risk. In addition to providing TEP with additional operating income, my recommended hypothetical capital structure will also provide TEP with a higher level of income tax expense.

Q. Please explain how your recommended hypothetical capital structure will provide TEP with additional cash flow through a higher level of income tax expense.

A. The lower level of debt in my recommended capital structure produces a lower interest deduction for the income tax calculation thus providing TEP with a higher level of income tax expense than what would result if the Company's higher actual level of deductible interest were used in the

calculation. As a result of this the Company's actual income tax expense is lower than the income tax calculated for ratemaking purposes thus providing TEP with additional cash. For the reasons stated above I have decided not to make any upward adjustment on my recommended 9.44 percent cost of common equity.

WEIGHTED COST OF CAPITAL

Q. How does the Company's proposed weighted cost of capital compare with your recommendation?

A. The Company has proposed a weighted cost of capital of 8.35 percent. This composite figure is the result of the Company-proposed hypothetical capital structure that produces a weighted average of 3.51 percent for long-term debt and a weighted cost of common equity of 4.84 percent. The Company-proposed 8.35 percent weighted cost of capital is 59 basis points higher than the 7.76 percent weighted cost of capital that I am recommending, which is the weighted cost of my recommended 6.39 percent cost of long-term debt and 9.44 percent cost of common equity.

COMMENTS ON TEP'S COST OF EQUITY CAPITAL TESTIMONY

Q. Have you reviewed TEP's testimony on the Company-proposed cost of equity capital?

A. Yes, I have reviewed the testimony prepared by Dr. Samuel C. Hadaway.

Q. Please compare the Company-proposed cost of equity with your recommended cost of equity.

A. The Company is recommending a cost of equity capital of 10.75 percent in conjunction with a hypothetical capital structure comprised of 55.0 percent debt and 45.0 percent equity. The Company-proposed 10.75 percent cost of equity is the low end of a 10.75 percent to 11.75 percent range of estimates recommended by Dr. Hadaway. The Company-proposed 10.75 percent cost of equity is 131 basis points higher than my recommended 9.44 percent cost of equity.

Q. Have you studied the specific methods that Company witness Hadaway used to derive the Company-proposed cost of equity capital?

A. Yes.

Q. What methods did Dr. Hadaway use to arrive at his cost of common equity for TEP?

A. Dr. Hadaway used the DCF, CAPM and risk premium methods to estimate TEP's cost of common equity.

Q. Can you provide a comparison of the results derived from Dr. Hadaway's models and yours?

A. Yes.

DCF Comparison

Q. Were there any differences in the way that you conducted your DCF analysis and the way that Dr. Hadaway conducted his?

A. Yes, In addition to the constant growth model that I used to estimate TEP's cost of equity, Dr. Hadaway also relied on the results of a multi-stage DCF model that used the proxy of twenty-eight electric utility companies that I described earlier in my testimony.

Q. Please compare Dr. Hadaway's constant growth DCF estimate to your constant growth DCF estimate.

A. Dr. Hadaway used two versions of the constant growth DCF model; what he refers to as his traditional constant growth DCF model, and a constant growth DCF model that uses a 6.60 percent estimate of gross domestic product ("GDP") figure for the growth component ("g") of the model. His traditional constant growth DCF model produces an estimate of 9.50 percent which is 88 basis points higher than my 8.66 percent estimate. Dr. Hadaway's constant growth DCF model that uses the aforementioned 6.60 percent GDP figure produces an estimate of 10.80 percent which is 218 basis points higher than my average 8.62 percent estimate. Dr. Hadaway ignores the lower estimate of 9.50 percent produced by his traditional version of the DCF model because it falls below the results produced by his other models used to estimate TEP's cost of common equity.

Q What created the 88 basis point difference between Dr. Hadaway's traditional constant growth DCF model estimate and your constant growth DCF model?

A. Dr. Hadaway's average dividend yield component ("$D_1 \div P_0$") of 4.15 percent is actually 17 basis points lower than my 4.32 percent figure. This is mainly attributed to an overall decline in the stock prices ("P_0") of the electric utilities included in our samples. Since Dr. Hadaway's average dividend estimate ("D_1") of $1.54 is just slightly higher than my average of $1.53, his higher average stock price of $37.18 produces a lower yield than my average stock price of $36.32. Thus the main reason for the difference in our constant growth DCF estimates is Dr. Hadaway's growth estimate which is the sum of a company's internal sustainable growth (br) and its external growth (sv) estimate.

Q. Can you explain why Dr. Hadaway's growth estimate is higher than yours?

A. Yes. Dr. Hadaway performed a b x r calculation that produced an internal sustainable growth rate figure of 3.90 percent which was 7 basis points higher than my 3.83 percent figure. However, he forgoes the type of s x v calculation (based on estimates of share growth) that I have performed and instead uses an average comprised of his b x r figure, Zack's 5-year earnings estimate, Value Line's 5-year earnings estimate and his 6.60 percent GDP figure. This produces a growth estimate of 5.39 percent which is 109 basis points higher than my growth estimate of 4.30 percent.

Q. Do you agree with Dr. Hadaway's use of long-term GDP growth in his models?

A. No. I do not. The use of the GDP estimate assumes that the long-term growth rate for the electric-utilities in his sample will be a combination of analysts' long-term growth rate projections and the growth rate of all goods and services produced by labor and property in the U.S., as opposed to relying on growth information that is specific to the electric companies included in our respective samples.

Q. Is this the same reason why Dr. Hadaway's second constant growth DCF estimate, that uses his 6.60 percent estimate of GDP for the growth component, is 218 basis points higher than your average 8.62 percent estimate?

A. Yes. Once again Dr. Hadaway's average dividend yield component of 4.15 percent is actually 17 basis points lower than my 4.32 percent figure. However, his growth component is the higher 6.60 percent GDP figure discussed above. The use of the 6.0 percent GDP figure as his growth estimate produces the 10.80 percent constant growth DCF result that Dr. Hadaway used in making his final cost of equity estimate for TEP.

...

Q. What is the difference between Dr. Hadaway's multi-stage DCF estimate and your single-stage constant-growth DCF estimate?

A. Dr. Hadaway's average multi-stage DCF estimate of 10.40 percent is 96 basis points higher than the 9.44 percent estimate produced by my single-stage constant growth model.

Q. Please describe the multi-stage DCF model used by Dr. Hadaway.

A. The multi-stage DCF model is comprised of three components: a dividend yield component similar to the one used in the constant growth model, a near-term (i.e. 5-year) growth estimate that is also similar to the one used in the constant growth DCF and a long-term growth estimate that is calculated into perpetuity through the use of an internal rate of return calculation on a computer spreadsheet. In this case, Dr. Hadaway used the same 6.60 percent GDP figure, discussed earlier, as the long-term growth estimate in the second-stage component of his multi-stage model.

Q. Why didn't you conduct a multi-stage DCF analysis like the one conducted by Dr. Hadaway?

A. Primarily because the growth rate component that I estimated for my single-stage model already takes into consideration 5-year long-term growth rate projections that are specific to the electric utilities included in my proxy as opposed to a GDP figure that assumes that an electric utility will grow at the same rate of growth of all goods and services produced in

the U.S. The 5-year period is in line with the number of years that a utility will file for rate relief as opposed to a GDP rate of growth that is calculated into perpetuity and inflates a utility's cost of equity capital.

CAPM Comparison

Q. Please describe the differences in the way that you conducted your CAPM analysis and the way that Dr. Hadaway conducted his?

A. The main differences between Dr. Hadaway's CAPM analysis and mine are the Treasury instruments that we relied on for the risk-free rate of return and the average beta coefficient that was used in our models. Dr. Hadaway performed a long-term CAPM analysis and a short-term CAPM analysis.

Q. What Treasury instruments did Dr. Hadaway use as a proxy for the risk free (i.e. r_f) rate in his CAPM model?

A. Dr. Hadaway used the 30-year U.S. Treasury Constant Maturity Rate of 5.01 percent, as of May 27, 2007, in his long-term CAPM analysis. For his short-term CAPM analysis he used the 3-month U.S. Treasury Secondary Market Rate of 4.89 percent.

...

Q. What are the current yields on the 30-year U.S. Treasury Constant Maturity Rate and the 3-month U.S. Treasury Secondary Market Rate that Dr. Hadaway used in his CAPM models?

A. As of the week ending February 8, 2008 the yield on the 30-year U.S. Treasury Constant Maturity Rate stood at 4.40 percent which is 67 basis points lower than the 5.07 percent rate used in Dr. Hadaway's long-term CAPM model. The yield on the 3-month U.S. Treasury Secondary Market Rate stood at 2.14 percent which is 275 basis points lower than the 4.89 percent rate used in Dr. Hadaway's long-term CAPM model.

Q. Did Dr. Hadaway use the same Value Line betas that you used in your CAPM analysis?

A. Yes. However the average of Value Line's beta's for the electric utility companies in our samples proxies have decreased since Dr. Hadaway filed his direct testimony. The mean average of the Value Line betas used by Dr. Hadaway is 0.91 as opposed to my average beta of 0.87 (the elimination of Energy East Corporation and Puget Energy, Inc. from my sample had no effect on my average beta).

Q. What was the difference between Dr. Hadaway's market risk premiums and your market risk premiums?

A. Dr. Hadaway used market risk premiums of 5.75 percent and 7.60 percent for his respective long-term and short-term CAPM models. I used market

risk premiums of 7.72 percent and 9.62 percent in my respective CAPM models using geometric and arithmetic means.

Q. What would Dr. Hadaway's expected returns be if his CAPM models were updated to include the aforementioned changes in Treasury yields and average beta coefficients?

A. An update of Dr. Hadaway's CAPM models using current Treasury instrument yields an average beta of 0.87 percent would produce expected returns of 9.41 percent in his long-term model and 8.76 percent in his short-term model. His average CAPM estimate would be 9.09 percent or 116 basis points lower than my 10.25 percent average estimate. Dr. Hadaway's revised CAPM estimates would fall into the same category as his traditional constant growth DCF estimate which he ignored because it fell below the results produced by his other models used to estimate TEP's cost of common equity.

Q. How do these results compare to TEP's parent, UniSource, on a stand alone basis?

A. TEP's parent, UniSource, has a Value Line beta of 0.60 which is lower than both the range (0.70 to 1.15) and the mean average (0.87) of the betas included in my CAPM sample. What this means is that, in terms of beta, UniSource is a lower investment risk than the twenty-six electric

utilities that made up my CAPM sample which included all but two of the companies in Dr. Hadaway's CAPM sample.

Using UniSource's 0.65 beta, the aforementioned current 4.40 percent long-term and 2.14 percent short-term Treasury yields, and Dr. Hadaway's long-term and short-term market risk premiums of 5.75 percent and 7.60 percent respectively produces expected returns of 7.85 percent (long-term) and 6.70 percent (short-term) for UniSource on a stand-alone basis). This is 246 to 511 basis points lower than the original expected returns presented in Dr. Hadaway's direct testimony, and 156 to 206 basis points lower than my 9.41 percent long-term and 8.76 percent short-term update of Dr. Hadaway's CAPM results.

Q. Did you perform a risk premium analysis similar to the one performed by Dr. Hadaway?

A. No I did not.

Final Cost of Equity Estimate

Q. How did TEP arrive at the Company-proposed 10.75 percent cost of equity capital?

A. The Company adopted the low end of Dr. Hadaway's recommended 10.75 to 11.75 range of cost of equity estimates.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Dr. Hadaway or any other witness for TEP constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on TEP?

A. Yes, it does.

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Appendix 1

Qualifications of William A. Rigsby, CRRA

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation
after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
Phoenix, Arizona
July 1991 – October 1994

Appendix 1

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase/ACRM
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase/ACRM

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase/ACRM
Tucson Electric Power	E-01933A-04-0408	Rate Review
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase/ACRM
Black Mountain Sewer Corporation	SW-02361A-05-0657	Rate Increase
Far West Water & Sewer Company	WS-03478A-05-0801	Rate Increase
Gold Canyon Sewer Company	SW-02519A-06-0015	Rate Increase
Arizona Public Service Company	E-01345A-05-0816	Rate Increase
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
Arizona-American Water Company	W-01303A-05-0718	Transaction Approval
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	WS-01303A-06-0403	Rate Increase
Arizona-American Water Company	WS-01303A-06-0491	Rate Increase
UNS Electric, Inc.	E-04204A-06-0783	Rate Increase
Arizona-American Water Company	W-01303A-07-0209	Rate Increase

ATTACHMENT A

All of the major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.

Utilities have long had a reputation as a safe haven during downturns in the market. This hasn't been the case in recent weeks.

More companies are asking the Nuclear Regulatory Commission for construction and operating licenses for new nuclear units.

Since utility stocks have declined, some have become more attractive. But others have merely become less overvalued.

Some Safe Haven

Utility stocks have long been known to attract investors for their defensive characteristics in turbulent markets. This held true, for a while, in the recent market turmoil. Eventually, however, electric utility equities "caught up with" the rest of the market. This has been the case even for the stocks of companies that have agreed to be taken over (*Puget Energy*, Energy East, and Aquila). Even the Fed's cut in interest rates didn't help these stocks at all. The Value Line Composite Average and the Value Line Utility Average (which includes stocks of utilities besides electrics) have each declined over 5% since the start of 2008, and the Value Line Utility Average has actually declined a bit more than the Composite Average.

What has caused the decline in this group? Perhaps it was inevitable, given the high valuation of electric utility equities. Many were fully valued or even overvalued after their sharp advances in 2006 and 2007. (Particularly strong were stocks of companies, such as Exelon, Constellation Energy, and Public Service Enterprise Group, that get more than half of their profits from nonregulated activities and thus benefit from high power prices.) Indeed, prior to their recent decline, most electric utility issues were trading within their 2010-2012 Target Price Ranges, and some are *still* trading well within those ranges, even after the downturn. Other concerns are how the weakening economy will affect the demand for electricity—and the prices for power. When the power markets collapsed in 2001 and

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2002, this didn't just occur due to an increase in generating capacity—a sudden decline in electric demand from industrial users was a factor as well. We aren't predicting a repeat of what happened six years ago, but this situation bears watching. The stocks of the three big nonregulated power sellers mentioned above have declined roughly as much as the rest of the group so far this year. Finally, the weakness in the economy could affect state commissions' willingness to grant rate relief to utilities due to the concern about the effect of higher prices on electric customers.

Nuclear Update

Our November industry report discussed the possibility of nuclear unit construction. Last September, NRG Energy became the first company in 29 years to file a request for a Construction and Operating License (COL). Since then, Duke Energy, Dominion Resources, and the Tennessee Valley Authority have requested COLs. Several other nuclear owners plan to do so in 2008. Each unit would cost many billions of dollars, and even before a shovel ever hits the ground, the application process itself will cost many millions of dollars. We reiterate that, even if a company proceeds with the COL process, this doesn't mean that a new unit or units will be built.

Investment Advice

Since the recent pullback, the average yield of the 58 stocks in the Electric Utility Industry is now 3.9%. That's still low, by historical standards, but is higher than the group's average yield for most of the past two to three years (which has usually been 3.5%-3.6%). There are some stocks of solid utilities that now have yields of nearly 5% (or higher) and offer good dividend-growth potential. *Pinnacle West*, Progress Energy, Duke Energy, ALLETE, and Vectren are worth mentioning in this regard. The stocks of CH Energy, Great Plains Energy, and Empire District Electric are yielding around 6%, but that's partly because none of these companies has raised the dividend for many years. Not all stocks with high yields are recommended, however. *Hawaiian Electric Industries* has one of the highest yields of any utility equity, but we do not advise its purchase.

Paul E. Debbas, CFA

Composite Statistics: ELECTRIC UTILITY INDUSTRY

2003	2004	2005	2006	2007	2008		10-12
277.0	288.9	325.1	336.0	**350**	**370**	Revenues ($bill)	**440**
18.5	20.2	22.2	25.0	**27.5**	**29.5**	Net Profit ($bill)	**36.0**
30.4%	30.4%	29.6%	31.9%	**33.5%**	**34.5%**	Income Tax Rate	**34.5%**
4.5%	3.6%	3.8%	4.5%	**6.0%**	**7.0%**	AFUDC % to Net Profit	**4.0%**
58.7%	56.0%	54.6%	52.6%	**51.0%**	**51.0%**	Long-Term Debt Ratio	**49.0%**
39.7%	42.8%	44.2%	46.3%	**48.0%**	**48.0%**	Common Equity Ratio	**50.0%**
418.1	426.8	432.3	447.7	**465**	**495**	Total Capital ($bill)	**570**
421.3	435.2	450.3	475.0	**490**	**525**	Net Plant ($bill)	**590**
6.4%	6.6%	6.9%	7.3%	**7.0%**	**7.0%**	Return on Total Cap'l	**7.5%**
10.7%	10.7%	11.3%	11.8%	**11.0%**	**11.0%**	Return on Shr. Equity	**11.5%**
10.8%	10.9%	11.5%	11.9%	**11.5%**	**11.5%**	Return on Com Equity	**11.5%**
4.7%	4.8%	4.9%	5.5%	**5.5%**	**5.0%**	Retained to Com Eq	**5.0%**
58%	57%	58%	55%	**60%**	**60%**	All Div'ds to Net Prof	**59%**
13.7	14.8	16.3	15.7			Avg Ann'l P/E Ratio	**14.5**
.78	.78	.87	.85			Relative P/E Ratio	**.95**
4.2%	3.8%	3.5%	3.4%			Avg Ann'l Div'd Yield	**3.9%**

Bold figures are Value Line estimates

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2004	2005	2006
% Change Retail Sales (kwh)	+.3	+5.4	+1.3
Average Indust. Use (mwh)	1384	1568	1570
Avg. Indust. Revs. per kwh (¢)	5.25	5.73	6.17
Capacity at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+1.6	+1.2	+1.7
Fixed Charge Coverage (%)	235	253	267

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

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All of the major utilities in the central United States are reviewed in this Issue. Those serving the western region may be found in Issue 11. The eastern companies are covered in Issue 1.

Demand for power in the U.S. is rising at an annual rate of 2%. That has resulted in steadily reduced reserve margins and has induced many companies to add generation in the past few years. But utilities are not all using the same fuel sources to meet their obligations. In this report, we discuss a few reasons for the differences.

The Dilemma Facing Coal-fired Plants

The U.S. Environmental Protection Agency (EPA) and many state regulatory bodies have taken a strong stand against coal-fired units and are compelling companies to spend large sums to reduce particulate emissions into the atmosphere or close down the facilities. Florida regulators have taken an even more drastic step, by rejecting outright FPL Group's request to build a coal plant because of high capital costs. This forces the company to rely on additional gas-fired units that already account for a large percentage of its fuel mix. In Nevada, a coalition of environmentalists and other parties seeks to derail Sierra Pacific's plan for a new coal plant because renewable resources and energy efficiency programs would be less expensive. The company is contesting the proposal. Still, other utilities have found it economical to reduce emissions in order to keep operating existing units. *Vectren*, for one, is investing large sums in its jointly owned Warrick plant to comply with EPA orders and is improving the efficiency of scrubbers at two other units, rather than looking elsewhere for new energy sources. *Alliant Energy*, for another, is seeking commission approval to add a circulating fluidized coal-fired bed unit, employing a commercially demonstrated clean-coal technology. In addition to reducing toxic emissions, the plant would not only improve import capability but would allow diverse fuel supplies in the boiler.

Renewable Energy

This source of power includes geothermal, wind, biomass, and solar energy. In 2006, it stood at 7% of total national output. It continues to expand because of high oil and natural gas prices and concern over global warming. To date, some 25 states have enacted legislation requiring utilities to generate a specific percentage

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of sales from renewable sources. This has stimulated interest in wind power, whose growth has also been driven by a federal production tax credit of 1.9 cents per kilowatt-hour for electricity generated in the first 10 years of a project. The credits are available for systems starting operation by the end of 2008. To beat the deadline, many utilities are constructing wind-powered plants to place them in service before the credit expires. Once the units are in service, the credits are grandfathered. The leader in this field is FPL Group, which has wind plants in 15 states and plans to add another 1,500 megawatts to 2,000 megawatts by 2012. It might be of concern, however, that wind does not provide guaranteed steady output and should be supported by fossil-fueled sources for reliability. Solar power is more predictable. Its one variable is cloud cover, which is not a serious drawback in the Southwest. Twelve states have explicit solar targets. New Mexico's is the largest, with a requirement that 4% of generation come from solar by 2020. But to make this source more efficient, capital costs must be streamlined, because they are currently far more expensive than those of coal.

The Nuclear Option

Unlike coal-fired plants, nuclear generators pose no environmental concern. Too, the cost of nuclear fuel compares favorably with fossil fuel. Only hydroelectric power is less expensive. Given these pluses, numerous nuclear plant owners have filed for extensions of their operating licenses and are seeking site locations for new units. Among those to do so are Exelon, *Entergy*, and Progress Energy, all three of which are owners of several units. But no new plant will be built until a permanent repository for nuclear waste is serviceable. And the timing of that is still undetermined.

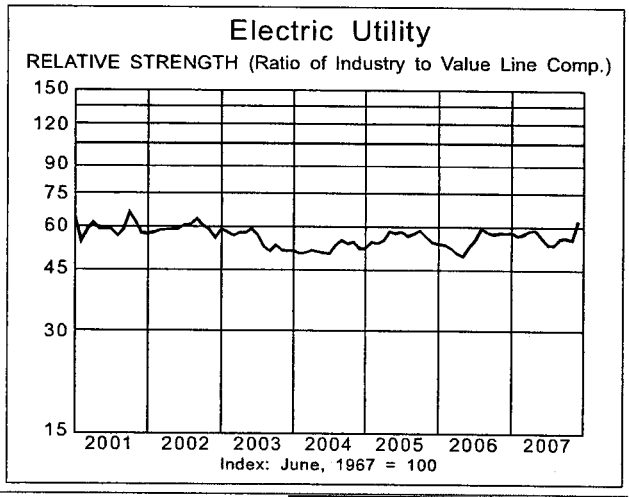
Investment Advice

The industry's Timeliness rank continues to lag that of most sectors we follow. On the plus side, the average year-ahead yield is almost double that of all dividend-paying companies in the *Value Line* survey. But a note of caution: Many of these utilities are already trading within their 3- to 5-year Target Price Range.

Arthur H. Medalie

Composite Statistics: Electric Utility Industry

2003	2004	2005	2006	2007	2008		10-12
289.2	299.3	336.7	354.1	**355**	**375**	Revenues ($bill)	**440**
19.3	20.3	24.0	25.7	**27.5**	**29.5**	Net Profit ($bill)	**36.0**
30.3%	30.3%	29.5%	29.7%	**33.5%**	**34.5%**	Income Tax Rate	**34.5%**
4.3%	3.5%	3.5%	3.3%	**6.0%**	**7.0%**	AFUDC % to Net Profit	**4.0%**
59.1%	57.2%	55.7%	55.0%	**51.0%**	**51.0%**	Long-Term Debt Ratio	**49.0%**
39.2%	41.7%	43.1%	43.9%	**48.0%**	**48.0%**	Common Equity Ratio	**50.0%**
439.5	441.8	446.1	473.9	**465**	**490**	Total Capital ($bill)	**565**
443.9	453.6	469.3	496.6	**490**	**520**	Net Plant ($bill)	**570**
6.4%	6.5%	7.2%	7.3%	**7.0%**	**7.0%**	Return on Total Cap'l	**7.5%**
10.7%	10.8%	12.1%	12.2%	**11.0%**	**11.0%**	Return on Shr. Equity	**11.5%**
10.9%	10.9%	12.3%	12.4%	**11.5%**	**11.5%**	Return on Com Equity	**11.5%**
4.8%	4.7%	5.5%	5.5%	**5.0%**	**5.0%**	Retained to Com Eq	**5.0%**
57%	57%	56%	56%	**60%**	**60%**	All Div'ds to Net Prof	**60%**
15.2	16.0	15.8	15.9			Avg Ann'l P/E Ratio	**14.5**
.80	.85	.85	.83	*Bold figures are Value Line estimates*		Relative P/E Ratio	**.95**
3.7%	3.5%	3.5%	3.4%			Avg Ann'l Div'd Yield	**3.9%**



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All of the major utilities in the eastern region of the United States are reviewed in this Issue. Those serving the central region will be found in Issue 5. All of the western companies are covered in Issue 11.

The Electric Utilities (East) have given investors reason to smile, having registered strong share-price performance in the three months since our last review. Led by *Constellation Energy* (up 19%), gainers outnumbered losers 19 to 2. Strong earnings, driven by the Baltimore utility's nonregulated power operations (generation, marketing), has not gone unnoticed by investors. *Central Vermont Public Service*, meanwhile, was the laggard of the group (down 22%).

Safe Haven

With recent interest rate cuts, investors have bid up utility stocks, driving down risk-adjusted yield premiums in the process. Recent volatility in the stock market likely also has given the group a lift, as investors seek out "safe havens". That said, a majority of these stocks are now trading within our three- to five-year Target Price Ranges. This suggests that future returns will mainly come from dividends.

Good Yields

Conservative income-oriented investors may find what they're looking for in the Electric Utility (East) group. The group's median dividend yield, at 3.8%, is double that of the *Value Line* Composite Index. What's more, a good majority of the stocks rank in the top decile for Price Stability. Allentown, Pennsylvania-based *PPL Corporation* is an interesting, and perhaps not so obvious, investment play here. The stock is currently trading at a relative pricey 18 times earnings and the dividend yield is a fairly modest 2.7%. Still, median total return potential out to 2010-2012 ranks among the highest within the group. In Pennsylvania, *PPL* will make a transition to higher market-based electricity rates, beginning in 2010. The change should really boost *PPL's* earnings and give it the financial wherewithal to aggressively increase its dividend payout. Indeed, we're looking for the annual payout to reach $2.20 a share over the 2010-2012 horizon. That's 80% higher than the current annualized rate.

Investors that are more inclined towards instant gratification may want to check out *Progress Energy*. The North Carolina-based utility sports the group's fattest payout (yield: 5.2%). That said, income-distribution increases are likely to be fairly modest over the next three to five years.

INDUSTRY TIMELINESS: 69 (of 98)

A Downer

Central Vermont Public Service has the ignominious distinction as the group's weakest performer. Shares of the Green Mountain state's largest power company have sold off 22% since our last review. Comparatively, the benchmark S&P 500 Index is relatively unchanged. *CVPS* is small (market capitalization: $300 million) and has relatively few shares outstanding. Recent selling by *CVPS's* largest investor, Charleston industrialist Jerry Zucker, has pressured shares and quieted takeover speculation.

Odds and Ends

Investors should increasingly pay attention to the fuels that utilities use to generate power. Looming regulations governing the emission of greenhouse gases suggest that utilities with clean carbon profiles will be competitively advantaged. Access to low-cost fuels, meanwhile, is more dear these days, given, for example, the high price of crude oil. That said, high fuel and pollution control costs are often recoverable, typically via rate hikes.

Investment Advice

Among the positive attributes that investors should look for when seeking an attractive utility are an economically healthy local service territory (such as those in the Southeast); a large customer base; good management-regulator relations; access to low-cost power generation (coal, nuclear); and ample fixed-charge coverage. As always, we recommend that investors read each report carefully before making any decisions.

Nils C. Van Liew

Composite Statistics: Electric Utility Industry

2003	2004	2005	2006	2007	2008		10-12
277.0	288.9	325.1	336.0	***355***	***375***	Revenues ($bill)	***440***
18.5	20.2	22.2	25.0	***27.5***	***29.5***	Net Profit ($bill)	***36.0***
30.4%	30.4%	29.6%	31.9%	***33.5%***	***34.5%***	Income Tax Rate	***34.5%***
4.5%	3.6%	3.8%	4.5%	***6.0%***	***7.0%***	AFUDC % to Net Profit	***4.0%***
58.7%	56.0%	54.6%	52.6%	***51.0%***	***51.0%***	Long-Term Debt Ratio	***49.0%***
39.7%	42.8%	44.2%	46.3%	***48.0%***	***48.0%***	Common Equity Ratio	***50.0%***
418.1	426.8	432.3	447.7	***465***	***490***	Total Capital ($bill)	***565***
421.3	435.2	450.3	475.0	***490***	***520***	Net Plant ($bill)	***570***
6.4%	6.6%	6.9%	7.3%	***7.0%***	***7.0%***	Return on Total Cap'l	***7.5%***
10.7%	10.7%	11.3%	11.8%	***11.0%***	***11.0%***	Return on Shr. Equity	***11.5%***
10.8%	10.9%	11.5%	11.9%	***11.5%***	***11.5%***	Return on Com Equity	***11.5%***
4.7%	4.8%	4.9%	5.5%	***5.0%***	***5.0%***	Retained to Com Eq	***5.0%***
58%	57%	58%	55%	***60%***	***60%***	All Div'ds to Net Prof	***60%***
13.7	14.8	16.3	15.7	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	***14.5***
.78	.78	.87	.85			Relative P/E Ratio	***.95***
4.2%	3.8%	3.5%	3.4%			Avg Ann'l Div'd Yield	***3.9%***

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2004	2005	2006
% Change Retail Sales (kwh)	+.3	+5.4	+1.3
Average Indust. Use (mwh)	1384	1568	1570
Avg. Indust. Revs. per kwh (¢)	5.25	5.73	6.17
Regulated Cap. at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+1.6	+1.2	+1.7
Fixed Charge Coverage (%)	230	260	281

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

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ALLETE NYSE-ALE

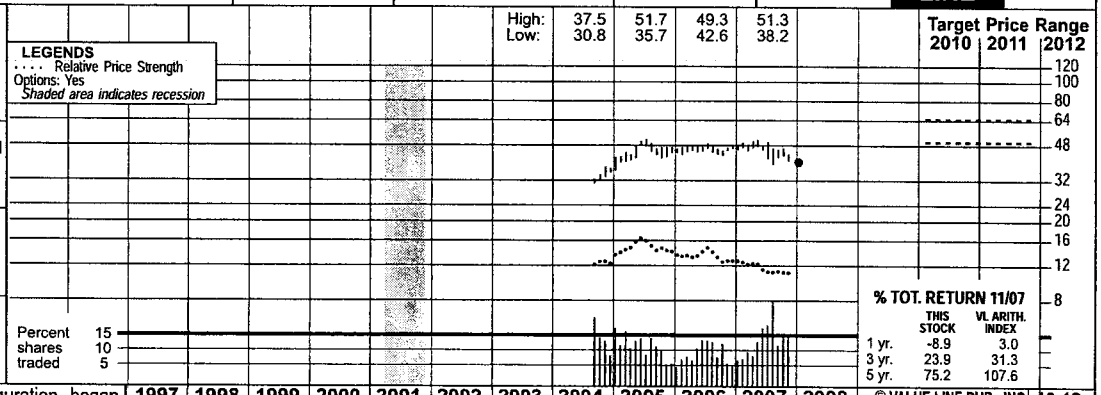
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
39.64	15.4	(Trailing: 12.7 Median: NMF)	0.91	4.2%	VALUE LINE

TIMELINESS 3 Lowered 11/9/07
SAFETY 2 New 10/1/04
TECHNICAL 3 Raised 12/7/07
BETA .95 (1.00 = Market)

High:								37.5	51.7	49.3	51.3	
Low:								30.8	35.7	42.6	38.2	

Target Price Range
2010 | 2011 | 2012

LEGENDS
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+65%)	16%
Low	50	(+25%)	9%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	1	1	0
Options	1	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	0	0

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	95	71	80
to Sell	51	81	71
Hld's(000)	19655	19222	19001

Percent shares traded 15 10 5

% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	-8.9	3.0
3 yr.	23.9	31.3
5 yr.	75.2	107.6

ALLETE, in its current configuration, began trading on September 21, 2004, the day after it spun off its automotive services business, ADESA (NYSE: KAR), to shareholders and effected a 1-for-3 reverse stock split. ALLETE shareholders received one share of ADESA for each ALLETE share held. Data for the "old" ALLETE are not shown because they are not comparable.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
--	--	--	--	--	--	--	25.30	24.50	25.23	*26.60*	*26.70*	Revenues per sh	*29.00*
--	--	--	--	--	--	--	2.97	3.85	4.14	*4.40*	*4.20*	"Cash Flow" per sh	*5.50*
--	--	--	--	--	--	--	1.35	2.48	2.77	*3.00*	*2.70*	Earnings per sh A	*3.50*
--	--	--	--	--	--	--	.30	1.25	1.45	*1.64*	*1.68*	Div'd Decl'd per sh B ■ †	*1.80*
--	--	--	--	--	--	--	2.12	1.95	3.37	*5.80*	*8.80*	Cap'l Spending per sh	*5.50*
--	--	--	--	--	--	--	21.23	20.03	21.90	*23.35*	*24.40*	Book Value per sh C	*28.75*
--	--	--	--	--	--	--	29.70	30.10	30.40	*30.85*	*31.30*	Common Shs Outst'g D	*32.50*
--	--	--	--	--	--	--	25.2	17.9	16.5	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
--	--	--	--	--	--	--	1.33	.95	.90	*Value Line*		Relative P/E Ratio	*1.05*
--	--	--	--	--	--	--	.9%	2.8%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*3.2%*
--	--	--	--	--	--	--	751.4	737.4	767.1	*820*	*835*	Revenues ($mill)	*945*
--	--	--	--	--	--	--	38.5	68.0	77.3	*85.0*	*75.0*	Net Profit ($mill)	*100*
--	--	--	--	--	--	--	38.8%	28.4%	37.5%	*34.5%*	*38.5%*	Income Tax Rate	*38.5%*
--	--	--	--	--	--	--	1.8%	.4%	.8%	*4.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
--	--	--	--	--	--	--	38.2%	39.1%	35.1%	*39.5%*	*45.0%*	Long-Term Debt Ratio	*45.5%*
--	--	--	--	--	--	--	61.8%	60.9%	64.9%	*60.5%*	*55.0%*	Common Equity Ratio	*54.5%*
--	--	--	--	--	--	--	1020.7	990.6	1025.6	*1190*	*1385*	Total Capital ($mill)	*1700*
--	--	--	--	--	--	--	883.1	860.4	921.6	*1050*	*1275*	Net Plant ($mill)	*1725*
--	--	--	--	--	--	--	5.1%	8.0%	8.6%	*8.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
--	--	--	--	--	--	--	6.1%	11.3%	11.6%	*11.5%*	*10.0%*	Return on Shr. Equity	*10.5%*
--	--	--	--	--	--	--	6.1%	11.3%	11.6%	*11.5%*	*10.0%*	Return on Com Equity E	*10.5%*
--	--	--	--	--	--	--	4.7%	5.2%	5.0%	*4.5%*	*3.0%*	Retained to Com Eq	*4.5%*
--	--	--	--	--	--	--	23%	54%	57%	*60%*	*68%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $438.4 mill. **Due in 5 Yrs** $143.0 mill.
LT Debt $409.0 mill. **LT Interest** $22.3 mill.
(LT interest earned: 7.3x)
Leases, Uncapitalized Annual rentals $8.2 mill.

Pension Assets-12/06 $364.7 mill. **Oblig.** $417.7 mill.

Pfd Stock None

Common Stock 30,821,767 shs.

MARKET CAP: $1.2 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+4.9	+2.0	+1.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.03	3.93	4.15
Capacity at Peak (Mw)	1511	1512	1761
Peak Load, Winter (Mw)	1498	1543	1586
Annual Load Factor (%)	80.0	80.0	80.0
% Change Customers (avg.)	+1.3	+1.1	+1.3
Fixed Charge Cov. (%)	307	461	503

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	--	--	2.5%
"Cash Flow"	--	--	7.0%
Earnings	--	--	8.0%
Dividends	--	--	NMF
Book Value	--	--	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2004	209.0	186.2	177.6	178.6	751.4
2005	193.3	174.4	177.4	192.3	737.4
2006	192.5	178.3	199.1	197.2	767.1
2007	205.3	223.3	200.8	*190.6*	*820*
2008	*210*	*205*	*210*	*210*	*835*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2004	.76	.08	.36	.15	1.35
2005	.64	.38	.58	.88	2.48
2006	.68	.49	.78	.82	2.77
2007	.93	.80	.58	*.69*	*3.00*
2008	*.70*	*.60*	*.70*	*.70*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	--	--	--	--	--
2004	--	--	--	.30	.30
2005	.30	.315	.315	.315	1.25
2006	.363	.363	.363	.363	1.45
2007	.41	.41	.41	.41	

BUSINESS: ALLETE, Inc. is the parent company of Minnesota Power, which supplies electricity to 141,000 customers in northeastern Minn., and Superior Water, Light & Power in northwestern Wisc. Electric revenue mix, '06: taconite mining/processing, 29%; paper/wood products, 11%; other industrial, 7%; residential, 13%; commercial, 14%; wholesale & other, 26%. Has real estate operation in Florida. Discontinued water-utility ops. in '01. Spun off automotive remarketing ops. (ADESA) in '04. Generating sources, '06: coal & lignite, 66%; hydro, 2%; purchased, 32%. '06 deprec. rate: 1.8%. Has 1,500 employees. Chairman, President & CEO: Donald J. Shippar. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

The difficult market conditions in Florida are hurting ALLETE's real estate operation. ALLETE owns land there that it adds value to through infrastructure development and enhancements, and then sells to developers. This has been lucrative for the company, and until several months ago, it hadn't felt the effects of the weak market in Florida. Now, however, some sales that were expected to close in 2007 have been delayed or canceled. Accordingly, ALLETE forecasts that its net income from real estate in 2008 will fall short of the $16 million-$18 million it will probably earn in 2007 (compared with $22.8 million in 2006). Thus, **we have slashed our 2008 share-earnings estimate by $0.50,** to $2.70. That's the low end of the company's targeted range of $2.70-$2.90. We have also trimmed our 2007 estimate by $0.05, to the low end of ALLETE's guidance of $3.00-$3.05.

ALLETE has the wherewithal to ride out the difficult conditions in Florida. Impairment charges aren't a concern, as the market value of its land is still well above its book value of $59 million as of September 30th. Also, the company's real estate operation has no debt. But it may well take a few years to return to the profit level of 2006.

The rest of ALLETE's operations are performing well. Minnesota Power is solid, and is benefiting from strong demand from its largely industrial customer base. The utility is about to file a wholesale rate case with the Federal Energy Regulatory Commission and will file a retail rate case in Minnesota in mid-2008. Minnesota Power also benefits from a regulatory mechanism that enables it to recover environmental capital expenditures through a rate rider, in advance of filing a general rate case. That's important because a $260 million environmental spending program will conclude in 2009. Finally, ALLETE is earning a healthy return of over 11% on its $65 million equity investment in American Transmission Company.

This stock offers an attractive yield. In fact, we're estimating a dividend increase in 2008, despite the expected earnings decline. We've lowered our sights for the 2010-2012 period, but total-return potential over that time is still worthwhile.

Paul E. Debbas, CFA *December 28, 2007*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢ net; '05, ($1.84); gain (losses) on discontinued operations: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next earnings report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '06: $2.30/sh. (D) In mill. (E) Rate base: Original cost deprec. Rate allowed on com. eq. in '95: 11.6%; earned on avg. com. eq., '06: 12.1%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	NMF
Earnings Predictability	NMF

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ALLIANT ENERGY NYSE-LNT

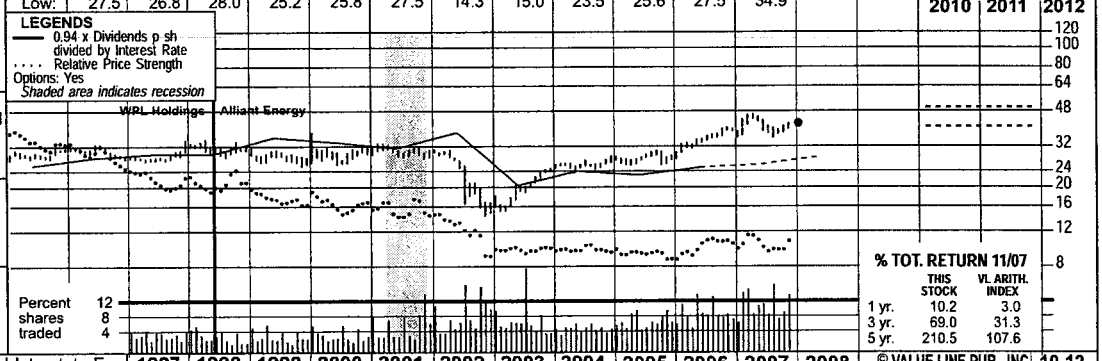
RECENT PRICE 41.70 | P/E RATIO 16.0 (Trailing: 17.4 Median: 14.0) | RELATIVE P/E RATIO 0.95 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 4 Lowered 11/10/06
SAFETY 2 Raised 9/28/07
TECHNICAL 4 Lowered 12/14/07
BETA .80 (1.00 = Market)

High:	32.9	34.4	34.9	32.4	37.8	33.2	31.0	25.1	28.8	30.6	40.0	46.5
Low:	27.5	26.8	28.0	25.2	25.8	27.5	14.3	15.0	23.5	25.6	27.5	34.9

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 0.94 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+20%)	8%
Low	40	(-5%)	2%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	8	1	1	4	2	2	0	0	0
to Sell	7	2	2	4	2	2	0	0	0

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	135	102	92
to Sell	120	138	146
Hld's(000)	69556	63981	62642

% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	10.2	3.0
3 yr.	69.0	31.3
5 yr.	210.5	107.6

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share. Data prior to 1998 are for WPL Holdings only and are not comparable with Alliant Energy data.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
29.86	27.45	27.83	30.44	30.97	28.26	28.19	25.56	28.02	28.93	*32.10*	*33.25*	Revenues per sh	*36.95*
5.60	4.85	5.71	6.57	5.82	4.52	4.19	4.69	5.46	4.33	*5.35*	*5.60*	"Cash Flow" per sh	*6.65*
1.90	1.26	2.19	2.47	2.42	1.18	1.57	1.85	2.21	2.06	*2.60*	*2.65*	Earnings per sh A	*2.85*
2.00	2.00	2.00	2.00	2.00	2.00	1.00	1.02	1.05	1.15	*1.27*	*1.40*	Div'd Decl'd per sh B ■ †	*1.70*
4.10	4.79	6.06	13.50	9.13	7.12	7.69	5.55	4.51	3.42	*5.40*	*10.05*	Cap'l Spending per sh	*4.50*
19.73	20.69	27.29	25.79	21.39	19.89	21.37	22.13	20.85	22.83	*22.40*	*23.80*	Book Value per sh C	*27.50*
30.79	77.63	78.98	79.01	89.68	92.30	110.96	115.74	117.04	116.13	*107.20*	*108.00*	Common Shs Outst'g D	*111.00*
15.0	25.1	13.0	11.8	12.6	19.9	12.7	14.0	12.6	16.8	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.86	1.31	.74	.77	.65	1.09	.72	.74	.67	.91	*Value Line*		Relative P/E Ratio	*1.05*
7.0%	6.3%	7.0%	6.9%	6.6%	8.5%	5.0%	3.9%	3.8%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*
919.3	2130.9	2198.0	2405.0	2777.3	2608.8	3128.2	2958.7	3279.6	3359.4	*3440*	*3590*	Revenues ($mill)	*4100*
64.6	103.4	178.2	203.1	194.9	113.1	176.6	229.5	337.8	260.1	*310*	*305*	Net Profit ($mill)	*335*
30.8%	36.0%	40.3%	54.0%	23.5%	24.2%	28.9%	26.7%	19.0%	43.8%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
4.3%	6.6%	4.1%	4.3%	5.7%	6.8%	11.7%	8.1%	3.0%	3.1%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
40.7%	47.3%	39.6%	47.0%	54.7%	56.4%	44.8%	45.0%	41.6%	31.4%	*38.0%*	*40.5%*	Long-Term Debt Ratio	*44.5%*
54.0%	49.2%	57.4%	50.2%	42.7%	39.2%	50.0%	50.2%	53.1%	62.9%	*56.0%*	*54.0%*	Common Equity Ratio	*51.5%*
1125.1	3262.9	3756.0	4061.4	4490.2	4679.1	4738.4	5104.7	4599.1	4218.4	*4270*	*4740*	Total Capital ($mill)	*5925*
1244.8	3101.7	3486.0	3719.3	3862.8	3729.2	4432.6	5284.6	4866.2	4944.9	*5240*	*6005*	Net Plant ($mill)	*6345*
7.4%	4.9%	6.1%	6.6%	6.2%	4.1%	5.7%	6.1%	8.9%	7.5%	*9.0%*	*8.0%*	Return on Total Cap'l	*7.5%*
9.7%	6.0%	7.9%	9.4%	9.6%	5.5%	6.8%	8.2%	12.6%	9.0%	*11.5%*	*11.0%*	Return on Shr. Equity	*10.0%*
10.1%	6.0%	8.0%	9.6%	9.8%	5.8%	6.7%	8.2%	13.1%	9.1%	*12.0%*	*11.0%*	Return on Com Equity E	*10.5%*
NMF	NMF	.7%	1.9%	1.6%	NMF	2.5%	3.8%	8.1%	4.0%	*6.0%*	*5.0%*	Retained to Com Eq	*4.0%*
100%	NMF	92%	81%	85%	NMF	67%	58%	42%	59%	*52%*	*56%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $1754.9 mill. **Due in 5 Yrs** $820.0 mill.
LT Debt $1593.9 mill. **LT Interest** $136.8 mill.
(LT interest earned: 5.3x)
Pension Assets-12/06 $738.1 mill. **Oblig.** $866.0 mill.
Pfd Stock $243.8 mill. **Pfd Div'd** $18.7 mill.
449,765 shs. $100 par; 8,199,460 shs. $25 par; 1,127,787 shs. $50 par.

Common Stock 110,315,565 shs. as of 10/31/07
MARKET CAP: $4.6 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+.3	+4.6	-1.7
Avg. Indust. Use (MWH)	4320	4215	4180
Avg. Indust. Revs. per KWH (¢)	4.84	5.26	5.96
Capacity at Peak (Mw)	5737	5446	4985
Peak Load, Summer (Mw)	5644	5932	5987
Annual Load Factor (%)	48.6	55.6	52.0
% Change Customers (yr-end)	+1.1	+1.3	+1.8
Fixed Charge Cov. (%)	235	252	350

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	--	-1.5%	5.0%
"Cash Flow"	-.5%	-4.5%	5.5%
Earnings	-1.0%	-3.0%	5.5%
Dividends	-6.0%	-11.5%	8.0%
Book Value	1.0%	-2.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	891.0	662.1	730.7	674.9	2958.7
2005	825.2	686.7	860.9	906.8	3279.6
2006	930.9	696.8	890.4	841.3	3359.4
2007	912.7	746.2	907.3	*873.8*	*3440*
2008	*950*	*760*	*960*	*920*	*3590*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.33	.30	.76	.46	1.85
2005	.23	.41	1.05	.52	2.21
2006	.56	.39	.75	.36	2.06
2007	.56	.43	1.05	*.56*	*2.60*
2008	*.55*	*.45*	*1.05*	*.60*	*2.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.25	.25	.25	.263	1.01
2005	.263	.263	.263	.263	1.05
2006	.288	.288	.288	.288	1.15
2007	.318	.318	.318	.318	
2008	.35				

BUSINESS: Alliant Energy, formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies elect. (73% of revs.), gas (19%), and other services (8%) in Wisconsin, Iowa, Minnesota, & Illinois. Elect. revs. by state: WI, 47%; IA, 48%; MN, 3%; IL, 2%. Elect. rev.: resid., 35%; comm'l, 23%; ind'l, 31%; wholesale, 6%; other, 5%. Fuel sources, '06: coal & gas, 57%; nuclear, 1%; purch., 42%. Fuel costs: 54% of revs. '06 deprec. rate: 2.8%. Est'd plant age: 10 yrs. Has 5,151 empls., Chrmn.: Erroll B. Davis, Jr. Pres. & CEO: William D. Harvey. Inc.: WI. Address: 4902 N. Biltmore Lane, P.O. Box 77007, Madison, WI 53707-1007. Tel.: 608-458-3391. Internet: www.alliant-energy.com.

Alliant Energy has an agreement to sell its remaining transmission assets. The sale includes 6,800 miles of transmission lines in Iowa, Minnesota, and Illinois; substation facilities; and related transmission land rights. ITC Midwest will pay $750 million in cash for the package, subject to various adjustments at closing. LNT was anxious to finalize the arrangement by yearend in order to capitalize on a provision in the Energy Policy Act of 2005 that allows a utility eight years to pay the tax on capital gains resulting from transmission sales consummated by December 31, 2007. As we go to press, all necessary commission approvals have been received. The transaction will now close before year-end. Since any aftertax gain will be subject to regulatory determination of amounts paid to customers, it isn't clear what impact the sale will have on operations.

The company is taking steps to cover generating needs. Demand for power in LNT's service territory is rising by 100 megawatts (mw) annually. To meet short-term obligations, it paid $180 million for the rights to Cedar Ridge's 68-mw wind farm, which is targeted to go on line in late 2008, and it plans to invest up to another $260 million in wind-driven power by the end of 2010. For the longer haul, it asked regulators for approval to build a 300-mw coal-fired station at the existing Nelson Dewey site. This location is desirable because it has ready access to rail and barge transportation, and would permit a 625-mw increase in import capability into Wisconsin. The facility is expected to begin operation in 2012.

Earnings should move sharply higher in 2007. Pluses include higher electric rates in Wisconsin, the repurchase of 10 million common shares, and profits from new plants on line. Despite a heavy storm in March that increased operating costs and raised interest expense, we estimate 2007 earnings will rise 26%, to $2.60 a share. A lesser gain is likely next year. For now, the stock is untimely.

We have a neutral long-term stance on these shares. Though the yield is a cut below the utility average, dividend growth prospects to 2010-2012 are above those of the group. Moreover, total return prospects mirror the industry average.

Arthur H. Medalie *December 28, 2007*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '96, net 7¢; '99, 32¢; '00, $2.56; '01, (28¢); '03, net 24¢; '04, (58¢); '05, ($1.05); '06, 84¢. Next egs. rpt. due late Jan. (B) Div'ds historically paid in mid-Feb., mid-May, mid-Aug., and mid-Nov. ■ Div'd reinvest. plan avail. † shareholder invest. plan avail. (C) Incl. deferred chgs. in '06: $228.8 mill., $1.96/sh. (D) In mill. (E) Rate base: Orig. cost. Rate allowed on com. eq.: in '05, WI, 10.8%; in '07, IA., 10.7%; earned on avg. com. eq., '06: 9.5%. Regul. Clim.: WI, Above Avg.; IA, Below Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	30
Earnings Predictability	65

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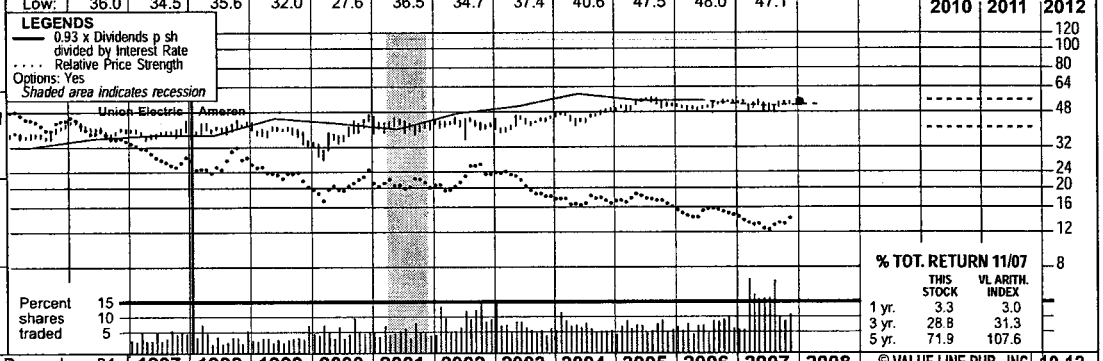
AMEREN NYSE-AEE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
53.80	16.7	(Trailing: 19.5 Median: 15.0)	0.99	4.7%	VALUE LINE

TIMELINESS 3 Raised 8/24/07
SAFETY 2 Lowered 3/30/07
TECHNICAL 3 Lowered 11/2/07
BETA .80 (1.00 = Market)

High:	44.1	43.8	44.3	42.9	46.9	46.0	45.3	46.5	50.4	56.8	55.2	55.0
Low:	36.0	34.5	35.6	32.0	27.6	36.5	34.7	37.4	40.6	47.5	48.0	47.1

Target Price Range
2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(Nil)	5%
Low	40	(-25%)	-2%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	1	0	0	0	0	0

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	168	153	136
to Sell	166	161	173
Hld's(000)	125194	128902	135064

% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	3.3	3.0
3 yr.	28.8	31.3
5 yr.	71.9	107.6

Ameren was formed on December 31, 1997 through the merger of Union Electric and CIPSCO. Each common share of Union Electric was exchanged for 1.00 share of Ameren, while each common share of CIPSCO was exchanged for 1.03 Ameren shares. Premerger data are for Union Electric only and are not comparable to Ameren data.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
24.24	24.18	25.68	28.10	32.64	24.93	28.20	26.43	33.12	33.30	36.00	37.35	Revenues per sh	41.30
4.96	5.36	5.36	6.11	6.33	5.28	6.29	5.57	6.10	5.79	6.85	7.15	"Cash Flow" per sh	8.00
2.44	2.82	2.81	3.33	3.41	2.66	3.14	2.82	3.13	2.66	3.25	3.30	Earnings per sh A	3.40
2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	Div'd Decl'd per sh B■	2.54
2.77	2.37	4.16	6.77	7.99	5.11	4.19	4.13	4.63	4.80	6.25	7.10	Cap'l Spending per sh	6.90
22.00	22.27	22.52	23.30	24.26	24.93	26.73	29.71	31.09	31.86	32.70	33.60	Book Value per sh C	36.50
137.22	137.22	137.22	137.22	138.05	154.10	162.90	195.20	204.70	206.60	208.80	210.80	Common Shs Outst'g E	216.80
15.5	14.2	13.5	11.0	12.1	15.8	13.5	16.3	16.7	19.4	Bold figures are		Avg Ann'l P/E Ratio	14.0
.89	.74	.77	.72	.62	.86	.77	.86	.89	1.05	Value Line		Relative P/E Ratio	.95
6.7%	6.3%	6.7%	6.9%	6.2%	6.1%	6.0%	5.5%	4.9%	4.9%	estimates		Avg Ann'l Div'd Yield	5.4%
3326.5	3318.2	3523.6	3855.8	4505.9	3841.0	4593.0	5160.0	6780.0	6880.0	7520	7870	Revenues ($mill)	8950
347.3	399.1	397.8	469.8	481.0	393.0	517.0	541.0	628.0	547.0	685	705	Net Profit ($mill)	750
40.3%	40.1%	39.4%	39.1%	38.4%	38.9%	36.8%	34.3%	35.6%	35.8%	36.0%	36.0%	Income Tax Rate	36.0%
3.7%	3.0%	3.6%	2.9%	4.3%	2.8%	1.9%	1.8%	2.9%	.7%	3.0%	3.0%	AFUDC % to Net Profit	3.0%
43.5%	41.0%	42.4%	44.4%	44.2%	46.0%	47.3%	45.5%	44.9%	43.8%	44.5%	44.5%	Long-Term Debt Ratio	45.5%
52.4%	54.8%	53.5%	51.8%	52.2%	51.4%	50.6%	52.6%	53.3%	54.6%	54.0%	53.5%	Common Equity Ratio	53.0%
5760.2	5580.7	5773.4	6176.9	6419.3	7468.0	8606.0	11036	11932	12063	12645	13300	Total Capital ($mill)	14925
6987.1	6928.0	7165.2	7705.7	8426.6	8914.0	10917	13297	13572	14286	14825	15505	Net Plant ($mill)	17185
7.5%	8.7%	8.2%	8.9%	8.7%	6.5%	7.4%	6.0%	6.5%	5.7%	6.5%	6.5%	Return on Total Cap'l	6.5%
10.7%	12.1%	12.0%	13.7%	13.4%	9.7%	11.4%	9.0%	9.5%	8.1%	9.5%	9.5%	Return on Shr. Equity	9.5%
11.1%	12.6%	12.5%	14.3%	14.0%	9.9%	11.6%	9.1%	9.7%	8.1%	10.0%	10.0%	Return on Com Equity D	9.0%
.1%	1.2%	1.2%	3.4%	3.6%	.2%	2.2%	.9%	1.7%	.2%	2.0%	2.0%	Retained to Com Eq	2.5%
99%	90%	91%	77%	75%	98%	81%	91%	83%	97%	79%	77%	All Div'ds to Net Prof	75%

CAPITAL STRUCTURE as of 9/30/07
Total Debt $6891.0 mill. **Due in 5 Yrs** $2395.0 mill.
LT Debt $5486.0 mill. **LT Interest** $288.7 mill.

(LT interest earned: 4.0x)

Pension Assets-12/06 $2.61 bill. **Oblig.** $3.12 bill.

Pfd Stock $211.0 mill. **Pfd Div'd** $11.0 mill.
1,137,595 shs. $3.50 to $7.64 cum. (no par), stated at liquid. value; 191,204 shs., $100 par, 4.50% to to 4.60%; 800,000 shs. 4.00% to 6.625%.

Common Stock 206,000,000 shs.

MARKET CAP: $11.1 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+7.4	+15.0	+4.5
Avg. Indust. Use (MWH)	3108	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.05	4.27	4.25
Capacity at Peak (Mw)	19439	20888	21177
Peak Load, Summer (Mw)	15991	17563	16416
Annual Load Factor (%)	58.2	NA	NA
% Change Customers (yr-end)	+19.4	NA	NA
Fixed Charge Cov. (%)	356	377	294

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	4.0%	1.5%	5.0%
"Cash Flow"	1.5%	-.5%	5.5%
Earnings	--	-2.0%	3.0%
Dividends	.5%	--	Nil
Book Value	3.0%	5.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1216	1152	1317	1475	5160.0
2005	1621	1590	1868	1701	6780.0
2006	1800	1550	1910	1620	6880.0
2007	2019	1723	1997	1781	7520
2008	2095	1790	2095	1890	7870

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.55	.65	1.20	.42	2.82
2005	.62	.93	1.37	.21	3.13
2006	.34	.60	1.42	.30	2.66
2007	.68	.69	1.36	.52	3.25
2008	.65	.70	1.50	.45	3.30

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.635	.635	.635	.635	2.54
2004	.635	.635	.635	.635	2.54
2005	.635	.635	.635	.635	2.54
2006	.635	.635	.635	.635	2.54
2007	.635	.635	.635	.635	

BUSINESS: Ameren Corp. is a holding company formed through the merger of Union Electric and CIPSCO. Acquired CILCORP 2003; Illinois Power 2004. Supplies elect. and gas to 3,400,000 customers in Missouri (40% elect. revs.) and Illinois (60%). Elect. revs.: resid., 31%; commer., 29%; indust., 18%; other, 22%. Largest indust. customers: primary metals, chemicals, transportation equipment, petroleum refining. 2006 fuels: coal, 85%; nuclear, 13%; other, 2%. Fuel costs, 45% of revenues; labor costs, 12%. 2006 depreciation rate: 3%-4%. Estimated plant age: 13 years. Has 8,988 employees, Chrmn., CEO, and Pres.: Gary L. Rainwater. Inc.: Missouri. Address: 1901 Chouteau Street, St. Louis, Missouri 63166. Telephone: 314-621-3222. Internet: www.ameren.com.

Ameren has filed for higher rates in Illinois. Last month, AEE's three utility subsidiaries in the state applied for increases totaling $180 million in electric transmission and distribution rates and $67 million in higher posted natural gas tariffs. The boosts would allow recovery of infrastructure investments and would permit recoupment of plans to spend $900 million to improve system reliability through 2010. Management maintains that the January, 2007 increase, from which $150 million will be returned to customers over four years, is inadequate to provide service and earn a reasonable return. Stiff resistance to the request is likely from consumer groups and state legislators. Whatever amount the commission approves will take effect in October, 2008.

In Missouri, the company plans capital outlays of $1 billion over three years to enhance performance. The increase includes expenditures of $300 million to protect the system against severe weather by placing transmission cables most at risk underground. Another $145 million will be spent on tree trimming to lessen the impact of ice storms that have been the cause of heavy damage. Finally, to comply with U.S. Environmental Protection Agency rules, AEE will spend $500 million to reduce pollution emissions. Since cash flow from operations won't cover these costs, long-term debt offerings will be necessary to bridge the gap.

Earnings should improve this year. Pluses include higher rates in two jurisdictions and wider electric margins on replacement of below-market contracts. Though costs related to last January's ice storm pared earnings by $0.09 a share, and refueling of the Callaway 1 nuclear plant will require additional power purchases, we estimate 2007 earnings will rise 22%, to $3.25 a share. Emphasis on core operations suggests slow, but steady, gains through 2010-2012.

The stock offers an even balance of positives and negatives. The probable absence of a dividend hike in our 3- to 5-year horizon is offset by an above-average yield. Though total return prospects are unexciting, those investors of a conservative bent might be satisfied because of Ameren's strong finances.

Arthur H. Medalie *December 28, 2007*

(A) EPS basic. Excl. nonrecur. gain, (loss): '03, 11¢; '05, (11¢). Next egs. report due late Jan. (B) Div'ds historically paid in late March, late June, late Sept., and late Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred chgs. in '06, $11.99/sh. (D) Rate base: orig. cost depreciated. Rate allowed in MO on common equity in '97: 10.25%; earned on average com. eq. in '06: 8.5%. Regul. Clim.: Average. (E) In millions.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	80

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AMERICAN ELEC. PWR. NYSE-AEP

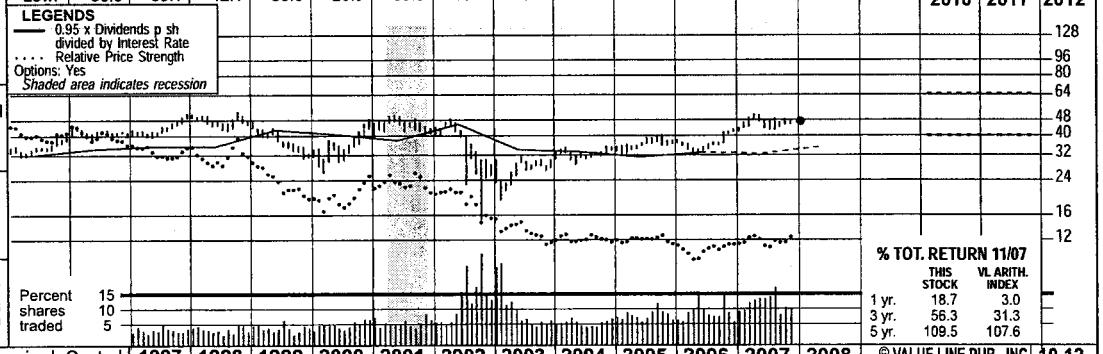
RECENT PRICE 47.14 | P/E RATIO 16.4 (Trailing: 16.9 Median: 13.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Lowered 6/8/07
SAFETY 3 Lowered 10/4/02
TECHNICAL 3 Raised 12/14/07
BETA .95 (1.00 = Market)

High:	44.8	52.0	53.3	48.2	48.9	51.2	48.8	31.5	35.5	40.8	43.1	51.2
Low:	38.6	39.1	42.1	30.6	25.9	39.3	15.1	19.0	28.5	32.3	32.3	41.7

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 0.95 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+40%)	12%
Low	40	(-15%)	1%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	6	1	0	1	0	2
to Sell	0	1	0	7	0	0	1	0	2

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	226	205	206
to Sell	222	230	199
Hld's(000)	286566	282116	278067

% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	18.7	3.0
3 yr.	56.3	31.3
5 yr.	109.5	107.6

American Electric Power acquired Central and South West Corporation (CSW) in 2000. CSW common stockholders received 0.6 of an AEP common share for each of their shares, for a total of $4.5 billion. The transaction was effected under pooling-of-interests accounting rules. The data on this page prior to 2000 do not reflect the addition of CSW.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
32.43	33.08	35.63	42.53	190.10	42.96	36.82	35.51	30.76	31.82	*33.20*	*34.65*	Revenues per sh	*39.00*
6.47	6.03	6.36	5.11	7.65	6.99	5.76	5.89	5.96	6.54	*6.55*	*6.90*	"Cash Flow" per sh	*8.25*
3.28	2.81	2.69	1.04	3.27	2.86	2.53	2.61	2.64	2.86	*2.80*	*3.15*	Earnings per sh A	*4.00*
2.40	2.40	2.40	2.40	2.40	2.40	1.65	1.40	1.42	1.50	*1.58*	*1.67*	Div'd Decl'd per sh B ■ †	*2.20*
4.00	4.13	4.47	5.51	5.69	5.08	3.44	4.28	6.11	8.89	*8.90*	*9.40*	Cap'l Spending per sh	*8.25*
24.62	25.24	25.79	25.01	25.54	20.85	19.93	21.32	23.08	23.73	*24.90*	*26.55*	Book Value per sh C	*32.00*
189.99	191.82	194.10	322.02	322.24	338.84	395.02	395.86	393.72	396.67	*400.50*	*404.00*	Common Shs Outst'g D	*413.00*
13.4	17.0	14.3	NMF	13.9	12.7	10.7	12.4	13.7	12.9	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.77	.88	.82	NMF	.71	.69	.61	.66	.73	.70	*Value Line*		Relative P/E Ratio	*.85*
5.5%	5.0%	6.2%	6.7%	5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
6161.4	6345.9	6916.0	13694	61257	14555	14545	14057	12111	12622	*13300*	*14000*	Revenues ($mill)	*16100*
638.2	547.1	532.0	332.0	1063.0	976.0	984.0	1038.0	1036.0	1131.0	*1120*	*1275*	Net Profit ($mill)	*1620*
34.8%	36.6%	32.8%	66.1%	36.0%	25.2%	38.8%	33.1%	29.3%	33.0%	*32.5%*	*33.0%*	Income Tax Rate	*33.0%*
1.6%	1.7%	1.9%	--	--	--	3.8%	3.6%	5.4%	9.9%	*11.0%*	*12.0%*	AFUDC % to Net Profit	*10.0%*
51.4%	57.6%	55.1%	52.9%	54.6%	56.0%	60.6%	56.2%	54.8%	56.7%	*58.0%*	*59.0%*	Long-Term Debt Ratio	*56.5%*
46.9%	41.0%	43.5%	44.4%	44.6%	43.1%	38.7%	43.1%	44.9%	43.0%	*42.0%*	*40.5%*	Common Equity Ratio	*43.0%*
9981.0	11815	11506	18151	18459	16393	20333	19584	20222	21902	*23800*	*26325*	Total Capital ($mill)	*30500*
11633	11730	13055	22393	24543	21684	22029	22801	24284	26781	*29325*	*31650*	Net Plant ($mill)	*37500*
8.1%	6.2%	6.6%	3.8%	7.5%	7.5%	6.6%	7.0%	6.6%	6.7%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
13.2%	10.9%	10.3%	3.9%	12.7%	13.5%	12.3%	12.1%	11.3%	11.9%	*11.0%*	*12.0%*	Return on Shr. Equity	*12.0%*
13.3%	11.1%	10.4%	3.7%	12.8%	13.7%	12.4%	12.2%	11.3%	12.0%	*11.0%*	*12.0%*	Return on Com Equity E	*12.5%*
3.6%	1.6%	1.1%	NMF	3.4%	2.4%	4.5%	5.7%	5.2%	5.7%	*5.0%*	*5.5%*	Retained to Com Eq	*5.5%*
74%	86%	89%	NMF	74%	82%	64%	54%	54%	53%	*57%*	*53%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $15363 mill. **Due in 5 Yrs** $4543 mill.
LT Debt $13866 mill. **LT Interest** $763 mill.
incl. $2.26 bill. securitized bonds.
(LT interest earned: 3.1x)

Leases, Uncapitalized Annual rentals $331 mill.

Pension Assets-12/06 $4.35 bill. **Oblig.** $4.11 bill.

Pfd Stock $61 mill. **Pfd Div'd** $3 mill.
607,044 shs. 4%-5%, cumulative, callable at $102-$110.
Common Stock 400,006,022 shs.
as of 10/31/07
MARKET CAP: $19 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+.7	+3.7	-.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	3.57	3.75	4.50
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.8	+1.3
Fixed Charge Cov. (%)	244	258	265

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	.5%	-18.0%	*3.0%*
"Cash Flow"	--	-1.0%	*5.0%*
Earnings	-.5%	3.0%	*6.5%*
Dividends	-5.0%	-9.5%	*7.5%*
Book Value	-.5%	-2.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	3364	3408	3780	3505	14057
2005	3065	2819	3328	2899	12111
2006	3108	2936	3594	2984	12622
2007	3169	3146	3789	*3196*	*13300*
2008	*3400*	*3300*	*4000*	*3300*	*14000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.73	.38	.80	.69	2.61
2005	.90	.57	.95	.23	2.64
2006	.96	.44	1.01	.45	2.86
2007	.68	.64	1.02	*.46*	*2.80*
2008	*.75*	*.65*	*1.20*	*.55*	*3.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.60	.35	.35	.35	1.65
2004	.35	.35	.35	.35	1.40
2005	.35	.35	.35	.37	1.42
2006	.37	.37	.37	.39	1.50
2007	.39	.39	.39	.41	

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves about 5.1 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. Electric revenue breakdown, '06: residential, 30%; commercial, 22%; industrial, 20%; wholesale, 22%; other, 6%. Sold 50% stake in Yorkshire Holdings (British utility) '01; sold SEEBOARD (British utility) '02; sold Houston Pipeline '05. Generating sources not available. Fuel costs: 37% of revenues. '06 depreciation rate: 3.5%. Has 20,400 employees. Chairman, President & CEO: Michael G. Morris. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

Capital spending, followed by rate relief, should continue to be the key driver of American Electric Power's earnings growth. Currently, much of the capital spending is associated with a $5.1 billion environmental program that began in 2004 and will run through 2010. As these expenditures start to wind down, transmission spending will begin ramping up. There will be some spending on generating assets as well—Southwestern Electric is proposing to build a coal-fired plant in Arkansas—plus the usual expenditures on the distribution system to accommodate growth in the utilities' service areas and to maintain system reliability.

The utilities have received some rate orders in 2007. Public Service of Oklahoma and Texas Central received rate orders that should boost pretax earnings by $20 million and $50 million, respectively. Appalachian Power was granted an increase of $48.9 million in Virginia for the recovery of environmental and reliability costs. Most of the rate orders have been good, but the Texas commission allowed AEP an ROE of just 9.96% on transmission investment in the state, well below the 11.25% requested.

Other rate cases are pending. AEP's utilities in Ohio are seeking a total of $50 million in rate relief to recover some generation-related expenditures. (It's still an open question what will happen to AEP's customers in the state when rate caps expire at the end of 2008.) Appalachian Power is seeking $97 million in Virginia for costs associated with fuel and a proposed generating facility.

We expect a solid earnings increase in 2008. Rate relief should be the key factor. Our estimate is at the midpoint of AEP's targeted range of $3.00-$3.30 a share.

The board of directors has increased the dividend. The board boosted the quarterly payout by two cents a share (5.1%), to $0.41. We project that solid dividend growth will continue through 2010-2012, but that the disbursement won't return to the level before it was cut in 2003. AEP is targeting a 55%-60% payout ratio.

We have a neutral stance on this stock. The yield and 3- to 5-year total-return potential are just average, by utility standards.

Paul E. Debbas, CFA *December 28, 2007*

(A) Excl. extra. gain (losses): '01, (26¢); '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); gains (losses) on disc. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢. '04 & '05 EPS don't add due to rounding. Next earnings report due late Jan. (B) Div'ds historically paid early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '06: $14.17/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.96%-15.7%; earned on avg. com. eq., '06: 12.1%. Regulat. Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	10
Earnings Predictability	65

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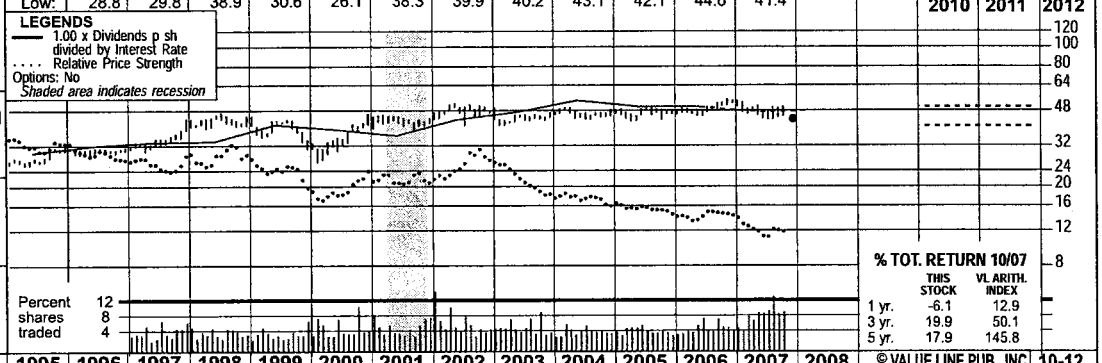
CH ENERGY GROUP NYSE-CHG

RECENT PRICE 43.64 | P/E RATIO 16.5 (Trailing: 17.0 Median: 15.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 4.9% | VALUE LINE

TIMELINESS 3 Raised 10/19/07
SAFETY 1 Raised 12/7/01
TECHNICAL 3 Raised 8/31/07
BETA .90 (1.00 = Market)

High:	31.5	43.9	47.1	45.0	46.3	45.9	52.4	49.7	49.6	50.2	54.9	53.8
Low:	28.8	29.8	38.9	30.6	26.1	38.3	39.9	40.2	43.1	42.1	44.6	41.4

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: No
Shaded area indicates recession



Target Price Range 2010 | 2011 | 2012
120 100 80 64 48 32 24 20 16 12 8

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+15%)	8%
Low	40	(-10%)	3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	1	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	55	60	56
to Sell	36	39	37
Hld's(000)	7948	8347	8641

Percent shares traded 12 8 4

% TOT. RETURN 10/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	-6.1	12.9
3 yr.	19.9	50.1
5 yr.	17.9	145.8

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
31.38	32.66	30.52	29.91	29.28	29.28	30.11	29.86	30.95	45.83	44.52	43.29	51.18	50.22	61.70	63.03	*72.95*	*80.90*	Revenues per sh	*100.00*
4.99	5.22	5.23	5.25	5.33	5.69	5.80	5.83	5.92	6.49	5.50	4.18	5.02	4.89	5.11	4.83	*5.10*	*5.40*	"Cash Flow" per sh	*6.25*
2.40	2.55	2.68	2.68	2.74	2.99	2.97	2.90	2.88	3.05	3.11	2.12	2.78	2.69	2.81	2.56	*2.60*	*2.80*	Earnings per sh A	*3.25*
1.90	1.98	2.05	2.08	2.10	2.12	2.14	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	*2.16*	*2.16*	Div'd Decl'd per sh B ■ †	*2.26*
4.44	3.81	3.13	3.37	2.87	2.84	2.54	2.71	2.76	3.58	4.14	4.50	3.79	3.98	4.05	4.76	*5.70*	*5.40*	Cap'l Spending per sh	*5.25*
22.84	23.60	24.65	25.33	25.96	26.87	27.61	28.00	28.73	29.38	30.33	30.31	30.80	31.31	31.97	32.54	*33.05*	*33.65*	Book Value per sh C	*35.50*
15.77	16.03	16.95	17.24	17.50	17.56	17.28	16.86	16.86	16.36	16.36	16.06	15.76	15.76	15.76	15.76	*15.76*	*15.76*	Common Shs Outst'g D	*15.00*
10.7	11.2	12.2	10.0	10.2	10.1	11.5	14.6	13.5	11.4	13.6	22.6	15.7	17.2	16.5	19.1	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.68	.68	.72	.66	.68	.63	.66	.76	.77	.74	.70	1.23	.90	.91	.88	1.03	*Value Line*		Relative P/E Ratio	*.95*
7.4%	6.9%	6.3%	7.8%	7.5%	7.0%	6.3%	5.1%	5.6%	6.2%	5.1%	4.5%	4.9%	4.7%	4.7%	4.4%	*estimates*		Avg Ann'l Div'd Yield	*5.0%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $439.9 mill. **Due in 5 Yrs** $77.0 mill.
LT Debt $403.9 mill. **LT Interest** $18.6 mill.
(LT interest earned: 4.2x)
Leases, Uncapitalized Annual rentals $3.1 mill.
Pension Assets-12/06 $359.6 mill. **Oblig.** $414.5 mill.
Pfd Stock $21.0 mill. **Pfd Div'd** $1.0 mill.
210,300 shs. 4½%-4.96% cum., $100 par, redeemable at $101-$107/sh.

Common Stock 15,762,000 shs. as of 11/1/07
MARKET CAP: $675 million (Small Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
520.3	503.5	521.9	749.9	728.4	695.5	806.7	791.5	972.5	993.4	*1150*	*1275*	Revenues ($mill)	*1500*
55.1	52.5	51.8	54.2	54.1	36.6	45.4	43.4	45.3	41.4	*42.0*	*45.0*	Net Profit ($mill)	*48.0*
32.3%	35.3%	35.8%	41.4%	--	36.6%	40.1%	41.9%	36.3%	36.3%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
1.2%	1.7%	.8%	1.4%	1.4%	2.3%	1.6%	.9%	.9%	1.5%	*1.0%*	*1.0%*	AFUDC % to Net Profit	*1.0%*
40.4%	40.3%	38.3%	37.4%	28.1%	34.1%	35.5%	38.3%	39.6%	38.8%	*42.5%*	*44.5%*	Long-Term Debt Ratio	*50.0%*
53.3%	53.3%	55.3%	56.1%	64.6%	61.6%	61.8%	59.1%	58.0%	58.8%	*55.0%*	*53.5%*	Common Equity Ratio	*48.5%*
895.0	885.1	875.9	857.1	768.5	790.3	785.3	834.4	868.7	871.8	*945*	*990*	Total Capital ($mill)	*1100*
932.8	928.2	921.4	930.9	561.8	601.7	707.5	745.1	779.5	827.1	*880*	*925*	Net Plant ($mill)	*1050*
7.4%	7.2%	7.3%	7.7%	8.1%	5.4%	6.5%	5.9%	6.0%	5.7%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
10.3%	9.9%	9.6%	10.1%	9.8%	7.0%	9.0%	8.4%	8.6%	7.7%	*7.5%*	*8.0%*	Return on Shr. Equity	*8.5%*
10.9%	10.4%	10.0%	10.6%	10.2%	7.1%	9.1%	8.6%	8.8%	7.9%	*8.0%*	*8.5%*	Return on Com Equity E	*9.0%*
3.1%	2.7%	2.5%	3.1%	3.1%	NMF	2.0%	1.7%	2.0%	1.2%	*1.5%*	*2.0%*	Retained to Com Eq	*2.5%*
73%	76%	77%	73%	71%	102%	78%	81%	77%	85%	*84%*	*79%*	All Div'ds to Net Prof	*73%*

ELECTRIC OPERATING STATISTICS

=	2004	2005	2006
% Change Retail Sales (KWH)	+2.1	+4.5	-4.2
Avg. Indust. Use (MWH)	1407	1407	1377
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1051	1204	1295
Peak Load, Summer (Mw)	1051	1204	1295
Annual Load Factor (%)	61.0	57.0	50.0
% Change Customers (avg.)	+1.0	+1.3	+.9
Fixed Charge Cov. (%)	374	408	328

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	7.0%	7.5%	*9.5%*
"Cash Flow"	-1.0%	-3.5%	*4.0%*
Earnings	-.5%	-2.5%	*3.0%*
Dividends	.5%	--	*1.0%*
Book Value	2.0%	1.5%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	263.0	165.3	161.9	201.3	791.5
2005	286.1	189.6	227.9	268.9	972.5
2006	317.2	213.9	239.8	222.5	993.4
2007	343.4	271.0	260.1	*275.5*	*1150*
2008	*375*	*300*	*300*	*300*	*1275*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1.46	.35	.28	.60	2.69
2005	1.29	.41	.36	.74	2.81
2006	1.16	.26	.55	.60	2.56
2007	1.37	.33	.27	*.63*	*2.60*
2008	*1.40*	*.35*	*.35*	*.70*	*2.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.54	.54	.54	.54	2.16
2004	.54	.54	.54	.54	2.16
2005	.54	.54	.54	.54	2.16
2006	.54	.54	.54	.54	2.16
2007	.54	.54	.54	.54	

BUSINESS: CH Energy Group, Inc. is a holding company for Central Hudson Gas & Electric, which provides electricity and gas in the Mid-Hudson Valley region of New York State (79% of '06 income). Customers: 293,000 electric, 71,000 gas. Griffith Energy provides gas, oil, electricity, & propane to over 100,000 customers in Northeast (4% of '06 income). Investments were 17% of '06 income. Electric revenue breakdown, '06: residential, 51%; commercial, 32%; industrial, 7%; other, 10%. Generating sources, '06: hydro, 3%; purchased, 97%. Fuel costs: 66% of revenues. '06 reported depreciation rate (utility): 3.0%. Chairman, President & CEO: Steven V. Lant. Inc.: NY. Address: 284 South Ave., Poughkeepsie, NY 12601-4879. Tel.: 845-452-2000. Internet: www.chenergy.com.

We have cut our earnings estimates for CH Energy Group. We had expected third-quarter earnings to decline from the unusually high level of 2006, but the drop was steeper than we had estimated. In addition, Central Hudson Gas and Electric is experiencing decelerating customer growth, which stems from the troubles in the housing market. This has caused electric and gas sales to fall below the levels that were assumed in the utility's last rate order, which was issued in 2006 and is in effect until mid-2009. On the nonutility end, the company's ethanol plant is experiencing a difficult commodities market, although it should be noted that this is a small equity investment, at just $2.7 million. Putting it all together, we have lowered our 2007 share-earnings estimate from $2.70 to $2.60 and have reduced our 2008 forecast from $2.85 to $2.80. The stock is ranked 3 (Average) for Timeliness.

The company's Griffith Energy subsidiary continues to expand through acquisitions. This heating oil distributor has spent approximately $16 million on eight acquisitions so far in 2007. There are ample opportunities for expansion, and not just from troubled operators. This is a fragmented industry with a lot of family-owned businesses, and some very successful owners have approached Griffith because they want to cash out as they prepare for retirement.

Finances are solid. The common-equity ratio should remain high even though Central Hudson has added some debt to finance its capital spending needs. Also, the fixed-charge coverage is well above the industry average. The company merits a Financial Strength rating of A.

High-quality CH Energy stock offers an above-average yield, even by utility standards. This reflects the fact that the dividend hasn't been raised since the late 1990s. Although we project that dividend growth will resume over the 3- to 5-year period, because the stock is already trading well within our 2010-2012 Target Price Range, total-return potential over that time is subpar. CH Energy has been viewed as a takeover candidate for several years, but we do not advise investors to purchase this equity with the hope that a buyout will occur.

Paul E. Debbas, CFA *November 30, 2007*

(A) Diluted earnings. Excl. nonrecurring gains: '92, 10¢; '02, 12¢; '06, 17¢; gain from discontinued operation: '02, 29¢. '05 & '06 earnings don't add to total due to rounding. Next earnings report due late Jan. (B) Div'ds historically paid in early Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '06: $299.2 mill., $18.98/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '06: 10.6%; earned on avg. com. eq., '06: 8.0%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	85

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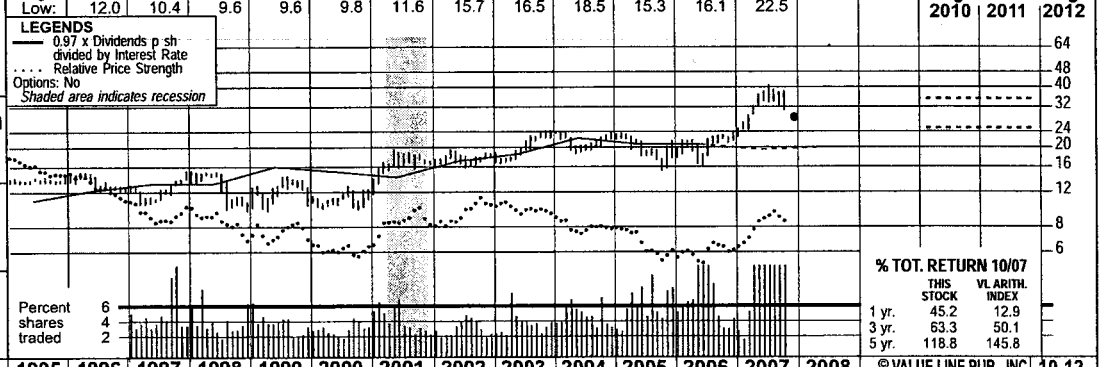
CENT. VERMONT P.S. NYSE-CV

RECENT PRICE **28.30** | P/E RATIO **18.7** (Trailing: 18.0 Median: 14.0) | RELATIVE P/E RATIO **1.11** | DIV'D YLD **3.3%** | VALUE LINE

TIMELINESS 4 Lowered 11/16/07
SAFETY 3 Raised 9/7/01
TECHNICAL 3 Lowered 11/2/07
BETA 1.00 (1.00 = Market)

High:	15.1	15.4	15.4	14.4	13.0	19.6	19.7	24.5	24.1	23.7	23.9	41.1
Low:	12.0	10.4	9.6	9.6	9.8	11.6	15.7	16.5	18.5	15.3	16.1	22.5

Target Price Range 2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+25%)	9%
Low	25	(-10%)	1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	5	0	0	0	0	0
to Sell	0	0	0	3	0	0	0	0	0

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	37	49	62
to Sell	24	24	35
Hld's(000)	3322	3520	3509

% TOT. RETURN 10/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	45.2	12.9
3 yr.	63.3	50.1
5 yr.	118.8	145.8

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
21.60	24.59	24.16	23.63	24.87	25.24	26.68	26.51	36.61	29.02	26.05	25.84	25.92	24.78	25.35	32.15	32.05	33.65	Revenues per sh	35.50
2.77	2.96	2.94	2.69	2.97	2.97	2.81	1.64	2.76	2.60	2.39	3.01	2.80	2.56	1.42	3.41	3.00	3.15	"Cash Flow" per sh	3.30
1.65	1.71	1.64	1.29	1.47	1.41	1.32	.18	1.28	1.14	.93	1.54	1.41	1.25	.08	1.63	1.40	1.50	Earnings per sh A	1.65
1.39	1.39	1.42	1.42	.80	.84	.88	.88	.88	.88	.88	.88	.88	.92	.92	.92	.92	.92	Div'd Decl'd per sh B ■	.92
1.75	1.83	1.77	1.93	1.84	1.65	1.21	1.59	1.37	1.40	1.47	1.23	1.28	1.66	1.43	1.92	3.60	2.40	Cap'l Spending per sh	2.35
14.03	14.21	15.03	14.56	15.51	16.19	16.38	15.63	16.05	16.57	15.81	16.83	17.89	18.49	17.70	17.70	18.40	19.00	Book Value per sh C	21.20
10.81	11.20	11.56	11.73	11.59	11.52	11.42	11.46	11.47	11.51	11.61	11.74	11.81	12.19	12.28	10.13	10.30	10.40	Common Shs Outst'g D	10.70
11.4	12.6	14.3	12.3	9.3	9.5	9.3	NMF	9.5	9.7	17.8	11.4	14.3	17.1	NMF	12.7	Bold figures are		Avg Ann'l P/E Ratio	18.0
.73	.76	.84	.81	.62	.60	.54	NMF	.54	.63	.91	.62	.82	.90	NMF	.69	Value Line		Relative P/E Ratio	1.20
7.3%	6.4%	6.0%	8.9%	5.8%	6.3%	7.2%	6.8%	7.2%	8.0%	5.3%	5.0%	4.4%	4.3%	4.6%	4.4%	estimates		Avg Ann'l Div'd Yield	3.1%

CAPITAL STRUCTURE as of 6/30/07
Total Debt $133.2 mill. **Due in 5 Yrs** $38.4 mill.
LT Debt $116.0 mill. **LT Interest** $7.8 mill.
Incl. $5.2 mill. capitalized leases.
(LT interest earned: 3.7x)
Pension Assets-12/06 $86.1 mill. **Oblig.** $103.9 mill.
Pfd Stock $10.1 mill. **Pfd Div'd** $.4 mill.
Incl. 37,856 shs. 4.15%; 10,000 shs. 4.65%; 17,682 shs. 4.75%; 15,000 shs. 5.375%; 50,000 shs. 8.30%, all cum. and $100 par.
Common Stock 10,194,531 shs. **as of 7/31/07**

MARKET CAP: $300 million (Small Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
304.7	303.8	419.8	333.9	302.5	303.4	306.0	302.2	311.4	325.7	330	350	Revenues ($mill)	380
17.2	4.0	16.6	14.8	12.4	20.0	18.4	15.6	1.4	18.50	15.0	16.0	Net Profit ($mill)	18.0
34.8%	3.5%	38.5%	39.5%	43.4%	37.8%	32.0%	18.4%	18.4%	35.1%	35.0%	35.0%	Income Tax Rate	35.0%
.6%	2.5%	.2%	.7%	.7%	.5%	.7%	1.3%	7.4%	.8%	1.0%	1.0%	AFUDC % to Net Profit	1.0%
34.0%	34.1%	44.9%	43.7%	45.5%	41.0%	37.6%	35.8%	34.7%	39.2%	40.0%	40.5%	Long-Term Debt Ratio	39.0%
57.7%	57.5%	48.5%	50.0%	48.4%	54.1%	57.8%	60.4%	61.8%	57.3%	57.0%	56.5%	Common Equity Ratio	58.0%
324.5	311.5	379.4	381.7	379.2	365.3	365.7	373.4	351.5	313.0	325	350	Total Capital ($mill)	390
321.6	319.9	314.7	311.0	308.6	304.6	298.7	299.5	301.2	308.8	330	335	Net Plant ($mill)	360
6.7%	2.9%	5.8%	5.7%	5.0%	7.2%	6.6%	5.4%	1.4%	7.1%	6.0%	5.5%	Return on Total Cap'l	6.0%
8.0%	1.9%	7.9%	6.9%	6.0%	9.3%	8.0%	6.5%	.6%	9.7%	7.5%	7.5%	Return on Shr. Equity	7.5%
8.1%	1.1%	8.0%	6.9%	5.8%	9.3%	8.1%	6.8%	.5%	10.1%	7.5%	8.0%	Return on Com Equity E	8.0%
2.4%	NMF	2.5%	1.5%	.5%	3.9%	3.2%	1.5%	NMF	4.6%	2.5%	3.0%	Retained to Com Eq	3.5%
74%	NMF	72%	80%	92%	61%	63%	78%	NMF	55%	69%	62%	All Div'ds to Net Prof	57%

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+2.0	+2.6	-.6
Avg. Indust. Use (MWH)	11327	11509	10015
Avg. Indust. Revs. per KWH (¢)	8.29	8.18	8.15
Capacity at Peak (Mw)	469	NA	NA
Peak Load, Winter (Mw)	427	NA	NA
Annual Load Factor (%)	N/A	NA	NA
% Change Customers (yr-end)	+1.0	+1.2	+1.3
Fixed Charge Cov. (%)	247	61	334

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	1.0%	-2.0%	4.5%
"Cash Flow"	-1.5%	-1.0%	5.0%
Earnings	-3.5%	-2.5%	9.0%
Dividends	-1.0%	1.0%	Nil
Book Value	1.5%	2.0%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	84.1	67.6	72.8	77.7	302.2
2005	75.7	75.1	75.0	85.6	311.4
2006	82.3	79.0	79.9	84.5	325.7
2007	86.7	77.4	79.2	86.7	330
2008	91.0	81.0	87.0	91.0	350

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.51	.26	.34	.14	1.25
2005	d.41	.21	.22	.06	.08
2006	.32	.08	.66	.57	1.63
2007	.55	.04	.41	.40	1.40
2008	.55	.15	.45	.35	1.50

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.22	.22	.22	.22	.88
2004	.23	.23	.23	.23	.92
2005	.23	.23	.23	.23	.92
2006	.23	.23	.23	.23	.92
2007	.23	.23	.23	.23	

BUSINESS: Central Vermont Public Service Corporation supplies electricity to 153,000 customers in a large portion of Vermont. 2006 electric retail revenues: residential, 38%; commercial, 32%; industrial, 12%; other, 18%. '06 Generating sources: nuclear, 54%; hydro, 38%; other, 8%. Purchased power costs: 52% of '06 revenues. Owns 47% of Vermont Electric Power Company and has 29% entitlement to Vermont Yankee Nuclear plant output. Divested Connecticut Valley Electric Co., 1/04. '06 depreciation rate: 3.2%. Has 535 employees. Chairperson: Mary Alice McKenzie. President & Chief Executive Officer: Robert H. Young. Incorporated: Vermont. Address: 77 Grove St., Rutland, Vermont 05701. Telephone: 802-773-2711. Internet: www.cvps.com.

Central Vermont Public Service awaits an order on its application for higher rates. It asked for an increase of $12.6 million to be operative next February 1st. The hike is needed to offset a decline in prices received from the sale of excess energy into the wholesale market and to recover higher transmission costs. In addition, CV seeks to recoup 2007 capital expenditures that have been raised to $26 million from last year's $18 million and will likely remain at the higher level for some time to come. The proposal also includes a power cost adjustment mechanism and sharing of earnings with customers. Too, it recommends a plan for making rate adjustments over a three-year period without the need for periodic rate requests. A regulatory order on the filing is expected shortly.

The company is heavily dependent on two energy sources. CV receives 40% of its requirements from Entergy's Vermont Energy nuclear plant's output. The owner is expected to seek an extension of the operating license, which expires in 2012. Hydro Quebec provides another 29% of the company's needs, but it can reduce deliveries on one year's notice if hydro conditions worsen. Negotiations for renewal of both agreements are under way. To protect its supply, management is studying the feasibility of building a gas-fired plant with other utilities, is purchasing power on the wholesale market, and is buying energy from cow waste.

We look for lower earnings in 2007. Vermont Yankee's downtime for refueling hurt second-quarter results. Other negatives include the sale of excess power at low prices and a storm in April that boosted maintenance costs. Despite higher rates and fewer common shares outstanding, we estimate 2007 earnings will fall 14%, to $1.40 a share. An order on the aforementioned rate request points to improvement in 2008. The stock is untimely.

These shares have little to offer utility investors. The year-ahead yield is a full percentage point below the industry norm, and we don't expect a dividend hike in the scope of our 3- to 5-year horizon. What's more, it may be a while before major rating organizations restore CV's finances to an investment-grade level.

Arthur H. Medalie *November 30, 2007*

(A) Diluted egs. Excludes nonrecur.: '94, d14¢; '95, 4¢; '96, 10¢; '97, d7¢; '00, 28¢; '01, d87¢; '02, net d1¢; '03, 12¢; '04, 65¢; '05, 40¢. Next egs. report due mid-Feb. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. (C) Incl. def'd chgs. In '06: $5.65/sh. (D) In mill., adj'd for split. (E) Rate base: net orig. cost. Rate all'w com. eq. in '07: 10.75%; earned in '06: 8.9%. Reg. Clim.: Below Avg.

Company's Financial Strength	B
Stock's Price Stability	65
Price Growth Persistence	55
Earnings Predictability	30

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CLECO CORPORATION NYSE-CNL

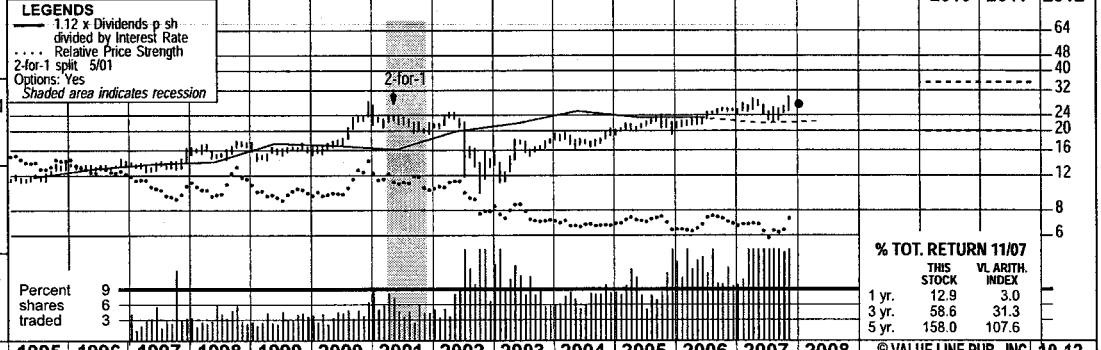
RECENT PRICE 27.25 | P/E RATIO 18.0 (Trailing: 21.0 Median: 14.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 4 Raised 8/11/06
SAFETY 3 Lowered 1/3/03
TECHNICAL 3 Raised 12/28/07
BETA 1.15 (1.00 = Market)

High:	14.6	16.6	18.1	17.8	28.3	27.3	24.9	18.4	20.8	24.4	26.2	29.8
Low:	12.6	12.4	14.3	14.1	15.1	19.2	9.7	11.0	16.2	18.9	20.5	22.1

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.12 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/01
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+30%)	10%
Low	20	(-25%)	-2%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	4	0	0	0	1	0
to Sell	0	0	0	10	0	0	0	1	0

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	88	96	97
to Sell	85	83	71
Hld's(000)	41756	48623	48236

% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	12.9	3.0
3 yr.	58.6	31.3
5 yr.	158.0	107.6

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
7.58	7.88	8.54	8.48	8.79	9.70	10.16	11.46	17.12	18.23	23.55	15.33	18.54	15.03	18.41	17.38	17.10	18.85	Revenues per sh	23.00
1.76	1.78	1.74	1.85	1.99	2.11	2.18	2.28	2.36	2.77	2.94	3.05	2.98	2.56	2.76	2.70	2.85	3.05	"Cash Flow" per sh	4.00
.96	.97	.89	.96	1.04	1.12	1.09	1.12	1.19	1.46	1.51	1.52	1.26	1.32	1.42	1.36	1.30	1.50	Earnings per sh A	2.00
.66	.69	.71	.73	.75	.77	.79	.81	.83	.85	.87	.90	.90	.90	.90	.90	.90	.90	Div'd Decl'd per sh B ■ †	1.30
1.23	1.44	1.15	1.24	1.29	1.43	1.73	2.09	3.99	2.52	1.10	1.91	1.58	1.61	3.19	4.11	8.65	5.40	Cap'l Spending per sh	1.75
6.76	7.06	7.29	7.56	7.91	8.30	8.68	9.07	9.44	10.04	10.69	11.77	10.09	10.83	13.69	15.22	16.25	17.00	Book Value per sh C	19.50
44.48	44.61	44.77	44.78	44.85	44.91	44.93	44.97	44.88	44.99	44.96	47.04	47.18	49.62	49.99	57.57	60.00	61.00	Common Shs Outst'g D	64.00
10.7	12.5	14.3	12.1	11.6	11.9	12.5	14.4	13.4	13.2	14.6	12.2	12.4	13.8	15.0	17.3	Bold figures are		Avg Ann'l P/E Ratio	14.0
.68	.76	.84	.79	.78	.75	.72	.75	.76	.86	.75	.67	.71	.73	.80	.93	Value Line		Relative P/E Ratio	.95
6.4%	5.7%	5.5%	6.2%	6.2%	5.8%	5.8%	5.0%	5.2%	4.4%	3.9%	4.8%	5.8%	5.0%	4.2%	3.8%	estimates		Avg Ann'l Div'd Yield	4.8%
						456.2	515.2	768.2	820.0	1058.6	721.2	874.6	745.8	920.2	1000.7	1025	1150	Revenues ($mill)	1475
						52.5	53.8	56.8	69.3	72.3	74.2	61.2	66.1	75.0	74.7	80.0	90.0	Net Profit ($mill)	130
						34.6%	33.1%	32.4%	33.5%	34.7%	36.9%	37.2%	35.2%	39.2%	36.0%	38.5%	38.5%	Income Tax Rate	38.5%
						1.5%	3.2%	10.6%	12.1%	16.7%	12.6%	5.8%	7.5%	4.3%	14.2%	53.0%	55.0%	AFUDC % to Net Profit	4.0%
						46.2%	43.6%	56.2%	57.9%	55.2%	60.0%	64.4%	44.5%	46.3%	40.9%	45.5%	51.0%	Long-Term Debt Ratio	50.0%
						49.2%	51.9%	41.0%	39.7%	42.4%	38.2%	33.8%	53.1%	52.0%	57.8%	54.5%	49.0%	Common Equity Ratio	50.0%
						792.1	786.2	1032.1	1139.2	1134.7	1448.7	1408.5	1011.6	1315.9	1515.6	1790	2115	Total Capital ($mill)	2475
						1025.6	1089.8	1211.6	1232.8	1224.7	1566.2	1417.1	1060.0	1188.7	1304.9	1740	1985	Net Plant ($mill)	2050
						8.1%	8.3%	6.9%	8.3%	8.6%	7.1%	6.7%	8.9%	7.1%	6.3%	5.5%	6.0%	Return on Total Cap'l	7.0%
						12.3%	12.1%	12.5%	14.4%	14.2%	12.8%	12.2%	11.8%	10.6%	8.3%	8.0%	9.0%	Return on Shr. Equity	10.5%
						12.9%	12.7%	12.9%	14.9%	14.6%	13.1%	12.5%	11.9%	10.7%	8.3%	8.0%	9.0%	Return on Com Equity E	10.5%
						3.9%	3.8%	4.2%	6.5%	6.5%	5.6%	3.5%	3.9%	4.1%	3.0%	2.5%	3.5%	Retained to Com Eq	3.5%
						71%	71%	69%	57%	57%	58%	72%	68%	62%	65%	68%	60%	All Div'ds to Net Prof	64%

CAPITAL STRUCTURE as of 9/30/07
Total Debt $779.1 mill. **Due in 5 Yrs** $275.5 mill.
LT Debt $654.1 mill. **LT Interest** $43.2 mill.
(LT interest earned: 3.4x)

Leases, Uncapitalized Annual rentals $5.4 mill.
Pension Assets-12/06 $250.5 mill. **Oblig.** $267.3 mill.
Pfd Stock $1.0 mill. **Pfd Div'd** $.1 mill.
Includes 10,288 shares 8.125%, each convertible into 9.6 common shares, callable at $100.8125.
Common Stock 60,007,352 shs.
as of 10/30/07
MARKET CAP: $1.6 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+2.6	-.2	+2.4
Avg. Indust. Use (MWH)	4194	4245	4496
Avg. Indust. Revs. per KWH (¢)	5.67	7.22	7.65
Capacity at Peak (Mw)	2190	2030	2124
Peak Load, Summer (Mw)	1940	2014	2137
Annual Load Factor (%)	60.0	57.2	56.0
% Change Customers (avg.)	+1.8	+.8	+.5
Fixed Charge Cov. (%)	174	247	227

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	6.5%	-3.0%	5.0%
"Cash Flow"	3.0%	-.5%	7.0%
Earnings	3.0%	--	6.5%
Dividends	2.0%	1.0%	6.5%
Book Value	5.5%	5.5%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	166.6	166.3	229.4	183.5	745.8
2005	172.1	194.1	283.7	270.3	920.2
2006	223.4	251.0	294.1	232.2	1000.7
2007	223.8	261.5	311.7	228	1025
2008	255	285	350	260	1150

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.26	.22	.56	.27	1.32
2005	.18	.40	.82	.03	1.42
2006	.23	.44	.50	.19	1.36
2007	.14	.25	.72	.19	1.30
2008	.25	.35	.65	.25	1.50

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.225	.225	.225	.225	.90
2004	.225	.225	.225	.225	.90
2005	.225	.225	.225	.225	.90
2006	.225	.225	.225	.225	.90
2007	.225	.225	.225	.225	

BUSINESS: Cleco Corporation is a holding company for Cleco Power, which supplies electricity to about 268,000 customers in central Louisiana. Through subsidiaries, has about 1,350 megawatts of wholesale capacity. Electric revenue breakdown, '06: residential, 46%; commercial, 23%; industrial, 16%; other, 15%. Largest industrial customers are paper mills and other wood-product industries. Generating sources, '06: coal & lignite, 31%; gas & oil, 13%; purchased, 56%. Fuel costs: 64% of revenues. '06 reported deprec. rate (utility): 3.3%. Has 1,200 employees. Chairman: J. Patrick Garrett. President & CEO: Michael H. Madison. Inc.: Louisiana. Address: P.O. Box 5000, Pineville, Louisiana 71361-5000. Tel.: 318-484-7400. Internet: www.cleco.com.

Cleco's Rodemacher Unit 3 project is on schedule and on budget. Cleco expects to spend $1 billion to build the 600-megawatt solid-fuel facility, which will probably use petroleum coke as the primary fuel source. The company will finance construction with the proceeds from a 2006 stock sale, debt, and the cash received from the resolution of a bankruptcy claim against Calpine (which was a partner in the Acadia gas-fired project that is still 50%-owned by Cleco). Once the plant enters commercial operation in the fourth quarter of 2009, it will lessen the utility's reliance on costly and volatile gas and purchased power. Even with the new plant, however, Cleco will still need additional capacity, so the company is now evaluating the submissions that resulted from its request for proposals.

Cleco plans to file a rate case in the fourth quarter of 2008. This would enable it to place Rodemacher 3 in rates. The new unit would essentially double the size of the utility's rate base. Cleco hasn't had a base rate increase since 1985, more than 20 years ago.

A strong third-quarter earnings comparison probably wasn't enough to prevent a profit decline in the year that is just ending. Earnings fell sharply in the first half of 2007 because in the first half of 2006 Cleco recorded income from Calpine's letters of credit following its bankruptcy filing. Also, in the second period of 2007, the utility incurred $0.06 a share in costs associated with a scheduled maintenance outage at a base-load generating plant. The stock is ranked 4 (Below Average) for Timeliness. Our share-net estimate is at the upper end of Cleco's guidance of $1.20-$1.30.

We look for higher earnings in 2008. There is likely to be an increase in the allowance for funds used during construction as the building of Rodemacher 3 continues. We expect modest growth in kilowatt-hour sales, too. Cleco has not yet established an earnings target for 2008.

We don't recommend this stock. Its yield is a bit below average for a utility, and dividend growth isn't likely to resume for a few years. Also, the stock is trading well within our 3- to 5-year Target Price Range.

Paul E. Debbas, CFA *December 28, 2007*

(A) Primary EPS through '96, then diluted. Excl. nonrec. gains (losses): '00, 5¢; '02, (5¢), '03, ($2.05); '05, $2.11; '07, $1.22; losses from disc. ops.: '00, 14¢; '01, 4¢. '04 & '05 EPS don't add due to rounding. Next egs. report due late Feb. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinv. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd chgs. In '06: $5.30/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '06: 11.65%; earned on avg. com. eq., '06: 9.3%. Regulatory Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	80
Price Growth Persistence	50
Earnings Predictability	70

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CON. EDISON NYSE-ED

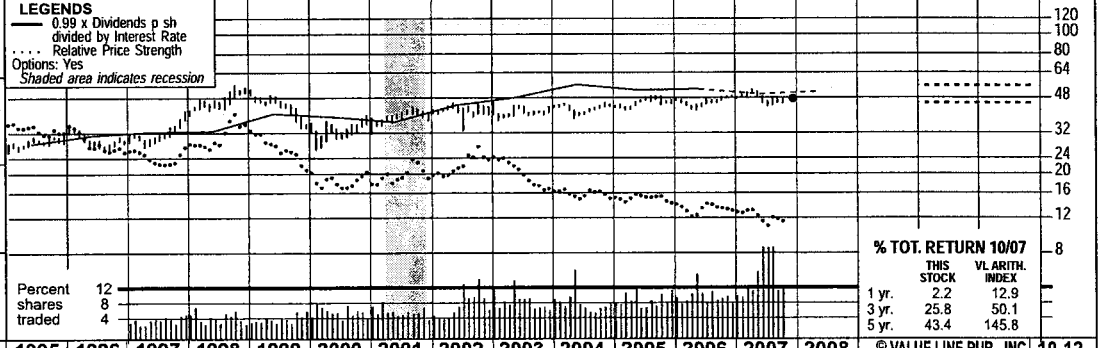
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
47.50	14.5	(Trailing: 13.6 Median: 14.0)	0.86	4.9%	VALUE LINE

TIMELINESS 3 Raised 8/11/06
SAFETY 1 New 7/27/90
TECHNICAL 4 Lowered 11/2/07
BETA .75 (1.00 = Market)

High:	34.8	41.5	56.1	53.4	39.5	43.4	45.4	46.0	45.6	49.3	49.3	52.9
Low:	25.9	27.0	39.1	33.6	26.2	31.4	32.7	36.6	37.2	41.1	41.2	43.1

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 0.99 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+15%)	8%
Low	45	(-5%)	3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	8	2	3	0	1	0	0	0
to Sell	0	1	2	3	0	2	0	0	0

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	211	200	222
to Sell	131	161	158
Hld's(000)	131243	130356	151880

Percent shares traded 12 8 4

% TOT. RETURN 10/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	2.2	12.9
3 yr.	25.8	50.1
5 yr.	43.4	145.8

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
25.72	25.36	26.73	27.13	27.82	29.62	30.24	30.46	35.04	44.48	45.41	39.65	43.51	40.24	47.66	47.14	**48.05**	**49.25**	Revenues per sh	**53.95**
3.90	4.06	4.38	4.77	4.87	4.97	5.08	5.29	5.74	5.51	5.70	5.44	5.12	4.54	5.27	5.28	**5.75**	**6.10**	"Cash Flow" per sh	**6.80**
2.32	2.46	2.66	2.98	2.93	2.93	2.95	3.04	3.13	2.74	3.21	3.13	2.83	2.32	2.99	2.95	**3.30**	**3.40**	Earnings per sh A	**3.50**
1.86	1.90	1.94	2.00	2.04	2.08	2.10	2.12	2.14	2.18	2.20	2.22	2.24	2.26	2.28	2.30	**2.32**	**2.34**	Div'd Decl'd per sh B ■	**2.40**
3.39	3.40	3.37	3.22	2.95	2.87	2.78	2.66	3.17	4.52	5.20	5.68	5.72	5.60	6.59	7.17	**7.35**	**7.45**	Cap'l Spending per sh	**6.10**
20.18	20.89	21.63	22.62	23.51	24.37	25.18	25.88	25.31	25.81	26.71	27.68	28.44	29.09	29.80	31.09	**34.25**	**35.90**	Book Value per sh C	**40.60**
228.33	233.93	234.37	234.91	234.96	234.99	235.49	232.83	213.81	212.03	212.15	213.93	225.84	242.51	245.29	257.46	**272.00**	**273.00**	Common Shs Outst'g	**278.00**
10.8	11.9	13.1	9.3	9.8	10.1	10.9	15.3	14.0	12.0	12.0	13.3	14.3	18.2	15.1	15.5	*Bold figures are*		Avg Ann'l P/E Ratio	**14.5**
.69	.72	.77	.61	.66	.63	.63	.80	.80	.78	.61	.73	.82	.96	.80	.84	*Value Line*		Relative P/E Ratio	**.95**
7.5%	6.5%	5.6%	7.2%	7.1%	7.0%	6.5%	4.6%	4.9%	6.6%	5.7%	5.3%	5.5%	5.3%	5.0%	5.0%	*estimates*		Avg Ann'l Div'd Yield	**4.8%**

CAPITAL STRUCTURE as of 9/30/07
Total Debt $9190 mill. **Due in 5 Yrs** $2905 mill.
LT Debt $7778 mill. **LT Interest** $505.0 mill.
(LT interest earned: 3.6x)
Pension Assets-12/06 $8.1 bill. **Oblig.** $8.3 bill.

Pfd Stock $212.6 mill. **Pfd Div'd** $12.5 mill.
1,915,319 shs. $5 cum. no par, call. $105 a sh.; 375,626 shs. 4.65% cum. $100 par, call. $101 to $102.50 a sh. Sinking Fund ends 2009.

Common Stock 271,515,822 shs. **as of 10/31/07**
MARKET CAP: $12.9 billion (Large Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
7121.3	7093.1	7491.3	9431.4	9634.0	8482.0	9827.0	9758.0	11690	12137	**13070**	**13450**	Revenues ($mill)	**15000**
712.8	729.8	714.2	596.4	695.8	682.1	639.0	560.0	719.0	749.0	**900**	**930**	Net Profit ($mill)	**980**
34.8%	35.8%	34.3%	34.8%	40.0%	36.9%	33.7%	34.3%	33.6%	35.2%	**35.0%**	**35.0%**	Income Tax Rate	**35.0%**
.9%	.5%	.8%	1.2%	1.3%	2.2%	4.2%	7.7%	2.2%	1.6%	**3.0%**	**3.0%**	AFUDC % to Net Profit	**3.0%**
40.1%	39.2%	44.4%	48.6%	48.2%	50.1%	50.4%	47.4%	49.6%	50.2%	**48.5%**	**48.0%**	Long-Term Debt Ratio	**47.0%**
56.8%	58.4%	53.1%	49.1%	49.6%	48.1%	48.0%	51.0%	49.0%	48.5%	**50.5%**	**51.0%**	Common Equity Ratio	**52.5%**
10437	10325	10186	11137	11417	12302	13369	13828	14921	16515	**18435**	**19220**	Total Capital ($mill)	**21605**
11267	11407	11354	11893	12248	13329	15225	16106	17112	18445	**18945**	**20245**	Net Plant ($mill)	**22960**
8.4%	8.6%	8.6%	7.0%	7.8%	7.1%	6.3%	5.6%	6.3%	6.0%	**6.5%**	**6.5%**	Return on Total Cap'l	**6.0%**
11.4%	11.6%	12.6%	10.4%	11.8%	11.1%	9.6%	7.7%	9.6%	9.1%	**9.5%**	**9.5%**	Return on Shr. Equity	**8.5%**
11.7%	11.8%	12.9%	10.7%	12.0%	11.3%	9.8%	7.8%	9.7%	9.2%	**9.5%**	**9.5%**	Return on Com Equity D	**8.5%**
3.4%	3.6%	4.1%	2.2%	3.8%	4.0%	2.9%	.8%	2.6%	2.6%	**3.0%**	**3.0%**	Retained to Com Eq	**2.5%**
72%	70%	69%	80%	69%	65%	71%	89%	74%	73%	**71%**	**69%**	All Div'ds to Net Prof	**69%**

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	-2.8	-1.8	-1.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	565	565	565
Peak Load, Summer (Mw)	11327	13059	13141
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.6	+.8	+.9
Fixed Charge Cov. (%)	257	312	291

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	5.0%	1.5%	*3.0%*
"Cash Flow"	.5%	-2.5%	*5.0%*
Earnings	-.5%	-2.0%	*4.0%*
Dividends	1.0%	1.0%	*1.0%*
Book Value	2.5%	3.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	2679	2164	2734	2181	9758.0
2005	2801	2406	3375	3108	11690
2006	3317	2555	3441	2824	12137
2007	3418	3029	3643	**2980**	**13070**
2008	**3600**	**2850**	**3800**	**3200**	**13450**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.69	.38	1.03	.22	2.32
2005	.75	.48	1.17	.59	2.99
2006	.74	.51	.92	.78	2.95
2007	.99	.58	1.15	**.58**	**3.30**
2008	**.90**	**.65**	**1.20**	**.65**	**3.40**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.56	.56	.56	.56	2.24
2004	.565	.565	.565	.565	2.26
2005	.57	.57	.57	.57	2.28
2006	.575	.575	.575	.575	2.30
2007	.58	.58	.58		

BUSINESS: Consolidated Edison, Inc., parent of Consolidated Edison Company of New York, Inc., sells electricity (77% of revs.), gas (16%), steam (7%) in most of New York City and Westchester County. Acquired Orange & Rockland Utilities 7/99. Commercial rev. ratio (52%) compares with 32% for the industry. Nonincome taxes and avg. price per kwh are among the highest in U.S. Fuel costs: 66% of revenues; labor costs, 14%. 2006 reported deprec. rate: 2.9%. In '06, purchased almost all energy it sold on firm contracts with nonutility generators. Has 14,795 employes, Chairman, Chief Executive Officer & President: Kevin Burke. Incorporated: N.Y. Add.: 4 Irving Place, New York, N.Y. 10003. Tel.: 212-460-3903. Internet: www.coned.com.

Consolidated Edison has received one rate order. A second is in the hopper. Effective last October 1st, regulators raised the company's natural gas rates $67.5 million each year for three years. The increase provides for continued recovery of fuel costs and energy-efficiency programs. ED now awaits approval of its request for a $1.2 billion hike in electric delivery revenues for 2008. It also seeks a $335 million increase in 2009 and $390 million in 2010. The hikes are necessary to support planned expenditures of $2 billion annually for several years on the transmission and distribution system. New substations would be built, and those near the end of their lives would be upgraded or replaced. Finally, the demand-side management program would be expanded to reduce energy usage. An order on the filing is due next April 1st.

Finances are among the strongest in the industry. As of last July 31st, the retained earnings account stood at $5.9 billion, and it keeps rising. Though capital spending for the next few years will require substantial external financing, a solid balance sheet should enable ED to borrow at reasonable rates. What's more, the issuance of debt and equity will be in a mix that won't lower the common equity ratio. Too, even if the company loses an appeal of a $216 million IRS tax charge related to lease-in/lease-out transactions in 1997 and 1999, a loss would not have a serious adverse effect on finances.

We look for improved earnings this year. Pluses include last April's $220 million electric rate increase, the aforementioned boost in posted gas tariffs, and a projected 1.5% rise in energy sales. On the down side, increased borrowing will lift interest expense, more common shares will be outstanding, and capital investments will result in higher real estate taxes. In all, we estimate 2007 earnings will advance 12%, to $3.30 a share. A further increase in electric rates suggests another gain next year.

The stock might interest conservative utility investors. The company merits our highest Financial Strength rating of A++. And the yield is above average for a power equity. Moreover, dividend growth prospects are near those of the group.

Arthur H. Medalie *November 30, 2007*

(A) EPS diluted. Excl. nonrecur.: '02, (11¢); '03, (45¢). Next egs. report due late Jan.
(B) Dividends historically paid in mid-Mar., mid-June, mid-Sept., and mid-Dec. ■ Div'd reinvest. plan avail. (C) Includes intangibles. In '06: $19.26/sh. (D) Rate base: net original cost. Rate all'd elec. common equity: '05, 11.4% to 13.0%; earned on '06 average common equity: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	A++
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	85

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DTE ENERGY CO. NYSE-DTE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
45.88	13.6	(Trailing: 15.7 Median: 13.0)	0.80	4.8%	VALUE LINE

TIMELINESS 3 Raised 9/15/06
SAFETY 3 Lowered 10/5/01
TECHNICAL 3 Lowered 12/29/06
BETA .80 (1.00 = Market)

High:	37.3	34.8	49.3	44.7	41.3	47.1	47.7	49.5	45.5	48.3	49.2	54.7
Low:	27.6	26.1	33.4	31.1	28.4	33.1	33.1	34.0	37.9	41.4	38.8	45.1

Target Price Range
2010 | 2011 | 2012

2010-12 PROJECTIONS

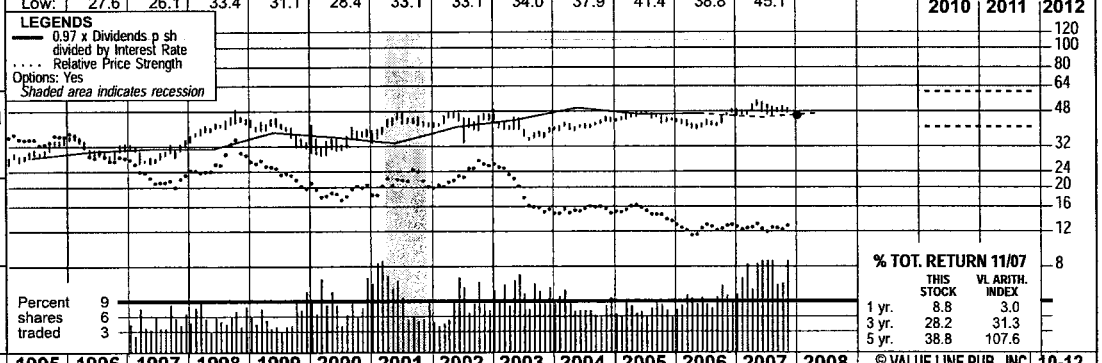
	Price	Gain	Ann'l Total Return
High	60	(+30%)	11%
Low	40	(-15%)	2%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	2	0	0	2	0	0
to Sell	0	4	0	2	0	0	1	0	0

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	164	130	127
to Sell	125	153	156
Hld's(000)	109349	102976	97954



% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	8.8	3.0
3 yr.	28.2	31.3
5 yr.	38.8	107.6

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
24.44	24.20	24.18	24.29	25.05	25.12	25.94	29.10	32.60	39.24	48.71	40.30	41.76	40.84	50.74	50.93	*57.55*	*61.80*	Revenues per sh	*69.50*
6.45	6.67	6.43	6.52	7.07	7.10	7.42	7.61	8.40	8.59	6.98	8.31	6.95	6.81	8.14	8.33	*9.10*	*9.25*	"Cash Flow" per sh	*11.00*
3.64	3.79	3.34	2.67	3.02	2.80	2.88	3.05	3.33	3.27	2.15	3.83	2.85	2.55	3.27	2.45	*3.05*	*2.85*	Earnings per sh A	*3.50*
1.88	1.98	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.08	*2.12*	*2.18*	Div'd Decl'd per sh B ■	*2.40*
1.85	2.83	2.71	2.61	3.13	3.66	3.14	3.83	5.10	5.25	6.80	5.88	4.45	5.19	5.99	7.92	*8.90*	*8.90*	Cap'l Spending per sh	*9.00*
19.37	21.18	22.41	22.96	23.68	23.73	24.55	25.49	26.95	28.15	28.48	27.26	31.36	31.85	32.44	33.02	*35.00*	*35.15*	Book Value per sh C	*38.00*
146.98	147.02	147.05	144.86	145.12	145.12	145.10	145.07	145.04	142.65	161.13	167.46	168.61	174.21	177.81	177.14	*162.50*	*157.00*	Common Shs Outst'g D	*157.00*
8.3	8.5	10.2	10.0	10.0	11.2	10.3	13.3	11.6	10.3	19.3	11.3	13.7	16.0	13.8	17.4	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.53	.52	.60	.66	.67	.70	.59	.69	.66	.67	.99	.62	.78	.85	.73	.94	*Value Line*		Relative P/E Ratio	*.95*
6.2%	6.1%	6.0%	7.7%	6.9%	6.6%	6.9%	5.1%	5.3%	6.1%	5.0%	4.8%	5.3%	5.0%	4.6%	4.9%	*estimates*		Avg Ann'l Div'd Yield	*4.9%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $8496.0 mill. **Due in 5 Yrs** $3995.0 mill.
LT Debt $6961.0 mill. **LT Interest** $446.0 mill.
Incl. $44.0 mill. capitalized leases, $289.0 mill. Trust Preferred Securities, & $1.1 bill. securitized bonds.
(LT interest earned: 2.4x)

Leases, Uncapitalized Annual rentals $53.0 mill.
Pension Assets-12/06 $2.74 bill. **Oblig.** $3.18 bill.
Pfd Stock None
Common Stock 163,713,691 shs.

MARKET CAP: $7.5 billion (Large Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
3764.0	4221.0	4728.0	5597.0	7849.0	6749.0	7041.0	7114.0	9022.0	9022.0	*9350*	*9700*	Revenues ($mill)	*10900*
429.0	449.0	483.0	468.0	329.0	632.0	480.0	443.0	576.0	437.0	*520*	*455*	Net Profit ($mill)	*540*
37.5%	25.5%	11.0%	1.9%	--	--	--	27.1%	26.0%	23.9%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
.5%	.9%	.8%	.6%	.9%	4.9%	1.3%	.7%	1.0%	3.4%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
51.4%	53.9%	50.9%	50.3%	63.3%	63.0%	59.2%	57.8%	55.1%	56.1%	*54.5%*	*56.0%*	Long-Term Debt Ratio	*56.5%*
46.7%	46.1%	49.1%	49.7%	36.7%	37.0%	40.8%	42.2%	44.9%	43.9%	*45.5%*	*44.0%*	Common Equity Ratio	*43.5%*
7620.0	8021.0	7961.0	8077.0	12517	12350	12956	13154	12849	13323	*12550*	*12550*	Total Capital ($mill)	*13700*
8934.0	6943.0	7148.0	7387.0	9543.0	9813.0	10324	10491	10830	11451	*11975*	*12400*	Net Plant ($mill)	*13300*
7.4%	7.4%	7.9%	7.5%	4.4%	7.3%	5.6%	5.2%	6.3%	5.1%	*6.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
11.6%	12.1%	12.4%	11.7%	7.2%	13.8%	9.1%	8.0%	10.0%	7.5%	*9.0%*	*8.0%*	Return on Shr. Equity	*9.0%*
11.7%	12.0%	12.4%	11.7%	7.2%	13.8%	9.1%	8.0%	10.0%	7.5%	*9.0%*	*8.0%*	Return on Com Equity E	*9.0%*
3.3%	3.9%	4.7%	4.3%	.1%	6.4%	2.5%	1.6%	3.7%	1.2%	*3.0%*	*2.0%*	Retained to Com Eq	*3.0%*
72%	68%	62%	63%	99%	53%	72%	80%	63%	84%	*69%*	*77%*	All Div'ds to Net Prof	*70%*

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	-1.5	+4.6	+.5
Avg. Indust. Use (MWH)	15524	13609	NA
Avg. Indust. Revs. per KWH (¢)	4.86	5.66	6.31
Capacity at Peak (Mw)	11078	11113	NA
Peak Load, Summer (Mw)	9587	10938	12778
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.6	+.4
Fixed Charge Cov. (%)	162	182	156

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	6.5%	3.5%	*6.5%*
"Cash Flow"	1.0%	-.5%	*6.0%*
Earnings	-.5%	-1.0%	*4.0%*
Dividends	--	--	*2.5%*
Book Value	3.5%	3.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	2093	1501	1594	1926	7114.0
2005	2309	1941	2060	2712	9022.0
2006	2635	1895	2196	2296	9022.0
2007	2730	1954	2417	*2249*	*9350*
2008	*2850*	*2000*	*2500*	*2350*	*9700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1.15	.20	.54	.68	2.55
2005	.72	.19	.17	2.18	3.27
2006	.76	d.18	1.07	.81	2.45
2007	.76	.17	1.19	*.93*	*3.05*
2008	*.80*	*.45*	*.80*	*.80*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.515	.515	.515	.515	2.06
2004	.515	.515	.515	.515	2.06
2005	.515	.515	.515	.515	2.06
2006	.515	.515	.515	.515	2.06
2007	.53	.53	.53	.53	

BUSINESS: DTE Energy Company is a holding company for The Detroit Edison Company, which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and Michigan Consolidated Gas (MichCon). Customers: 2.2 mill. electric, 1.3 mill. gas. Acq'd MCN Energy 6/01. Has various nonutility operations. Electric rev. breakdown, '06: residential, 35%; commercial, 34%; industrial, 18%; other, 13%. Generating sources, '06: coal, 67%; nuclear, 13%; oil & gas, 3%; purchased, 17%. Fuel costs: 34% of revs. '06 reported depr. rates: 3.3% elec., 2.8% gas. Has 9,100 employees. Chairman & CEO: Anthony F. Earley, Jr. President: Gerard M. Anderson. Inc.: MI. Address: 2000 Second Ave., Detroit, MI 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's asset-monetization plan is making progress. The latest announcement was the sale of some unconventional gas properties in Texas, which should net the company cash of $175 million. This deal, and the sale of a 50% stake in some power and industrial projects, should close in the first quarter of 2008. DTE has already sold some unconventional gas properties in Michigan and some gas-fired peaking power plants. These moves arose from the company's belief that the value of its nonregulated assets wasn't reflected in its stock price. In all, DTE expects this program to raise $1.7 billion, which it is using to buy back common stock and retire debt. It has repurchased most of the $1 billion of common stock it plans to buy back and intends to retire $700 million of debt. DTE still owns some unconventional gas acreage in Texas, but has to develop these properties before it becomes opportune to sell.

Detroit Edison has a rate case pending. The utility is seeking a rate hike of $199 million (4.7%) based on an 11.25% return on a common-equity ratio of 50%. An order is likely in the third quarter of 2008, unless the utility and intervenors can reach a settlement before then. The utility and its MichCon sibling will need additional rate relief in the next few years so that they can earn a return on the significant capital expenditures that they are making.

An earnings decline appears likely in 2008. DTE has been booking profits from its synthetic fuel investments. These are expected to produce net income of $150 million-$215 million in 2007. The synfuel program will cease at the end of 2007, however. A decline in average shares outstanding and the effects of any rate relief (and the expiration of a temporary rate cut in mid-April) at Detroit Edison should be positive factors for share net in 2008, but these probably won't be enough to replace the effect of the synfuel profits entirely.

DTE stock offers an above-average yield, even for a utility, plus the likelihood of dividend growth over the 3- to 5-year period. With the asset-sale program nearly complete, the stock is much more like a traditional utility investment. Total-return potential to 2010-2012 is only a bit above average for a utility, however.

Paul E. Debbas, CFA *December 28, 2007*

(A) Diluted EPS. Excl. nonrec. gains (losses): '01, 2¢; '03, (16¢); '05, (2¢); '06, 1¢; '07, $2.03; gain (losses) on disc. ops.: '03, 40¢; '04, (6¢); '05, (20¢); '06, (2¢). '04 EPS don't add due to change in shares, '05 & '06 due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in mid-Jan., April, July, and Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '06: $37.20/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. (elec.) in '04: 11%; gas in '05: 11%; earned on avg. com. eq., '06: 7.5%. Regul. Clim.: Below Avg.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	50

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EMPIRE DISTRICT NYSE-EDE

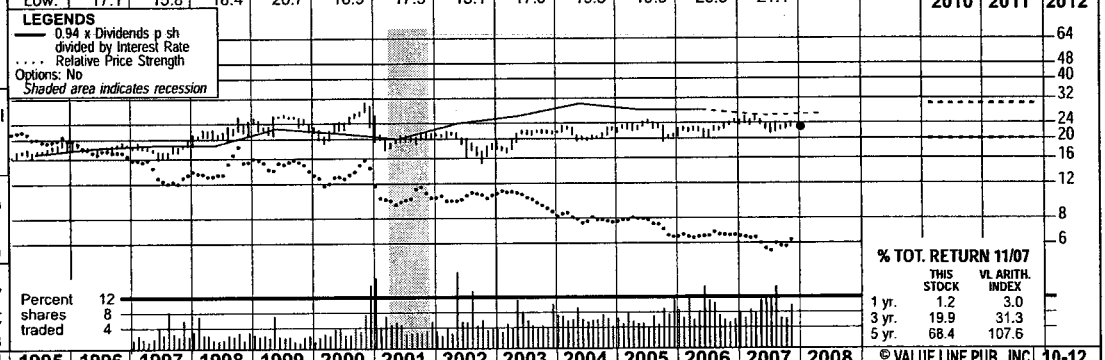
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
22.87	17.9	(Trailing: 16.8 Median: 18.0)	1.06	5.6%	VALUE LINE

TIMELINESS 3 Lowered 8/10/07
SAFETY 3 Lowered 10/4/02
TECHNICAL 3 Raised 12/7/07
BETA .85 (1.00 = Market)

High:	19.5	20.0	26.1	26.8	30.8	26.6	22.0	22.5	23.5	25.0	25.1	26.1	
Low:	17.1	15.8	18.4	20.7	18.9	17.5	15.1	17.0	19.5	19.3	20.3	21.1	

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 0.94 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: No
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+30%)	11%
Low	20	(-15%)	3%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	4	0	0	0	0	0	0	0	0
to Sell	2	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	50	63	44
to Sell	43	37	47
Hld's(000)	13362	14420	13678

Percent shares traded 12 8 4

% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.2	3.0
3 yr.	19.9	31.3
5 yr.	68.4	107.6

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
11.58	11.31	12.41	12.75	12.67	12.53	12.83	14.02	13.94	14.78	13.37	13.56	13.03	12.67	14.80	13.67	*14.30*	*14.25*	Revenues per sh	*16.00*
2.68	2.55	2.49	2.62	2.52	2.67	2.67	2.97	2.89	3.12	2.19	2.43	2.48	2.22	2.45	2.80	*2.70*	*2.95*	"Cash Flow" per sh	*3.75*
1.43	1.26	1.16	1.32	1.18	1.23	1.29	1.53	1.13	1.35	.59	1.19	1.29	.86	.92	1.41	*1.25*	*1.45*	Earnings per sh A	*1.75*
1.22	1.26	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	*1.28*	*1.28*	Div'd Decl'd per sh B ■ †	*1.35*
1.79	2.36	3.27	5.14	3.34	3.79	3.38	3.03	4.14	7.61	4.02	3.43	2.65	1.64	2.83	3.97	*5.50*	*5.70*	Cap'l Spending per sh	*2.75*
12.08	12.29	12.37	12.47	12.69	12.96	13.06	13.43	13.48	13.65	13.58	14.59	15.17	14.76	15.08	15.49	*16.10*	*16.65*	Book Value per sh C	*18.00*
12.99	13.29	13.57	13.94	15.22	16.44	16.78	17.11	17.37	17.60	19.76	22.57	24.98	25.70	26.08	30.25	*34.25*	*35.80*	Common Shs Outst'g D	*36.00*
12.8	18.0	19.6	13.3	14.9	14.8	13.9	14.0	21.7	17.7	33.9	16.2	15.8	24.8	24.5	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.82	1.09	1.16	.87	1.00	.93	.80	.73	1.24	1.15	1.74	.88	.90	1.31	1.30	.86	*Value Line*		Relative P/E Ratio	*.95*
6.7%	5.6%	5.6%	7.3%	7.3%	7.0%	7.1%	6.0%	5.2%	5.4%	6.4%	6.6%	6.3%	6.0%	5.7%	5.7%	*estimates*		Avg Ann'l Div'd Yield	*5.3%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $609.8 mill. **Due in 5 Yrs** $101.1 mill.
LT Debt $541.9 mill. **LT Interest** $36.5 mill.
Incl. $50 mill. 8.5% trust preferred securities.
(LT interest earned: 2.6x)
Leases, Uncapitalized Annual rentals $1.5 mill.
Pension Assets-12/06 $126.8 mill. **Oblig.** $136.3 mill.
Pfd Stock None

Common Stock 30,546,570 shs.
as of 11/1/07

MARKET CAP: $700 million (Small Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
215.3	239.9	242.2	260.0	264.3	305.9	325.5	325.5	386.2	413.5	*490*	*510*	Revenues ($mill)	*575*
23.8	28.3	22.2	23.6	10.4	25.5	29.5	21.8	23.8	39.9	*39.0*	*50.0*	Net Profit ($mill)	*65.0*
50.8%	36.4%	41.9%	32.7%	--	34.3%	34.5%	34.1%	33.4%	35.4%	*33.5%*	*33.5%*	Income Tax Rate	*35.5%*
5.1%	2.3%	5.4%	24.5%	34.7%	2.2%	1.0%	1.0%	2.4%	10.7%	*15.0%*	*11.0%*	AFUDC % to Net Profit	*2.0%*
43.8%	48.4%	59.6%	57.6%	57.2%	55.5%	52.0%	51.3%	51.0%	49.7%	*49.5%*	*50.0%*	Long-Term Debt Ratio	*49.5%*
48.9%	45.2%	40.4%	42.4%	42.8%	44.5%	48.0%	48.7%	49.0%	50.3%	*50.5%*	*50.0%*	Common Equity Ratio	*50.5%*
448.3	508.5	580.0	565.8	626.9	740.3	789.2	779.1	803.3	931.0	*1095*	*1200*	Total Capital ($mill)	*1275*
547.0	572.2	616.0	720.3	750.5	794.1	833.9	857.0	896.0	1031.0	*1170*	*1320*	Net Plant ($mill)	*1500*
7.2%	7.3%	5.5%	6.5%	4.0%	5.4%	5.7%	4.7%	4.7%	5.9%	*5.0%*	*5.5%*	Return on Total Cap'l	*7.0%*
9.4%	10.8%	9.5%	9.8%	3.9%	7.8%	7.8%	5.8%	6.0%	8.5%	*7.0%*	*8.5%*	Return on Shr. Equity	*10.5%*
9.8%	11.3%	8.8%	9.8%	3.9%	7.8%	7.8%	5.8%	6.0%	8.5%	*7.0%*	*8.5%*	Return on Com Equity E	*10.5%*
.1%	1.8%	NMF	.5%	NMF	NMF	.1%	NMF	NMF	.8%	*NMF*	*1.0%*	Retained to Com Eq	*3.0%*
99%	85%	107%	95%	NMF	109%	99%	NMF	NMF	90%	*106%*	*89%*	All Div'ds to Net Prof	*73%*

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+.9	+6.1	+2.6
Avg. Industrial Use (MWH)	3040	3032	3096
Avg. Industrial Rev/KWH (¢)	4.78	5.38	5.66
Capacity at Peak (Mw)	1264	1264	1262
Peak Load, Summer (Mw)	1014	1087	1159
Annual Load Factor (%)	56.0	55.6	52.5
% Change Customers (avg.)	+1.7	+1.9	+2.1
Fixed Charge Cov. (%)	214	224	273

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	1.0%	-.5%	*2.5%*
"Cash Flow"	-.5%	-2.0%	*7.0%*
Earnings	-1.5%	1.0%	*8.5%*
Dividends	--	--	*1.0%*
Book Value	1.5%	2.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	77.2	77.3	96.7	74.3	325.5
2005	79.5	87.9	125.0	93.8	386.2
2006	84.0	91.7	131.2	106.6	413.5
2007	125.9	107.5	142.5	*114.1*	*490*
2008	*130*	*110*	*150*	*120*	*510*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.06	.08	.64	.08	.86
2005	d.01	.12	.75	.05	.92
2006	.08	.28	.74	.26	1.41
2007	.15	.19	.76	*.15*	*1.25*
2008	*.13*	*.24*	*.77*	*.31*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.32	.32	.32	.32	1.28
2004	.32	.32	.32	.32	1.28
2005	.32	.32	.32	.32	1.28
2006	.32	.32	.32	.32	1.28
2007	.32	.32	.32	.32	

BUSINESS: The Empire District Electric Company supplies electricity to 165,000 customers in a 10,000 sq. mi. area in Missouri (89% of '06 retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (3%). Acq'd Missouri Gas (47,000 customers) 6/06. Supplies water service and has various nonregulated operations. Electric revenue breakdown, '06: residential, 42%; commercial, 30%; industrial, 17%; other, 11%. Generating sources, '06: coal, 46%; gas & oil, 17%; hydro, less than 1%; purchased, 37%. Fuel costs: 42% of revenues. '06 reported deprec. rate: 3.0%. Has about 700 employees. Chairman: Myron W. McKinney. President & CEO: William L. Gipson. Inc.: KS. Address: 602 Joplin St., P.O. Box 127, Joplin, MO 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

Empire District Electric has filed a rate case in Missouri. The utility is seeking an electric tariff increase of $34.7 million (10.1%) based on an 11.6% return on equity. Empire District is seeking to place a 150-megawatt plant and other capital spending in the rate base. The utility also wants to recover $6.6 million in deferred expenses that stemmed from an ice storm in January. (Empire District swallowed an additional $4.4 million of storm-related costs.) Importantly, the company's application includes a fuel-adjustment clause, now that state law finally allows the commission to implement one. Empire District has requested a mechanism that would enable it to recover (or pass through to customers) 95% of changes in fuel costs over and above what is reflected in base rates. (It is asking for 95%, not 100%, because that's what Aquila's two utilities in Missouri received in a rate order earlier in 2007.) A decision by the Missouri commission is due by the start of September. Any rate relief will have just a modest benefit to earnings in 2008, because it will come too late for the seasonally strongest part of the year, but it should be a plus in 2009.

Empire District sold some common stock. The company sold three million shares, with an underwriters' option for an additional 450,000, for $23 each. This will help the utility finance its rising capital budget. Most notably, Empire District will have a 12% stake in a coal-fired unit that is scheduled to come on line in 2010.

We have cut our earnings estimates for 2007 and 2008. In December, Empire District's service area was hit with another ice storm. This will hurt earnings in the fourth quarter of 2007. In addition, an extended outage at a coal-fired plant will reduce net income by an estimated $4.0 million-$5.5 million in the fourth quarter of 2007 and the first period of 2008. Finally, in 2008 there will be some dilution from the aforementioned stock sale.

This equity offers a yield that is well above average for a utility. The payout is secure, especially since Empire District earned it in 2006 and will probably do so in 2008. In fact, we project some dividend growth through the 2010-2012 period, which should produce a total return over that time that exceeds the industry mean.

Paul E. Debbas, CFA *December 28, 2007*

(A) Excl. loss from discontinued operations: '06, 2¢. '05 EPS don't add due to rounding convention, '06 due to change in shares. Next earnings report due late Jan. (B) Div'ds historically paid in mid-March, June, Sept., and Dec. ■ Div'd reinvestment plan available (3% discount). † Shareholder investment plan available. (C) Incl. intangibles. In '06: $151.6 mill., $5.01/sh. (D) In millions. (E) Rate base: Deprec. original cost. Rate allowed on common equity in '07 (MO): 10.9%; earned on avg. com. eq., '06: 9.2%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	15
Earnings Predictability	50

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ENERGY EAST CORP. NYSE-EAS

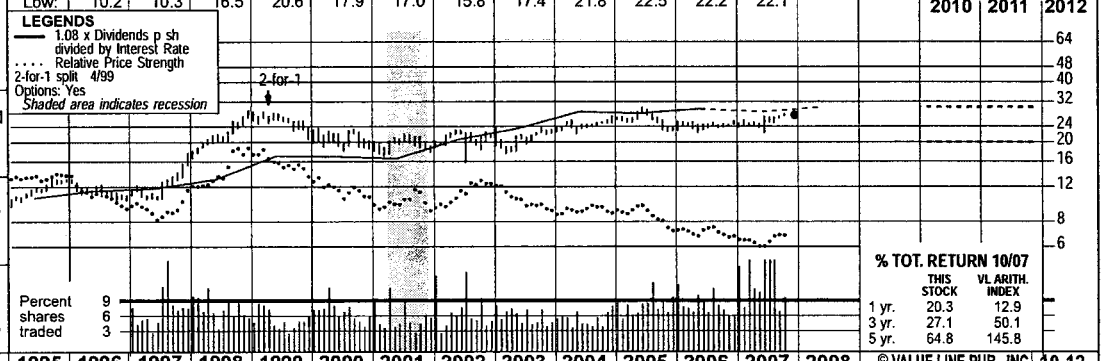
RECENT PRICE 27.45 | P/E RATIO 16.8 (Trailing: 16.1 Median: 14.0) | RELATIVE P/E RATIO 1.00 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS — Suspended 7/6/07
SAFETY 2 Lowered 3/9/01
TECHNICAL — Suspended 7/6/07
BETA .80 (1.00 = Market)

High:	13.2	17.9	29.0	28.6	23.6	22.1	23.1	23.7	27.1	30.1	25.7	27.9
Low:	10.2	10.3	16.5	20.6	17.9	17.0	15.8	17.4	21.8	22.5	22.2	22.1

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.08 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 4/99
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+10%)	7%
Low	20	(-25%)	-1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	120	152	141
to Sell	91	80	116
Hld's(000)	80289	82460	88399

% TOT. RETURN 10/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	20.3	12.9
3 yr.	27.1	50.1
5 yr.	64.8	145.8

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
12.27	12.18	12.75	13.28	14.05	14.78	15.78	19.85	20.84	25.15	32.21	27.65	31.41	32.33	35.87	35.36	*32.90*	*34.20*	Revenues per sh	*39.75*
2.37	2.32	2.20	2.43	2.54	2.64	2.77	3.06	3.37	3.42	3.75	3.12	4.28	4.18	4.33	4.67	*4.30*	*4.45*	"Cash Flow" per sh	*5.00*
1.18	1.20	1.04	1.19	1.25	1.26	1.29	1.51	1.91	2.07	2.00	1.50	1.43	1.62	1.74	1.76	*1.60*	*1.60*	Earnings per sh A	*1.75*
1.05	1.07	1.09	1.00	.70	.70	.70	.78	.84	.88	.92	.96	1.00	1.06	1.12	1.17	*1.21*	*1.25*	Div'd Decl'd per sh B ■	*1.45*
1.92	1.75	1.88	1.72	1.14	1.54	.92	1.04	.64	1.32	1.79	1.55	1.98	2.07	2.26	2.79	*3.15*	*3.50*	Cap'l Spending per sh	*4.50*
11.08	11.42	11.44	11.64	12.19	12.70	13.36	13.61	12.84	14.59	15.26	16.97	17.59	17.89	19.45	19.37	*20.05*	*20.40*	Book Value per sh C	*21.50*
126.80	138.88	141.19	143.01	143.01	139.34	135.02	125.89	109.34	117.66	116.72	144.97	146.26	147.12	147.70	147.91	*158.00*	*158.00*	Common Shs Outst'g D	*158.00*
11.1	12.3	16.2	9.9	9.3	9.1	9.7	14.6	13.4	10.1	9.8	14.0	14.6	15.1	14.9	13.8	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.71	.75	.96	.65	.62	.57	.56	.76	.76	.66	.50	.76	.83	.80	.79	.75	*Value Line*		Relative P/E Ratio	*.95*
8.0%	7.3%	6.5%	8.5%	6.0%	6.1%	5.6%	3.5%	3.3%	4.2%	4.7%	4.6%	4.8%	4.3%	4.3%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*5.5%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $4024.9 mill. **Due in 5 Yrs** $1060.7 mill.
LT Debt $3689.7 mill. **LT Interest** $221.4 mill.
(LT interest earned: 2.7x)

Pension Assets-12/06 $2.82 bill. **Oblig.** $2.31 bill.
Pfd Stock $24.6 mill. **Pfd Div'd** $1.1 mill.
242,524 shs. 3.75%-6.00%, cum., $100 par, redeemable at $100-$110; 108,706 shs. 8.0%, cum., $3.125 par, noncallable.

Common Stock 158,278,536 shs.
as of 10/31/07
MARKET CAP: $4.3 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
2130.0	2499.4	2278.6	2959.5	3759.8	4008.9	4593.8	4756.7	5298.5	5230.7	*5200*	*5400*	Revenues ($mill)	*6300*
184.6	202.8	225.1	237.6	235.4	199.6	212.1	241.3	258.3	261.0	*250*	*255*	Net Profit ($mill)	*285*
38.9%	40.4%	36.7%	39.7%	44.2%	34.1%	37.6%	51.0%	39.7%	37.3%	*38.5%*	*38.5%*	Income Tax Rate	*38.5%*
.4%	.2%	.1%	.4%	.3%	.7%	.9%	.2%	.6%	.8%	*1.0%*	*1.0%*	AFUDC % to Net Profit	*1.0%*
42.5%	44.8%	46.6%	57.1%	60.7%	58.9%	59.8%	58.6%	55.9%	56.3%	*53.0%*	*53.0%*	Long-Term Debt Ratio	*54.5%*
52.8%	53.5%	53.0%	41.8%	38.4%	39.2%	38.5%	40.6%	43.8%	43.3%	*46.5%*	*47.0%*	Common Equity Ratio	*45.0%*
3413.0	3203.0	2649.2	4106.7	4640.8	6273.5	6681.3	6475.6	6564.4	6615.6	*6820*	*6880*	Total Capital ($mill)	*7550*
3922.3	3862.7	2139.8	3632.9	3626.4	4801.8	5778.1	5662.2	5783.5	5948.0	*6145*	*6380*	Net Plant ($mill)	*7275*
7.0%	7.9%	10.5%	7.4%	7.2%	5.1%	5.1%	5.5%	5.7%	5.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.4%	11.5%	15.9%	13.5%	12.9%	7.7%	7.9%	9.0%	8.9%	9.0%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
9.7%	11.3%	15.8%	13.8%	13.1%	8.0%	8.1%	9.0%	8.9%	9.1%	*8.0%*	*8.0%*	Return on Com Equity E	*8.5%*
4.4%	5.5%	8.8%	8.0%	7.1%	2.9%	3.1%	3.8%	3.7%	3.2%	*2.0%*	*2.0%*	Retained to Com Eq	*2.0%*
57%	54%	45%	42%	46%	65%	63%	58%	59%	65%	*75%*	*78%*	All Div'ds to Net Prof	*78%*

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+1.4	+3.2	-2.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	3.82	3.66	3.81
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.9	+.9	+1.0
Fixed Charge Cov. (%)	264	238	225

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	9.5%	6.0%	*2.5%*
"Cash Flow"	5.5%	4.5%	*2.0%*
Earnings	3.5%	-3.0%	*.5%*
Dividends	3.5%	5.0%	*4.0%*
Book Value	4.5%	6.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1551.4	968.9	967.8	1268.9	4756.7
2005	1637	1082	1096	1483	5298.5
2006	1696	1113	1090	1332	5230.7
2007	1714	1089	1031	*1366*	*5200*
2008	*1750*	*1150*	*1100*	*1400*	*5400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.83	.29	.12	.38	1.62
2005	1.05	.12	.14	.43	1.74
2006	.90	.19	.14	.53	1.76
2007	.90	.12	.16	*.42*	*1.60*
2008	*.90*	*.15*	*.10*	*.45*	*1.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.25	.25	.25	.25	1.00
2004	.26	.26	.26	.275	1.06
2005	.275	.275	.275	.275	1.10
2006	.29	.29	.29	.30	1.17
2007	.30	.30	.30	.31	

BUSINESS: Energy East Corporation is a holding company for New York State Electric & Gas (NYSEG), Rochester Gas and Electric, Central Maine Power, Connecticut Natural Gas, & Southern Connecticut Gas. Serves 1.8 million electric, 921,000 gas customers in NY & New England. Acq'd Connecticut Energy 2/00; CMP Group, CTG Resources & Berkshire Energy 9/00; RGS Energy 6/02. Electric revenue breakdown, '06: residential, 45%; commercial, 20%; industrial, 10%; other, 25%. Purchases most of its power. Fuel costs: 57% of revenues. '06 reported deprec. rate: 3.1%. Has 5,900 employees. Chairman, Pres. & CEO: Wesley W. von Schack. Inc.: New York. Address: 52 Farm View Dr., New Gloucester, Maine 12212-2904. Tel.: 207-688-6300. Internet: www.energyeast.com.

Energy East shareholders have approved the takeover of the company by IBERDROLA, a Spanish company. Under the agreement, Energy East stockholders will receive $28.50 in cash for each of their shares. The deal still requires the approval of the Federal Energy Regulatory Commission and the regulatory commissions in New York, Maine, Connecticut, and New Hampshire. It should be completed in the first half of 2008.

The price is very fair for Energy East shareholders, at nearly 18 times estimated 2007 and 2008 earnings. The Timeliness rank of Energy East stock remains suspended due to the positive influence that the deal has on the share price.

We now advise shareholders to sell their stock on the open market. The current quotation is just 4% below the buyout price, leaving little upside potential for stockholders who wait for completion of the transaction. And, given the regulatory approvals that are still pending, completion is by no means certain. If the deal fails to win regulatory approval, the stock will probably fall — perhaps to the low $20 range. Thus, shareholders can avoid downside risk by selling now.

The capital budget will be rising in the coming years. Energy East's utilities in upstate New York and Maine want to install advanced meter reading systems. The company is also planning transmission projects in these two states. Finally, Rochester Gas and Electric proposes to build a gas-fired plant to replace an old, coal-fired facility and meet the increased demand for power that is expected in the 2013-2014 time frame. In all, Energy East projects to spend over $3 billion in the next five years. IBERDROLA could provide capital to help finance these projects. But the utilities will need regulatory support to maintain the company's return on equity.

We have raised our 2007 earnings estimate by $0.10 a share, to $1.60. This merely reflects a better-than-expected tally in the September quarter. Note, too, that in early October the board of directors boosted the quarterly dividend by a cent a share, as we had expected. For now, we're sticking with our $1.60-a-share earnings estimate for 2008.

Paul E. Debbas, CFA *November 30, 2007*

(A) Diluted EPS. Excl. nonrecurring losses: '00, 40¢; '01, 39¢; '02, 6¢; gain (loss) from discontinued operations: '03, 2¢; '04, (5¢). Next earnings report due early Feb. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '06: $20.70/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. for NYSEG in '07: 9.55% elec., 10.5% gas; RG&E in '04: 12.25% elec., 12% gas; earned on avg. com. eq., '06: 8.9%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	85

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FIRSTENERGY NYSE-FE

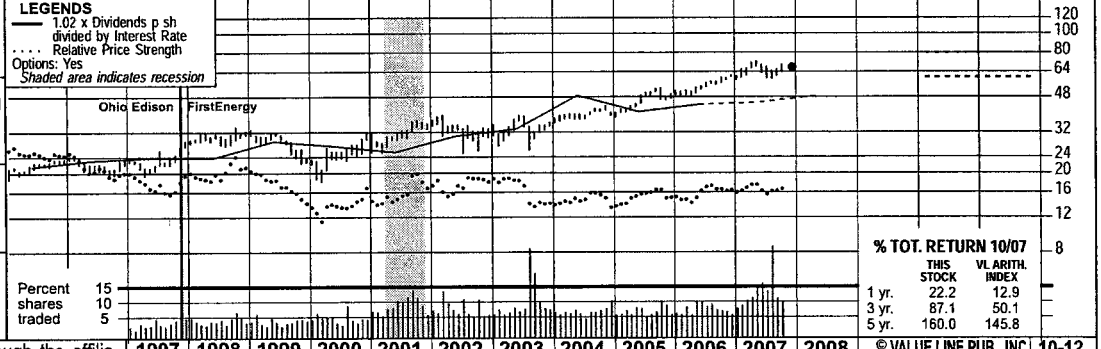
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
67.74	16.0	(Trailing: 16.1 Median: 13.0)	0.95	3.1%	VALUE LINE

TIMELINESS 3 Raised 5/5/06
SAFETY 2 Raised 6/2/06
TECHNICAL 3 Lowered 9/28/07
BETA .85 (1.00 = Market)

High:	24.9	29.0	34.1	33.2	32.1	37.0	39.1	38.9	43.4	53.4	61.7	72.9
Low:	19.3	19.3	27.1	22.1	18.0	25.1	24.8	25.8	35.2	37.7	47.8	57.8

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.02 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+20%)	7%
Low	60	(-10%)	1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	1	18	1	0	0	2	2
to Sell	0	1	1	15	0	5	0	3	1

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	213	199	200
to Sell	164	195	202
Hld's(000)	229031	229298	237675

% TOT. RETURN 10/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	22.2	12.9
3 yr.	87.1	50.1
5 yr.	160.0	145.8

FirstEnergy was formed through the affiliation of Ohio Edison Company and Centerior Energy in November of 1997. Ohio Edison stockholders received one share of FirstEnergy for every Ohio Edison share, and Centerior stockholders received .52 of a FirstEnergy share for each Centerior share. In November of 2001, FirstEnergy acquired GPU. GPU holders received $40 in cash or stock for each GPU share. Data prior to 1998 reflect Ohio Edison on a stand-alone basis and are not comparable with FirstEnergy data.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
12.26	24.72	27.19	31.31	26.88	40.83	37.31	37.76	36.35	36.03	*41.50*	*41.50*	Revenues per sh	*46.00*
3.66	5.33	6.89	7.28	5.48	6.45	4.79	7.60	7.55	7.22	*7.70*	*8.10*	"Cash Flow" per sh	*9.25*
1.94	1.95	2.50	2.69	2.84	2.54	1.47	2.77	2.84	3.82	*4.25*	*4.30*	Earnings per sh A	*5.25*
1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.91	1.71	1.85	*2.03*	*2.15*	Div'd Decl'd per sh B ■ †	*2.50*
.89	2.75	2.69	2.74	2.86	3.35	2.60	2.57	3.66	4.12	*5.50*	*6.40*	Cap'l Spending per sh	*4.50*
18.07	18.77	19.63	20.72	24.86	23.92	25.13	26.04	27.86	28.30	*28.95*	*31.10*	Book Value per sh C	*38.75*
230.21	237.07	232.45	224.53	297.64	297.64	329.84	329.84	329.84	319.21	*304.80*	*304.80*	Common Shs Outst'g D	*304.80*
11.8	15.4	11.3	9.2	10.9	13.0	22.5	14.1	16.1	14.2	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.68	.80	.64	.60	.56	.71	1.28	.74	.86	.77	*Value Line*		Relative P/E Ratio	*.90*
6.6%	5.0%	5.3%	6.1%	4.8%	4.6%	4.5%	4.9%	3.7%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*
2821.4	5861.3	6319.6	7029.0	7999.4	12152	12307	12453	11989	11501	*12650*	*12650*	Revenues ($mill)	*14000*
333.6	507.2	644.8	661.7	727.0	827.6	490.8	932.6	951.0	1265.0	*1300*	*1310*	Net Profit ($mill)	*1610*
38.4%	38.8%	38.0%	36.3%	39.5%	41.5%	43.9%	42.2%	42.1%	38.6%	*41.0%*	*41.0%*	Income Tax Rate	*41.0%*
1.0%	1.5%	2.1%	4.1%	4.9%	3.0%	6.5%	2.7%	2.0%	2.1%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
57.5%	54.0%	52.3%	52.3%	60.1%	60.2%	53.1%	52.8%	46.5%	48.6%	*50.5%*	*50.0%*	Long-Term Debt Ratio	*48.0%*
34.3%	37.8%	39.8%	41.5%	37.2%	38.0%	45.0%	45.4%	52.4%	51.4%	*49.5%*	*50.0%*	Common Equity Ratio	*52.0%*
12124	11756	11470	11205	19907	18756	18414	18938	17527	17570	*17900*	*18950*	Total Capital ($mill)	*22800*
9573.2	9242.6	9093.3	7575.1	12428	12680	13269	13478	13998	14667	*14325*	*15275*	Net Plant ($mill)	*16200*
3.8%	6.4%	7.8%	7.9%	4.9%	6.3%	4.6%	6.5%	7.1%	9.0%	*8.5%*	*8.5%*	Return on Total Cap'l	*8.5%*
6.5%	9.4%	11.8%	12.4%	9.2%	11.1%	5.7%	10.4%	10.1%	14.0%	*15.0%*	*14.0%*	Return on Shr. Equity	*13.5%*
7.4%	9.9%	12.5%	12.9%	8.9%	10.5%	5.4%	10.6%	10.2%	13.9%	*15.0%*	*14.0%*	Return on Com Equity E	*13.5%*
1.6%	2.3%	5.0%	5.7%	4.3%	4.3%	NMF	4.9%	4.2%	7.4%	*7.5%*	*7.0%*	Retained to Com Eq	*7.0%*
80%	80%	65%	60%	56%	63%	101%	55%	59%	47%	*49%*	*50%*	All Div'ds to Net Prof	*47%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $11455 mill. **Due in 5 Yrs** $5297.0 mill.
LT Debt $8617.0 mill. **LT Interest** $517.0 mill.
Incl. $284.8 mill. 9% ($25 par) cumulative mandatorily redeemable preferred securities.
(LT interest earned: 4.4x)
Leases, Uncapitalized Annual rentals $204.0 mill.
Pension Assets-12/06 $4.82 bill. **Oblig.** $4.86 bill.
Pfd Stock None
Common Stock 304,835,407 shs. **as of 10/31/07**
MARKET CAP: $21 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	-.6	+5.2	+6.7
Avg. Indust. Use (MWH)	NMF	NMF	NMF
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	66.7	62.1	NA
% Change Customers (yr-end)	+1.1	+.8	+.5
Fixed Charge Cov. (%)	316	299	355

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	8.5%	5.0%	*4.0%*
"Cash Flow"	6.0%	2.5%	*3.5%*
Earnings	4.5%	3.5%	*9.0%*
Dividends	2.0%	4.0%	*5.5%*
Book Value	5.5%	4.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	3027	3041	3435	2950	12453
2005	2750	2843	3504	2892	11989
2006	2705	2751	3365	2680	11501
2007	2973	3109	3641	*2927*	*12650*
2008	*2900*	*3100*	*3700*	*2950*	*12650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.53	.62	.91	.71	2.77
2005	.42	.76	1.01	.65	2.84
2006	.67	.93	1.40	.84	3.82
2007	.92	1.10	1.34	*.89*	*4.25*
2008	*.90*	*1.10*	*1.35*	*.95*	*4.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.375	.375	.375	.375	1.50
2004	.375	.375	.375	.375	1.50
2005	.413	.413	.413	.43	1.67
2006	.45	.45	.45	.45	1.80
2007	.50	.50	.50		

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, and Jersey Central Power & Light. Provides electric service to 4.5 million customers in Ohio (58% of revenues), New Jersey (22%) and Pennsylvania (20%). Electric revenue breakdown by customer class not provided by company. Generating sources: coal, 44%; nuclear, 26%; purchased, 30%. Fuel costs: 37% of revenues. '06 reported deprec. rates: 2.1%-4.1%. Has 13,700 employees. Chairman: George M. Smart. President & CEO: Anthony J. Alexander. COO: Richard R. Grigg. Inc.: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Tel.: 330-384-5100. Internet: www.firstenergycorp.com.

Distribution rate cases are pending at FirstEnergy's three utilities in Ohio. Ohio Edison, Cleveland Electric, and Toledo Edison are seeking base rate hikes totaling $332 million, based on a return of 11.75% on a common-equity ratio of 49%. The utilities are seeking recovery of higher costs and expenses that were deferred under previous regulatory plans. An order is due by March of 2008. New rates would take effect at the start of 2009 for Ohio Edison and Toledo Edison, and in May of 2009 for Cleveland Electric.

Two of FirstEnergy's utilities in Pennsylvania have appealed a regulatory ruling to the courts. The Pennsylvania commission rejected the request of MetEd and Penelec for a total of $219 million in rate relief associated with power generation. A court decision is expected in 2008.

Earnings should wind up much higher in 2007. Earlier this year, FirstEnergy executed a sale/leaseback transaction for its largest coal-fired unit. The deal raised $1.2 billion, $900 million of which was used to repay short-term debt that was used to fund a stock buyback. Also, FirstEnergy's generating assets are earning higher margins on the power they are supplying to the company's Penn Power subsidiary, since Penn Power made its scheduled transition to market-based rates. This should benefit share net by $0.12.

There's a lot of uncertainty in our earnings estimate for 2008. Higher kilowatt-hour sales and margins on power generation should be pluses, but higher transition-cost amortization will be a minus. Operating and maintenance expenses could go either way. We're tentatively estimating a slight earnings increase. FirstEnergy plans to issue 2008 earnings guidance in early December.

We expect a dividend hike at the next board meeting, in December. We estimate that the directors will raise the quarterly dividend by $0.03 a share (6%), to $0.53. That would be below recent increases, but would still be a very healthy rate of growth.

We think FirstEnergy's solid earnings- and dividend-growth potential is reflected in the stock price. The yield and 3- to 5-year total-return potential are subpar, by utility standards.

Paul E. Debbas, CFA *November 30, 2007*

(A) Dil. EPS. Excl. nonrec. losses: '02, 40¢; '03, 25¢; '04, 11¢; '05, 28¢; gains (losses) from disc. ops.: '03, (33¢); '04, 1¢; '05, 5¢; '06, (1¢). '06 EPS don't add due to chg. in shs. Next egs. due early Feb. (B) Div'ds historically paid early Mar., June, Sept., & Dec. Five div'ds decl. in '04. ■ Div'd reinv. plan avail. † Shareholder inv. plan avail. (C) Incl. intang.: In '06: $32.39/sh. (D) In mill. (E) Rate base: Depr. orig. cost. Rate all'd on com. eq. in NJ in '05: 9.75%; in PA in '07: 10.1%; earn. on avg. com. eq., '06: 13.5%. Regul. Climate: OH, Above Avg.; PA, NJ, Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	60

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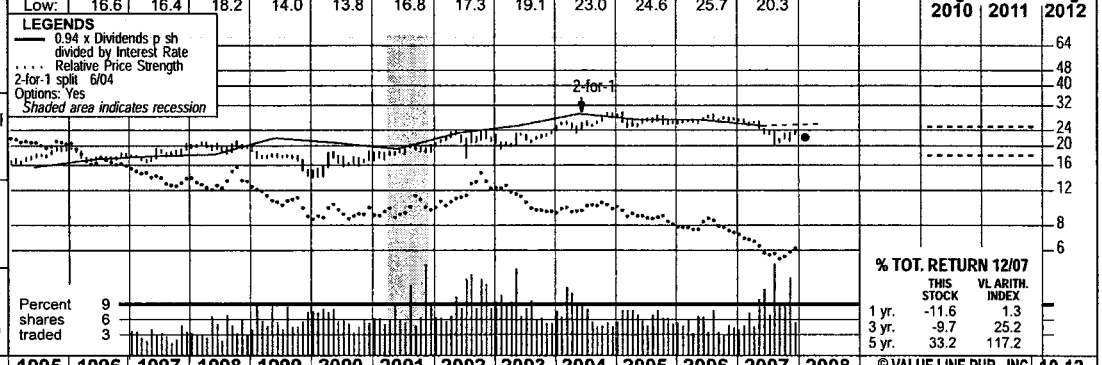
HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
22.08	19.7	(Trailing: 26.9 Median: 13.0)	1.23	5.6%	VALUE LINE

TIMELINESS 3 Raised 1/25/08
SAFETY 2 Raised 2/15/02
TECHNICAL 3 Lowered 2/1/08
BETA .75 (1.00 = Market)

High:	19.8	20.8	21.3	20.3	19.0	20.6	24.5	24.0	29.5	29.8	28.9	27.5
Low:	16.6	16.4	18.2	14.0	13.8	16.8	17.3	19.1	23.0	24.6	25.7	20.3

Target Price Range
2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+15%)	8%
Low	18	(-20%)	1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	2	0	0	2	1	0	2	0
Options	1	0	1	0	0	0	0	0	0
to Sell	3	0	2	0	0	0	0	0	0

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	93	74	57
to Sell	68	83	89
Hld's(000)	28334	29301	26611

% TOT. RETURN 12/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	-11.6	1.3
3 yr.	-9.7	25.2
5 yr.	33.2	117.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
22.71	20.83	20.64	20.74	21.76	22.86	22.95	23.12	23.64	26.05	24.26	22.46	23.49	23.85	27.36	30.21	*29.95*	*31.60*	Revenues per sh	*35.75*
2.37	2.51	2.23	2.52	2.73	2.81	3.01	3.23	3.35	3.08	3.33	3.52	3.54	3.09	3.22	3.19	*2.85*	*3.20*	"Cash Flow" per sh	*3.75*
1.20	1.27	1.19	1.30	1.33	1.30	1.38	1.48	1.45	1.27	1.60	1.62	1.58	1.36	1.46	1.33	*.90*	*1.25*	Earnings per sh A	*1.50*
1.11	1.13	1.15	1.17	1.19	1.21	1.22	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	*1.24*	Div'd Decl'd per sh B ■ †	*1.24*
3.42	4.03	4.06	3.50	3.27	3.33	2.31	2.60	2.09	2.04	1.77	1.74	2.15	2.66	2.76	2.58	*2.80*	*3.55*	Cap'l Spending per sh	*2.25*
12.18	11.06	11.62	11.90	12.25	12.52	12.77	12.87	13.16	12.72	13.06	14.21	14.36	15.01	15.02	13.44	*13.60*	*13.75*	Book Value per sh C	*14.25*
47.73	49.52	55.35	57.31	59.55	61.71	63.79	64.23	64.43	65.98	71.20	73.62	75.84	80.69	80.98	81.46	*83.50*	*85.50*	Common Shs Outst'g D	*87.00*
14.2	15.3	15.5	12.5	13.5	13.7	13.2	13.4	12.1	12.9	11.8	13.5	13.8	19.2	18.3	20.3	*26.6*		Avg Ann'l P/E Ratio	*14.0*
.91	.93	.92	.82	.90	.86	.76	.70	.69	.84	.60	.74	.79	1.01	.97	1.10	*1.40*		Relative P/E Ratio	*.95*
6.5%	5.8%	6.2%	7.2%	6.6%	6.8%	6.7%	6.2%	7.1%	7.5%	6.6%	5.7%	5.7%	4.8%	4.6%	4.6%	5.2%		Avg Ann'l Div'd Yield	*6.0%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $1331.0 mill. **Due in 5 Yrs** $320.4 mill.
LT Debt *$1205.0* mill. **LT Interest** *$67.0* mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 2.6x)
Pension Assets-12/06 $875.3 mill. **Oblig.** $985.6 mill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100.
Sinking fund ends 2018.
Common Stock 83,040,566 shs.
as of 10/29/07
MARKET CAP: $1.8 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
1464.0	1485.2	1523.3	1719.0	1727.3	1653.7	1781.3	1924.1	2215.6	2460.9	*2500*	*2700*	Revenues ($mill)	*3100*
103.3	113.2	111.1	84.6	109.8	120.2	120.1	109.6	120.3	109.9	*75.0*	*110*	Net Profit ($mill)	*140*
34.9%	33.5%	33.9%	41.6%	34.6%	34.6%	34.9%	45.8%	36.4%	36.5%	*39.0%*	*39.0%*	Income Tax Rate	*40.0%*
16.5%	14.2%	6.1%	9.8%	5.9%	4.8%	5.1%	7.6%	5.9%	8.4%	*12.0%*	*14.0%*	AFUDC % to Net Profit	*6.0%*
43.4%	44.7%	47.2%	58.4%	56.9%	52.0%	48.6%	47.6%	45.2%	49.9%	*53.0%*	*53.0%*	Long-Term Debt Ratio	*51.5%*
44.0%	43.1%	41.4%	39.9%	41.6%	46.5%	49.8%	51.0%	53.3%	48.6%	*46.0%*	*45.5%*	Common Equity Ratio	*47.0%*
1851.3	1918.9	2049.5	2101.2	2235.8	2251.0	2186.9	2375.1	2283.9	2252.7	*2475*	*2575*	Total Capital ($mill)	*2625*
2019.6	2093.4	2066.2	2091.3	2067.5	2079.3	2311.9	2422.3	2542.8	2647.5	*2720*	*2855*	Net Plant ($mill)	*2950*
7.0%	7.4%	6.8%	5.9%	6.7%	7.3%	7.3%	6.0%	6.8%	6.4%	*4.5%*	*5.5%*	Return on Total Cap'l	*6.5%*
9.8%	10.7%	10.3%	9.7%	11.4%	11.1%	10.7%	8.8%	9.6%	9.7%	*6.5%*	*9.0%*	Return on Shr. Equity	*11.0%*
10.6%	11.4%	11.0%	9.8%	11.6%	11.3%	10.8%	8.9%	9.7%	9.9%	*6.5%*	*9.0%*	Return on Com Equity E	*11.0%*
3.0%	1.8%	1.5%	1.7%	4.4%	4.3%	3.9%	1.1%	1.5%	.7%	*NMF*	*Nil*	Retained to Com Eq	*2.5%*
76%	87%	88%	84%	63%	63%	64%	87%	85%	93%	*NMF*	*99%*	All Div'ds to Net Prof	*79%*

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+2.9	+.3	+.3
Avg. Indust. Use (MWH)	6816	6718	6623
Avg. Indust. Revs. per KWH (¢)	12.86	15.21	17.38
Capacity at Yearend (Mw)	2171	2184	2204
Peak Load, Winter (Mw)	1694	1641	1685
Annual Load Factor (%)	71.5	74.1	72.5
% Change Customers (yr-end)	+1.2	+1.7	+1.2
Fixed Charge Cov. (%)	335	325	301

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	2.0%	2.0%	*4.5%*
"Cash Flow"	1.5%	-.5%	*3.0%*
Earnings	.5%	-1.0%	*1.5%*
Dividends	.5%	--	*Nil*
Book Value	1.5%	2.0%	*-.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	437.1	461.8	506.8	518.4	1924.1
2005	472.6	522.3	595.9	624.8	2215.6
2006	574.9	605.0	673.9	607.1	2460.9
2007	554.0	600.8	673.5	*671.7*	*2500*
2008	*675*	*675*	*675*	*675*	*2700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.40	.14	.51	.31	1.36
2005	.30	.35	.46	.35	1.46
2006	.40	.33	.40	.20	1.33
2007	.17	.21	.24	*.28*	*.90*
2008	*.30*	*.30*	*.35*	*.30*	*1.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.31	.31	.31	.31	1.24
2005	.31	.31	.31	.31	1.24
2006	.31	.31	.31	.31	1.24
2007	.31	.31	.31	.31	1.24
2008					

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company (HECO) & American Savings Bank (ASB). HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 434,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Discontinued int'l power sub. in '01. Elec. rev. breakdown, '06: residential, 34%; commercial, 34%; large light & power, 32%. Generating sources, '06: oil, 62%; purchased, 38%. Fuel costs: 52% of revs. '06 reported depr. rate (utility): 3.9%. Has 3,400 employees. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: P.O. Box 730, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Web: www.hei.com.

One of Hawaiian Electric Industries' utilities received an interim rate order in late December. Maui Electric Company (MECO) was granted an interim tariff hike of $13.2 million (3.7%) based on a 10.7% return on equity. Importantly, the commission also granted MECO a regulatory mechanism to track pension costs. HEI's other two utilities, Hawaiian Electric Company (HECO) and Hawaii Electric Light Company (HELCO), have pension trackers as well.

Despite the rate relief that HEI's utilities have received in recent years, keeping up with rising costs is tough. And the increases in operating expenses are not only due to inflation. Maintenance and repair expenses are up because the utilities' plants have to be run harder due to a tight capacity situation. As a result, the utilities have not been earning their allowed returns on equity.

Earnings probably didn't cover the dividend in 2007, and we think HEI will barely earn the disbursement in 2008. Last year, third-quarter profits were especially weak because HECO received a final rate increase that was lower than an interim rate boost received in 2005. This forced the company to take an $8.3 million ($0.10 a share) reserve for a refund of previously collected revenues. In addition to the aforementioned problems at the utilities, HEI's American Savings Bank subsidiary is also experiencing difficult business conditions. The net interest margin is down, loan growth is slowing, and deposits are declining. Despite HEI's bottom-line weakness, we think the dividend will hold at the current level for the time being.

Some large capital spending projects should be completed in the next year or two. HECO plans to add a 110-megawatt biofuel-fired peaking unit at a cost of $164 million. The utility also plans a $69.6 million transmission project. HELCO is adding 18 mw of capacity at a cost of $92 million. This will necessitate some debt and equity financing.

We don't recommend this stock, despite its high yield. HEI's weak earnings are a concern, and we project no dividend growth, even over the 3- to 5-year period. Note that we have cut HEI's Financial Strength rating a notch, to B++.

Paul E. Debbas, CFA *February 8, 2008*

(A) Diluted EPS. Excl. gains (losses) from disc. ops.: '98, (16¢); '99, 6¢; '00, (56¢); '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (loss): '05, 11¢; '07, (9¢). Next egs. due late Feb.
(B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. † Sharehldr. invest. plan avail. (C) Incl. intang. In '06: $2.45/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate all'd on com. eq. in '07: HECO, 10.7% (interim); in '01: HELCO, 11.5%; in '07: MECO, 10.7%; earned on avg. com. eq., '06: 9.3%. Regulat. Climate: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	70

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IDACORP, INC. NYSE-IDA

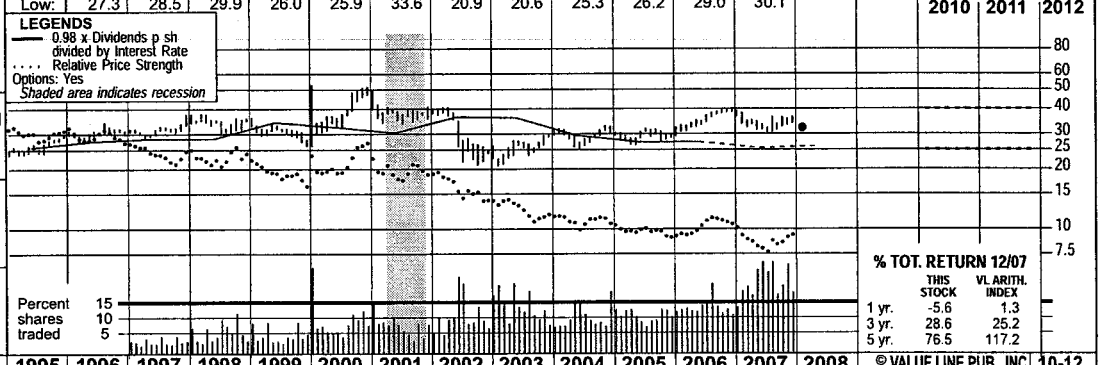
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
32.14	15.7	(Trailing: 15.7 Median: 15.0)	0.98	3.7%	VALUE LINE

TIMELINESS 3 Raised 8/17/07
SAFETY 3 Lowered 2/14/03
TECHNICAL 2 Lowered 2/8/08
BETA .95 (1.00 = Market)

High:	34.3	37.8	38.1	36.5	53.0	49.4	41.0	30.2	32.9	32.1	40.2	39.2
Low:	27.3	28.5	29.9	26.0	25.9	33.6	20.9	20.6	25.3	26.2	29.0	30.1

Target Price Range
2010 | 2011 | 2012

LEGENDS
— 0.98 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+25%)	9%
Low	25	(-20%)	-2%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	2	2	2	0	0	1	0	0	0

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	84	93	70
to Sell	84	78	74
Hld's(000)	27777	34771	37672

Percent shares traded 15 10 5

% TOT. RETURN 12/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	-5.6	1.3
3 yr.	28.6	25.2
5 yr.	76.5	117.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
14.22	13.76	14.57	14.45	14.51	15.38	19.90	29.83	17.50	27.10	150.10	24.43	20.41	20.00	20.15	21.23	*19.80*	*21.80*	Revenues per sh	*27.80*
3.26	3.16	3.53	3.39	3.89	4.05	4.22	4.69	4.50	5.63	5.63	4.08	3.50	4.12	3.87	4.64	*4.25*	*4.55*	"Cash Flow" per sh	*5.25*
1.56	1.55	1.97	1.80	2.10	2.21	2.32	2.37	2.43	3.50	3.35	1.63	.96	1.90	1.75	2.35	*2.00*	*2.15*	Earnings per sh A	*2.25*
1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	*1.20*	Div'd Decl'd per sh B† ■	*1.20*
3.94	3.26	3.32	2.94	2.23	2.49	2.51	2.37	2.95	3.73	4.78	3.53	3.89	4.73	4.53	5.16	*6.80*	*6.15*	Cap'l Spending per sh	*5.25*
17.06	17.28	17.86	17.91	18.15	18.47	18.93	19.42	20.02	21.82	23.15	23.01	22.54	23.88	24.04	25.76	*26.05*	*27.75*	Book Value per sh C	*30.95*
33.98	36.19	37.09	37.61	37.61	37.61	37.61	37.61	37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.63	*45.00*	*46.30*	Common Shs Outst'g D	*47.50*
16.8	17.0	15.4	13.9	12.4	13.7	13.6	14.4	12.7	10.9	11.4	18.9	26.5	15.5	16.7	15.1	*16.1*		Avg Ann'l P/E Ratio	*14.5*
1.07	1.03	.91	.91	.83	.86	.78	.75	.72	.71	.58	1.03	1.51	.82	.89	.82	*.85*		Relative P/E Ratio	*.95*
7.1%	7.1%	6.1%	7.4%	7.2%	6.1%	5.9%	5.4%	6.0%	4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.7%		Avg Ann'l Div'd Yield	*3.6%*
						748.5	1122.0	658.3	1019.4	5648.0	928.8	782.7	844.5	859.5	926.3	*890*	*1010*	Revenues ($mill)	*1320*
						92.3	94.8	96.9	137.6	130.0	66.3	40.1	77.8	63.7	100.1	*88.0*	*97.0*	Net Profit ($mill)	*105*
						33.5%	32.0%	32.0%	32.1%	33.3%	--	--	--	16.9%	13.3%	*32.0%*	*32.0%*	Income Tax Rate	*32.0%*
						.6%	1.3%	3.2%	3.6%	3.1%	3.0%	7.5%	3.9%	4.7%	4.0%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
						46.2%	49.4%	48.9%	48.3%	46.4%	49.2%	50.8%	49.3%	50.0%	45.2%	*47.5%*	*47.5%*	Long-Term Debt Ratio	*50.0%*
						46.8%	44.2%	44.8%	45.9%	47.9%	47.9%	46.4%	50.7%	50.0%	54.8%	*52.5%*	*52.5%*	Common Equity Ratio	*50.0%*
						1522.2	1652.3	1680.3	1790.0	1818.0	1826.9	1862.5	1987.8	2048.8	2052.8	*2245*	*2455*	Total Capital ($mill)	*2940*
						1716.9	1711.5	1745.7	1805.0	1886.0	1906.5	2088.3	2209.5	2314.3	2419.1	*2620*	*2795*	Net Plant ($mill)	*3175*
						7.8%	7.3%	7.4%	9.2%	8.7%	5.1%	3.7%	5.3%	4.5%	6.2%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.0%*
						11.3%	11.3%	11.3%	14.9%	13.3%	7.1%	4.4%	7.7%	6.2%	8.9%	*7.5%*	*7.5%*	Return on Shr. Equity	*7.0%*
						12.2%	12.2%	12.1%	16.0%	14.4%	7.0%	4.2%	7.2%	6.2%	8.9%	*7.5%*	*7.5%*	Return on Com Equity E	*7.0%*
						2.4%	2.6%	2.9%	7.5%	6.3%	NMF	NMF	2.7%	1.3%	4.3%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
						82%	80%	78%	55%	58%	113%	NMF	65%	80%	51%	*60%*	*56%*	All Div'ds to Net Prof	*53%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $1298.5 mill. **Due in 5 Yrs** $460.7 mill.
LT Debt $1061.3 mill. **LT Interest** $57.2 mill.
(LT interest earned: 2.6x)

Pension Assets-12/06 $400.9 mill. **Oblig.** $425.6 mill.

Pfd Stock None

Common Stock 44,995,330 shs.

MARKET CAP: $1.6 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+2.0	--	+1.0
Avg. Indust. Use (MWH)	26548	26535	26731
Avg. Indust. Revs. per KWH (¢)	3.35	3.45	2.96
Capacity at Peak (Mw)	2912	3084	3085
Peak Load, Summer (Mw)	2843	2963	3084
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+3.2	+3.8	+3.6
Fixed Charge Cov. (%)	148	207	274

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	3.5%	-20.5%	*5.0%*
"Cash Flow"	1.0%	-4.5%	*4.0%*
Earnings	--	-8.5%	*2.0%*
Dividends	-4.5%	-8.5%	*Nil*
Book Value	3.0%	2.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	188.2	211.9	246.7	197.7	844.5
2005	195.6	204.9	248.4	210.6	859.5
2006	268.4	242.6	230.5	184.8	926.3
2007	206.7	213.8	261.5	*208.0*	*890*
2008	*235*	*260*	*270*	*245*	*1010*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.51	.34	.68	.37	1.90
2005	.55	.22	.56	.42	1.75
2006	.64	.53	.76	.42	2.35
2007	.56	.42	.65	*.37*	*2.00*
2008	*.60*	*.43*	*.75*	*.37*	*2.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B†■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.465	.465	.465	.30	1.70
2005	.30	.30	.30	.30	1.20
2006	.30	.30	.30	.30	1.20
2007	.30	.30	.30	.30	1.20
2008					

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a utility that owns 17 hydroelectric generation developments and partly owns three coal plants. Sold a patented fuel cell system in 2006. Sells electricity in Idaho (96% of revenues.) and Oregon (4%). Revenue breakdown: residential, 33%; commercial, 18%; industrial, 11%; other, 38%. Fuel and purchased power cost: 43% of '06 revenues; estimated labor costs: 9.0%. 2006 depreciation rate: 2.8%. Fuel sources: hydro, 43%; thermal, 33%; purchases, 24%. Has 1,976 employees. Chairman: Jon H. Miller. Chief Executive Officer & President: J. LaMont Kean. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP's construction budget will be large for the next few years. To cover an expected 2% annual rise in customer energy demand, IDA issued a 10-year resource plan that calls for an increase of 2,350 megawatts (mw) in generation and 285 mw of new transmission lines over the next 18 years. For starters, it has bought 13 (mw) of geothermal power and has contracts to purchase 100 mw of wind-driven power that will go on line by year-end 2008. To diversify the energy mix, it will build a 170-mw gas-fired unit at the Evander Andrews site with a transmission line to carry the power where needed. On the hydro side, Shoshone Falls' capacity will be boosted from 12.5 mw to 62.5 mw, if water is available. New coal plants outside of Idaho are under consideration. The package will require capital spending of about $380 million annually through 2009 and lesser amounts thereafter.

The company has filed for higher rates. Since the last rate case, IDA has invested large sums in its electric superstructure. These expenditures include some $200 million on 650 miles of transmission and distribution lines and 10 new substations. Another $127 million was spent on maintenance and improvement of existing facilities and on environmental upgrading at coal- and gas-fired plants. Too, costs of $34 million have been incurred for relicensing hydroelectric units. All told, the utility seeks a hike of $63.9 million, based on an 11.50% return on equity, up from the present 10.25%. A regulatory order on the request is due by late February. It will take effect when issued.

We look for improved earnings in 2008. Last year's results were hurt by poor hydro conditions. This increased O&M expenses and raised the need for more costly fossil fuel generation. Our 2008 earnings estimate of $2.15 a share assumes a return to average winter snowpack and a reasonable rate award. Slow, but steady, gains are likely to 2010-2012.

Dividend growth is not the company's strong suit. Though the yield is fractionally above the industry norm, we expect no increase in the payout for a while, because of the need to save cash for the building program. Income-oriented investors will likely fare better elsewhere.

Arthur H. Medalie *February 8, 2008*

(A) EPS diluted. Excl. nonrecurring gains (loss): '93, 16¢; '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Next earnings report due mid-Feb. (B) Div'ds historically paid in late Feb., late May, late Aug., and late Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '06: $9.65/sh. (D) In mill. (E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '04: 10.25%; earned on avg. system com. eq., '06: 9.3%. Regulatory Climate: Above Average.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	15
Earnings Predictability	50

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MGE ENERGY INC. NDQ-MGEE

RECENT PRICE **35.24** | P/E RATIO **14.8** (Trailing: 15.3 Median: 16.0) | RELATIVE P/E RATIO **0.88** | DIV'D YLD **4.0%** | VALUE LINE

TIMELINESS 3 Raised 8/17/07
SAFETY 1 New 1/3/03
TECHNICAL 3 Raised 11/30/07
BETA .95 (1.00 = Market)

High:	27.5	23.8	23.8	23.9	23.7	27.8	30.1	35.8	36.4	38.8	37.0	37.0
Low:	19.6	18.5	20.6	16.4	16.8	20.9	24.6	25.0	27.6	30.5	29.2	29.4

Target Price Range 2010 | 2011 | 2012

2010-12 PROJECTIONS

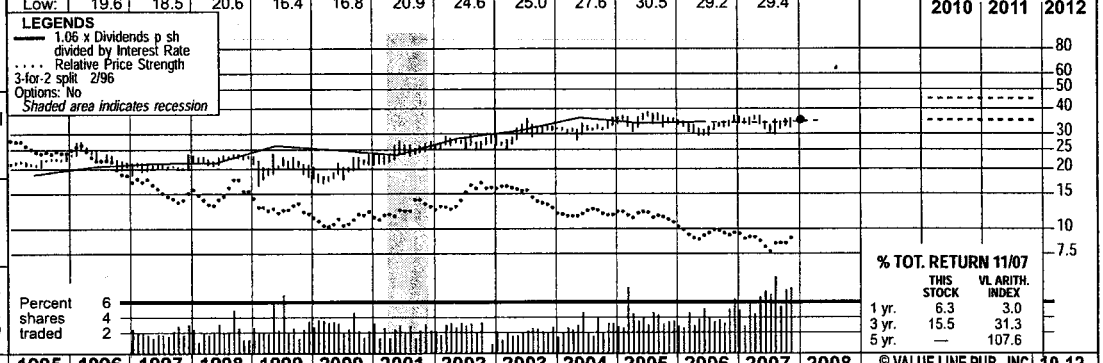
	Price	Gain	Ann'l Total Return
High	45	(+30%)	10%
Low	35	(Nil)	4%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	1	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	49	38	44
to Sell	16	33	30
Hld's(000)	6829	7891	7907



% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	6.3	3.0
3 yr.	15.5	31.3
5 yr.	—	107.6

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
14.47	14.21	15.18	15.23	15.46	15.75	16.46	15.53	16.96	19.50	19.55	19.75	21.89	20.84	25.10	24.20	*24.65*	*25.10*	Revenues per sh	*26.50*
2.83	2.79	2.86	2.92	3.03	2.41	3.26	3.59	3.81	3.89	3.78	3.33	2.94	2.88	3.00	3.52	*3.50*	*3.55*	"Cash Flow" per sh	*4.10*
1.52	1.45	1.51	1.53	1.49	.82	1.40	1.38	1.48	1.67	1.62	1.69	1.71	1.77	1.57	2.06	*2.35*	*2.40*	Earnings per sh A	*2.60*
1.17	1.19	1.19	1.25	1.26	1.28	1.29	1.30	1.31	1.32	1.33	1.34	1.35	1.36	1.37	1.39	*1.41*	*1.43*	Div'd Decl'd per sh B ■	*1.50*
1.24	.77	1.47	1.64	1.19	1.36	1.35	1.92	3.16	4.44	2.47	4.45	4.52	4.70	4.19	4.41	*4.00*	*4.00*	Cap'l Spending per sh	*4.00*
10.98	11.24	11.51	11.78	12.01	11.14	11.25	11.34	11.49	12.05	12.67	12.94	14.34	16.59	16.81	17.89	*17.00*	*17.90*	Book Value per sh	*18.70*
16.05	16.05	16.08	16.08	16.08	16.08	16.08	16.08	16.16	16.62	17.07	17.57	18.34	20.39	20.45	20.98	*21.90*	*21.90*	Common Shs Outst'g C	*21.90*
11.3	14.3	15.2	14.3	14.5	28.1	14.5	16.2	14.0	11.7	14.8	16.0	17.5	18.0	22.4	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.72	.87	.90	.94	.97	1.76	.84	.84	.80	.76	.76	.87	1.00	.95	1.19	.86	*Value Line*		Relative P/E Ratio	*1.00*
6.8%	5.7%	5.2%	5.7%	5.8%	5.5%	6.3%	5.8%	6.3%	6.7%	5.5%	5.0%	4.5%	4.3%	3.9%	4.3%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*
						264.7	249.8	274.0	324.1	333.7	347.1	401.5	424.9	513.4	507.5	*540*	*550*	Revenues ($mill)	*580*
						22.5	22.2	23.8	27.4	27.2	29.2	30.6	33.8	32.1	42.4	*51.0*	*53.0*	Net Profit ($mill)	*58.0*
						37.5%	37.1%	36.9%	36.5%	36.9%	39.1%	39.4%	37.9%	38.2%	37.9%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
						.2%	.9%	1.9%	1.9%	2.2%	--	--	--	2.2%	1.7%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
						41.8%	46.7%	44.5%	47.8%	42.2%	45.8%	43.5%	37.4%	39.3%	38.7%	*39.5%*	*39.0%*	Long-Term Debt Ratio	*39.0%*
						58.2%	53.3%	55.5%	52.2%	57.8%	54.2%	56.5%	62.6%	60.7%	61.3%	*60.5%*	*61.0%*	Common Equity Ratio	*61.0%*
						310.8	342.0	334.3	383.7	373.9	419.5	465.3	540.5	566.2	612.6	*620*	*640*	Total Capital ($mill)	*670*
						284.7	258.6	260.1	342.8	401.2	451.5	537.5	607.4	667.7	728.4	*680*	*690*	Net Plant ($mill)	*700*
						8.8%	8.0%	8.8%	8.8%	9.0%	8.1%	7.8%	7.1%	6.6%	7.8%	*9.0%*	*9.5%*	Return on Total Cap'l	*9.5%*
						12.4%	12.2%	12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	9.3%	11.3%	*12.5%*	*13.5%*	Return on Shr. Equity	*14.0%*
						12.4%	12.2%	12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	9.3%	11.3%	*12.5%*	*13.5%*	Return on Com Equity D	*14.0%*
						1.0%	.7%	1.5%	2.9%	2.3%	2.6%	2.5%	2.3%	1.2%	3.7%	*5.0%*	*5.5%*	Retained to Com Eq	*6.0%*
						92%	94%	89%	79%	82%	79%	79%	77%	87%	67%	*61%*	*59%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $336.3 mill. **Due in 5 Yrs** $65.0 mill.
LT Debt $232.3 mill. **LT Interest** $12.0 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $1.4 mill.
Pension Assets-12/05 $116.7 mill.
Obligation $173.5 mill.

Pfd Stock None

Common Stock 21,868,684 shs.
as of 10/31/07
MARKET CAP: $725 million (Small Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+1.6	-0.7	-0.7
Avg. Indust. Use (MWH)	4624	3023	2865
Avg. Indust. Revs. per KWH (¢)	4.40	5.42	6.20
Capacity at Peak (Mw)	763	812	780
Peak Load, Summer (Mw)	714	690	NA
Annual Load Factor (%)	59.1	48.1	NA
% Change Customers (avg.)	+1.0	+1.6	NA
Fixed Charge Cov. (%)	388	352	340

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	4.0%	4.5%	.5%
"Cash Flow"	1.0%	-4.0%	.5%
Earnings	3.5%	2.5%	6.0%
Dividends	1.0%	1.0%	.5%
Book Value	4.0%	7.0%	7.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	135.4	85.4	86.8	117.3	424.9
2005	138.9	100.5	114.4	159.6	513.4
2006	158.6	99.7	110.6	138.6	507.5
2007	167.9	110.5	116.3	*145.3*	*540*
2008	*171*	*113*	*118*	*148*	*550*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.74	.30	.48	.25	1.77
2005	.40	.27	.48	.42	1.57
2006	.56	.34	.62	.54	2.06
2007	.59	.47	.71	*.58*	*2.35*
2008	*.60*	*.49*	*.71*	*.60*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.336	.336	.338	.338	1.35
2004	.338	.338	.342	.342	1.36
2005	.342	.342	.345	.345	1.37
2006	.345	.345	.348	.348	1.39
2007	.348	.348	.355	.355	

BUSINESS: MGE Energy Inc. is a holding company for Madison Gas and Electric, which provides electric service to nearly 132,000 customers in a 250-square-mile area of Dane County and gas service to 129,000 customers in 1,375 square miles in seven counties in Wisconsin. Electric revenue breakdown, '06: residential, 34%; commercial, 52%; industrial, 6%; public authorities and other, 7%. Generating sources, '06: coal, 49%; purchased power, 44%; natural gas and other, 7%. Fuel costs: 43% of revenues. '06 reported depreciation rate: electric, 3.4%; gas, 3.3%. Has 750 employees. Chairman, President & CEO: Gary J. Wolter. Inc.: Wisconsin. Address: 133 South Blair St., P.O. Box 1231, Madison, WI 53701-1231. Telephone: 608-252-7000. Internet: www.mge.com.

MGE Energy should report its 2007 results sometime in late February. We look for share net to increase 14% over the $2.06 that the Wisconsin-based electric and gas utility earned in 2006. Revenues, meanwhile, ought to come in at $540 million, some 6% higher on the year. Strong residential power demand will no doubt be a key driver. So, too, should increased power "sales for resale", coinciding with MGE's involvement in the MISO and PJM regional transmission organizations.

We look for MGE to build on its success in 2008 and out to 2010-2012. Importantly, the utility should continue to benefit from favorable demographics within its Dane County service area. Strong commercial and residential development in and around the city of Madison, in particular, should boost power demand. Madison is home to a major campus in the state university system, and its outlying population is growing fast.

MGE should soon finish construction on a new wind farm in north-central Iowa. The $59 million project reached a major milestone in October when the first giant turbine towers were erected on site. Upon completion, the 18-turbine, 30-megawatt wind farm should generate enough electricity to meet the annual power needs of some 12,000 homes. The project, along with other renewable energy commitments, is allowing MGE to increase its wind capacity by nearly eight times, to 86 megawatts. Importantly, the new wind farm will help provide energy for an expanded "green" pricing program slated for launch early in 2008. As part of MGE's Green Power Tomorrow program, customers can pay a premium to add more renewable energy to their mix.

MGE Energy shares may appeal to income investors. The dividend yield, at 4.0%, is nicely above the *Value Line* average. What's more, additional dividend hikes are likely, given the utility's good earnings prospects and its enviable record of payout increases (30-plus years and counting). At the current quotation, the stock is trading just within our 3- to 5-year Target Price Range. However, the prospect of lower interest rates should lead to an adjustment in risk-adjusted yields, which ought to support the stock price.

Nils C. Van Liew *December 28, 2007*

(A) Excl. nonrecurring loss: '96, 42¢. Next earnings report due late Feb. (B) Dividends historically paid in mid-March, June, September, December. ■ Dvd. reinvestment plan available. (C) In millions, adjusted for stock split. (D) Rate allowed on common equity in '02: 12.9%; earned on average common equity, '02: 13.0%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	50
Earnings Predictability	75

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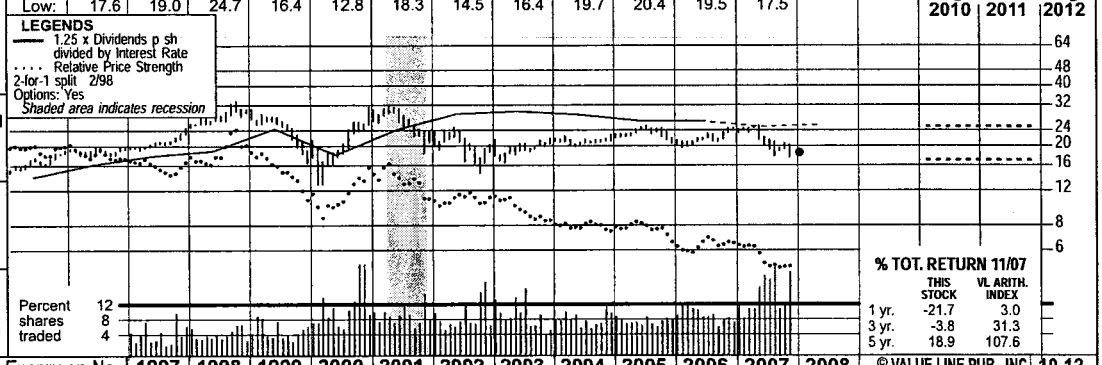
NISOURCE INC. NYSE-NI

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
18.56	16.4	(Trailing: 15.1 Median: 16.0)	0.97	5.0%	VALUE LINE

TIMELINESS 3 Lowered 6/8/07
SAFETY 3 Lowered 1/4/02
TECHNICAL 3 Raised 12/28/07
BETA .90 (1.00 = Market)

High:	20.1	24.9	33.8	30.9	31.5	32.6	25.0	22.0	22.8	25.5	24.8	25.4
Low:	17.6	19.0	24.7	16.4	12.8	18.3	14.5	16.4	19.7	20.4	19.5	17.5

Target Price Range
2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+35%)	11%
Low	17	(-10%)	3%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	1	0	0	1	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	163	176	136
to Sell	149	142	179
Hld's(000)	202459	215399	209234

% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	-21.7	3.0
3 yr.	-3.8	31.3
5 yr.	18.9	107.6

NiSource acquired Columbia Energy on November 1, 2000, paying approximately $6 billion in cash and stock. Columbia shareholders who chose cash received $70 a share, plus a security with a face value of $2.60. Those who chose stock received $74 a share in NiSource common stock. Shareholders' selections were prorated to reflect a 30% stock portion of the transaction. In 2003, NiSource sold Columbia's exploration and production business.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
20.81	24.95	25.33	29.34	45.59	26.09	23.78	24.63	28.97	27.37	*28.40*	*29.75*	Revenues per sh	*33.75*
3.54	3.83	3.80	2.74	4.23	3.94	3.47	3.47	3.08	3.20	*3.30*	*3.40*	"Cash Flow" per sh	*4.00*
1.54	1.59	1.27	1.39	1.13	1.91	1.59	1.62	1.08	1.14	*1.20*	*1.25*	Earnings per sh A	*1.50*
.92	.98	1.04	.81	1.16	1.16	1.10	.92	.92	.92	*.92*	*.92*	Div'd Decl'd per sh B ■	*1.00*
1.76	2.09	2.75	1.80	3.22	2.50	2.19	1.91	2.17	2.33	*2.90*	*2.90*	Cap'l Spending per sh	*3.00*
10.17	9.78	10.90	16.61	16.72	16.78	16.81	17.69	18.09	18.32	*18.60*	*18.90*	Book Value per sh C	*20.25*
124.31	117.53	124.14	205.55	207.49	248.86	262.63	270.63	272.62	273.65	*274.75*	*275.50*	Common Shs Outst'g D	*277.00*
13.6	17.7	19.6	14.9	23.4	10.8	12.2	13.0	21.4	19.2	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.78	.92	1.12	.97	1.20	.59	.70	.69	1.14	1.04	*Value Line*		Relative P/E Ratio	*.95*
4.4%	3.5%	4.2%	3.9%	4.4%	5.6%	5.7%	4.4%	4.0%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.8%*
2586.5	2932.8	3144.6	6030.7	9458.7	6492.3	6246.6	6666.2	7899.1	7490.0	*7800*	*8200*	Revenues ($mill)	*9375*
199.5	202.4	168.7	196.9	243.5	412.5	419.4	434.6	298.7	314.6	*335*	*345*	Net Profit ($mill)	*420*
34.7%	33.3%	34.9%	33.3%	44.7%	35.5%	35.3%	35.7%	33.3%	35.2%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
.2%	1.8%	3.4%	2.0%	1.8%	.6%	.6%	.5%	1.1%	3.5%	*4.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
54.2%	56.4%	51.8%	63.4%	63.3%	55.7%	57.1%	49.8%	51.2%	50.7%	*54.0%*	*53.0%*	Long-Term Debt Ratio	*51.0%*
41.1%	38.8%	35.5%	35.2%	35.8%	43.4%	42.1%	49.3%	48.0%	49.3%	*46.0%*	*47.0%*	Common Equity Ratio	*49.0%*
3077.2	2959.7	3813.3	9695.6	9683.8	9622.8	10490	9704.1	10285	10160	*11060*	*11110*	Total Capital ($mill)	*11525*
3656.1	3662.1	5230.4	9546.7	9554.7	10068	9304.9	9384.7	9554.3	9694.5	*9935*	*10160*	Net Plant ($mill)	*10700*
8.2%	8.7%	6.0%	2.7%	4.7%	6.7%	6.0%	6.4%	4.8%	4.8%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
14.2%	15.7%	9.2%	5.5%	6.8%	9.7%	9.3%	8.9%	6.0%	6.3%	*6.5%*	*6.5%*	Return on Shr. Equity	*7.5%*
15.1%	16.9%	11.9%	5.5%	6.8%	9.7%	9.4%	9.0%	6.0%	6.3%	*6.5%*	*6.5%*	Return on Com Equity E	*7.5%*
6.3%	6.7%	2.6%	1.7%	NMF	3.9%	3.0%	3.9%	.9%	1.2%	*1.5%*	*2.0%*	Retained to Com Eq	*2.5%*
60%	62%	79%	71%	101%	60%	69%	57%	85%	80%	*76%*	*73%*	All Div'ds to Net Prof	*66%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $6657.3 mill. **Due in 5 Yrs** $2563.1 mill.
LT Debt $5923.4 mill. **LT Interest** $374.0 mill.
(LT interest earned: 2.5x)

Leases, Uncapitalized Annual rentals $47.2 mill.
Pension Assets-12/06 $2.05 bill. **Oblig.** $2.29 bill.

Pfd Stock None

Common Stock 274,171,749 shs.
as of 10/31/07

MARKET CAP: $5.1 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+2.4	+2.9	+.7
Avg. Indust. Use (MWH)	3672	3621	3783
Avg. Indust. Revs. per KWH (¢)	4.45	4.87	5.40
Capacity at Peak (Mw)	3297	3560	3313
Peak Load, Summer (Mw)	2922	3166	3238
Annual Load Factor (%)	66.0	62.8	61.5
% Change Customers (yr-end)	+1.2	+1.0	+.7
Fixed Charge Cov. (%)	258	223	223

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	6.5%	-4.0%	*4.0%*
"Cash Flow"	.5%	-2.0%	*3.5%*
Earnings	-.5%	.5%	*2.5%*
Dividends	1.5%	-1.5%	*1.5%*
Book Value	7.5%	4.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	2473	1245	980	1968	6666.2
2005	2683	1356	1165	2695	7899.1
2006	2972	1312	1156	2050	7490.0
2007	2894	1577	1241	*2088*	*7800*
2008	*3050*	*1650*	*1300*	*2200*	*8200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.82	.13	.08	.58	1.62
2005	.77	.07	d.02	.27	1.08
2006	.63	.08	.10	.33	1.14
2007	.76	.11	.03	*.30*	*1.20*
2008	*.75*	*.05*	*.05*	*.40*	*1.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.29	.29	.29	.23	1.10
2004	.23	.23	.23	.23	.92
2005	.23	.23	.23	.23	.92
2006	.23	.23	.23	.23	.92
2007	.23	.23	.23	.23	

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 454,000 electric in IN, 3.3 million gas in IN, OH, PA, KY, VA, MD, MA, NH, ME. Acquired IWC Resources 3/97; Bay State Gas 2/99; Columbia Energy 11/00. Electric rev. breakdown, '06: residential, 28%; commercial, 28%; industrial, 39%; other, 5%. Generating sources, '06: coal, 81%; purchased & other, 19%. Fuel costs: 58% of revs. '06 reported deprec. rates: 3.6% electric, 2.8% gas. Has 7,400 employees. Chairman: Ian M. Rolland. President & CEO: Robert C. Skaggs, Jr. Inc.: Indiana. Address: 801 East 86th Ave., Merrillville, Indiana 46410. Tel.: 877-647-5990. Internet: www.nisource.com.

We have lowered our 2007 and 2008 earnings estimates for NiSource. In the third quarter, the company took a charge of $16.2 million ($0.06 a share) for a rate refund associated with a regulatory settlement related to Northern Indiana Public Service's purchased-power costs. The settlement will also affect ongoing earnings. Accordingly, we have cut our 2007 and 2008 share-earnings estimates by $0.15 and $0.10, respectively. NiSource stock continues to languish, having fallen more than 20% since the start of 2007.

NiSource's outsourcing agreement with IBM didn't meet expectations. Many of the functions that were outsourced will be brought back in house because things didn't go smoothly. The company stated that the expected cost savings will not be achieved, even though the 10-year contract still has 7.5 years remaining.

The company has received two rate orders, and more rate cases are coming up in 2008. Columbia Gas of Kentucky was granted a tariff hike of $7.25 million, based on a 10.5% return on equity. A $5.9 million increase for Bay State Gas in Massachusetts took effect on November 1st. Bay State is seeking an additional $7.5 million. In early 2008, Columbia Gas plans to file rate applications in Pennsylvania and Ohio. By mid-2008, NIPSCO must file an electric case in Indiana. The utility is seeking to acquire 1,060 megawatts of gas-fired capacity—including the 525-mw Whiting plant, which is now a nonregulated (and money-losing) asset owned by NiSource. This will be reflected in the upcoming rate case.

NiSource is evaluating the possibility of placing some of its midstream gas assets in a master limited partnership (MLP). This would lower the cost of capital for this operation. NiSource is already building gas infrastructure to serve the Northeast, and the possibility of additional projects exists.

We don't recommend this equity, despite its above-average yield. Even the announcement of an MLP likely wouldn't be enough to push the stock upward. The modest earnings and dividend growth we project through 2010-2012 suggests that total-return potential over that timeframe isn't impressive.

Paul E. Debbas, CFA *December 28, 2007*

(A) Diluted EPS. Excl. nonrec. gains (losses): '00, 24¢; '01, (10¢); '02, 9¢; '03, 1¢ net; '05, (4¢); gains (losses) on disc. ops.: '00, 7¢; '02, (25¢); '03, ($1.27); '04, 2¢; '05, 10¢; '06, (11¢); '07, 3¢. '04 & '05 EPS don't add due to rounding. Next egs. due late Jan. (B) Div'ds historically paid in mid-Feb., May, Aug., Nov. There were only 3 declarations in '00. ■ Div'd reinv. avail. (C) Incl. intang. In '06: $19.77/sh. (D) In mill., adj. for split. (E) Rate base: Fair val. Rate all'd on com. eq. in '87: 13.5%; earned on avg. com. eq., '06: 6.2%. Reg. Climate: Above Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	10
Earnings Predictability	65

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NSTAR NYSE-NST

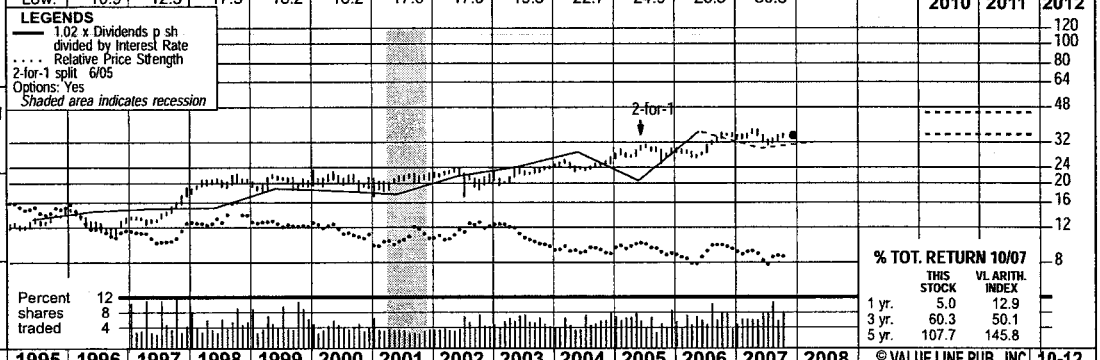
RECENT PRICE **34.70** | P/E RATIO **15.9** (Trailing: 16.6 Median: 14.0) | RELATIVE P/E RATIO **0.95** | DIV'D YLD **4.1%** | VALUE LINE

TIMELINESS 4 Lowered 12/8/06
SAFETY 1 Raised 6/11/99
TECHNICAL 3 Raised 7/6/07
BETA .75 (1.00 = Market)

High:	15.1	19.2	22.5	22.3	23.5	22.6	24.1	24.5	27.2	31.5	35.9	37.4	
Low:	10.9	12.3	17.5	18.2	18.2	17.0	17.0	19.3	22.7	24.9	26.5	30.8	

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.02 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 6/05
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+30%)	10%
Low	35	(Nil)	5%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	5	0	0	0
to Sell	0	0	2	0	0	7	0	0	1

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	123	124	111
to Sell	85	90	106
Hld's(000)	48400	51648	48595

% TOT. RETURN 10/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	5.0	12.9
3 yr.	60.3	50.1
5 yr.	107.7	145.8

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
15.69	15.77	16.42	17.00	16.96	17.17	18.31	17.19	15.94	25.45	30.09	25.64	27.48	27.73	30.36	33.50	*30.90*	*32.75*	Revenues per sh	*39.00*
2.87	2.94	2.98	3.35	3.11	3.65	3.66	3.84	3.04	3.78	3.81	3.95	3.98	4.09	5.00	5.40	*5.65*	*5.95*	"Cash Flow" per sh	*7.00*
.98	1.05	1.14	1.21	1.04	1.31	1.36	1.38	1.39	1.60	1.64	1.69	1.74	1.76	1.83	1.93	*2.10*	*2.25*	Earnings per sh A	*3.00*
.80	.83	.86	.89	.92	.94	.94	.95	.98	1.01	1.04	1.07	1.09	1.13	.87	1.54	*1.35*	*1.43*	Div'd Decl'd per sh B ■	*1.75*
2.55	2.58	2.81	2.42	2.08	2.13	1.23	1.57	1.53	1.78	2.22	3.50	2.94	2.95	3.63	3.99	*3.80*	*2.95*	Cap'l Spending per sh	*2.75*
8.96	9.39	9.71	10.06	10.31	10.54	10.98	11.14	13.29	12.65	11.90	12.25	12.84	13.52	14.37	14.82	*15.60*	*16.45*	Book Value per sh C	*19.75*
84.09	89.53	90.26	91.07	96.01	97.02	97.03	94.37	116.12	106.07	106.07	106.07	106.07	106.55	106.81	106.81	*106.81*	*106.81*	Common Shs Outst'g D	*106.81*
10.6	11.9	13.1	10.7	12.3	9.7	10.6	14.6	14.6	12.9	12.7	12.7	12.8	14.0	15.5	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.68	.72	.77	.70	.82	.61	.61	.76	.83	.84	.65	.69	.73	.74	.83	.86	*Value Line*		Relative P/E Ratio	*.90*
7.7%	6.6%	5.8%	6.9%	7.2%	7.4%	6.5%	4.7%	4.8%	4.9%	5.0%	4.9%	4.9%	4.6%	3.1%	5.0%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $2891.4 mill. **Due in 5 Yrs** $1838.9 mill.
LT Debt $2203.6 mill. **LT Interest** $136.6 mill.
Incl. $484.0 mill. securitized bonds.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $18.1 mill.

Pension Assets-12/06 $1.03 bill. **Oblig.** $1.08 bill.
Pfd Stock $43.0 mill. **Pfd Div'd** $2.0 mill.
430,000 shs. 4.25%-4.78%, cum., redeemable at $102.80-$103.625.
Common Stock 106,808,376 shs.
as of 10/30/07
MARKET CAP: $3.7 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
1776.2	1622.5	1851.4	2699.5	3191.8	2719.1	2914.1	2954.3	3243.1	3577.7	*3300*	*3500*	Revenues ($mill)	*4175*
144.6	141.0	146.5	181.0	179.1	181.3	188.0	190.4	198.1	208.7	*225*	*245*	Net Profit ($mill)	*315*
36.3%	34.3%	29.1%	41.6%	41.4%	35.8%	37.5%	38.5%	35.6%	37.8%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
.8%	1.2%	1.5%	2.5%	2.8%	1.6%	2.4%	.5%	1.9%	3.3%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
46.1%	45.5%	50.0%	59.4%	59.2%	60.9%	58.5%	58.6%	60.4%	59.2%	*58.5%*	*58.0%*	Long-Term Debt Ratio	*48.0%*
46.5%	50.1%	47.2%	39.4%	39.5%	37.8%	40.2%	40.2%	38.6%	39.7%	*40.5%*	*41.0%*	Common Equity Ratio	*51.0%*
2291.6	2099.5	3269.3	3409.8	3197.4	3433.7	3387.1	3585.3	3980.4	3986.3	*4100*	*4280*	Total Capital ($mill)	*4150*
2854.1	2270.7	2550.6	2523.6	2625.4	2847.6	3216.1	3425.0	3701.8	3945.3	*4130*	*4215*	Net Plant ($mill)	*4375*
8.3%	8.7%	6.1%	7.6%	8.1%	7.5%	7.8%	7.4%	7.1%	7.3%	*7.5%*	*7.5%*	Return on Total Cap'l	*9.0%*
11.7%	12.3%	9.0%	13.1%	13.7%	13.5%	13.4%	12.8%	12.6%	12.8%	*13.5%*	*13.5%*	Return on Shr. Equity	*14.5%*
12.3%	12.6%	9.1%	13.0%	13.7%	13.8%	13.7%	13.1%	12.8%	13.1%	*13.5%*	*14.0%*	Return on Com Equity E	*14.5%*
3.7%	3.9%	2.4%	4.8%	5.0%	5.2%	5.1%	4.8%	4.6%	4.9%	*5.0%*	*5.0%*	Retained to Com Eq	*6.0%*
73%	71%	74%	64%	65%	63%	63%	64%	64%	63%	*63%*	*63%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+1.5	+2.5	-1.9
Avg. Indust. Use (MWH)	1027	1022	1001
Avg. Indust. Revs. per KWH (¢)	7.90	8.20	8.40
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	4254	4682	4958
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (avg.)	+.4	+.7	+1.5
Fixed Charge Cov. (%)	287	266	262

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	6.0%	5.0%	*4.0%*
"Cash Flow"	3.5%	6.5%	*6.5%*
Earnings	4.5%	3.5%	*8.5%*
Dividends	2.5%	3.0%	*7.0%*
Book Value	3.5%	2.5%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	809.9	649.8	781.5	713.1	2954.3
2005	880.0	692.0	858.5	812.6	3243.1
2006	1034.8	784.6	956.3	802.0	3577.7
2007	984.4	725.1	804.9	*785.6*	*3300*
2008	*1050*	*775*	*850*	*825*	*3500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.46	.35	.59	.35	1.76
2005	.43	.31	.72	.36	1.83
2006	.41	.43	.72	.38	1.93
2007	.45	.47	.79	*.39*	*2.10*
2008	*.50*	*.50*	*.80*	*.45*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.278	.278	.278	.278	1.11
2005	.29	.29	.29	.29	1.16
2006	.303	.303	.303	.303	1.21
2007	.325	.325	.325	.325	
2008	.35				

BUSINESS: NSTAR is a holding company for Boston Edison Company, which supplies electricity to an area of approx. 590 sq. mi. in eastern Massachusetts, encompassing Boston and 39 surrounding towns and cities, and Commonwealth Energy (acq'd 8/99), which provides electric and gas service in eastern Massachusetts. Serves 1.1 million electric, 300,000 gas customers. Electric revenue breakdown, '06: residential, 43%; commercial, 52%; industrial, 5%; other, less than 1%. Sold fossil plants in '98, nuclear plant in '99. Fuel costs: 59% of revenues. '06 reported deprec. rate: 3.0%. Has 3,100 employees. Chairman, President & CEO: Thomas J. May. Inc.: Massachusetts. Address: 800 Boylston St., Boston, Massachusetts 02199-8003. Tel.: 617-424-2000. Internet: www.nstaronline.com.

We have raised our 2007 earnings estimate for NSTAR by $0.05 a share, to $2.10. Third-quarter profits were better than we expected, due in part to interest income associated with a tax matter. This added $0.03 to share net. Our revised estimate is still within the company's targeted range of $2.02-$2.12 a share. But, NSTAR stock is ranked 4 (Below Average) for year-ahead relative performance.

We expect the company to continue to produce strong earnings growth over the 3- to 5-year period. NSTAR has an electric regulatory agreement that runs through 2012. It provides for annual base rate increases and opportunities to earn additional incentive revenues. The utility may earn a return on equity of up to 12.5% (on a regulatory basis, which differs from a financial ROE) before a sharing mechanism kicks in. NSTAR can also reopen the regulatory agreement if its regulatory ROE falls below 8.5%, but we consider such a decline very unlikely. The utility faces no commodity risk, as it passes on any increases in power and gas costs to its customers. (It also passes on any decreases, which is why we estimate that revenues will decline in 2007, despite the increase in base rates mentioned above.) In all, we think NSTAR's target of 6%-8% annual earnings growth is attainable. Our 2008 forecast of $2.25 would produce an earnings increase within this goal.

Earlier this month, the board of directors raised the dividend. The board boosted the quarterly disbursement by $0.025 a share (7.7%). The increase was within NSTAR's target of providing 6%-8% annual dividend growth. We project that the company will attain this goal over the 2010-2012 period. NSTAR has been raising the dividend annually, but since one declaration was postponed from the fourth quarter of 2005 until the first period of 2006, the statistical array above shows unusual fluctuations.

Conservative investors might consider this stock for its good yield, which is above average even by utility standards. The stock is ranked 1 (Highest) for Safety. It offers respectable, risk-adjusted total returns over the 3- to 5-year period, thanks to NSTAR's solid earnings- and dividend-growth potential.

Paul E. Debbas, CFA *November 30, 2007*

(A) Diluted EPS. Excl. nonrecurring losses: '01, $1.66 net; '02, 17¢; '03, 4¢. '04,'05, & '06 EPS don't add to full-year total due to rounding. Next earnings report due late Jan. (B) Div'ds historically paid in early Feb., May, Aug., and Nov. There were only 3 div'd declarations in '05, 5 in '06. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '06: $2.5 bill., $23.52/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in '06: 12.5%; earned on avg. com. eq., '06: 13.3%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	95

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PNM RESOURCES NYSE-PNM

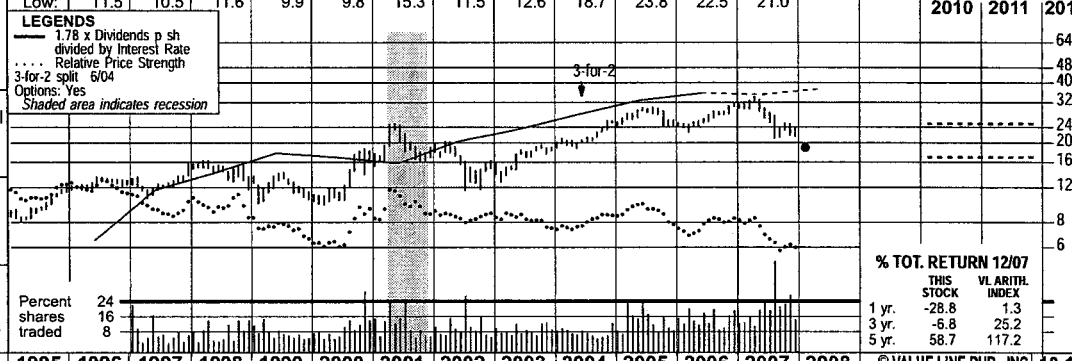
RECENT PRICE **18.96** | P/E RATIO **13.4** (Trailing: 12.3 Median: 12.0) | RELATIVE P/E RATIO **0.84** | DIV'D YLD **5.1%** | VALUE LINE

TIMELINESS 4 Raised 1/25/08
SAFETY 2 Raised 8/16/02
TECHNICAL 3 Raised 12/14/07
BETA .90 (1.00 = Market)

High:	13.7	15.8	16.5	14.3	18.9	25.2	20.5	19.6	26.1	30.5	32.1	34.3
Low:	11.5	10.5	11.6	9.9	9.8	15.3	11.5	12.6	18.7	23.8	22.5	21.0

Target Price Range
2010 | 2011 | 2012

LEGENDS
— 1.78 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 6/04
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+30%)	11%
Low	17	(-10%)	3%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	3	0	2	0	0	0	0	0	0
to Sell	3	0	2	0	0	1	0	0	0

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	99	79	70
to Sell	81	101	98
Hld's(000)	67772	78128	72969

% TOT. RETURN 12/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	-28.8	1.3
3 yr.	-6.8	25.2
5 yr.	58.7	117.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
13.68	13.60	13.95	14.44	12.90	14.10	18.12	17.43	18.96	27.46	40.09	19.92	24.11	26.54	30.19	32.25	32.60	33.75	Revenues per sh	41.25
1.76	2.10	2.34	2.55	2.38	2.61	2.58	3.04	2.82	3.16	4.31	2.83	3.05	3.14	3.56	3.57	3.45	4.00	"Cash Flow" per sh	5.00
.21	.50	.81	1.11	.91	1.15	1.25	1.50	1.29	1.55	2.61	1.07	1.15	1.43	1.59	1.72	1.35	1.65	Earnings per sh A	1.85
--	--	--	--	--	.24	.42	.51	.53	.53	.53	.57	.61	.63	.79	.86	.93	.97	Div'd Decl'd per sh B ■†	1.09
1.28	1.52	1.61	1.90	1.70	1.42	2.05	2.06	1.56	2.50	4.51	4.09	2.78	2.25	3.07	4.04	3.90	3.75	Cap'l Spending per sh	3.75
11.79	10.00	8.86	10.08	11.22	12.04	12.84	13.75	14.74	15.76	17.25	16.60	17.84	18.19	18.70	22.09	22.45	23.70	Book Value per sh C	25.90
62.66	62.66	62.66	62.66	62.66	62.66	62.66	62.66	61.05	58.68	58.68	58.68	60.39	60.46	68.79	76.65	77.00	80.00	Common Shs Outst'g D	80.00
29.1	16.5	9.5	7.5	10.6	11.0	10.0	9.8	9.5	8.5	7.3	15.1	14.7	15.0	17.1	15.6	14.0		Avg Ann'l P/E Ratio	10.5
1.86	1.00	.56	.49	.71	.69	.58	.51	.54	.55	.37	.82	.84	.79	.91	.84	.74		Relative P/E Ratio	.70
--	--	--	--	--	1.9%	3.3%	3.5%	4.4%	4.1%	2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	4.9%		Avg Ann'l Div'd Yield	5.3%
						1135.3	1092.4	1157.5	1611.3	2352.1	1169.0	1455.7	1604.8	2076.8	2471.7	2510	2700	Revenues ($mill)	3300
						79.3	105.2	79.9	92.7	156.3	64.3	68.9	88.3	106.6	122.1	95	130	Net Profit ($mill)	150
						37.1%	34.9%	34.6%	44.5%	34.2%	24.5%	29.0%	28.2%	31.1%	24.7%	25.0%	25.0%	Income Tax Rate	25.0%
						--	--	--	--	--	--	1.7%	3.4%	3.4%	3.8%	3.0%	3.0%	AFUDC % to Net Profit	3.0%
						46.6%	53.2%	52.0%	50.4%	48.2%	49.8%	47.5%	47.1%	57.4%	50.9%	50.5%	49.5%	Long-Term Debt Ratio	48.5%
						52.5%	45.4%	47.3%	48.9%	51.1%	49.5%	51.9%	52.4%	42.3%	48.8%	49.0%	50.0%	Common Equity Ratio	51.0%
						1531.2	1896.4	1901.2	1891.3	1978.7	1966.9	2077.3	2098.9	3044.4	3470.7	3510	3765	Total Capital ($mill)	4050
						1573.2	1593.8	1582.4	1617.3	1781.0	1867.3	2194.4	2324.6	2984.1	3761.9	3890	4000	Net Plant ($mill)	4200
						6.7%	6.9%	5.9%	6.6%	9.5%	4.7%	4.7%	5.3%	4.7%	4.9%	4.0%	5.0%	Return on Total Cap'l	5.0%
						9.7%	11.8%	8.8%	9.9%	15.3%	6.5%	6.3%	7.9%	8.2%	7.2%	5.5%	7.0%	Return on Shr. Equity	7.0%
						9.8%	12.1%	8.8%	10.0%	15.4%	6.5%	6.3%	8.0%	8.2%	7.2%	5.5%	7.0%	Return on Com Equity E	7.0%
						6.5%	8.4%	5.2%	6.5%	12.3%	3.1%	3.0%	4.5%	4.3%	3.7%	1.5%	3.0%	Retained to Com Eq	3.0%
						34%	31%	42%	35%	20%	53%	53%	44%	48%	49%	74%	58%	All Div'ds to Net Prof	58%

CAPITAL STRUCTURE as of 9/30/07
Total Debt $1566.9 mill. **Due in 5 Yrs** $2161.5 mill.
LT Debt $1233.6 mill. **LT Interest** $92.3 mill.
(LT interest earned: 2.6x)
Pension Assets-12/06 $485.8 mill. **Oblig.** $535.7 mill.
Pfd Stock $11.5 mill. **Pfd Div'd** $.6 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 76,777,076 shs. **as of 11/1/07**
MARKET CAP: $1.9 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+2.4	+2.9	+3.5
Avg. Indust. Use (MWH)	4428	4544	4756
Avg. Indust. Revs. per KWH (¢)	4.82	4.79	4.71
Capacity at Peak (Mw)	1729	1744	1934
Peak Load, Summer (Mw)	1655	1779	1855
Annual Load Factor (%)	65.0	64.8	65.0
% Change Customers (yr-end)	+2.6	+2.9	+2.7
Fixed Charge Cov. (%)	250	165	166

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	8.0%	.5%	5.5%
"Cash Flow"	3.0%	--	6.5%
Earnings	4.0%	-2.5%	2.5%
Dividends	--	7.5%	6.0%
Book Value	6.0%	4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	437.4	370.4	386.8	410.2	1604.8
2005	427.9	405.3	597.1	646.5	2076.8
2006	655.8	546.7	650.2	619.0	2471.7
2007	653.5	580.7	629.4	646.4	2510
2008	700	610	680	710	2700

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.40	.28	.45	.30	1.43
2005	.50	.22	.46	.41	1.59
2006	.38	.23	.62	.49	1.72
2007	.38	.26	.41	.30	1.35
2008	.40	.30	.55	.40	1.65

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.153	.16	.16	.16	.63
2005	.185	.185	.20	.20	.77
2006	.20	.20	.22	.22	.84
2007	.22	.23	.23	.23	.91
2008					

BUSINESS: PNM Resources, parent of Public Service Company of New Mexico, sells electricity (86% of revenues), gas (14%), other less than (1%) in north-central New Mexico (popul.: 1,300,000). Acquired TNP Enterprises 6/05. Largest customer: City of Albuquerque. Elect. rev. breakdown: resid., 35%; commer., 35%; indust, 16%; other, 14%. Area's military establishments are major customers. Fuels: coal, 70%; nuclear, 24%; gas/oil, 6%. Fuel costs: 59% of revs.; labor costs: 16%. '06 reported deprec. rates: 2.4% elec., 2.9% gas. Est'd plant age: 11 years. Has 5,675 employees. Chairman, Chief Executive Officer & President: Jeffry E. Sterba. Inc.: New Mexico. Address: Alvarado Square, Albuquerque, New Mexico 87158. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources is increasing emphasis on its electric business. It has an agreement to sell its natural gas operations to Continental Energy Systems and, conditioned on the sale, to buy Continental's regulated Texas electric delivery holdings. The gas operations will be sold for $620 million, the electric bought for $202.5 million. Both transactions will be for 100% cash. The electric enterprises, which own no generation, are supplied with energy under long-term purchase-power contracts. Regulation permits pass-through of all power costs on a monthly basis. The purchase is expected to be slightly accretive to earnings in the first year and more so thereafter. Simultaneous closings of both deals are expected by yearend.

The company has filed its first electric general rate case in 20 years. It asked for an annual increase of $82.4 million, based on an allowed return on equity of 10.75%, down from the present 12.52%. Chief drivers of the hike are rising fuel prices, higher O&M expenses, and the cost of the Afton gas-fired plant's upgrades. The proposal includes a fuel and purchased power cost adjustment clause and consumption-based rates designed to encourage energy efficiency. Finally, it seeks recovery of environmental outlays as they are incurred. This would reimburse PNM in a timely manner for its $94 million share of costs to improve pollution controls at the San Juan coal-fired station. A decision on the request is due in early May.

Earnings should have no difficulty exceeding 2007's poor results. Last year's profits were hurt by cost overruns in converting Afton to a combined-cycle unit and by weaker-than-expected plant operations. The current year will benefit from payroll savings resulting from an outsourcing contract with Alliance Data and from higher rates. All told, we project 2008 earnings will rise 22% over last year's estimated $1.35 a share. Smaller gains are likely through 2010-2012. The stock is untimely.

The yield is a full percentage point above the industry norm. And our projection of higher earnings to 2010-2012 suggests dividend growth over the same time frame well above that of the group. The stock might interest income-oriented investors.

Arthur H. Medalie *February 8, 2008*

(A) EPS diluted. Next earnings report due mid-Feb. Excl. nonrecur. gains (losses): '92, ($2.28); '93, ($1.90); '94, 7¢; '95, net 23¢; '97, 3¢; '98, net (16¢); '99, 5¢; '00, 14¢; '01, (10¢); '03, 45¢; '05, (56¢). (B) Div'ds historically paid in mid-Feb., mid-May, mid-Aug., and mid-Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '06: $16.68/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. Elect. ROE allowed in '90: 12.52%; earned on avg. com. eq., '06: 8.1%. Regulatory Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	80
Earnings Predictability	60

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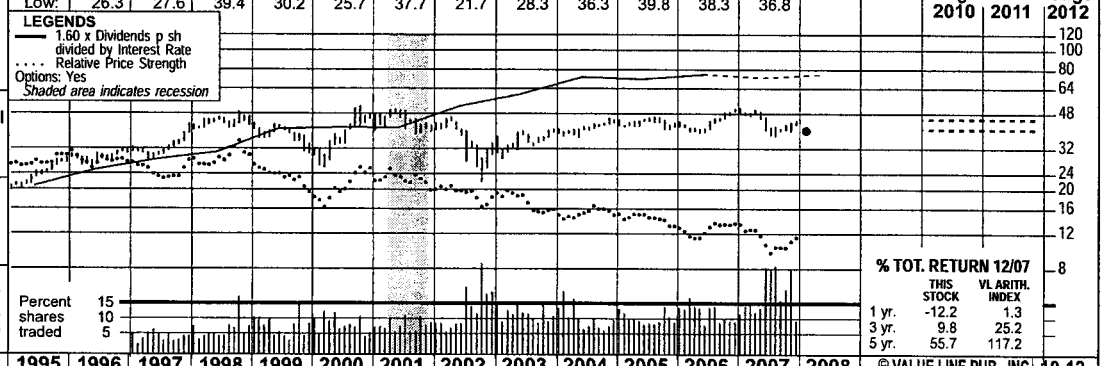
PINNACLE WEST NYSE-PNW

RECENT PRICE **39.53** | P/E RATIO **13.4** (Trailing: 13.0 / Median: 14.0) | RELATIVE P/E RATIO **0.84** | DIV'D YLD **5.4%** | VALUE LINE

TIMELINESS 3 Raised 10/5/07
SAFETY 1 Raised 5/16/03
TECHNICAL 1 Raised 2/8/08
BETA .80 (1.00 = Market)

High:	32.3	42.8	49.3	43.4	52.7	50.7	46.7	40.5	45.8	46.7	51.0	51.7
Low:	26.3	27.6	39.4	30.2	25.7	37.7	21.7	28.3	36.3	39.8	38.3	36.8

Target Price Range 2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+15%)	8%
Low	40	(Nil)	6%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	2
to Sell	0	0	1	0	0	0	0	0	2

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	155	159	135
to Sell	124	132	135
Hld's(000)	79933	88538	87323

% TOT. RETURN 12/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	-12.2	1.3
3 yr.	9.8	25.2
5 yr.	55.7	117.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
16.95	19.39	19.66	19.28	19.08	20.77	23.52	25.12	28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.10	37.40	Revenues per sh	43.65
d1.39	4.70	5.25	5.09	5.16	5.90	7.12	7.34	7.73	7.99	8.72	7.01	7.33	6.93	5.76	6.76	6.85	7.45	"Cash Flow" per sh	8.90
d3.90	1.73	1.95	1.99	2.22	2.47	2.76	2.85	3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.94	2.55	Earnings per sh A	2.95
--	--	.20	.83	.93	1.03	1.13	1.23	1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.12	Div'd Decl'd per sh B■†	2.28
2.10	2.57	2.69	2.92	3.38	2.95	3.63	3.76	4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.38	10.95	10.65	Cap'l Spending per sh	9.90
15.23	17.00	18.87	20.32	21.49	22.51	23.90	25.50	26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.47	35.30	36.25	Book Value per sh C	37.55
87.01	87.16	87.42	87.43	87.52	87.52	84.83	84.83	84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.40	100.50	Common Shs Outst'g D	100.80
--	10.8	11.5	9.6	10.8	11.8	11.8	15.2	11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	13.4		Avg Ann'l P/E Ratio	14.0
--	.66	.68	.63	.72	.74	.68	.79	.68	.73	.61	.79	.80	.83	1.02	.74	.71		Relative P/E Ratio	.95
--	--	.9%	4.3%	3.9%	3.5%	3.5%	2.8%	3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	5.4%		Avg Ann'l Div'd Yield	5.4%

CAPITAL STRUCTURE as of 9/30/07
Total Debt $3503.0 mill. **Due in 5 Yrs** $746.8 mill.
LT Debt $3229.4 mill. **LT Interest** $194.4 mill.
(LT interest earned: 3.3x)

Pension Assets-12/06 $1.21 bill. **Oblig.** $1.67 bill.

Pfd Stock None

Common Stock 100,385,036 shs. **as of 11/2/07**
MARKET CAP: $4.1 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
1995.0	2130.6	2423.4	3690.2	4551.4	2637.3	2817.9	2899.7	2988.0	3401.8	3523.6	3760	Revenues ($mill)	4400
248.7	252.6	270.8	283.6	312.2	215.2	230.6	235.2	223.2	317.1	295	255	Net Profit ($mill)	295
37.7%	39.5%	38.3%	44.1%	40.6%	39.1%	31.4%	35.4%	36.2%	33.0%	33.0%	33.0%	Income Tax Rate	33.0%
6.5%	7.4%	4.3%	7.6%	15.3%	20.5%	6.2%	6.9%	10.4%	6.6%	4.0%	4.0%	AFUDC % to Net Profit	4.0%
50.5%	47.6%	50.0%	45.1%	51.7%	51.8%	50.6%	46.7%	43.2%	48.4%	48.5%	49.0%	Long-Term Debt Ratio	49.5%
45.6%	50.2%	50.0%	54.9%	48.3%	48.2%	49.4%	53.3%	56.8%	51.6%	51.5%	51.0%	Common Equity Ratio	50.5%
4442.9	4307.6	4411.8	4337.8	5172.4	5567.9	5727.5	5535.2	6033.4	6678.8	6875	7025	Total Capital ($mill)	7515
4677.6	4730.6	4778.5	5133.2	5907.3	6479.4	7480.1	7535.5	7577.1	7881.9	8590	9320	Net Plant ($mill)	10930
7.4%	7.6%	7.9%	8.1%	7.6%	5.4%	5.5%	5.6%	5.0%	6.2%	6.0%	5.0%	Return on Total Cap'l	5.5%
11.3%	11.2%	12.3%	11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	7.0%	Return on Shr. Equity	8.0%
11.6%	11.2%	12.2%	11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	7.0%	Return on Com Equity E	8.0%
6.9%	6.4%	7.1%	6.8%	7.3%	2.9%	2.6%	2.3%	1.0%	3.4%	2.5%	1.0%	Retained to Com Eq	2.0%
44%	45%	42%	43%	41%	64%	68%	71%	85%	63%	71%	83%	All Div'ds to Net Prof	77%

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+3.2	+4.4	+5.6
Avg. Indust. Use (MWH)	707	670	730
Avg. Indust. Revs. per KWH (¢)	5.57	6.28	6.87
Capacity at Peak (Mw)	7758	7412	7652
Peak Load, Summer (Mw)	6402	7000	7652
Annual Load Factor (%)	52.2	50.0	48.0
% Change Customers (yr-end)	+3.7	+4.3	+4.4
Fixed Charge Cov. (%)	261	278	324

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	5.0%	-5.5%	5.5%
"Cash Flow"	2.0%	-4.5%	5.5%
Earnings	2.0%	-5.0%	1.5%
Dividends	7.5%	6.0%	3.0%
Book Value	4.5%	4.0%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	566.3	711.9	886.8	734.7	2899.7
2005	585.0	755.8	955.6	691.6	2988.0
2006	670.2	925.0	1076.5	730.1	3401.8
2007	695.1	863.4	1205.9	759.2	3523.6
2008	750	910	1260	840	3760

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.34	.78	1.14	.32	2.58
2005	.26	.88	.86	.24	2.24
2006	.12	1.11	1.84	.10	3.17
2007	.16	.78	1.97	.03	2.94
2008	.15	.80	1.50	.10	2.55

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.45	.45	.45	.475	1.83
2005	.475	.475	.475	.50	1.93
2006	.50	.50	.50	.525	2.03
2007	.525	.525	.525	.525	2.10
2008					

BUSINESS: Pinnacle West Capital Corporation (parent of Arizona Public Service) supplies electricity to approx. 1,780,000 people in 11 of 15 Arizona counties. Electric revenue sources: residential, 51%; commercial, industrial, and other, 49%. Power costs: 36% of electric revenues; labor costs: 13% of total revenues. The mining industry is the largest industrial customer. Energy sources: coal, 31%; nuclear, 17%; gas & other, 17%; purchased power, 35%. Has 7,140 employees. Reported '06 depreciation rate: 3.1%. Est'd plant age: 10 years. Chairman & Chief Executive Officer: William J. Post. Pres.: Jack E. Davis. Inc.: Arizona. Address: 400 E. Van Buren St., Suite 700, P.O. Box 52132, Phoenix, AZ 85072-2132. Tel.: 602-379-2568. Internet: www.pinnaclewest.com.

Pinnacle West plans new transmission lines to enhance import capability. Construction is well under way on a 100-mile, 500-kilovolt project around the greater Phoenix metropolitan area, which accounts for about 80% of the company's load requirements. The $160 million line should begin serving customers this summer. Under discussion is development of a 300-mile to 400-mile line from southwestern New Mexico into southeastern Arizona. The line's 1,200 megawatts of capacity would bolster the regional grid and provide a major east-west interconnection where none currently exists. Management has also proposed building a 122-mile line from the Palo Verde nuclear station to Yuma, Arizona to ensure adequate power in that area. For the longer term, PNW is considering a venture with partners for a 600-mile, $3 billion line from Wyoming to the Southwest to gain access to inexpensive coal and wind resources.

The company's ongoing requests for power have met with good response. Offers received over the last two years have resulted in purchased-power agreements for 1,200 megawatts (mw) from various sources for delivery starting in June, 2007. Too, PNW will buy the 40-mw output of a wind farm for 20 years and has approval for a 96-mw peaking facility adjacent to its existing plant in Yuma. Since outlays for these additions and for the transmission system won't be fully covered by cash flow, some debt and equity offerings will be necessary to close the gap.

Earnings are headed lower in 2008. A repetition of last year's favorable weather conditions that lifted 2007's third-quarter earnings to a record high can't be counted on this year. Other negatives include the absence of 2007's one-time tax benefits and weakness in SunCor's land sales because of a depressed housing market. On balance, we estimate 2008 earnings will decline 13%, to $2.55 a share. New plants on line point to gains over the coming 3 to 5 years.

Despite mid-2007's disappointing rate order, dividend growth prospects still exceed those of the group. What's more, finances are strong. PNW remains an above-average electric utility choice, in our opinion.

Arthur H. Medalie *February 8, 2008*

(A) Diluted egs. Excl. nonrecurring gains (losses): '91, ($4.68); '93, 22¢; '94, 31¢; '95, net 6¢; '99, ($1.20); '02, (77¢); excl. gains (losses) from discontinued ops.: '91, $1.76; '92, 7¢; '99, ($1.97); '00, 22¢; '05, (36¢); '06, 10¢. Next earnings report due late Apr. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Divd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def. chgs. In '06: $9.51/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in '05: 10.25%; earned on avg. com. eq., '06: 9.2%. Reg. Clim.: Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	60

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PPL CORPORATION NYSE-PPL

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
49.23	18.3	(Trailing: 18.6 Median: 12.0)	1.09	2.7%	VALUE LINE

TIMELINESS **3** Raised 8/10/07
SAFETY **2** Raised 6/2/06
TECHNICAL **3** Lowered 10/12/07
BETA .90 (1.00 = Market)

High:	13.0	12.1	14.5	16.0	23.1	31.2	20.0	22.2	27.1	33.7	37.3	52.8
Low:	10.8	9.5	10.4	10.2	9.2	15.5	13.0	15.8	19.9	25.5	27.8	34.4

Target Price Range
2010 | 2011 | 2012

2010-12 PROJECTIONS

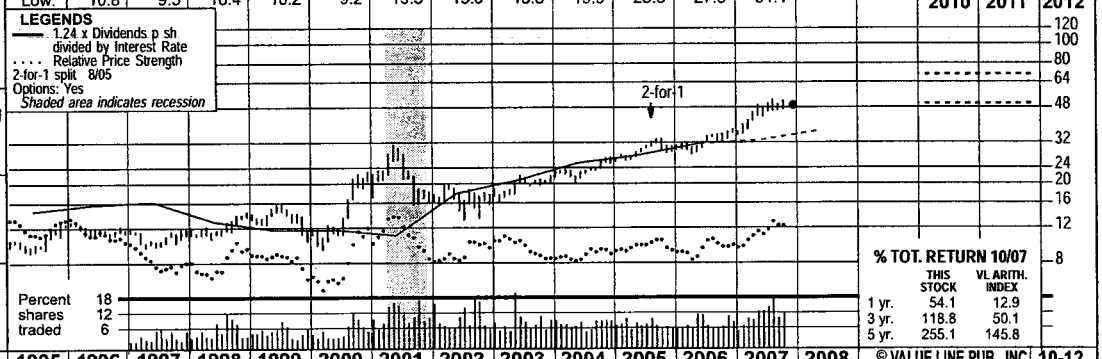
	Price	Gain	Ann'l Total Return
High	70	(+40%)	12%
Low	50	(Nil)	4%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	1	0	2	1	0	5
to Sell	1	0	0	5	0	2	1	0	5

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	191	213	163
to Sell	196	183	235
Hld's(000)	238199	227703	236649



% TOT. RETURN 10/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	54.1	12.9
3 yr.	118.8	50.1
5 yr.	255.1	145.8

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
8.44	9.03	8.96	8.76	8.63	8.94	9.17	12.03	15.97	19.59	19.53	16.38	15.75	15.37	16.36	17.92	*18.30*	*19.75*	Revenues per sh	*25.50*
1.86	1.90	1.98	1.84	2.05	2.14	2.11	2.43	2.56	3.32	3.51	3.20	3.60	3.59	3.84	4.26	*5.00*	*4.80*	"Cash Flow" per sh	*7.75*
1.00	1.01	1.04	.84	.97	1.03	.99	1.12	1.01	1.64	1.79	1.54	1.84	1.87	1.92	2.29	*2.75*	*2.45*	Earnings per sh A	*4.50*
.78	.80	.83	.84	.84	.84	.84	.67	.50	.53	.53	.72	.77	.82	.96	1.10	*1.22*	*1.34*	Div'd Decl'd per sh B ■	*2.20*
1.23	1.39	1.60	1.62	1.26	1.11	.93	.97	1.11	1.59	2.99	2.74	2.17	1.94	2.13	3.62	*4.70*	*4.35*	Cap'l Spending per sh	*4.25*
7.58	7.79	7.97	7.89	8.15	8.44	8.45	5.69	5.61	6.94	6.33	6.71	9.19	11.21	11.62	13.30	*13.90*	*15.10*	Book Value per sh C	*19.75*
303.31	303.77	304.26	310.96	318.81	325.33	332.50	314.82	287.39	290.08	293.16	331.47	354.72	378.14	380.15	385.04	*372.00*	*372.00*	Common Shs Outst'g D	*360.00*
11.4	12.9	14.1	13.0	10.8	11.4	10.8	10.9	13.4	8.9	12.4	11.1	10.6	12.5	15.1	14.1	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.73	.78	.83	.85	.72	.71	.62	.57	.76	.58	.64	.61	.60	.66	.80	.76	*Value Line*		Relative P/E Ratio	*.95*
6.8%	6.1%	5.7%	7.7%	8.0%	7.1%	7.8%	5.5%	3.7%	3.6%	2.4%	4.2%	4.0%	3.5%	3.3%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $7833.0 mill. **Due in 5 Yrs** $2528.0 mill.
LT Debt $7171.0 mill. **LT Interest** $457.0 mill.
Incl. 23 mill. units 7.75%, $25 liq. value; 82,000 units 8.23%, $1000 face value.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $49.0 mill.
Pension Assets-12/06 $5.18 bill. **Oblig.** $5.54 bill.
Pfd Stock $301.0 mill. **Pfd Div'd** $18.0 mill.
505,189 shs. 3.35%-6.75%, $100 par, cumulative, callable $102.00-$110.00; 10 mill. shs. 6.25%, $100 liq. preference, redeemable after 4/6/11.
Common Stock 372,196,010 shs. **as of 10/31/07**
MARKET CAP: $18 billion (Large Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
3049.0	3786.0	4590.0	5683.0	5725.0	5429.0	5587.0	5812.0	6219.0	6899.0	*6800*	*7350*	Revenues ($mill)	*9200*
348.0	393.0	332.0	500.0	576.0	536.0	667.0	692.0	739.0	899.0	*1070*	*955*	Net Profit ($mill)	*1700*
41.5%	40.7%	33.5%	36.3%	29.7%	25.7%	27.1%	22.8%	14.0%	23.2%	*17.0%*	*35.0%*	Income Tax Rate	*35.0%*
2.0%	2.3%	2.1%	4.0%	4.3%	3.4%	1.2%	.7%	1.1%	2.6%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*2.0%*
46.1%	59.1%	65.7%	65.4%	64.8%	66.5%	71.1%	61.6%	57.5%	55.4%	*56.5%*	*53.0%*	Long-Term Debt Ratio	*48.5%*
48.0%	34.2%	28.2%	29.5%	23.7%	25.1%	28.5%	37.9%	42.0%	42.2%	*41.0%*	*44.5%*	Common Equity Ratio	*49.5%*
5854.0	5229.0	5716.0	6826.0	7845.0	8868.0	11455	11171	10513	12151	*12625*	*12700*	Total Capital ($mill)	*14400*
6820.0	4480.0	5644.0	5948.0	6135.0	9566.0	10446	11209	10916	12069	*13050*	*13850*	Net Plant ($mill)	*15300*
7.6%	9.5%	7.9%	9.7%	9.6%	8.8%	7.6%	8.4%	9.4%	9.4%	*10.0%*	*9.5%*	Return on Total Cap'l	*13.5%*
11.0%	18.4%	16.9%	21.2%	20.8%	18.1%	20.2%	16.1%	16.5%	16.6%	*19.5%*	*16.0%*	Return on Shr. Equity	*23.0%*
11.5%	20.6%	19.0%	23.6%	28.2%	21.1%	19.6%	16.3%	16.7%	17.3%	*20.5%*	*16.5%*	Return on Com Equity E	*23.5%*
1.8%	6.4%	9.4%	16.1%	20.2%	12.4%	11.7%	9.3%	8.8%	9.3%	*11.5%*	*8.0%*	Retained to Com Eq	*12.5%*
86%	71%	54%	35%	35%	49%	43%	43%	47%	47%	*45%*	*54%*	All Div'ds to Net Prof	*48%*

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+2.4	+4.6	-1.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw) F	7199	7035	7554
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.6	+1.1	+.9
Fixed Charge Cov. (%)	264	259	300

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	6.5%	-2.0%	*7.5%*
"Cash Flow"	7.0%	4.5%	*12.0%*
Earnings	8.0%	6.5%	*14.0%*
Dividends	1.5%	13.0%	*15.0%*
Book Value	4.0%	14.0%	*8.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1520	1362	1465	1465	5812.0
2005	1600	1478	1643	1498	6219.0
2006	1781	1642	1752	1724	6899.0
2007	1638	1613	1763	*1786*	*6800*
2008	*1850*	*1750*	*1900*	*1850*	*7350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.52	.36	.52	.47	1.87
2005	.45	.46	.51	.50	1.92
2006	.73	.52	.58	.46	2.29
2007	.63	.63	.93	*.56*	*2.75*
2008	*.60*	*.60*	*.65*	*.60*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.18	.193	.193	.193	.76
2004	.193	.205	.205	.205	.81
2005	.205	.23	.23	.25	.92
2006	.25	.275	.275	.275	1.08
2007	.275	.305	.305	.305	

BUSINESS: PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Utilities (formerly Pennsylvania Power & Light Company), which distributes electricity to about 1.4 million customers in a 10,000-square-mile area in eastern & central Pennsylvania. Distributes gas to 110,000 customers. Also has subs. in power generation & marketing, foreign electricity distribution in U.K. (2.6 million customers) and Latin America (1.1 million customers). Electric revenue breakdown & generating sources not provided. Fuel costs: 32% of revenues. '06 deprec. rate: 3.8%. Has 12,600 employees. Chairman, President & CEO: James H. Miller. Inc.: Pennsylvania. Address: Two North Ninth St., Allentown, PA 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

PPL has reached a settlement of its general rate case. This calls for a distribution rate increase of $55.0 million (1.7%). The agreement, which has the recommendation of an administrative law judge, is subject to the approval of the Pennsylvania commission. If approved, it will take effect at the start of 2008.

The company has completed the sale of the last of its three utilities in Latin America. In all, these properties fetched $851 million, before taxes and transaction costs. PPL is using the proceeds to fund a $750 million stock buyback. The company has already recorded a modest gain on the first two sales, but the third gain, at an estimated $205 million-$225 million after taxes, will be the largest, by far. In all, the gains are expected to total $251 million-$271 million. We are *excluding* this income from our presentation because it is from discontinued operations.

Earnings will probably decline in 2008. PPL will lose $0.11 a share of earnings from its synthetic fuel investments, since the synfuel credits will cease at the end of 2007. Also, earnings in 2007 benefited from some unusual tax credits. Our 2008 estimate is at the top of PPL's targeted range of $2.35-$2.45 a share. But . . .

Earnings should rise sharply in 2010. The price that PPL Energy Supply may charge to its utility sibling in Pennsylvania is now limited by a price structure that, although increasing each year, is well below market rates. Since customers in PPL's service area will be paying higher market-based rates beginning in 2010, this will benefit suppliers such as PPL Energy Supply. Based on higher observed prices for energy and capacity in 2010, PPL has raised its profit guidance for that year from $3.50 a share to $4.00-$4.60. In order to lessen the rate shock that customers would otherwise experience then, the company has proposed a 54-month rate phase-in plan.

This stock's valuation is higher than it has been historically, in anticipation of much greater profits beginning in 2010. Dividends should be much higher over that time, too. The current yield is below average for a utility, but 3- to 5-year total-return potential is above the utility norm.

Paul E. Debbas, CFA *November 30, 2007*

(A) Diluted EPS. Excl. nonrec. gains (losses): '97, (9¢); '98, ($2.85); '99, 41¢; '00, 8¢; '01, ($1.18) net; '02, (89¢); '03, 24¢; '04, 3¢; '05, (2¢); '07, (12¢); gain (losses) on disc. ops.: '03, (6¢); '04, (1¢); '05, (12¢); '07, 19¢. Next earnings report due early Feb. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '06: $6.25/sh. (D) In mill., adj. for split. (E) Rate base: Fair value. Rate allowed on com. eq. in '05: 10.7%; earn. on avg. com. eq., '06: 17.8%. Regulat. Climate: Avg. (F) Summer peak in '06.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	95
Earnings Predictability	80

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PROGRESS ENERGY NYSE-PGN

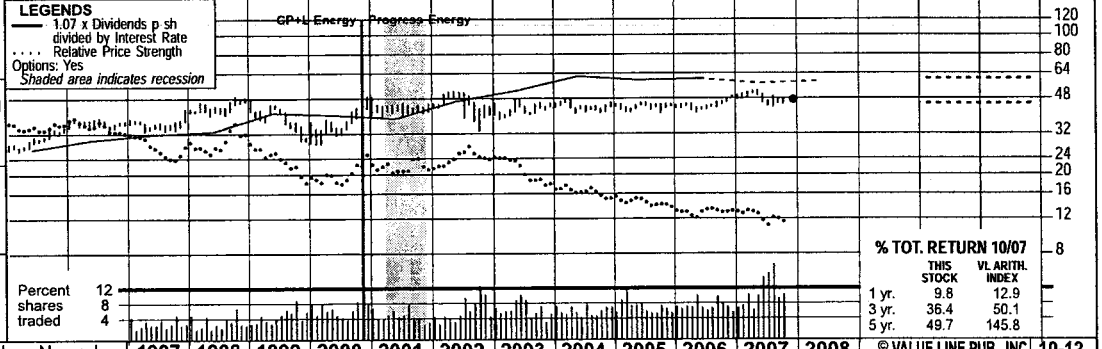
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
47.37	16.2	(Trailing: 15.9 Median: 14.0)	0.96	5.2%	VALUE LINE

TIMELINESS 3 Lowered 7/27/07
SAFETY 2 Lowered 6/7/02
TECHNICAL 3 Raised 11/2/07
BETA .85 (1.00 = Market)

High:	38.8	42.7	49.6	47.9	49.4	49.3	52.7	48.0	47.9	46.0	49.6	52.8
Low:	33.8	32.8	39.2	29.3	28.3	38.8	32.8	37.4	40.1	40.2	40.3	43.1

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.07 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+25%)	10%
Low	45	(-5%)	4%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	1	1	2	4	1	5	0	0	0
to Sell	2	1	2	10	2	5	0	0	0

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	217	212	222
to Sell	164	173	178
Hld's(000)	158683	151020	160423

% TOT. RETURN 10/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	9.8	12.9
3 yr.	36.4	50.1
5 yr.	49.7	145.8

Progress Energy was formed on November 30, 2000 through the merger of CP&L Energy and Florida Progress. Florida Progress common shareholders exchanged each share held for $54 in cash and/or CP&L common stock. They also received one Contingent Value Obligation for each share of Florida Progress stock, entitling them to payments in the event that four synthetic fuel plants achieve certain economic levels from 2001 to 2007. Data prior to merger are for CP&L only and are not comparable with Progress Energy data.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
19.98	20.68	21.04	19.99	38.69	34.18	35.54	39.56	40.11	37.38	*39.25*	*39.00*	Revenues per sh	*40.90*
6.26	6.44	6.06	5.37	8.14	7.02	7.54	7.40	6.53	5.93	*7.00*	*7.35*	"Cash Flow" per sh	*8.40*
2.66	2.75	2.55	2.34	3.43	3.84	3.41	3.10	2.94	2.05	*2.90*	*3.00*	Earnings per sh A	*3.30*
1.90	1.96	2.02	2.08	2.14	2.18	2.26	2.32	2.38	2.42	*2.45*	*2.47*	Div'd Decl'd per sh B†■	*2.53*
2.57	2.80	4.32	4.61	5.56	5.05	4.14	4.04	4.29	5.56	*9.35*	*9.55*	Cap'l Spending per sh	*7.30*
18.63	19.49	21.38	26.32	27.45	28.73	30.26	30.90	31.90	32.37	*32.75*	*33.15*	Book Value per sh C	*35.05*
151.34	151.34	159.60	206.09	218.73	232.43	246.00	247.00	252.00	256.00	*260.00*	*264.00*	Common Shs Outst'g E	*274.00*
13.6	15.9	15.2	15.3	12.4	11.9	12.4	14.1	14.8	21.62	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.78	.83	.87	.99	.64	.65	.71	.74	.79	1.17	*Value Line*		Relative P/E Ratio	*1.05*
5.3%	4.5%	5.2%	5.8%	5.0%	4.8%	5.3%	5.3%	5.5%	5.5%	*estimates*		Avg Ann'l Div'd Yield	*4.9%*
3024.1	3130.1	3357.6	4118.9	8461.5	7945.0	8743.0	9772.0	10108	9570	*10200*	*10290*	Revenues ($mill)	*11200*
388.3	399.2	382.3	369.9	695.1	815.2	818.1	763.5	727.0	514.0	*760*	*790*	Net Profit ($mill)	*900*
37.6%	39.2%	40.3%	35.4%	--	--	--	13.1%	13.1%	28.4%	*28.0%*	*28.0%*	Income Tax Rate	*28.0%*
1.3%	1.7%	3.0%	5.6%	2.6%	1.0%	3.4%	.8%	1.8%	1.4%	*1.0%*	*1.0%*	AFUDC % to Net Profit	*1.0%*
45.6%	46.5%	46.6%	51.6%	60.9%	59.0%	56.1%	55.2%	56.2%	51.3%	*51.5%*	*51.0%*	Long-Term Debt Ratio	*49.5%*
53.2%	52.4%	52.5%	47.6%	38.5%	40.4%	43.4%	44.3%	43.3%	48.1%	*48.0%*	*48.5%*	Common Equity Ratio	*50.0%*
5293.8	5623.1	6500.6	11407	15580	16517	17162	17247	18577	17214	*17735*	*18075*	Total Capital ($mill)	*18955*
6293.5	6299.5	6764.8	10437	10915	10656	14434	14363	14442	15245	*16605*	*17975*	Net Plant ($mill)	*20395*
8.9%	8.6%	7.3%	4.3%	6.4%	6.8%	6.5%	6.2%	5.6%	4.8%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
13.5%	13.3%	11.0%	6.7%	11.4%	12.0%	10.9%	9.9%	8.9%	6.1%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
13.6%	13.4%	11.1%	6.7%	11.5%	12.1%	10.9%	9.9%	9.0%	6.1%	*9.0%*	*9.0%*	Return on Com Equity D	*9.5%*
3.9%	4.0%	2.5%	NMF	4.3%	5.0%	3.7%	2.6%	1.7%	NMF	*1.5%*	*1.5%*	Retained to Com Eq	*2.5%*
72%	71%	78%	101%	63%	59%	67%	74%	81%	119%	*84%*	*82%*	All Div'ds to Net Prof	*76%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $10,201 mill. **Due in 5 Yrs** $3697 mill.
LT Debt $8436 mill. **LT Interest** $581 mill.
(LT interest earned: 2.2x)
Pension Assets-12/06 $1.84 bill. **Oblig.** $2.12 bill.
Pfd Stock $92.8 mill. **Pfd Div'd** $4.5 mill.
921,814 shs. $4.00 to $5.44 cum. no par. callable from $101 to $110 per sh. Sinking funds began in 1984 and 1986, respectively.
Common Stock 259,000,000 shs.
MARKET CAP: $12.3 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+.5	1.4	-2.3
Avg. Indust. Use (MWH)	2394	2399	2328
Avg. Indust. Revs. per KWH (¢)	4.84	5.74	6.38
Capacity at Peak (Mw)	23878	24500	21322
Peak Load, Summer (Mw)	19711	21983	21717
Annual Load Factor (%)	61.3	55.0	NA
% Change Customers (yr-end)	+2.2	+3.1	+2.0
Fixed Charge Cov. (%)	227	198	204

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	7.5%	8.0%	*1.0%*
"Cash Flow"	2.5%	.5%	*4.0%*
Earnings	1.0%	-.5%	*3.5%*
Dividends	3.0%	2.5%	*1.0%*
Book Value	6.5%	5.0%	*1.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	2245	2408	2761	2358	9772
2005	2168	2295	3067	2578	10108
2006	2250	2316	2731	2273	9570
2007	2334	2406	3100	*2360*	*10200*
2008	*2410*	*2480*	*2960*	*2440*	*10290*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.45	.63	1.24	.78	3.10
2005	.43	.03	1.85	.64	2.94
2006	.34	.08	1.12	.51	2.05
2007	.61	.51	1.21	*.57*	*2.90*
2008	*.63*	*.52*	*1.25*	*.60*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID ■B† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.56	.56	.56	.56	2.24
2004	.575	.575	.575	.575	2.30
2005	.59	.59	.59	.59	2.36
2006	.605	.605	.605	.605	2.42
2007	.61	.61	.61	.61	

BUSINESS: Progress Energy, parent of CP&L Energy and Florida Progress, supplies electricity to portions of North Carolina, South Carolina, and Florida. Other operations include synthetic fuels, coal mining, wholesale generation, and financial services. Electric revenues: residential, 37%; commercial, 25%; industrial, 18%; other, 20%. Power costs: 43% of revs; labor costs: 14%. Fuel sources: gas/oil/coal, 50%; nuclear, 43%; hydro, 1%; purch. power, 6%. Has 11,600 employees. '06 depreciation rate: 2.7%. Est'd plant age: 8 years. Chairman, CEO, and President: William D. Johnson. Incorporated: North Carolina. Address: 411 Fayetteville Street, Raleigh, North Carolina 27602. Telephone: 1-800-662-7232. Internet: www.progress-energy.com.

Progress Energy plans to add 12,500 megawatts (mw) of capacity by 2025. For starters, the 500-mw gas-fired Hines 4 plant is scheduled to go on line next month at a cost of $327 million. Its location at the same site where three facilities are already operating will spread fixed costs over an additional unit. PGN has also begun major renovation at the Bartow station. Three plants are being converted from burning heavy oil to burning natural gas, and their combined output will be increased by 600 mw. The first two units are targeted to go on line in 2009, the third one year later. The project will cost $435 million. Too, the company is seeking approval to construct four diesel plants of 1,000 mw each. Additional generation will be built as the need arises. Meanwhile, the company is ramping up its energy-efficiency program to delay the need for the next coal-fired plant. These activities will require some long-term debt financing over the next few years.

Rate adjustments in Florida are in the works. Under a 2005 agreement with regulators, base rates will be increased $52 million when the Hines 4 plant begins operating. Furthermore, last year's storm-related surcharge to replenish the reserve fund has been extended through July, 2008. This will add $130 million to the fund. On the down side, the company has been ordered to refund $13.8 million to ratepayers for imprudent coal purchases in 2001 and 2005. The order has been appealed.

A strong first half points to improved earnings in 2007. The installation of 2.7 million "smart" meters will reduce yearly payroll by $24 million. Higher margins on energy sales, a 2% increase in kilowatt-hour sales, and lower income taxes are additional pluses. Despite an increase in nuclear plant downtime for refuelings, we estimate 2007 earnings will rise more than 40%, to $2.90 a share. The sale of non-utility businesses suggests steady, but modest, profit growth to 2010-2012.

The yield is above the industry norm. That reflects a probable slowdown in earnings growth and the likelihood that dividend hikes will be slower than they have been. All told, we rate PGN an average utility investment.

Arthur H. Medalie *November 30, 2007*

(A) EPS diluted. Next egs. report due late Jan. Excl. nonrecur.: '00, 69¢; '01, (75¢); '02, ($1.32); '03, (3¢); '05, (39¢). (B) Div'ds historically paid in early Feb., May, Aug, and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan avail. (C) Incl. def. charges in '06: $26.84/sh. (D) Rate Base: orig. cost. Rate allowed on common equity. In '88 in N.C.: 12.75%; in '88 in S.C.: 12.75%; in '02 in Fla.: rev. sharing incentive plan; earn. on '06 avg. com. eq.: 6.3%. Regul. Clim.: Avg. (E) In millions.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	5
Earnings Predictability	70

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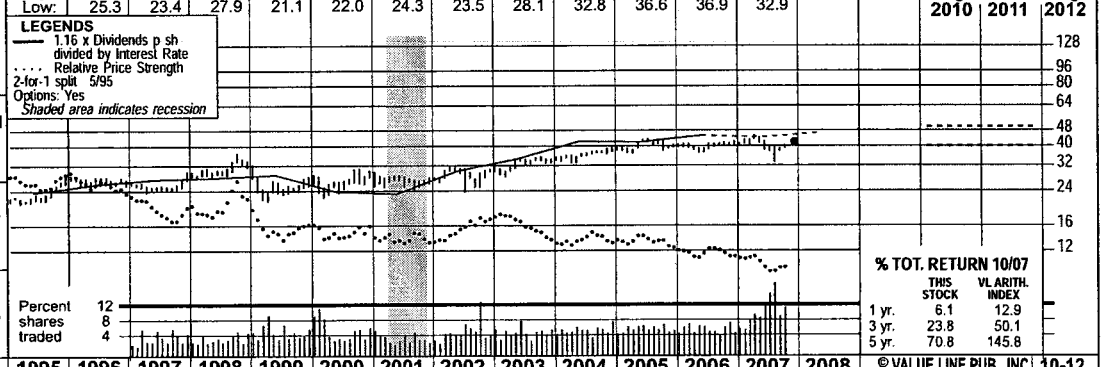
SCANA CORP. NYSE-SCG

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
41.99	14.7	(Trailing: 16.4 Median: 14.0)	0.88	4.3%	VALUE LINE

TIMELINESS 4 Raised 8/10/07
SAFETY 2 Lowered 9/10/99
TECHNICAL 4 Lowered 11/2/07
BETA .85 (1.00 = Market)

High:	28.6	29.9	37.3	32.6	31.1	30.0	32.1	35.7	39.7	43.7	42.4	45.5
Low:	25.3	23.4	27.9	21.1	22.0	24.3	23.5	28.1	32.8	36.6	36.9	32.9

Target Price Range
2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+20%)	8%
Low	40	(-5%)	3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	1	0	0	1
Options	0	0	2	0	0	2	0	0	0
to Sell	0	0	2	0	0	3	0	0	1

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	135	141	129
to Sell	107	108	111
Hld's(000)	48538	48063	50548

% TOT. RETURN 10/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	6.1	12.9
3 yr.	23.8	50.1
5 yr.	70.8	145.8

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
14.07	12.96	13.56	13.77	13.06	14.25	14.19	15.76	15.93	32.78	32.95	26.65	30.85	34.38	41.54	39.00	40.15	42.75	Revenues per sh	50.00
3.10	2.78	3.50	3.77	3.68	3.75	3.53	3.62	3.15	4.43	4.55	4.56	4.95	5.26	7.41	5.67	5.80	6.05	"Cash Flow" per sh	7.00
1.69	1.42	1.86	1.60	1.86	2.05	1.90	2.12	1.44	2.12	2.15	2.38	2.50	2.67	2.78	2.59	2.70	2.90	Earnings per sh A	3.25
1.31	1.34	1.37	1.41	1.44	1.47	1.51	1.54	1.32	1.15	1.20	1.30	1.38	1.46	1.56	1.68	1.76	1.82	Div'd Decl'd per sh B ■ †	2.00
2.93	3.16	3.46	4.21	3.09	2.34	2.45	2.87	2.37	3.28	4.99	6.41	6.94	4.84	3.37	4.50	6.40	7.45	Cap'l Spending per sh	5.25
12.62	13.23	14.30	14.69	15.00	15.86	16.66	16.86	20.27	19.40	20.95	19.64	20.82	21.69	23.28	24.32	25.40	26.50	Book Value per sh C	30.00
81.57	87.82	93.24	96.04	103.62	106.18	107.32	103.57	103.57	104.73	104.73	110.83	110.74	113.00	115.00	117.00	117.00	117.00	Common Shs Outst'g D	117.00
11.3	14.5	12.8	14.0	12.3	13.1	13.4	14.5	17.5	12.5	12.6	12.2	13.0	13.6	14.4	15.4	Bold figures are		Avg Ann'l P/E Ratio	13.5
.72	.88	.76	.92	.82	.82	.77	.75	1.00	.81	.65	.67	.74	.72	.77	.83	Value Line		Relative P/E Ratio	.90
6.9%	6.5%	5.8%	6.3%	6.3%	5.5%	5.9%	5.0%	5.2%	4.3%	4.4%	4.5%	4.2%	4.0%	3.9%	4.2%	estimates		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 6/30/07
Total Debt $3586.0 mill. **Due in 5 Yrs** $1658.0 mill.
LT Debt $2959.0 mill. **LT Interest** $176.0 mill.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $30.0 mill.
Pension Assets-12/06 $912.5 mill. **Oblig.** $713.0 mill.
Pfd Stock $113.0 mill. **Pfd Div'd** $6.0 mill.
125,209 shs. 5% cum., $50 par., callable $52.50; 220,287 shs. 4.50% to 6.00% cum., $50 par, callable $50.50 to $51.00; 1,000,000 shs. 6.52% cum., $100 par, callable $100.00.
Common Stock 116,664,933 shs. **as of 7/31/07**
MARKET CAP: $4.9 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
1523.0	1632.0	1650.0	3433.0	3451.0	2954.0	3416.0	3885.0	4777.0	4563.0	4700	5000	Revenues ($mill)	5850
213.0	235.0	160.0	228.0	231.0	259.0	285.0	305.0	323.0	306.0	325	345	Net Profit ($mill)	385
32.8%	35.8%	41.0%	38.2%	34.9%	32.2%	31.5%	32.5%	32.5%	26.5%	33.5%	35.0%	Income Tax Rate	35.0%
6.1%	6.8%	4.4%	3.9%	11.3%	13.5%	10.5%	8.5%	.9%	2.6%	7.0%	9.0%	AFUDC % to Net Profit	3.0%
44.5%	45.9%	40.8%	57.4%	53.9%	55.7%	57.1%	55.4%	51.4%	50.9%	50.0%	51.0%	Long-Term Debt Ratio	49.5%
50.8%	49.4%	54.8%	40.3%	43.8%	42.1%	40.8%	42.6%	46.6%	47.2%	48.5%	47.0%	Common Equity Ratio	49.0%
3522.0	3536.0	3829.0	5048.0	5006.0	5176.0	5646.0	5752.0	5739.0	6027.0	6155	6580	Total Capital ($mill)	7175
3648.0	3764.0	3829.0	4475.0	4803.0	5474.0	6417.0	6762.0	6734.0	7007.0	7395	7900	Net Plant ($mill)	8650
7.7%	8.4%	5.9%	6.8%	6.9%	7.0%	6.9%	7.1%	7.4%	6.8%	7.0%	7.0%	Return on Total Cap'l	7.0%
10.9%	12.3%	7.1%	10.6%	10.0%	11.3%	11.8%	11.9%	11.6%	10.3%	10.5%	10.5%	Return on Shr. Equity	10.5%
11.4%	12.8%	7.1%	10.9%	10.2%	11.6%	12.1%	12.2%	11.8%	10.5%	10.5%	11.0%	Return on Com Equity E	11.0%
2.4%	3.4%	--	4.8%	4.6%	5.5%	5.5%	5.6%	5.3%	3.8%	3.5%	4.0%	Retained to Com Eq	4.0%
80%	74%	99%	57%	56%	54%	55%	55%	56%	65%	66%	64%	All Div'ds to Net Prof	62%

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+4.9	+.9	-1.4
Avg. Indust. Use (MWH)	NA	13249	12005
Avg. Indust. Revs. per KWH (¢)	4.32	4.82	5.16
Capacity at Yearend (Mw)	5776	5776	5749
Peak Load, Summer (Mw)	4574	4820	4747
Annual Load Factor (%)	60.2	57.3	57.5
% Change Customers (yr-end)	+2.5	+3.1	+2.2
Fixed Charge Cov. (%)	264	190	261

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	11.0%	7.0%	4.5%
"Cash Flow"	5.0%	8.5%	2.5%
Earnings	4.0%	7.0%	3.5%
Dividends	1.0%	5.0%	4.0%
Book Value	4.5%	2.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1136	846.0	857.0	1046	3885.0
2005	1266	891.0	1127	1493	4777.0
2006	1389	944.0	1062	1168	4563.0
2007	1363	1007	1079	1251	4700
2008	1450	1100	1150	1300	5000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.91	.54	.71	.51	2.67
2005	.89	.36	.88	.65	2.78
2006	.80	.46	.76	.57	2.59
2007	.73	.47	.79	.71	2.70
2008	.85	.50	.88	.67	2.90

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.325	.345	.345	.345	1.36
2004	.345	.365	.365	.365	1.44
2005	.365	.39	.39	.39	1.54
2006	.39	.42	.42	.42	1.65
2007	.42	.44	.44	.44	

BUSINESS: SCANA Corporation is a holding company for South Carolina Electric & Gas Company, which supplies electricity to 636,000 customers in South Carolina. Supplies gas and transmission service to 1.2 million customers in North and South Carolina and Georgia. Owns gas pipelines. Acquired PSNC Energy 2/00. Electric revenue breakdown, '06: residential, 40%; commercial, 31%; industrial, 17%; other, 12%. Generating sources, '06: coal, 66%; nuclear, 19%; oil & gas, 9%; hydro, 4%; purchased, 2%. Fuel costs: 63% of revenues. '06 reported deprec. rate: 3.2%. Has 5,700 employees. Chairman, President & CEO: William B. Timmerman. Incorporated: South Carolina. Address: 1426 Main St., Columbia, SC 29201-2845. Tel.: 803-217-9000. Internet: www.scana.com.

SCANA's utility subsidiary in South Carolina has reached a settlement of its electric rate case. South Carolina Electric & Gas had filed for a rate hike of $118 million (6.75%) based on an 11.75% return on equity. The utility, the commission's staff, and intervenor groups reached a settlement for a $76.9 million (4.4%) increase, based on an 11% ROE. The South Carolina commission must approve the agreement. Its decision is expected by mid-December, with new tariffs taking effect at the start of 2008. We think the settlement is very reasonable.

The South Carolina commission has increased SCE&G's base gas rates. The $4.6 million boost took effect in November. It was granted in accordance with a regulatory mechanism that allows the commission to raise the utility's gas rates (if necessary), without a full-blown rate case, to provide SCE&G with an opportunity to earn its allowed ROE of 10.25%.

Earnings will probably increase in 2007, despite the fact that they declined in the first nine months. The fourth-quarter comparison should be easy, since profits were weak a year ago due to mild weather and a settlement with the Federal Energy Regulatory Commission that reduced share net by $0.08. Our estimate is at the low end of SCANA's targeted range of $2.70-$2.85 a share.

We look for higher profits in 2008. We assume that the electric rate settlement in South Carolina is approved. Also, we assume normal weather conditions, and the first quarter of 2007 was milder than usual. SCANA should also benefit from customer growth at SCE&G and the company's gas utility subsidiary in North Carolina. Our earnings forecast is at the low end of management's guidance of $2.90-$3.05 a share.

We expect a dividend hike at the board meeting in February. We estimate that the directors will boost the annual disbursement by $0.06 a share. That's lower than recent increases due to the rising payout ratio. Even so, we wouldn't be shocked by a higher boost.

SCANA stock is untimely but offers an above-average yield, even by utility standards. Total-return potential to 2010-2012 is only average for a utility, however.

Paul E. Debbas, CFA *November 30, 2007*

(A) Excl. nonrec. gains (losses): '95, (16¢); '97, 16¢; '99, 29¢; '00, 28¢; '01, $3.00; '02, ($3.72); '03, 31¢; '04, (23¢); '05, 3¢; '06, 9¢. Next earnings report due mid-Feb. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '06: $9.90/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '05 in SC: 10.7% electric, 10.25% gas; in '06 in NC: none specified; earned on avg. com. eq., '06: 10.9%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	95

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SOUTHERN CO. NYSE-SO

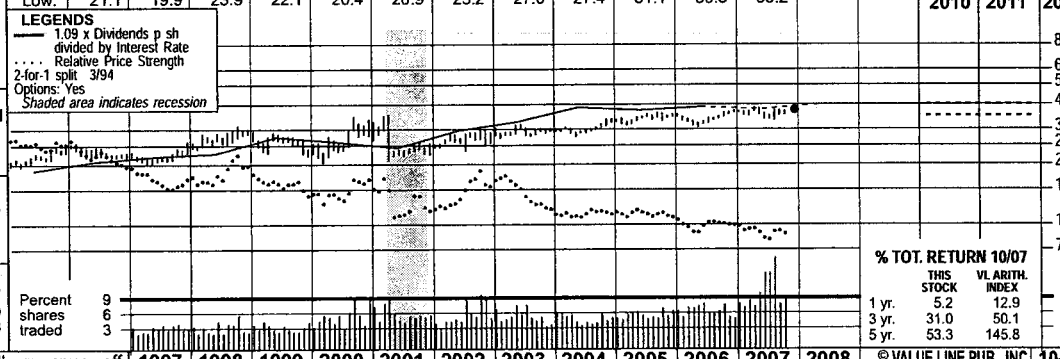
RECENT PRICE 37.69 | P/E RATIO 17.7 (Trailing: 16.7 Median: 15.0) | RELATIVE P/E RATIO 1.05 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 3 Raised 8/4/06
SAFETY 1 Raised 6/3/05
TECHNICAL 3 Raised 8/24/07
BETA .70 (1.00 = Market)

High:	25.9	26.3	31.6	29.6	35.0	35.7	31.1	32.0	34.0	36.5	37.4	38.9
Low:	21.1	19.9	23.9	22.1	20.4	20.9	23.2	27.0	27.4	31.1	30.5	33.2

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.09 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 3/94
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+5%)	6%
Low	35	(-5%)	3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	2	0	0	0	0
Options	0	2	0	0	2	2	0	0	0
to Sell	0	2	0	0	2	2	0	0	0

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	292	250	279
to Sell	233	283	253
Hld's(000)	334197	330260	368747

Percent shares traded 9 6 3

% TOT. RETURN 10/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	5.2	12.9
3 yr.	31.0	50.1
5 yr.	53.3	145.8

In September, 2000, Southern spun off Mirant, its independent power marketing and trading subsidiary. Issuing 66.7 million shares, the company and Mirant shared $1.8 billion in gross proceeds. In April, 2001, management spun off the remaining 80.3% stake in Mirant to Southern investors; 0.4 of a common share in the subsidiary was distributed for each common share in the parent held. Mirant filed for Chapter 11 bankruptcy protection in July, 2003 and emerged from bankruptcy in January, 2006.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
18.41	16.32	17.39	14.76	14.53	14.71	15.31	16.04	18.28	19.23	*19.95*	*20.55*	Revenues per sh	*23.25*
3.90	4.25	4.17	3.89	3.54	3.45	3.53	3.65	4.03	4.01	*4.20*	*4.25*	"Cash Flow" per sh	*4.75*
1.58	1.73	1.83	2.01	1.61	1.85	1.97	2.06	2.13	2.10	*2.20*	*2.30*	Earnings per sh A	*2.50*
1.30	1.34	1.34	1.34	1.34	1.36	1.39	1.42	1.48	1.54	*1.60*	*1.66*	Div'd Decl'd per sh B ■ †	*1.85*
2.71	2.87	3.84	3.26	3.74	3.79	2.72	2.84	3.20	4.01	*5.10*	*5.75*	Cap'l Spending per sh	*4.25*
14.08	14.02	13.82	15.67	11.42	12.15	13.13	13.86	14.41	15.23	*16.30*	*17.35*	Book Value per sh C	*19.50*
685.00	698.63	666.00	682.00	699.00	716.90	734.80	741.80	741.60	746.40	*765.00*	*783.00*	Common Shs Outst'g D	*805.00*
14.0	15.7	14.3	13.2	14.6	14.6	14.8	14.7	15.9	16.2	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.81	.82	.82	.86	.75	.80	.84	.78	.85	.87	*Value Line*		Relative P/E Ratio	*1.00*
5.9%	4.9%	5.1%	5.0%	5.7%	5.0%	4.7%	4.7%	4.4%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*5.0%*
12611	11403	11585	10066	10155	10549	11251	11902	13554	14356	*15250*	*16100*	Revenues ($mill)	*18650*
1245.0	1372.0	1457.0	1501.0	1306.0	1510.0	1602.1	1589.0	1621.0	1608.0	*1730*	*1830*	Net Profit ($mill)	*2080*
36.9%	24.1%	25.6%	31.0%	29.9%	25.9%	27.0%	27.0%	26.9%	32.7%	*34.0%*	*35.0%*	Income Tax Rate	*35.0%*
1.6%	1.8%	1.9%	4.7%	5.1%	5.4%	4.6%	5.2%	4.4%	4.8%	*6.0%*	*7.0%*	AFUDC % to Net Profit	*5.0%*
46.4%	45.9%	48.2%	37.1%	43.8%	43.1%	45.9%	53.5%	53.2%	50.8%	*51.5%*	*52.0%*	Long-Term Debt Ratio	*54.0%*
43.5%	42.9%	37.8%	50.6%	42.2%	43.4%	43.6%	44.1%	44.3%	46.2%	*46.0%*	*45.5%*	Common Equity Ratio	*44.0%*
22158	22817	24372	21147	18925	20086	22135	23288	24131	24618	*27225*	*29925*	Total Capital ($mill)	*35700*
23652	24124	24544	21622	23084	24642	27534	28361	29480	31092	*33525*	*36500*	Net Plant ($mill)	*43400*
7.1%	7.6%	7.8%	8.5%	8.2%	8.6%	8.4%	8.1%	8.2%	8.2%	*7.5%*	*7.5%*	Return on Total Cap'l	*7.5%*
10.5%	11.1%	11.5%	11.3%	12.3%	13.2%	13.4%	14.7%	14.4%	13.3%	*13.0%*	*13.0%*	Return on Shr. Equity	*12.5%*
11.2%	12.2%	13.6%	12.3%	14.0%	15.1%	14.8%	14.9%	14.9%	13.8%	*13.5%*	*13.0%*	Return on Com Equity E	*13.0%*
2.0%	2.7%	3.6%	4.1%	2.5%	4.1%	4.4%	4.7%	4.6%	3.8%	*4.0%*	*3.5%*	Retained to Com Eq	*3.5%*
84%	81%	77%	71%	85%	76%	73%	69%	70%	73%	*72%*	*73%*	All Div'ds to Net Prof	*74%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $16823 mill. **Due in 5 Yrs** $4724 mill.
LT Debt $13817 mill. **LT Interest** $725.0 mill.
(LT interest earned: 3.9x)
Leases, Uncapitalized Annual rentals $135.0 mill.
Pension Assets-12/06 $6.69 bill. **Oblig.** $5.49 bill.
Pfd Stock $766.3 mill. **Pfd Div'd** $41.8 mill.
Incl. 1 mill. shs. 4.20%-5.44% cum. sub. pfd. ($100 par); 12 mill. shs. 4.95%-5.83% cum. sub. pfd. ($1 par); 2 mill. shs. 6.0% noncum. sub. pfd. ($25 par); 1 mill. shs. 6.0% noncum. sub. pfd. ($100 par).
Common Stock 759,478,801 shs.
MARKET CAP: $29 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+3.6	+1.2	+1.4
Avg. Indust. Use (MWH)	4029	3676	3670
Avg. Indust. Revs. per KWH (¢)	4.34	5.05	5.21
Capacity at Yearend (Mw)	38622	40502	41785
Peak Load, Summer (Mw)	34414	35050	35890
Annual Load Factor (%)	61.4	60.2	60.8
% Change Customers (yr-end)	+1.5	+1.2	+1.7
Fixed Charge Cov. (%)	358	358	335

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	2.5%	3.0%	*4.5%*
"Cash Flow"	1.0%	--	*3.5%*
Earnings	2.5%	3.0%	*3.0%*
Dividends	2.0%	2.0%	*4.0%*
Book Value	1.0%	1.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	2732	3009	3441	2720	11902
2005	2787	3120	4358	3289	13554
2006	3063	3592	4549	3152	14356
2007	3409	3772	4832	*3237*	*15250*
2008	*3600*	*3950*	*5100*	*3450*	*16100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.45	.48	.87	.26	2.06
2005	.43	.52	.97	.21	2.13
2006	.35	.52	.99	.25	2.10
2007	.45	.57	1.00	*.18*	*2.20*
2008	*.40*	*.55*	*1.05*	*.30*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.343	.343	.35	.35	1.39
2004	.35	.35	.358	.358	1.42
2005	.358	.373	.373	.373	1.48
2006	.373	.388	.388	.388	1.54
2007	.388	.403	.403		

BUSINESS: The Southern Company's four operating subsidiaries supply electricity to 4.3 million customers in about 120,000 square miles of Georgia, Alabama, Florida, and Mississippi. Revenue breakdown, '06: residential, 35%; commercial, 30%; industrial, 21%; other, 14%. Retail revenues by state: Georgia, 52%; Alabama, 34%; Florida, 8%; Mississippi, 6%. Also has competitive generation business. Generating sources, '06: coal, 67%; nuclear, 14%; oil & gas, 12%; hydro, 2%; purchased, 5%. Fuel costs: 40% of revenues. '06 reported deprec. rate: 3.0%. Has 26,100 employees. Chairman, President, and CEO: David M. Ratcliffe. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-5000. Internet: www.southernco.com.

Southern Company's largest utility subsidiary has reached a settlement of its general rate case. Georgia Power had asked the state regulators for a rate increase of $406.7 million based on a return of 12.5% on a 52.7% common-equity ratio. Since the utility will need additional rate relief for capital expenditures and operating expenses, its filing included an option for additional increases of $191 million at the start of 2009 and $45 million at the start of 2010. Georgia Power, the commission's staff, and other intervenors reached a settlement that calls for a general rate increase of $99.7 million at the start of 2008, plus an environmental cost recovery tariff that would average $222 million a year over a three-year period. The new rates would be based on an 11.25% return on a common-equity ratio of 52.7%, with an allowed ROE within a range of 10.25%-12.25%. The commission must still approve the agreement. Its order is expected in December, with new tariffs taking effect at the start of 2008.

We expect earnings to increase this year and next. The utilities are benefiting from kilowatt-hour sales growth of around 2% annually. Weather patterns in 2007 have been favorable, too. Although third-quarter earnings topped our estimate, we've trimmed our full-year estimate by $0.05 a share because the company expects to incur higher expenses for scheduled plant maintenance outages and it will take a $0.04 charge for the cancellation of a project. Our 2007 estimate includes $0.07 a share of income associated with Southern Company's synthetic fuel investments. Despite the cessation of the synfuel program at the end of 2007, we estimate an earnings increase in 2008, assuming that Georgia Power receives reasonable regulatory treatment.

Finances are solid. The capitalization ratios should remain sound, despite the company's need for financing through 2009 (driven by a capital budget that includes $4.6 billion of costs for environmental compliance). The fixed-charge coverage is well above the utility average, too.

This high-quality stock offers an attractive yield. It is above the utility mean. But 3- to 5-year total-return potential is only about average for a utility.

Paul E. Debbas, CFA *November 30, 2007*

(A) Diluted earnings. Excl. nonrecurring gain: '03, 6¢. '06 earnings don't add to total due to rounding. Next earnings report due late Jan. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. def'd charges. In '06: $6.28/sh. (D) In mill., adj. for split. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on com. eq. (blended): 13.5%. Earned on avg. com. eq., '06: 14.3%. Regulatory Climate: AL, FL: Above Average; GA, MS: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	95

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TECO ENERGY, INC. NYSE-TE

RECENT PRICE	17.07	P/E RATIO	14.0 (Trailing: 13.1 / Median: 15.0)	RELATIVE P/E RATIO	0.83	DIV'D YLD	4.7%	VALUE LINE

TIMELINESS 3 Lowered 8/17/07
SAFETY 3 Lowered 3/7/03
TECHNICAL 3 Raised 11/30/07
BETA .95 (1.00 = Market)

High:	27.0	28.2	30.6	28.2	33.2	33.0	29.0	17.0	15.5	19.3	17.7	18.6
Low:	23.0	22.8	24.8	18.4	17.3	24.8	10.0	9.5	11.3	14.9	14.4	14.8

Target Price Range 2010 | 2011 | 2012

2010-12 PROJECTIONS

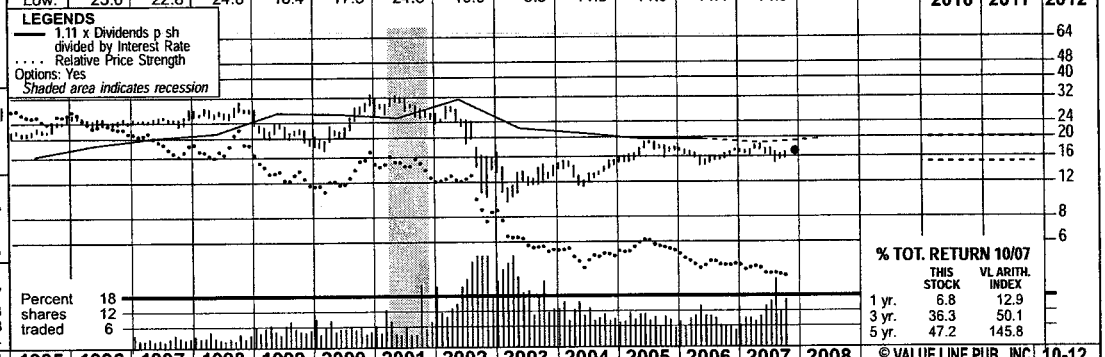
	Price	Gain	Ann'l Total Return
High	20	(+15%)	8%
Low	15	(-10%)	2%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	1	0	1
Options	1	0	1	0	0	1	2	0	0
to Sell	1	0	1	0	0	3	1	0	0

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	149	151	153
to Sell	121	139	138
Hld's(000)	118899	114475	118284



% TOT. RETURN 10/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	6.8	12.9
3 yr.	36.3	50.1
5 yr.	47.2	145.8

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
10.10	10.29	11.10	11.55	11.90	12.53	14.23	14.83	15.01	18.17	18.97	15.22	14.59	13.37	14.46	16.46	*16.65*	*17.00*	Revenues per sh	*20.00*
2.43	2.54	2.70	2.80	3.08	3.28	3.34	3.25	3.28	4.11	4.31	3.20	1.96	2.14	2.37	2.57	*2.65*	*2.50*	"Cash Flow" per sh	*2.75*
1.28	1.30	1.30	1.32	1.60	1.71	1.61	1.52	1.53	1.97	2.24	1.95	d.08	.71	1.00	1.17	*1.35*	*1.15*	Earnings per sh A	*1.25*
.85	.90	.95	1.00	1.05	1.11	1.17	1.23	1.29	1.33	1.37	1.41	.93	.76	.76	.76	*.78*	*.80*	Div'd Decl'd per sh B ■	*.86*
3.59	2.22	2.34	2.64	3.70	2.28	1.62	2.24	3.23	5.45	6.92	6.06	3.14	1.37	1.42	2.18	*2.45*	*2.80*	Cap'l Spending per sh	*2.00*
7.80	8.31	8.89	9.27	9.98	10.73	11.04	11.42	10.73	11.93	14.12	14.86	8.93	6.43	7.65	8.25	*8.95*	*9.35*	Book Value per sh C	*10.75*
114.22	114.97	115.62	116.92	116.96	117.60	130.90	132.00	132.10	126.30	139.60	175.80	187.80	199.70	208.20	209.50	*210.50*	*211.50*	Common Shs Outst'g D	*215.00*
13.9	15.1	17.9	15.0	13.8	14.3	15.4	17.8	14.2	11.9	12.9	11.0	--	19.3	17.1	13.8	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.89	.92	1.06	.98	.92	.90	.89	.93	.81	.77	.66	.60	--	1.02	.91	.75	*Value Line*		Relative P/E Ratio	*.95*
4.8%	4.6%	4.1%	5.0%	4.7%	4.5%	4.7%	4.5%	5.9%	5.7%	4.8%	6.6%	7.4%	5.5%	4.4%	4.7%	*estimates*		Avg Ann'l Div'd Yield	*4.7%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $3534.5 mill. **Due in 5 Yrs** $1104.1 mill.
LT Debt $3454.4 mill. **LT Interest** $224.5 mill.
(LT interest earned: 2.5x)

Leases, Uncapitalized Annual rentals $28.1 mill.

Pension Assets-12/06 $434.7 mill. **Oblig.** $569.9 mill.
Pfd Stock None

Common Stock 210,678,423 shs.
as of 10/29/07
MARKET CAP: $3.6 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
1862.3	1958.1	1983.0	2295.1	2648.6	2675.8	2740.0	2669.1	3010.1	3448.1	*3500*	*3600*	Revenues ($mill)	*4300*
211.9	200.4	200.9	250.9	303.7	298.2	d14.7	137.4	211.0	244.4	*285*	*245*	Net Profit ($mill)	*270*
30.9%	28.8%	30.2%	6.9%	--	--	--	38.5%	45.1%	40.4%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
.1%	--	.9%	.9%	3.0%	4.4%	--	.7%	--	1.6%	*2.0%*	*6.0%*	AFUDC % to Net Profit	*4.0%*
42.8%	45.9%	46.0%	47.7%	48.3%	50.5%	72.4%	75.1%	70.0%	65.0%	*64.5%*	*61.5%*	Long-Term Debt Ratio	*58.0%*
57.2%	54.1%	54.0%	52.3%	51.7%	39.7%	27.6%	24.9%	30.0%	35.0%	*35.5%*	*38.5%*	Common Equity Ratio	*42.0%*
2524.9	2787.4	2625.6	2881.5	3814.1	6585.1	6070.3	5163.9	5300.9	4941.6	*5350*	*5140*	Total Capital ($mill)	*5475*
3236.5	3307.6	3627.8	3970.1	4838.3	5464.0	5679.0	4657.9	4566.9	4766.9	*5025*	*5350*	Net Plant ($mill)	*5850*
10.2%	9.0%	9.8%	10.7%	9.7%	5.7%	2.1%	5.6%	6.5%	7.3%	*7.5%*	*7.0%*	Return on Total Cap'l	*7.0%*
14.7%	13.3%	14.2%	16.7%	15.4%	9.1%	NMF	10.7%	13.3%	14.1%	*15.0%*	*12.5%*	Return on Shr. Equity	*11.5%*
14.6%	13.3%	14.2%	16.7%	15.4%	9.9%	NMF	10.7%	13.3%	14.1%	*15.0%*	*12.5%*	Return on Com Equity E	*11.5%*
4.5%	2.6%	2.3%	5.5%	6.1%	3.2%	NMF	NMF	3.3%	5.0%	*6.5%*	*4.0%*	Retained to Com Eq	*3.5%*
70%	81%	84%	67%	61%	72%	NMF	106%	75%	65%	*57%*	*69%*	All Div'ds to Net Prof	*68%*

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+1.1	+2.6	+.6
Avg. Indust'l Use (Mw)	NA	NA	NA
Avg. Indust'l Revs. per KWH (¢)	6.49	6.44	7.66
Capacity at Peak (Mw)	NA	4423	NA
Peak Load, Winter (Mw)	3774	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+2.4	+2.6	+2.8
Fixed Charge Cov. (%)	NMF	124	150

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	2.0%	-3.0%	*5.0%*
"Cash Flow"	-2.5%	-9.5%	*2.5%*
Earnings	-4.5%	-13.0%	*4.5%*
Dividends	-3.0%	-10.5%	*2.0%*
Book Value	-3.0%	-9.5%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	625.2	677.9	705.8	660.2	2669.1
2005	684.7	719.0	836.4	770.0	3010.1
2006	836.4	862.6	922.9	826.2	3448.1
2007	821.3	866.5	990.0	*822.2*	*3500*
2008	*850*	*925*	*975*	*850*	*3600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.17	.09	.28	.17	.71
2005	.25	.04	.45	.24	1.00
2006	.26	.29	.38	.23	1.17
2007	.35	.28	.44	*.28*	*1.35*
2008	*.25*	*.25*	*.40*	*.25*	*1.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.355	.19	.19	.19	.93
2004	.19	.19	.19	.19	.76
2005	.19	.19	.19	.19	.76
2006	.19	.19	.19	.19	.76
2007	.19	.195	.195	.195	

BUSINESS: TECO Energy, Inc. is a holding company for Tampa Electric, which serves around 661,000 customers in west central Florida, and Peoples Gas (acq'd 6/97), which serves around 332,000 customers in Florida. TECO also mines and transports coal and has generation and distribution investments in Guatemala. Electric revenue breakdown, '06: residential, 46%; commercial, 29%; industrial, 8%; other, 17%. Generating sources, '06: coal, 54%; gas, 32%; oil, 1%; purchased, 13%. Fuel costs: 40% of revenues. '06 reported deprec. rate: 3.9%. Has 5,200 employees. Chairman & CEO: Sherrill W. Hudson. President & COO: John B. Ramil. Inc.: FL. Address: TECO Plaza, 702 N. Franklin St., Tampa, FL 33602. Tel.: 813-228-1111. Internet: www.tecoenergy.com.

TECO Energy has reached an agreement to sell its barge transportation subsidiary, TECO Transport. This operation generated a net profit of $22.8 million in 2006 and $27.0 million in the first nine months of 2007. TECO Transport fetched a price of $405 million, which will net the company $370 million-$380 million after taxes and transaction costs. TECO plans to use the proceeds to accelerate its goal of reducing debt by $500 million. The company expects to record a pretax gain of $225 million-$275 million on the sale, which we will *exclude* from our earnings presentation. The deal should close by the end of 2007. We won't adjust our figures to reflect the sale of TECO Transport until after it has been completed, but we figure the transaction will be slightly dilutive. Even so, we think the sale makes sense because it will enable the company to strengthen its balance sheet.

The end of the synthetic fuel program is likely to result in an earnings decline in 2008. Through hedging, TECO locked in a profit of $65 million ($0.31 a share) from its synfuel investments. Since the synfuel program will cease at yearend, the company will record no such income in 2008. Note that we have boosted our share-earnings estimates for 2007 and 2008 by a nickel each year because depreciation is likely to wind up lower than we had estimated. TECO hasn't provided earnings guidance for 2008 and won't do so until early next year.

Tampa Electric has decided not to build a coal gasification plant to meet its 2013 power needs. Uncertainty about changing environmental regulations and the rising cost of the project induced the company to look for alternative sources of power generation. Thus, our projection for capital spending in the 2010-2012 period is much lower than in our last report, in late August. For the time being, Tampa Electric plans to add peaking units in 2009 and 2010.

This stock's main appeal is its high yield. It is about a percentage point above the norm for dividend-paying utilities. We project just modest dividend growth over the 3- to 5-year period, however, so total-return potential over that time is only around average, by utility standards.

Paul E. Debbas, CFA *November 30, 2007*

(A) Diluted earnings. Excl. nonrecurring losses: '97, 6¢; '99, 11¢; '03, $4.97; gains (loss) on disc. ops.: '04, (77¢); '05, 31¢; '06, 1¢; '07, 7¢. '05 EPS don't add due to change in shares, '06 due to rounding. Next earnings report due early Feb. (B) Div'ds paid in late Feb., May, Aug., & Nov. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '06: $1.80/sh. (D) In millions. (E) Rate base: Net orig. cost. Allowed return on com. eq. in '00 (elec.): 10.75%-12.75%; in '02 (gas): 10.25%-12.25%; earned on avg. com. eq., '06: 14.7%. Regulat. Climate: Above Avg.

Company's Financial Strength	B
Stock's Price Stability	80
Price Growth Persistence	10
Earnings Predictability	30

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UIL HOLDINGS NYSE-UIL

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
35.09	18.5	(Trailing: 21.9 Median: 15.0)	1.10	4.9%	VALUE LINE

TIMELINESS **3** Raised 11/16/07
SAFETY **3** Lowered 12/6/02
TECHNICAL **2** Raised 11/30/07
BETA .95 (1.00 = Market)

High:	24.0	27.6	32.5	32.2	33.6	31.8	35.3	27.6	32.8	33.7	43.8	43.0
Low:	18.7	14.2	25.0	23.3	22.7	26.3	16.9	18.5	25.1	27.4	27.4	27.0

2010-12 PROJECTIONS

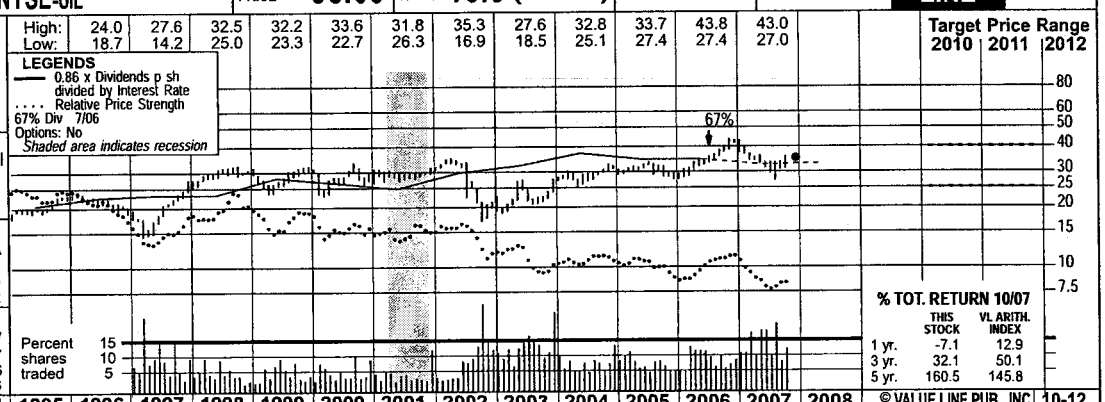
	Price	Gain	Ann'l Total Return
High	40	(+15%)	8%
Low	25	(-30%)	-2%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	2
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	2

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	82	73	57
to Sell	34	51	66
Hld's(000)	12105	12263	12276



Target Price Range 2010 | 2011 | 2012

% TOT. RETURN 10/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	-7.1	12.9
3 yr.	32.1	50.1
5 yr.	160.5	145.8

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
29.00	28.53	27.82	27.97	29.38	30.89	30.64	29.34	29.01	37.54	46.15	47.55	40.39	45.87	49.88	34.03	*38.10*	*42.30*	Revenues per sh	*52.25*
4.79	4.90	4.90	4.77	4.91	4.81	5.40	5.34	4.67	5.53	6.61	5.89	4.69	4.37	4.13	4.65	*5.00*	*5.85*	"Cash Flow" per sh	*7.40*
1.93	1.90	1.88	1.91	2.18	1.90	1.96	1.80	2.23	2.56	2.53	1.85	1.24	1.54	1.30	1.86	*1.85*	*1.95*	Earnings per sh A	*2.15*
1.46	1.54	1.60	1.66	1.69	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	*1.73*	*1.73*	Div'd Decl'd per sh B ■	*1.73*
2.72	2.84	4.04	2.69	2.53	2.01	1.44	1.63	1.48	2.31	2.01	2.41	2.19	2.04	2.25	3.09	*10.15*	*5.50*	Cap'l Spending per sh	*3.75*
17.30	18.07	18.03	18.23	18.72	18.72	18.94	19.05	19.55	20.42	21.25	20.28	20.65	22.84	22.39	18.53	*18.70*	*19.05*	Book Value per sh C	*19.95*
23.22	23.39	23.47	23.48	23.50	23.50	23.18	23.39	23.44	23.46	23.53	23.79	23.86	24.01	24.32	24.86	*25.20*	*25.40*	Common Shs Outst'g E	*26.60*
10.6	11.9	13.6	10.5	9.3	11.4	10.1	16.3	12.6	10.8	11.5	15.0	18.0	18.7	23.5	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.68	.72	.80	.69	.62	.71	.58	.85	.72	.70	.59	.82	1.03	.99	1.25	1.01	*Value Line*		Relative P/E Ratio	*1.00*
7.2%	6.8%	6.2%	8.2%	8.3%	8.0%	8.8%	5.9%	6.2%	6.2%	5.9%	6.2%	7.7%	6.0%	5.7%	5.0%	*estimates*		Avg Ann'l Div'd Yield	*5.4%*

CAPITAL STRUCTURE as of 6/30/07
Total Debt $528.6 mill. **Due in 5 Yrs.** $337.4 mill.
LT Debt $404.3 mill. **LT Interest** $21.5 mill.
(LT interest earned: 3.3x)
Leases, Uncapitalized: Ann. rentals $13.4 mill.

Pension Assets-12/06 $317 mill. **Oblig.** $362 mill.

Pfd Stock None

Common Stock 25,160,004 shs. **as of 8/1/07**

MARKET CAP: $875 million (Small Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
710.3	686.2	680.0	880.9	1085.8	1131.0	963.7	1101.3	1213.1	846.0	*960*	*1075*	Revenues ($mill)	*1390*
45.8	42.2	52.2	59.9	59.4	44.0	29.5	36.9	31.4	45.4	*46.0*	*49.0*	Net Profit ($mill)	*57.0*
47.4%	56.0%	56.0%	44.5%	44.8%	45.2%	53.1%	45.4%	44.1%	31.2%	*31.0%*	*31.0%*	Income Tax Rate	*31.0%*
3.5%	1.1%	4.3%	4.4%	3.2%	5.1%	8.5%	1.1%	9.0%	8.0%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*3.0%*
57.3%	57.7%	50.5%	52.2%	49.9%	45.0%	50.1%	47.2%	47.2%	47.0%	*49.5%*	*50.0%*	Long-Term Debt Ratio	*49.5%*
38.0%	37.7%	44.6%	47.8%	50.1%	55.0%	49.9%	52.8%	52.8%	53.0%	*50.5%*	*50.0%*	Common Equity Ratio	*50.5%*
1154.8	1180.8	1026.5	1001.3	998.6	877.8	988.2	1039.6	1031.5	869.2	*930*	*965*	Total Capital ($mill)	*1050*
1273.6	1226.4	521.5	550.7	546.4	517.1	548.8	563.9	592.1	647.0	*825*	*870*	Net Plant ($mill)	*810*
6.7%	5.4%	7.1%	7.9%	8.1%	7.3%	4.3%	4.5%	4.1%	6.5%	*6.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
9.3%	8.4%	10.3%	12.5%	11.9%	9.1%	6.0%	6.7%	5.8%	9.9%	*9.5%*	*10.0%*	Return on Shr. Equity	*10.5%*
10.4%	9.4%	11.4%	12.5%	11.9%	9.1%	6.0%	6.7%	5.8%	9.9%	*9.5%*	*10.0%*	Return on Com Equity D	*10.5%*
1.2%	.4%	2.5%	4.0%	3.8%	.6%	NMF	NMF	NMF	NMF	*.5%*	*1.0%*	Retained to Com Eq	*2.0%*
89%	96%	78%	68%	68%	93%	NMF	112%	NMF	93%	*93%*	*89%*	All Div'ds to Net Prof	*80%*

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+3.3	+2.6	-3.1
Avg. Indust. Use (MWH)	639	665	657
Avg. Indust. Revs. per KWH (¢)	9.13	9.70	10.2
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	-.1	Nil	Nil
Fixed Charge Cov. (%)	375	263	323

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	4.0%	3.0%	*3.0%*
"Cash Flow"	-1.0%	-5.0%	*9.0%*
Earnings	-2.5%	-8.5%	*5.5%*
Dividends	--	--	*Nil*
Book Value	1.5%	1.0%	*-1.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	249.4	260.7	323.4	267.8	1101.3
2005	278.5	279.9	369.4	285.3	1213.1
2006	200.3	199.8	261.1	184.8	846.0
2007	274.6	216.7	267.9	*200.8*	*960*
2008	*300*	*240*	*310*	*225*	*1075*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.24	.43	.68	.19	1.54
2005	.13	.14	.77	.26	1.30
2006	.15	.42	1.21	.08	1.86
2007	.22	.38	.92	*.33*	*1.85*
2008	*.22*	*.43*	*1.00*	*.30*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.432	.432	.432	.432	1.73
2004	.432	.432	.432	.432	1.73
2005	.432	.432	.432	.432	1.73
2006	.432	.432	.432	.432	1.73
2007	.432	.432	.432	.432	

BUSINESS: UIL Holdings, parent of The United Illuminating Company, provides electricity to 320,000 customers in largely urban and suburban southern Connecticut. Revenue distribution: resid, 46%; commer, 41%; indust, 11%; other, 2%. Largest industrial customers: primary metals, fabricated metal products, transportation equipment. 2004, sold American Payment Systems. 2006, sold Xcelecom. Fuel costs: 49% of revenues; labor costs, 13%. '06 deprec. rate: 3.8%. Has 920 employees. Non-Executive Chairman: F. Patrick McFadden. Chief Executive Officer & President: James P. Torgerson. Incorporated: Connecticut. Address: 157 Church Street, P.O. Box 1564, New Haven, Connecticut 06506-0901. Tel.: 203-499-2394. Internet: www.uil.com.

UIL Holdings' major project is construction of a 69-mile transmission line. The company and Northeast Utilities are jointly building a 345-kilovolt line between Middletown and Norwalk, Connecticut to strengthen the weak grid in the southwestern part of the state. UIL will have a 20% ownership in the facility. Since 24 miles will have to be built underground to satisfy demands of towns and property owners along the route, the initial cost of $600 million rose to $1.3 billion. Work is well under way, and a new substation is nearly finished. Upon completion in late 2009, the project will not only serve the two owners but will supply power to other New England utilities. Regulation permits the company to recover 50% of prudently incurred costs as building progresses. The balance will be recouped through rate filings. In the early stages, UIL will finance its share of the cost internally, later with debt.

The company seeks to build a gas-fired peaking plant. The utility sold all of its generating facilities in 2000 when state law allowed consumers to choose their energy supplier. Pursuant to a 2007 law that permits utilities to build peaking units, UIL and NRG Energy plan to submit a proposal for a new peaking plant. If regulatory approval is granted, the company would recover the cost of building on a cost-of-service basis, and would earn a reasonable return on its investment. Re-entry into the generating business would offer UIL new opportunities.

Earnings may show no progress this year. The company will benefit from improved pricing, higher rates of $4.3 million, and recovery of work on the transmission system. But an IRS ruling on accumulated deferred investment tax credits that boosted third-quarter 2006 earnings by $0.26 a share will negate these positives. For now, we estimate 2007 earnings of $1.85 a share. A $10.3 million rate hike effective next January points to improved results next year.

These shares have an even balance of pluses and minuses. The year-ahead yield is more than a full percentage point above the industry norm. But a high payout ratio suggests no dividend increase in our 3- to 5-year timeframe.

Arthur H. Medalie *November 30, 2007*

(A) EPS basic. Excl. nonrecur. gains (losses): '91, 27¢; '92, 35¢; '93, (34¢); '94, (6¢); '96, 17¢; '00, net 4¢; '03, (26¢); '04, $2.14; '06, ($5.07). Next egs. report due late Jan. (B) Div'ds historically paid in early Jan., early April, early July, and early Oct. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. & regul. assets. In '06: 77¢/sh. (D) Rate base: orig. cost. Rate allowed on common equity in '06: 9.75%. Earned on average common equity in '06: 9.0%. Regul. Clim.: Below Average. (E) In millions.

Company's Financial Strength	B+
Stock's Price Stability	80
Price Growth Persistence	45
Earnings Predictability	60

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VECTREN CORP. NYSE-VVC

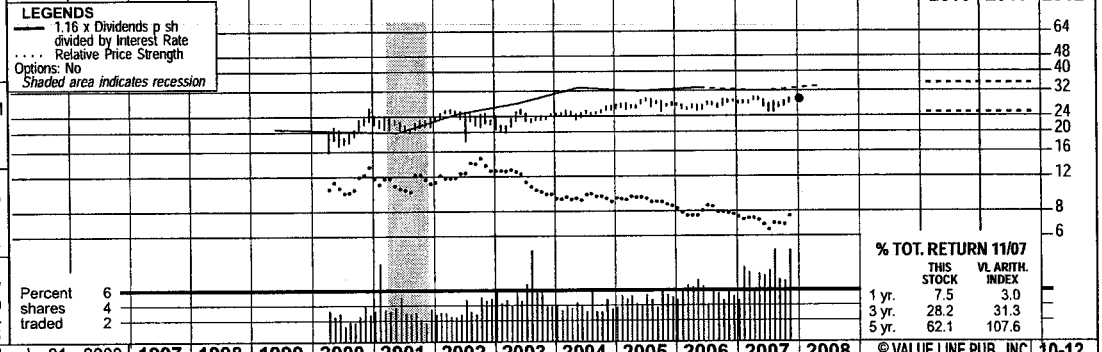
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
29.11	15.7	(Trailing: 16.4 Median: NMF)	0.93	4.5%	VALUE LINE

TIMELINESS 2 Raised 12/28/07
SAFETY 2 Lowered 1/5/01
TECHNICAL 3 Raised 8/31/07
BETA .90 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:			26.5	24.4	26.1	26.1	27.1	29.5	29.3	30.5	
Low:			15.8	19.8	18.0	19.7	22.9	25.0	25.2	24.8	

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.16 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: No
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+20%)	9%
Low	25	(-15%)	1%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	1	0	0	0	0	1	0	0
Options	0	0	0	1	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	106	108	79
to Sell	55	76	104
Hld's(000)	40427	42063	43375

Percent shares traded 6 4 2

% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	7.5	3.0
3 yr.	28.2	31.3
5 yr.	62.1	107.6

Vectren was formed on March 31, 2000 through the merger of Indiana Energy and SIGCORP. The merger was consummated with a tax-free exchange of shares and has been accounted for as a pooling of interests. Indiana Energy common stockholders received one Vectren common share for each share held. SIGCORP stockholders exchanged each common share for 1.333 common shares of Vectren. Data prior to the merger are pro forma.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
--	--	16.88	26.84	32.05	26.53	21.00	22.26	26.62	26.83	*28.70*	*30.25*	Revenues per sh	*37.40*
--	--	2.87	2.88	2.89	3.43	3.17	3.27	3.87	3.69	*4.15*	*4.45*	"Cash Flow" per sh	*5.15*
--	--	1.48	1.17	1.08	1.68	1.56	1.42	1.81	1.44	*1.85*	*1.95*	Earnings per sh A	*2.05*
--	--	.95	.98	1.03	1.07	1.11	1.15	1.19	1.23	*1.27*	*1.31*	Div'd Decl'd per sh B■†	*1.43*
--	--	--	2.67	3.48	3.22	3.12	3.66	3.04	3.70	*3.85*	*3.85*	Cap'l Spending per sh	*3.65*
--	--	11.55	11.91	12.53	12.79	14.18	14.42	15.01	15.43	*16.80*	*17.50*	Book Value per sh C	*19.55*
--	--	61.47	61.42	67.70	68.01	75.60	75.90	76.19	76.10	*80.80*	*81.00*	Common Shs Outst'g D	*81.60*
--	--	--	17.4	20.3	14.2	14.8	17.6	15.1	18.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
--	--	--	1.13	1.04	.78	.84	.93	.80	1.02	*Value Line*		Relative P/E Ratio	*.95*
--	--	--	4.8%	4.7%	4.5%	4.8%	4.6%	4.4%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*4.8%*
--	--	1037.4	1648.7	2170.0	1804.3	1587.6	1689.8	2028.0	2041.6	*2320*	*2450*	Revenues ($mill)	*3050*
--	--	90.8	72.0	73.1	114.0	111.2	108.0	136.8	108.8	*150*	*160*	Net Profit ($mill)	*165*
--	--	33.6%	32.2%	20.3%	25.4%	25.3%	26.5%	24.4%	21.8%	*22.0%*	*22.0%*	Income Tax Rate	*22.0%*
--	--	--	--	7.7%	4.6%	4.5%	3.0%	1.4%	3.8%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
--	--	40.0%	45.8%	54.4%	52.3%	50.0%	48.1%	51.2%	50.7%	*47.0%*	*48.0%*	Long-Term Debt Ratio	*48.5%*
--	--	58.4%	53.0%	45.5%	47.7%	50.0%	51.8%	48.8%	49.3%	*53.0%*	*52.0%*	Common Equity Ratio	*51.5%*
--	--	1215.8	1380.6	1863.1	1824.4	2144.7	2111.5	2341.3	2382.2	*2565*	*2725*	Total Capital ($mill)	*3105*
--	--	1336.3	1555.8	1595.0	1648.1	2003.7	2156.2	2251.9	2385.5	*2520*	*2625*	Net Plant ($mill)	*2795*
--	--	8.6%	6.1%	5.5%	7.7%	6.6%	6.4%	7.2%	6.0%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
--	--	12.5%	9.6%	8.6%	13.1%	10.4%	9.9%	12.0%	9.3%	*11.0%*	*11.0%*	Return on Shr. Equity	*10.5%*
--	--	12.6%	9.7%	8.5%	13.1%	10.4%	9.9%	12.0%	9.3%	*11.0%*	*11.0%*	Return on Com Equity E	*10.5%*
--	--	4.8%	1.5%	.3%	4.8%	3.0%	1.9%	4.0%	1.3%	*3.5%*	*3.5%*	Retained to Com Eq	*3.0%*
--	--	63%	85%	96%	63%	71%	81%	66%	86%	*69%*	*67%*	All Div'ds to Net Prof	*70%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $1732.8 mill. **Due in 5 Yrs** $822.0 mill.
LT Debt $1208.3 mill. **LT Interest** $68.1 mill.
(LT interest earned: 3.6x)

Pension Assets-12/06 $185.0 mill. **Oblig.** $255.4 mill.

Pfd Stock None

Common Stock 76,517,056 shs. **as of 10/31/07**
MARKET CAP: $2.2 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+1.5	+3.5	-3.1
Avg. Indust. Use (MWH)	23469	24074	23582
Avg. Indust. Revs. per KWH (¢)	4.24	4.64	4.99
Capacity at Peak (Mw)	1507	1534	1517
Peak Load, Summer (Mw)	1222	1291	1300
Annual Load Factor (%)	69.0	66.8	74.0
% Change Customers (yr-end)	+2.6	+.6	+1.1
Fixed Charge Cov. (%)	262	256	226

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	--	--	*7.0%*
"Cash Flow"	--	4.5%	*6.0%*
Earnings	--	4.5%	*4.5%*
Dividends	--	4.0%	*3.0%*
Book Value	--	4.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2004	645.3	276.7	254.4	513.4	1689.8
2005	677.2	326.2	310.8	713.8	2028.0
2006	774.5	317.5	340.5	609.1	2041.6
2007	834.0	421.7	381.4	*682.9*	*2320*
2008	*870*	*420*	*420*	*740*	*2450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2004	.72	.04	.13	.53	1.42
2005	.74	.18	.22	.67	1.81
2006	.76	.06	.16	.46	1.44
2007	.88	.21	.22	*.54*	*1.85*
2008	*.90*	*.20*	*.20*	*.65*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.275	.275	.275	.285	1.11
2004	.285	.285	.285	.295	1.15
2005	.295	.295	.295	.305	1.19
2006	.305	.305	.305	.315	1.23
2007	.315	.315	.315	.325	

BUSINESS: Vectren is a holding company formed through the merger of Indiana Energy and SIGCORP. Supplies electricity and gas to an area nearly two-thirds of the state of Indiana. Owns gas distribution assets in Ohio. Has a customer base of 1,136,000. 2006 Elect. (gas) revs: resid., 30% (67%); commer., 24% (27%); indust., 32% (5%); other, 14% (1%). Revenue sources: Elect., 20%; Gas, 80%. Fuel costs: elect., 37%; gas, 69%. Also provides energy-related products and services and has an investment subsidiary. Est'd plant age: electric, 10 years. '06 deprec. rate: 3.7%. Has 1,975 employees. Chairman & CEO: Niel C. Ellerbrook. President: Carl Chapman. Inc.: IN. Address: 20 Northwest 4th St., Evansville, Indiana 47741. Tel.: 812-465-5300. Internet: www.vectren.com.

Vectren's construction budget will require external financing through 2010. A large portion of the outlays is needed to comply with the U.S. Environmental Protection Agency's requirements. VVC and Alcan Aluminum, joint owners in the Warrick coal-fired station, are spending $300 million to reduce sulfur dioxide emissions at all four units by 98%. VVC's share of the cost will be $70 million. The company will also enhance the efficiency of existing scrubbers at the Culley 2 and 3 coal burners and will upgrade the infrastructure. All told, management plans capital spending of $300 million annually for the next three years. Since internally generated cash won't fully cover these costs, some external financing will be needed to close the gap.

The company has applied for higher rates in two jurisdictions. Last May, it filed for increased gas base rates of $41 million in its northern Indiana territory to recover costs of maintaining and expanding the 12,000-mile distribution and storage system. An order on the petition is expected in the second quarter of 2008. In Ohio, VVC issued a pre-filing notice in September, indicating it planned to request a $29 million hike for its gas distribution business. The increase is needed to recoup the cost of operating and expanding the 5,200-mile system that serves a 17-county area in west-central Ohio. An order here is due late next year.

Earnings may post a record high in 2007. Electric and gas margins are up, and environmental outlays are being recovered on a timely basis. What's more, a rate hike in southern Indiana will help fourth-quarter results. Too, the ProLiance subsidiary is benefiting from increased gas storage capacity. Our 2007 earnings estimate of $1.85-a-share excludes expected profits of $0.12 a share from synfuel operations, which have been classified as discontinued. Orders on two outstanding rate requests suggest further improvement in 2008. The stock is timely.

The yield is almost a full percentage point above the industry norm. And dividend growth prospects to 2010-2012 exceed those of the group. Income-oriented investors might consider these good-quality shares.

Arthur H. Medalie *December 28, 2007*

(A) Diluted EPS. Next earnings report due late Jan. Excl. nonrecur. gain (losses): '00, 8¢; '01, (13¢); '03, (6¢); incl. charges for merger costs: '00, 60¢; '01, 17¢. (B) Div'ds historically paid in early March, early June, early September, and early December. ■Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. in '06, $5.27/sh. (D) In millions. (E) Electric rate base determination: fair value. Rate allowed on elect. common equity in '95: 12.25%. Earned on avg. com. eq. '06: 9.4%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	75

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XCEL ENERGY NYSE-XEL

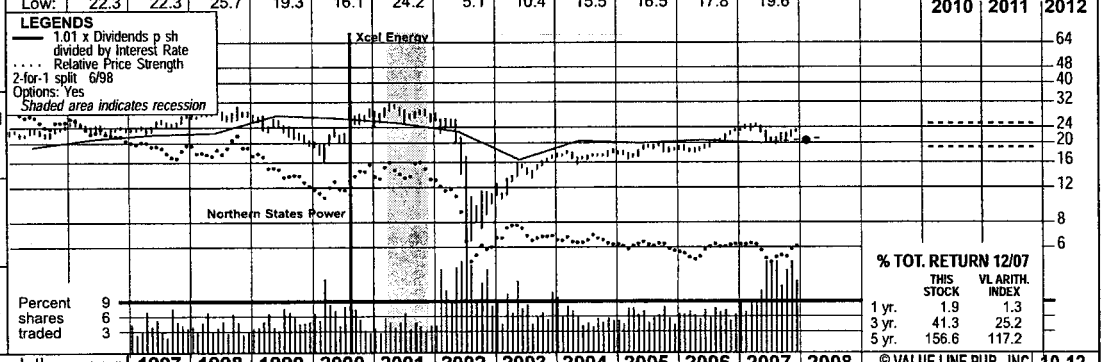
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
20.60	13.6	(Trailing: 15.4 Median: 15.0)	0.85	4.6%	VALUE LINE

TIMELINESS 3 Lowered 3/16/07
SAFETY 2 Raised 5/14/04
TECHNICAL 2 Raised 1/11/08
BETA .80 (1.00 = Market)

High:	26.7	29.4	30.8	27.9	30.0	31.8	28.5	17.4	18.8	20.2	23.6	25.0
Low:	22.3	22.3	25.7	19.3	16.1	24.2	5.1	10.4	15.5	16.5	17.8	19.6

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.01 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 6/98
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+20%)	9%
Low	19	(-10%)	3%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	1	0	0	0
Options	0	0	0	1	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	170	175	160
to Sell	156	177	179
Hld's(000)	272870	275060	269962

% TOT. RETURN 12/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.9	1.3
3 yr.	41.3	25.2
5 yr.	156.6	117.2

Xcel Energy was formed through the merger of Northern States Power and New Century Energies on August 21, 2000. NSP stockholders received one share of Xcel for every NSP share, and NCE stockholders received 1.55 shares of Xcel for each NCE share. Data prior to 2000 reflect NSP on a stand-alone basis and are not comparable with Xcel data.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
18.32	18.46	18.42	34.11	43.56	23.89	19.90	20.84	23.86	24.16	23.50	24.50	Revenues per sh	28.25
3.92	4.30	4.13	4.12	5.09	3.14	3.35	3.27	3.28	3.70	3.70	4.00	"Cash Flow" per sh	4.50
1.61	1.84	1.43	1.60	2.27	.42	1.23	1.27	1.20	1.35	1.35	1.50	Earnings per sh A	1.75
1.40	1.43	1.45	1.48	1.50	1.13	.75	.81	.85	.88	.91	.95	Div'd Decl'd per sh B ■	1.10
2.90	2.99	13.87	3.63	7.40	6.04	2.49	3.19	3.25	4.00	4.90	4.90	Cap'l Spending per sh	4.50
15.89	16.25	16.42	16.37	17.95	11.70	12.95	12.99	13.37	14.28	14.70	15.30	Book Value per sh C	17.00
149.24	152.70	155.73	339.79	345.02	398.71	398.96	400.46	403.39	407.30	427.00	429.00	Common Shs Outst'g D	435.00
15.5	15.2	16.6	14.3	12.4	NMF	11.6	13.6	15.4	14.8	16.7		Avg Ann'l P/E Ratio	13.0
.89	.79	.95	.93	.64	NMF	.66	.72	.82	.80	.88		Relative P/E Ratio	.85
5.6%	5.1%	6.1%	6.4%	5.3%	6.6%	5.2%	4.7%	4.6%	4.4%	4.0%		Avg Ann'l Div'd Yield	4.8%
2733.7	2819.2	2869.0	11592	15028	9524.4	7937.5	8345.3	9625.5	9840.3	10034	10500	Revenues ($mill)	12300
251.8	298.1	240.1	545.8	784.7	177.6	510.0	526.9	499.0	568.7	575.9	655	Net Profit ($mill)	750
27.8%	26.0%	21.6%	35.8%	28.2%	32.7%	23.7%	23.2%	25.8%	24.2%	33.8%	33.5%	Income Tax Rate	35.0%
6.6%	5.3%	2.5%	4.4%	7.1%	46.7%	8.9%	10.9%	8.5%	9.8%	12.5%	16.0%	AFUDC % to Net Profit	9.0%
40.4%	39.9%	54.7%	58.8%	66.7%	59.6%	55.3%	55.0%	51.7%	52.1%	51.5%	54.0%	Long-Term Debt Ratio	54.5%
51.0%	53.5%	40.5%	40.5%	32.8%	39.5%	43.8%	44.1%	47.3%	47.0%	47.5%	45.0%	Common Equity Ratio	45.0%
4650.9	4637.7	6316.2	13745	18911	11815	11790	11801	11398	12371	13150	14525	Total Capital ($mill)	16500
4361.3	4395.2	4451.5	15273	21165	18816	13667	14096	14696	15549	16675	17750	Net Plant ($mill)	19700
6.9%	8.1%	5.4%	6.0%	6.0%	5.4%	6.1%	6.2%	6.2%	6.2%	6.0%	6.0%	Return on Total Cap'l	6.5%
9.1%	10.7%	8.4%	9.6%	12.5%	3.7%	9.7%	9.9%	9.1%	9.6%	9.0%	10.0%	Return on Shr. Equity	10.0%
9.5%	11.2%	8.6%	9.7%	12.6%	3.7%	9.8%	10.0%	9.2%	9.7%	9.0%	10.0%	Return on Com Equity E	10.0%
1.2%	2.5%	NMF	.9%	4.3%	NMF	3.9%	3.9%	2.9%	3.6%	3.0%	3.5%	Retained to Com Eq	3.5%
88%	79%	100%	91%	66%	NMF	60%	62%	69%	63%	67%	63%	All Div'ds to Net Prof	64%

CAPITAL STRUCTURE as of 9/30/07
Total Debt $7980.0 mill. **Due in 5 Yrs** $2751.0 mill.
LT Debt $7252.8 mill. **LT Interest** $471.0 mill.
Incl. 8,000,000 shares 7.875% tax-deductible Trust Originated Preferred Securities, liquidation value $25/share; 7,760,000 shares 7.60%, cumulative, $25 par; $100 mill. 7.85% tax-deductible Trust Preferred Securities.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $57.4 mill.
Pension Assets-12/06 $3.18 bill. **Oblig.** $2.67 bill.
Pfd Stock $105.0 mill. **Pfd Div'd** $4.2 mill.
1,049,800 shares $3.60 to $4.56, cumulative, $100 par, callable $102.00 to $103.75.
Common Stock 419,930,078 shs. **as of 10/19/07**
MARKET CAP: $8.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+.3	+3.6	+1.8
Avg. C & I Use (MWH)	145	150	153
Avg. C & I Revs. per KWH (¢)	5.51	6.22	6.55
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	19827	20854	21255
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	-.4	+1.2
Fixed Charge Cov. (%)	230	232	238

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	2.0%	-6.5%	3.5%
"Cash Flow"	-2.0%	-5.5%	4.5%
Earnings	-3.5%	-6.5%	5.5%
Dividends	-4.5%	-10.5%	4.5%
Book Value	-1.0%	-4.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	2280	1797	2009	2259	8345.3
2005	2381	2074	2289	2882	9625.5
2006	2888	2074	2412	2466	9840.3
2007	2764	2267	2400	2603	10034
2008	2850	2350	2600	2700	10500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.36	.21	.40	.31	1.27
2005	.31	.18	.47	.24	1.20
2006	.36	.24	.53	.23	1.35
2007	.28F	.16F	.59F	.31	1.35
2008	.32	.30	.58	.30	1.50

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.188	.188	.208	.208	.79
2005	.208	.208	.215	.215	.85
2006	.215	.215	.223	.223	.88
2007	.223	.223	.23	.23	.91
2008					

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies power to Minnesota, Wisconsin, North Dakota, South Dakota, Michigan, & gas to Minnesota, Wisconsin, North Dakota, & Michigan; Public Service of Colorado, which supplies power & gas to Colorado; & Southwestern Public Service, which supplies power to Texas & New Mexico. Customers: 3.3 mill. electric, 1.8 mill. gas. Electric revenue breakdown, '06: residential, 28%; commercial & industrial, 53%; other, 19%. Generating sources not available. Fuel costs: 58% of revs. '06 reported deprec. rate: 3.2%. Has 9,700 employees. Chairman, President & CEO: Richard C. Kelly. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy has received a rate order in Wisconsin. The electric and gas tariffs of Northern States Power (NSP) were raised by $39.4 million (8.1%) and $5.3 million (3.3%), based on a return of 10.75% on a common-equity ratio of 52.5%. New rates went into effect on January 9th.

Several other regulatory matters are pending or upcoming. In North Dakota, NSP filed for an electric rate hike of $20.5 million (14%) based on a return of 11.5% on a common-equity ratio of 51.77%. An interim rate increase of $17.2 million took effect on February 5th, and a final order is expected this fall. The utility and the commission's staff have agreed on an allowed ROE of 10.75%, subject to commission approval. In New Mexico, Southwestern Public Service (SPS) is seeking a $17.3 million (6.6%) electric tariff increase, based on a return of 11% on a common-equity ratio of 51.2%. An order is due this summer. The company intends to file electric rate cases in Texas this spring, and in Colorado and Minnesota this fall.

We expect higher earnings in 2008. Rate relief and an increase in the Allowance for Funds Used During Construction, a noncash credit to income, should be the key factors. Our estimate is at the midpoint of Xcel's targeted range of $1.45-$1.55 a share.

Frequent rate cases are necessary for Xcel to place its capital spending into the rate base and to recover ongoing increases in operating expenses. The company has had major capital projects in Minnesota and Colorado. The utility is earning or nearly earning its allowed return on equity in most of its jurisdictions, but the returns of SPS in Texas and New Mexico are still a sore spot.

This stock offers a yield that is fractionally above the average for the electric utility industry. Total-return potential to 2010-2012 is only about average for a utility, however.

The SEC ordered Xcel to reclassify the cost of a settlement with the IRS concerning the deductibility of company-owned life insurance. Xcel was treating this charge as a discontinued item, but had to shift it to ongoing results. This lowered 2007 share net by $0.08. We are *including* this in our presentation.

Paul E. Debbas, CFA *February 8, 2008*

(A) Diluted EPS. Excl. nonrec. loss: '02, $6.27; gains (losses) on disc. ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢. '04, '06, & '07 EPS don't add due to rounding. Next egs. report due late Apr. (B) Div'ds historically paid in mid-Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '06: $4.36/sh. (D) In mill., adj. for split. (E) Rate base: Varies. Rate all'd on com. eq.: MN '93, 11.47%; WI '08, 10.75%; CO '03 (elec.), 10.75%; CO '07 (gas) 10.25%; TX '86, 15.05%; earned on avg. com. eq., '06: 10.1%. Regulatory Climate: Avg. (F) Restated.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	5
Earnings Predictability	45

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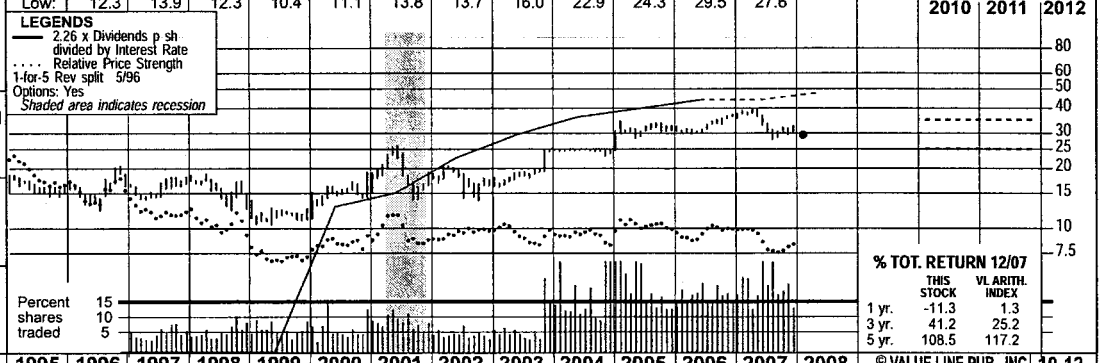
UNISOURCE ENERGY NYSE-UNS

RECENT PRICE 29.41 | P/E RATIO 17.0 (Trailing: 20.4 Median: 16.0) | RELATIVE P/E RATIO 1.06 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 4 Raised 8/17/07
SAFETY 3 New 12/31/04
TECHNICAL 2 Raised 2/1/08
BETA .60 (1.00 = Market)

High:	20.8	18.3	18.9	13.9	19.3	26.0	20.8	24.9	24.9	34.8	37.5	40.0
Low:	12.3	13.9	12.3	10.4	11.1	13.8	13.7	16.0	22.9	24.3	29.5	27.6

Target Price Range 2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+20%)	8%
Low	25	(-15%)	Nil

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	4	0	0	1	0	0	2
to Sell	1	0	4	0	0	0	0	0	1

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	87	73	56
to Sell	67	81	87
Hld's(000)	31380	30634	31880

% TOT. RETURN 12/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	-11.3	1.3
3 yr.	41.2	25.2
5 yr.	108.5	117.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
114.58	19.56	20.61	21.51	20.87	22.28	22.71	23.83	24.85	31.12	43.12	25.50	28.71	34.13	35.26	37.42	38.65	40.60	Revenues per sh	45.60
d12.43	d.30	2.06	3.44	4.58	6.82	5.29	3.48	3.96	4.23	5.41	4.80	5.20	5.29	5.21	5.68	5.40	5.70	"Cash Flow" per sh	6.35
d28.05	d12.40	d.25	.65	1.70	3.76	2.60	.68	1.08	1.27	1.79	.97	1.30	1.31	1.30	1.85	1.60	1.75	Earnings per sh A	1.90
--	--	--	--	--	--	--	--	--	.32	.40	.50	.60	.64	.76	.84	.90	.96	Div'd Decl'd per sh B ■ †	1.14
8.75	1.08	1.50	1.95	1.84	2.07	2.22	2.52	2.87	3.19	3.63	3.36	4.06	4.49	5.83	6.77	5.55	6.50	Cap'l Spending per sh	7.75
d37.31	d1.19	d1.96	d1.31	.39	4.15	6.75	7.65	10.02	11.20	12.68	13.05	15.97	16.95	17.68	18.59	19.55	20.85	Book Value per sh C	22.25
5.14	32.09	32.14	32.14	32.13	32.13	32.14	32.26	32.35	33.22	33.50	33.58	33.79	34.26	34.87	35.19	35.70	36.20	Common Shs Outst'g D	37.70
--	--	--	26.7	9.6	4.3	6.1	23.3	10.8	11.8	10.8	18.2	14.6	18.7	23.9	17.7	18.4		Avg Ann'l P/E Ratio	16.0
--	--	--	1.75	.64	.27	.35	1.21	.62	.77	.55	.99	.83	.99	1.27	.96	.97		Relative P/E Ratio	1.05
--	--	--	--	--	--	--	--	--	2.1%	2.1%	2.8%	3.2%	2.6%	2.5%	2.6%	3.1%		Avg Ann'l Div'd Yield	3.8%
						729.9	768.7	803.8	1033.7	1444.7	856.2	969.9	1169.0	1229.5	1316.9	1380	1470	Revenues ($mill)	1720
						83.6	21.9	35.5	26.3	60.9	33.3	45.2	45.9	46.1	69.2	57.0	63.0	Net Profit ($mill)	71.0
						--	45.6%	46.8%	32.9%	43.8%	33.7%	19.7%	42.5%	41.4%	38.8%	39.0%	39.0%	Income Tax Rate	39.0%
						--	--	--	--	--	--	2.2%	--	2.2%	2.9%	3.0%	3.0%	AFUDC % to Net Profit	3.0%
						90.7%	89.4%	86.1%	84.2%	79.6%	81.5%	79.2%	77.1%	75.3%	72.9%	68.5%	67.0%	Long-Term Debt Ratio	61.0%
						9.3%	10.6%	13.9%	15.8%	20.4%	18.5%	20.8%	22.9%	24.7%	27.1%	31.5%	33.0%	Common Equity Ratio	39.0%
						2322.3	2320.6	2340.5	2362.4	2081.3	2368.8	2589.0	2540.3	2494.9	2414.1	2230	2245	Total Capital ($mill)	2290
						1935.5	1915.6	1729.9	1706.3	1677.7	1668.4	2069.2	2081.1	2171.5	2259.6	2320	2415	Net Plant ($mill)	2545
						5.0%	2.5%	2.9%	2.5%	4.4%	2.8%	4.9%	5.1%	5.1%	5.9%	5.5%	5.5%	Return on Total Cap'l	6.0%
						38.5%	8.9%	11.0%	7.1%	14.3%	7.6%	8.4%	7.9%	7.5%	10.6%	8.0%	8.5%	Return on Shr. Equity	8.5%
						38.5%	8.9%	11.0%	7.1%	14.3%	7.6%	8.4%	7.9%	7.5%	10.6%	8.0%	8.5%	Return on Com Equity E	8.5%
						38.5%	8.9%	11.0%	4.3%	11.2%	3.8%	4.6%	4.1%	3.2%	6.1%	3.5%	3.5%	Retained to Com Eq	3.5%
						--	--	--	39%	22%	51%	45%	48%	57%	43%	56%	55%	All Div'ds to Net Prof	60%

CAPITAL STRUCTURE as of 9/30/07
Total Debt $1607.2 mill. **Due in 5 Yrs** $1079.6 mill.
LT Debt $1532.3 mill. **LT Interest** $145.6 mill.
Incl. $528.9 mill. capitalized leases.

(LT interest earned: 1.6x)

Pension Assets-12/06 $176 mill. **Oblig.** $218 mill.
Pfd Stock None

Common Stock 35,338,420 shs. **as of 10/31/07**
MARKET CAP: $1.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+3.2	+3.9	+3.7
Avg. Indust. Use (MWH)	3293	3421	3431
Avg. Indust. Revs. per KWH (¢)	6.50	6.60	6.60
Capacity at Peak (Mw)	2275	2567	2696
Peak Load, Summer (Mw)	2458	2792	2913
Annual Load Factor (%)	64.6	63.9	64.0
% Change Customers (yr-end)	+2.1	+2.6	+1.8
Fixed Charge Cov. (%)	130	131	157

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	5.0%	1.5%	4.0%
"Cash Flow"	1.0%	3.5%	3.0%
Earnings	-3.0%	1.5%	4.0%
Dividends	--	NMF	7.0%
Book Value	32.5%	9.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	270.1	290.1	335.3	273.5	1169.0
2005	260.9	300.6	349.3	318.7	1229.5
2006	305.0	318.4	375.6	317.9	1316.9
2007	317.8	329.8	398.2	334.2	1380
2008	345	360	415	350	1470

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.18	.37	.68	.08	1.31
2005	d.11	.27	.49	.65	1.30
2006	.52	.28	.73	.32	1.85
2007	.14	.33	.66	.47	1.60
2008	.25	.35	.75	.40	1.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.16	.16	.16	.16	.64
2005	.19	.19	.19	.19	.76
2006	.21	.21	.21	.21	.84
2007	.225	.225	.225	.225	.90
2008					

BUSINESS: UniSource Energy Corp., parent of Tucson Electric Power Company, supplies electricity in Tucson, Arizona and the surround. area (serv. area: 1,155 sq. miles). Nonutility subsidiaries engage in plant construction, fuel supply, and related businesses. Revenue sources: residential, 44%; commercial, 26%; industrial, 21%; other, 9%. Copper mining is largest industry served. Fuels: coal, 81%; gas, 6%; purchased power, 13%. Fuel: 46% of electric revenues; labor costs: 9%. '06 depreciation rate: 3.1%. Estimated plant age: 10 years. Has 1,260 employees. Chairman, President, and CEO: James S. Pignatelli. Inc.: AZ. Address: One South Church Ave. Suite 1820, Tucson, AZ 85701. Tel.: 520-884-3650. Internet: www.unisourceenergy.com.

UniSource seeks higher rates. A 1999 agreement froze electric rates through the end of 2008. As required by regulators, UNS filed for new rates that would take effect in January, 2009. It recommended that the commission use one of three methods in setting new tariffs. In all three cases, transmission and distribution rates are based on historic cost-based calculations. But rates for generated power are figured differently under each approach. In the first instance, charges would be based on wholesale market prices. An alternative ties rates to historic costs, subject to a separate charge. Either procedure would raise annual rates by about 22%. A third option blends the first two and results in lesser rates. All proposals reward customers for energy conservation. An order on the application will take effect January 1, 2009.

Financial indicators will remain weak for a while. Though long-term debt has been reduced steadily since 1996, it still accounts for about 70% of total capital. What's more, meaningful reductions are unlikely for a while because of the need to finance the capital spending program. That, in turn, keeps pressure on fixed charges, which have been barely earned since 1997. Too, though a large percentage of profits are being plowed back into retained earnings, this account still had a negative balance last September, 30th. Finally, UNS is having difficulty earning its allowed return on equity. In view of these negatives, we rate the company's Financial Strength a below-average C++.

Earnings should improve in 2008. Planned and unplanned plant outages, which took a toll in last year's first quarter, are behind the company. UNS should also benefit from an order on a filing for $9 million in higher posted gas tariffs. In all, we think 2008 earnings will rise 9% over last year's estimated $1.60 a share. An order on the aforementioned electric rate filing suggests a further gain next year. The stock is untimely.

These shares offer an even balance of pluses and minuses. Above-average dividend growth prospects to 2010-2012 might interest income-oriented investors. But those of a conservative bent may hesitate because of the company's weak finances.

Arthur H. Medalie *February 8, 2008*

(A) EPS diluted. Next earnings report due late Feb. Excl. nonrecur. gains (losses): '91, ($12.49); '92, 18¢; '93, ($0.11); '98, 19¢; '99, $1.35; '00, 48¢; '03, $2.00. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '06: $6.38/sh. (D) In millions, adjusted for split. (E) Rate base: fair value. Rate allowed on com. eq. in '94: 11.0%; earned on avg. com. eq., '06: 10.3%. Regulatory Climate: Avg.

Company's Financial Strength	C++
Stock's Price Stability	90
Price Growth Persistence	90
Earnings Predictability	40

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ATTACHMENT B

Zacks.com Quotes and Research

ALLETE INC. (NYSE)

Scottrade

ALE	37.05	▼-0.35	(-0.94%)	Vol. 46,300	11:54 ET

ALLETE is a multi-services company. ALLETE's holdings include the one of the largest wholesale automobile auction networks in North America; a provider of independent auto dealer inventory financing; one of the largest investor-owned water utilities in Florida and North Carolina; significant real estate holdings in Florida and a low-cost electric utility that serves some of the largest industrial customers in the United States. (Company Press Release)

General Information

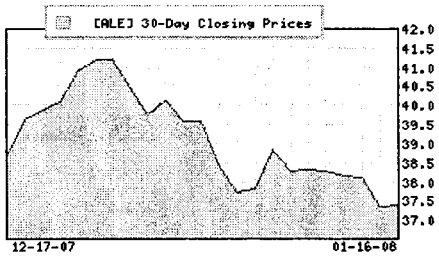
ALLETE INC
30 West Superior Street
Duluth, MN 55802-2093
Phone: 218 279-5000
Fax: -
Web: www.allete.com
Email: tthorp@allete.com

Industry	DIVERSIFIED OPS
Sector:	Multi-Sector Conglomerates

Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	02/15/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	37.40
52 Week High	51.30
52 Week Low	37.04
Beta	1.17
20 Day Moving Average	193,200.91
Target Price Consensus	52.67



% Price Change		% Price Change Relative to S&P 500	
4 Week	-6.27	4 Week	-0.82
12 Week	-15.99	12 Week	-7.26
YTD	-5.51	YTD	1.02

Share Information		Dividend Information	
Shares Outstanding (millions)	30.82	Dividend Yield	4.39%
		Annual Dividend	$1.64
Market Capitalization (millions)	1,152.74	Payout Ratio	0.00
Short Ratio	15.00	Change in Payout Ratio	0.00
Last Split Date	09/21/2004	Last Dividend Payout / Amount	11/13/2007 / $0.41

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.69	Current (1=Strong Buy, 5=Strong Sell)	1.60
Current Year EPS Consensus Estimate	3.00	30 Days Ago	1.60
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	1.60
Next EPS Report Date	02/15/2008	90 Days Ago	1.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.33	vs. Previous Year	-26.58%	vs. Previous Year	0.85%
Trailing 12 Months:	11.95	vs. Previous Quarter	-27.50%	vs. Previous Quarter:	-10.08%
PEG Ratio	2.67				

Price Ratios	ROE	ROA

Price/Book	1.58	09/30/07	-	09/30/07	-
Price/Cash Flow	9.02	06/30/07	12.67	06/30/07	5.55
Price / Sales	-	03/31/07	13.83	03/31/07	6.13
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	2.06	06/30/07	1.69	06/30/07	10.69
03/31/07	2.35	03/31/07	1.99	03/31/07	11.37
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	16.66	06/30/07	16.66	06/30/07	23.60
03/31/07	17.81	03/31/07	17.81	03/31/07	23.37
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	7.25	06/30/07	0.56	06/30/07	36.59
03/31/07	7.20	03/31/07	0.57	03/31/07	36.95

Zacks.com Quotes and Research

ALLIANT ENERGY CP (NYSE)

Scottrade

LNT	36.88	▼-0.02	(-0.05%)	Vol. 276,425	12:25 ET

Alliant Energy Corp. is a growing energy-services provider with operations both domestically and internationally. Alliant Energy provides electric, natural gas, water and steam services to customers worldwide. Alliant Energy Resources, Inc., the home of the company's non-regulated businesses, has operations and investments throughout the United States as well as in Australia, Brazil, China, Mexico and New Zealand. (Company Press Release)

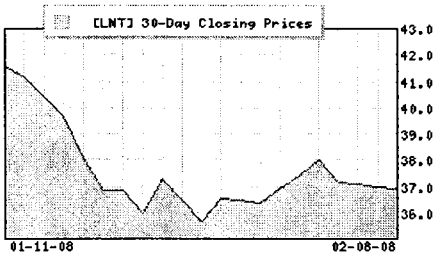
General Information

ALLIANT ENGY CP
4902 N. Biltmore Lane
Madison, WI 53718
Phone: 608 458-3311
Fax: 608-259-7269
Web: www.alliantenergy.com
Email: shareownerservices@alliantenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	05/09/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	36.90
52 Week High	46.53
52 Week Low	34.95
Beta	0.83
20 Day Moving Average	729,997.63
Target Price Consensus	42.56



% Price Change		% Price Change Relative to S&P 500	
4 Week	-11.30	4 Week	-6.65
12 Week	-10.13	12 Week	-1.53
YTD	-9.31	YTD	0.02

Share Information		Dividend Information	
Shares Outstanding (millions)	110.32	Dividend Yield	3.79%
		Annual Dividend	$1.40
Market Capitalization (millions)	4,070.66	Payout Ratio	0.50
Short Ratio	3.09	Change in Payout Ratio	-0.04
Last Split Date	N/A	Last Dividend Payout / Amount	01/29/2008 / $0.35

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.65	Current (1=Strong Buy, 5=Strong Sell)	2.33
Current Year EPS Consensus Estimate	2.68	30 Days Ago	2.33
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	2.33
Next EPS Report Date	05/09/2008	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.77	vs. Previous Year	-3.51%	vs. Previous Year	3.84%
Trailing 12 Months:	14.41	vs. Previous Quarter	-47.62%	vs. Previous Quarter:	-3.71%
PEG Ratio	2.29				

Price Ratios		ROE		ROA	
Price/Book	1.64	12/31/07	11.37	12/31/07	4.22

Price/Cash Flow	8.68	09/30/07	11.45	09/30/07	4.26
Price / Sales	1.18	06/30/07	10.37	06/30/07	3.84
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	-	12/31/07	-	12/31/07	8.34
09/30/07	1.13	09/30/07	0.84	09/30/07	8.59
06/30/07	0.81	06/30/07	0.61	06/30/07	7.79
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	20.28	09/30/07	20.28	09/30/07	22.44
06/30/07	19.09	06/30/07	19.09	06/30/07	21.95
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	8.50	09/30/07	0.63	09/30/07	36.71
06/30/07	10.44	06/30/07	0.52	06/30/07	32.19

Zacks.com Quotes and Research

AMEREN CP (NYSE)

Scottrade

AEE	49.06	▼-1.50	(-2.97%)	Vol. 1,331,490	12:10 ET

Ameren Corporation companies provide energy services customers in Missouri and Illinois. AmerenUE, one of its subsidiaries, is the one of the largest electric utilities in Missouri and distributors of natural gas. AmerenCIPS, another subsidiary, is both an electric and natural gas utility and serves one of the largest geographic areas of Illinois-based utility companies. (Company Press Release)

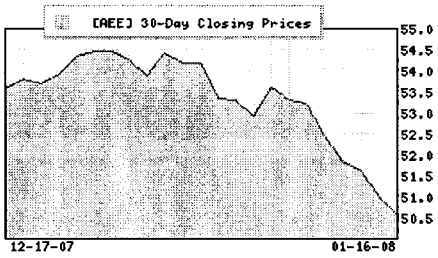
General Information

AMEREN CORP
1901 Chouteau Avenue
St. Louis, MO 63103
Phone: 314 621-3222
Fax: 314 621-2888
Web: www.ameren.com
Email: invest@ameren.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	02/14/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	50.56
52 Week High	55.00
52 Week Low	47.10
Beta	0.68
20 Day Moving Average	1,027,967.31
Target Price Consensus	54



% Price Change		% Price Change Relative to S&P 500	
4 Week	-5.83	4 Week	-0.36
12 Week	-3.71	12 Week	6.29
YTD	-6.73	YTD	0.26

Share Information		Dividend Information	
Shares Outstanding (millions)	208.01	Dividend Yield	5.02%
		Annual Dividend	$2.54
Market Capitalization (millions)	10,516.94	Payout Ratio	0.00
Short Ratio	4.36	Change in Payout Ratio	0.00
Last Split Date	N/A	Last Dividend Payout / Amount	12/03/2007 / $0.63

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.55	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	3.29	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	6.20	60 Days Ago	3.00
Next EPS Report Date	02/14/2008	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.17	vs. Previous Year	-4.23%	vs. Previous Year	4.55%
Trailing 12 Months:	16.47	vs. Previous Quarter	97.10%	vs. Previous Quarter:	15.90%
PEG Ratio	2.29				

Price Ratios		ROE		ROA	
Price/Book	1.55	09/30/07	-	09/30/07	-

Price/Cash Flow	7.98	06/30/07	9.60	06/30/07	3.18
Price / Sales	-	03/31/07	9.85	03/31/07	3.30
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	0.93	06/30/07	0.63	06/30/07	8.65
03/31/07	0.91	03/31/07	0.69	03/31/07	8.91
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	12.18	06/30/07	12.18	06/30/07	32.54
03/31/07	13.48	03/31/07	13.48	03/31/07	31.97
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	5.39	06/30/07	0.81	06/30/07	45.83
03/31/07	5.31	03/31/07	0.83	03/31/07	45.52

Zacks.com Quotes and Research

AMER ELECTRIC POW CO (NYSE)

Scottrade

AEP	43.40	▲0.24	(0.56%)	Vol. 1,978,800	12:30 ET

American Electric Power is a public utility holding company which owns,directly or indirectly, all of the outstanding common stock of its domesticelectric utility subsidiaries and varying percentages of other subsidiaries. Substantially all of the operating revenues of AEP and its subsidiaries are derived from the furnishing of electric service. The Company's operations are divided into three business segments: Wholesale, Energy Delivery and Other.

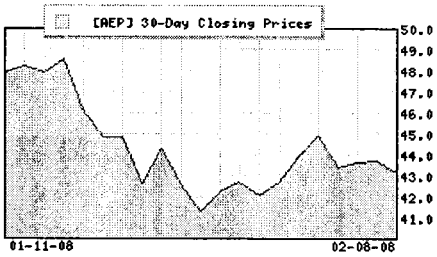
General Information

AMER ELEC PWR
1 Riverside Plaza
Columbus, OH 43215
Phone: 614 716-1000
Fax: 614 223-1823
Web: www.aep.com
Email: jsloat@aep.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	04/24/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	43.16
52 Week High	51.24
52 Week Low	40.68
Beta	0.88
20 Day Moving Average	3,815,779.25
Target Price Consensus	49.6



% Price Change		% Price Change Relative to S&P 500	
4 Week	-10.01	4 Week	-5.29
12 Week	-7.00	12 Week	1.90
YTD	-7.30	YTD	2.24

Share Information		Dividend Information	
Shares Outstanding (millions)	400.01	Dividend Yield	3.80%
		Annual Dividend	$1.64
Market Capitalization (millions)	17,264.26	Payout Ratio	0.55
Short Ratio	1.24	Change in Payout Ratio	-0.02
Last Split Date	N/A	Last Dividend Payout / Amount	02/06/2008 / $0.41

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.72	Current (1=Strong Buy, 5=Strong Sell)	2.45
Current Year EPS Consensus Estimate	3.18	30 Days Ago	2.42
Estimated Long-Term EPS Growth Rate	5.40	60 Days Ago	2.42
Next EPS Report Date	04/24/2008	90 Days Ago	2.42

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.56	vs. Previous Year	36.84%	vs. Previous Year	10.00%
Trailing 12 Months:	14.39	vs. Previous Quarter	-55.17%	vs. Previous Quarter:	-13.16%
PEG Ratio	2.51				

Price Ratios		ROE		ROA	
Price/Book	1.74	12/31/07	12.36	12/31/07	3.09

Price/Cash Flow	6.67	09/30/07	11.85	09/30/07	2.95
Price / Sales	1.29	06/30/07	11.23	06/30/07	2.83
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	-	12/31/07	-	12/31/07	8.95
09/30/07	0.53	09/30/07	0.33	09/30/07	8.71
06/30/07	0.56	06/30/07	0.38	06/30/07	8.30
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	12.53	09/30/07	12.53	09/30/07	24.82
06/30/07	11.06	06/30/07	11.06	06/30/07	24.22
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	6.01	09/30/07	1.40	09/30/07	58.17
06/30/07	7.15	06/30/07	1.35	06/30/07	57.51

Zacks.com Quotes and Research

CH ENERGY GRP HLDG (NYSE)

Scottrade

CHG	38.09	▼-0.93	(-2.38%)	Vol. 32,800	12:15 ET

CENTRAL HUDSON GAS & ELECTRIC generates, purchases and distributes electricity and purchases and distributes gas. The Company, in the opinion of its general counsel, has, with minor exceptions, valid franchises, unlimited in duration, to serve a territory extending about 85 miles along the Hudson River and about 25 to 40 miles east and west from such River. The southern end of the territory is about 25 miles north of New York City, and the northern end is about 10 miles south of the City of Albany.

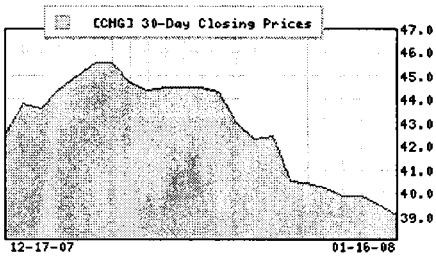
General Information

CH ENERGY GRP
284 South Avenue
Poughkeepsie, NY 12601-4879
Phone: 845 452-2000
Fax: 914 486-5415
Web: www.chenergygroup.com
Email: customerservices@cenhud.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	02/12/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	39.02
52 Week High	53.00
52 Week Low	38.87
Beta	0.77
20 Day Moving Average	94,920.00
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	-10.57	4 Week	-5.37
12 Week	-15.12	12 Week	-6.30
YTD	-12.39	YTD	-6.18

Share Information		Dividend Information	
Shares Outstanding (millions)	15.76	Dividend Yield	5.54%
		Annual Dividend	$2.16
Market Capitalization (millions)	615.03	Payout Ratio	0.00
Short Ratio	16.83	Change in Payout Ratio	0.00
Last Split Date	N/A	Last Dividend Payout / Amount	01/08/2008 / $0.54

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	N/A	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	2.60	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	0.00
Next EPS Report Date	02/12/2008	90 Days Ago	0.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	-	vs. Previous Year	-61.43%	vs. Previous Year	8.46%
Trailing 12 Months:	15.07	vs. Previous Quarter	-18.18%	vs. Previous Quarter:	-4.01%
PEG Ratio	-				

Price Ratios	ROE	ROA

Price/Book	1.16	09/30/07	-	09/30/07	-
Price/Cash Flow	7.80	06/30/07	7.84	06/30/07	2.77
Price / Sales	-	03/31/07	9.18	03/31/07	3.30
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	1.75	06/30/07	1.51	06/30/07	3.74
03/31/07	1.64	03/31/07	1.45	03/31/07	4.42
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	5.70	06/30/07	5.70	06/30/07	33.51
03/31/07	6.65	03/31/07	6.65	03/31/07	33.22
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	26.17	06/30/07	0.76	06/30/07	42.47
03/31/07	26.75	03/31/07	0.71	03/31/07	41.55

Zacks.com Quotes and Research

CENTRAL VT PUB SVC (NYSE)

Scottrade

CV	28.76	▼-0.41	(-1.41%)	Vol. 36,900	12:21 ET

Central Vermont Public Service Corporation is engaged in the purchase, production, transmission, distribution and sale of electricity.

General Information

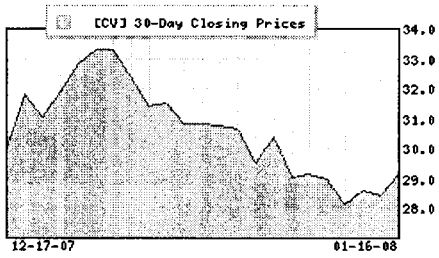
CENTRAL VT PS
77 Grove Street
Rutland, VT 05701
Phone: 802 773-2711
Fax: 802 773-1775
Web: www.cvps.com
Email: eryan@cvps.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	N/A

Price and Volume Information

Zacks Rank	2
Yesterday's Close	29.17
52 Week High	41.05
52 Week Low	22.68
Beta	1.30
20 Day Moving Average	47,156.80
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	-5.99	4 Week	-0.53
12 Week	-10.49	12 Week	-1.19
YTD	-5.41	YTD	-4.34

Share Information		Dividend Information	
Shares Outstanding (millions)	10.21	Dividend Yield	3.15%
		Annual Dividend	$0.92
Market Capitalization (millions)	297.71	Payout Ratio	0.00
Short Ratio	11.92	Change in Payout Ratio	0.00
Last Split Date	02/12/1993	Last Dividend Payout / Amount	10/29/2007 / $0.23

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	N/A	Current (1=Strong Buy, 5=Strong Sell)	4.00
Current Year EPS Consensus Estimate	N/A	30 Days Ago	4.00
Estimated Long-Term EPS Growth Rate	N/A	60 Days Ago	4.00
Next EPS Report Date	N/A	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	-	vs. Previous Year	-37.88%	vs. Previous Year	-0.92%
Trailing 12 Months:	18.58	vs. Previous Quarter	925.00%	vs. Previous Quarter:	2.32%
PEG Ratio	-				

Price Ratios		ROE		ROA	
Price/Book	1.63	09/30/07	-	09/30/07	-
Price/Cash Flow	8.54	06/30/07	9.18	06/30/07	3.28

Price / Sales	-	03/31/07	10.81	03/31/07	3.92
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	-	06/30/07	-	06/30/07	5.05
03/31/07	-	03/31/07	-	03/31/07	5.85
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	-	06/30/07	-	06/30/07	-
03/31/07	-	03/31/07	-	03/31/07	-
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	-	06/30/07	-	06/30/07	-
03/31/07	-	03/31/07	-	03/31/07	-

Zacks.com Quotes and Research

CLECO CP(HLDG CO) (NYSE)

Scottrade

CNL	27.07	▼-0.46	(-1.67%)	Vol. 188,492	12:24 ET

Cleco Corporation holds investments in several subsidiaries, including Utility Group, Cleco Midstream Resources LLC and Utility Construction & Technology Solutions LLC. Utility Group, incorporated on January 2, 1935 under the laws of the State of Louisiana, contains the LPSC jurisdictional generation, transmission and distribution electric utility operations serving the Company's traditional retail and wholesale customers. Utility Group serves customers in communities and rural areas in the State of Louisiana.

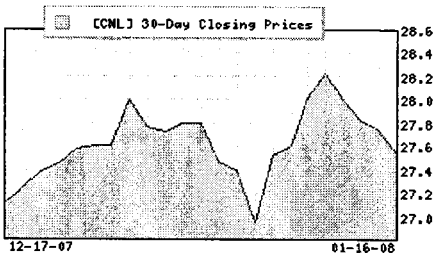
General Information

CLECO CORP
2030 Donahue Ferry Road
Pineville, LA 71360-5226
Phone: 318 484-7400
Fax: 318 484-7465
Web: www.cleco.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	03/04/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	27.53
52 Week High	29.84
52 Week Low	22.14
Beta	1.21
20 Day Moving Average	473,498.00
Target Price Consensus	29.75



% Price Change		% Price Change Relative to S&P 500	
4 Week	0.55	4 Week	6.39
12 Week	10.03	12 Week	21.47
YTD	-0.97	YTD	5.56

Share Information		Dividend Information	
Shares Outstanding (millions)	60.01	Dividend Yield	3.27%
		Annual Dividend	$0.90
Market Capitalization (millions)	1,651.99	Payout Ratio	0.00
Short Ratio	8.56	Change in Payout Ratio	0.00
Last Split Date	05/22/2001	Last Dividend Payout / Amount	10/25/2007 / $0.22

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.21	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	1.33	30 Days Ago	1.80
Estimated Long-Term EPS Growth Rate	9.50	60 Days Ago	2.00
Next EPS Report Date	03/04/2008	90 Days Ago	1.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.16	vs. Previous Year	46.94%	vs. Previous Year	5.98%
Trailing 12 Months:	21.34	vs. Previous Quarter	188.00%	vs. Previous Quarter:	19.19%
PEG Ratio	1.60				

Price Ratios	ROE	ROA

Price/Book	1.73	09/30/07	-	09/30/07	-
Price/Cash Flow	21.20	06/30/07	8.70	06/30/07	3.89
Price / Sales	-	03/31/07	6.99	03/31/07	2.97
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	-	06/30/07	-	06/30/07	7.67
03/31/07	1.10	03/31/07	0.92	03/31/07	6.22
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	-	06/30/07	-	06/30/07	-
03/31/07	12.76	03/31/07	12.76	03/31/07	15.94
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	-	06/30/07	-	06/30/07	-
03/31/07	-0.58	03/31/07	0.68	03/31/07	40.38

Zacks.com Quotes and Research

CONS EDISON INC (NYSE)

Scottrade

ED	42.74	▼-0.05	(-0.12%)	Vol. 965,012	12:33 ET

Consolidated Edison, Inc. is one of the nation's largest investor-owned energy companies. The company provides a wide range of energy- related products and services to its customers through regulated utility subsidiaries and competitive energy and telecommunications businesses.

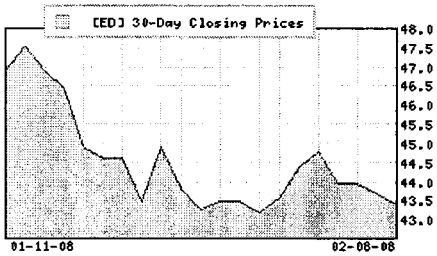
General Information

CONSOL EDISON
4 Irving Place
New York, NY 10003
Phone: 212 460-4600
Fax: 212 475-0734
Web: www.conedison.com
Email: investor.conedison.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	05/08/2008

Price and Volume Information

Zacks Rank	2
Yesterday's Close	42.78
52 Week High	52.90
52 Week Low	42.46
Beta	0.49
20 Day Moving Average	2,809,663.50
Target Price Consensus	46.68



% Price Change		% Price Change Relative to S&P 500	
4 Week	-7.57	4 Week	-2.72
12 Week	-7.39	12 Week	1.48
YTD	-11.22	YTD	-2.08

Share Information		Dividend Information	
Shares Outstanding (millions)	271.52	Dividend Yield	5.35%
		Annual Dividend	$2.32
Market Capitalization (millions)	11,775.65	Payout Ratio	0.66
Short Ratio	3.36	Change in Payout Ratio	-0.11
Last Split Date	07/03/1989	Last Dividend Payout / Amount	NA / $0.00

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.03	Current (1=Strong Buy, 5=Strong Sell)	2.98
Current Year EPS Consensus Estimate	3.20	30 Days Ago	2.98
Estimated Long-Term EPS Growth Rate	3.20	60 Days Ago	2.98
Next EPS Report Date	05/08/2008	90 Days Ago	2.89

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.53	vs. Previous Year	-2.56%	vs. Previous Year	5.78%
Trailing 12 Months:	12.32	vs. Previous Quarter	-33.91%	vs. Previous Quarter:	20.13%
PEG Ratio	4.27				

Price Ratios		ROE		ROA	
Price/Book	1.31	12/31/07	10.83	12/31/07	3.45

Price/Cash Flow	8.20	09/30/07	10.97	09/30/07	3.44
Price / Sales	-	06/30/07	10.35	06/30/07	3.19
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	0.89	09/30/07	0.75	09/30/07	7.23
06/30/07	0.88	06/30/07	0.75	06/30/07	6.70
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	10.51	09/30/07	10.51	09/30/07	33.18
06/30/07	10.05	06/30/07	10.05	06/30/07	32.55
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	16.42	09/30/07	0.89	09/30/07	46.72
06/30/07	16.15	06/30/07	0.89	06/30/07	46.52

Zacks.com Quotes and Research

D T E ENERGY CO HLDG (NYSE)

Scottrade

DTE	44.00	▼-0.37	(-0.83%)	Vol. 607,500	12:31 ET

DTE Energy is a Detroit-based diversified energy company involved in the development and management of energy-related businesses and services nationwide. Its largest operating units are Detroit Edison, an electric utility serving 2.1 million customers in Southeastern Michigan, and MichCon, a natural gas utility serving 1.2 million customers in Michigan. Detroit Edison is the Company's principal operating subsidiary. Affiliates of the Company are engaged in non-regulated businesses, including energy-related services and products.

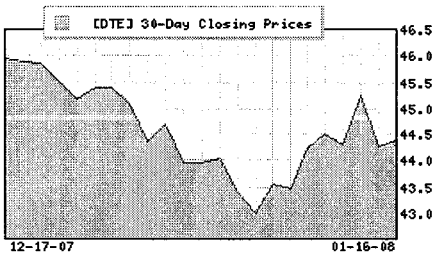
General Information

DTE ENERGY CO
2000 2nd Avenue
Detroit, MI 48226-1279
Phone: 313 235-4000
Fax: 313-235-6743
Web: www.dteenergy.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	03/10/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	44.37
52 Week High	54.74
52 Week Low	43.00
Beta	0.69
20 Day Moving Average	1,494,765.88
Target Price Consensus	50.67



% Price Change	
4 Week	-3.23
12 Week	-7.49
YTD	0.93

% Price Change Relative to S&P 500	
4 Week	2.40
12 Week	2.13
YTD	5.62

Share Information	
Shares Outstanding (millions)	163.71
Market Capitalization (millions)	7,263.99
Short Ratio	4.24
Last Split Date	N/A

Dividend Information	
Dividend Yield	4.78%
Annual Dividend	$2.12
Payout Ratio	0.00
Change in Payout Ratio	0.00
Last Dividend Payout / Amount	12/13/2007 / $0.53

EPS Information	
Current Quarter EPS Consensus Estimate	0.76
Current Year EPS Consensus Estimate	2.59
Estimated Long-Term EPS Growth Rate	6.00
Next EPS Report Date	03/10/2008

Consensus Recommendations	
Current (1=Strong Buy, 5=Strong Sell)	3.13
30 Days Ago	3.13
60 Days Ago	3.13
90 Days Ago	3.11

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.80	vs. Previous Year	4.81%	vs. Previous Year	10.06%
Trailing 12 Months:	13.17	vs. Previous Quarter	84.75%	vs. Previous Quarter:	23.69%
PEG Ratio	2.47				

Price Ratios	ROE	ROA

Price/Book	1.33	09/30/07	-	09/30/07	-
Price/Cash Flow	5.07	06/30/07	10.02	06/30/07	2.45
Price / Sales	-	03/31/07	10.03	03/31/07	2.51
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	0.94	06/30/07	0.75	06/30/07	6.20
03/31/07	1.04	03/31/07	0.87	03/31/07	6.40
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	10.88	06/30/07	10.88	06/30/07	33.38
03/31/07	11.48	03/31/07	11.48	03/31/07	33.45
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	4.91	06/30/07	1.17	06/30/07	54.08
03/31/07	4.63	03/31/07	1.19	03/31/07	55.52

Zacks.com Quotes and Research

EMPIRE DISTRICT ELCT (NYSE)

Scottrade

EDE	22.05	▼-0.21	(-0.94%)	Vol. 88,630	12:37 ET

The Empire District Electric Company is an operating public utility engagedin the generation, purchase, transmission, distribution and sale ofelectricity in parts of Missouri, Kansas, Oklahoma and Arkansas. TheCompany also provides water service to several towns in Missouri.

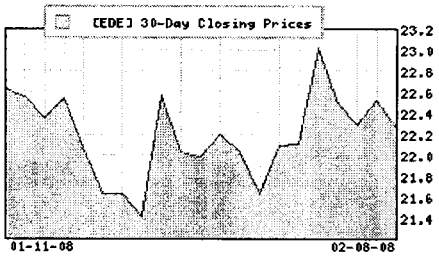
General Information

EMPIRE DISTRICT
602 Joplin Street
Joplin, MO 64801
Phone: 417 625-5100
Fax: 417 625-5173
Web: www.empiredistrict.com
Email: jwatson@empiredistrict.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	04/24/2008

Price and Volume Information

Zacks Rank	2
Yesterday's Close	22.26
52 Week High	26.13
52 Week Low	21.09
Beta	0.84
20 Day Moving Average	224,398.05
Target Price Consensus	24.25



% Price Change		% Price Change Relative to S&P 500	
4 Week	-1.63	4 Week	3.52
12 Week	-5.76	12 Week	3.26
YTD	-2.28	YTD	7.78

Share Information		Dividend Information	
Shares Outstanding (millions)	33.55	Dividend Yield	5.75%
		Annual Dividend	$1.28
Market Capitalization (millions)	746.89	Payout Ratio	1.23
Short Ratio	10.58	Change in Payout Ratio	0.07
Last Split Date	01/30/1992	Last Dividend Payout / Amount	11/28/2007 / $0.32

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.15	Current (1=Strong Buy, 5=Strong Sell)	2.20
Current Year EPS Consensus Estimate	1.40	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	2.00
Next EPS Report Date	04/24/2008	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.87	vs. Previous Year	-103.33%	vs. Previous Year	8.29%
Trailing 12 Months:	21.40	vs. Previous Quarter	-101.32%	vs. Previous Quarter:	32.49%
PEG Ratio	-				

Price Ratios		ROE		ROA	
Price/Book	1.41	12/31/07	6.70	12/31/07	2.27

Price/Cash Flow	8.14	09/30/07	8.71	09/30/07	2.99
Price / Sales	-	06/30/07	8.58	06/30/07	3.01
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	0.89	09/30/07	0.58	09/30/07	8.50
06/30/07	0.94	06/30/07	0.59	06/30/07	8.52
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	8.27	09/30/07	8.27	09/30/07	15.73
06/30/07	8.40	06/30/07	8.40	06/30/07	15.44
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	5.23	09/30/07	1.13	09/30/07	53.06
06/30/07	4.75	06/30/07	1.16	06/30/07	53.62

Zacks.com Quotes and Research

FIRSTENERGY CP (NYSE)

Scottrade

FE	74.24	▼-1.57	(-2.07%)	Vol. 1,142,983	12:41 ET

FirstEnergy Corp. is a diversified energy services holding company as the result of the merger of Ohio Edison Company and Centerior Energy Corporation. FirstEnergy companies provide electricity and natural gas services and a wide array of energy-related products and services. FirstEnergy's four electric utility companies, Ohio Edison and its Pennsylvania Power subsidiary, The Illuminating Company and Toledo Edison, serve customers in northern and central Ohio and western Pennsylvania. (Company Press Release)

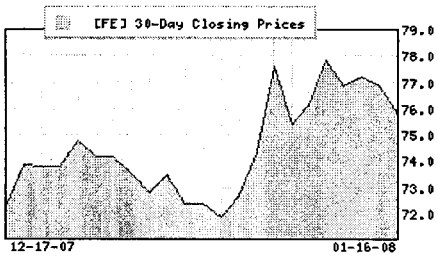
General Information

FIRSTENERGY CP
76 South Main Street
Akron, OH 44308
Phone: 800 736-3402
Fax: -
Web: www.firstenergycorp.com
Email: turoskyk@firstenergycorp.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	02/19/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	75.81
52 Week High	78.51
52 Week Low	57.83
Beta	0.41
20 Day Moving Average	1,845,050.75
Target Price Consensus	77.94



% Price Change		% Price Change Relative to S&P 500	
4 Week	2.72	4 Week	8.69
12 Week	14.73	12 Week	26.65
YTD	4.80	YTD	11.37

Share Information		Dividend Information	
Shares Outstanding (millions)	304.83	Dividend Yield	2.64%
		Annual Dividend	$2.00
Market Capitalization (millions)	23,109.54	Payout Ratio	0.00
Short Ratio	2.58	Change in Payout Ratio	0.00
Last Split Date	N/A	Last Dividend Payout / Amount	11/05/2007 / $0.50

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.91	Current (1=Strong Buy, 5=Strong Sell)	1.88
Current Year EPS Consensus Estimate	4.20	30 Days Ago	1.75
Estimated Long-Term EPS Growth Rate	7.50	60 Days Ago	1.75
Next EPS Report Date	02/19/2008	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	17.73	vs. Previous Year	-4.96%	vs. Previous Year	5.88%
Trailing 12 Months:	18.18	vs. Previous Quarter	19.64%	vs. Previous Quarter:	16.13%
PEG Ratio	2.36				

Price Ratios	ROE	ROA

Price/Book	2.67	09/30/07	-	09/30/07	-
Price/Cash Flow	8.90	06/30/07	15.11	06/30/07	4.13
Price / Sales	-	03/31/07	15.38	03/31/07	4.25
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	-	06/30/07	-	06/30/07	10.60
03/31/07	0.40	03/31/07	0.31	03/31/07	11.13
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	-	06/30/07	-	06/30/07	-
03/31/07	18.31	03/31/07	18.31	03/31/07	28.34
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	-	06/30/07	-	06/30/07	-
03/31/07	7.86	03/31/07	1.01	03/31/07	50.29

Zacks.com Quotes and Research

HAWAIIAN ELEC INDS (NYSE)

Scottrade

HE	22.35	-0.05	(0.22%)	Vol. 207,500	12:44 ET

Hawaiian Electric Industries, Inc. is a holding company with subsidiaries engaged in the electric utility, savings bank, freight transportation, real estate development and other businesses, primarily in the State of Hawaii, and in the pursuit of independent power projects in Asia and the Pacific.

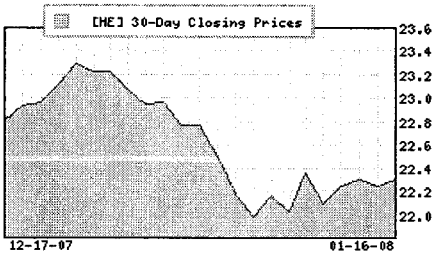
General Information

HAWAIIAN ELEC
900 Richards Street
Honolulu, HI 96813
Phone: 808 543-5662
Fax: 808 543-7966
Web: www.hei.com
Email: shollinger@hei.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	02/22/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	22.30
52 Week High	27.42
52 Week Low	20.25
Beta	0.60
20 Day Moving Average	287,359.31
Target Price Consensus	22.2



% Price Change		% Price Change Relative to S&P 500	
4 Week	-2.92	4 Week	2.72
12 Week	0.09	12 Week	10.49
YTD	-2.06	YTD	2.37

Share Information		Dividend Information	
Shares Outstanding (millions)	83.04	Dividend Yield	5.56%
		Annual Dividend	$1.24
Market Capitalization (millions)	1,851.81	Payout Ratio	0.00
Short Ratio	12.70	Change in Payout Ratio	0.00
Last Split Date	06/14/2004	Last Dividend Payout / Amount	11/13/2007 / $0.31

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.32	Current (1=Strong Buy, 5=Strong Sell)	3.20
Current Year EPS Consensus Estimate	0.98	30 Days Ago	3.20
Estimated Long-Term EPS Growth Rate	4.50	60 Days Ago	3.20
Next EPS Report Date	02/22/2008	90 Days Ago	3.60

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.91	vs. Previous Year	-15.00%	vs. Previous Year	-0.06%
Trailing 12 Months:	24.24	vs. Previous Quarter	61.90%	vs. Previous Quarter:	12.10%
PEG Ratio	3.31				

Price Ratios		ROE		ROA	
Price/Book	1.63	09/30/07	-	09/30/07	-

Price/Cash Flow	6.98	06/30/07	6.82	06/30/07	0.76
Price / Sales	-	03/31/07	7.02	03/31/07	0.80
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	0.24	06/30/07	0.24	06/30/07	3.10
03/31/07	0.24	03/31/07	0.24	03/31/07	3.27
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	3.77	06/30/07	3.77	06/30/07	13.70
03/31/07	4.60	03/31/07	4.60	03/31/07	13.52
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	-	06/30/07	1.09	06/30/07	52.79
03/31/07	-	03/31/07	1.11	03/31/07	53.30

Zacks.com Quotes and Research

IDACORP INC HLDG CO (NYSE)

Scottrade

IDA	33.93	▼-0.16	(-0.47%)	Vol. 219,400	12:46 ET

Idacorp Inc. is an electric public utility company. The company is engaged in the generation, purchase, transmission, distribution and sale of electric energy primarily in the areas including southern Idaho, eastern Oregon and northern Nevada. The company relies heavily on hydroelectric power for its generating needs and is one of the nation's few investor-owned utilities with a predominantly hydro base. The company's principal commercial and industrial customers include lodges, condominiums, and ski lifts and related facilities.

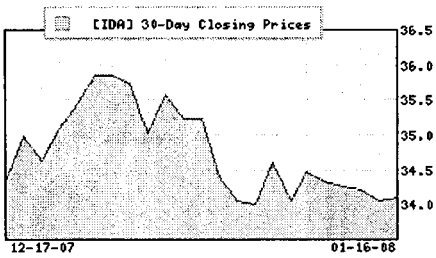
General Information

IDACORP INC
1221 West Idaho Street
Boise, ID 83702-5627
Phone: 208 388-2200
Fax: 208 388-6916
Web: www.idacorpinc.com
Email: LSpencer@idacorpinc.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	02/14/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	34.09
52 Week High	38.39
52 Week Low	30.07
Beta	0.80
20 Day Moving Average	416,759.00
Target Price Consensus	35.67



% Price Change		% Price Change Relative to S&P 500	
4 Week	-1.59	4 Week	4.13
12 Week	3.46	12 Week	14.21
YTD	-3.21	YTD	1.95

Share Information		Dividend Information	
Shares Outstanding (millions)	44.99	Dividend Yield	3.52%
		Annual Dividend	$1.20
Market Capitalization (millions)	1,533.88	Payout Ratio	0.00
Short Ratio	12.36	Change in Payout Ratio	0.00
Last Split Date	N/A	Last Dividend Payout / Amount	11/01/2007 / $0.30

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.21	Current (1=Strong Buy, 5=Strong Sell)	3.25
Current Year EPS Consensus Estimate	1.82	30 Days Ago	3.25
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	3.25
Next EPS Report Date	02/14/2008	90 Days Ago	3.25

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.76	vs. Previous Year	-14.47%	vs. Previous Year	13.42%
Trailing 12 Months:	16.63	vs. Previous Quarter	54.76%	vs. Previous Quarter:	22.31%
PEG Ratio	3.15				

Price Ratios	ROE	ROA

Price/Book	1.28	09/30/07	-	09/30/07	-
Price/Cash Flow	6.57	06/30/07	7.84	06/30/07	2.60
Price / Sales	-	03/31/07	8.26	03/31/07	2.73
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	-	06/30/07	-	06/30/07	10.39
03/31/07	0.84	03/31/07	0.67	03/31/07	11.20
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	-	06/30/07	-	06/30/07	-
03/31/07	12.51	03/31/07	12.51	03/31/07	26.59
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	-	06/30/07	-	06/30/07	-
03/31/07	5.74	03/31/07	0.91	03/31/07	47.65

Zacks.com Quotes and Research

MGE ENERGY INC. (NASDAQ)

Scottrade

MGEE	33.75	▼-0.88	(-2.54%)	Vol. 41,499	12:55 ET

MGE Energy is a public utility holding company. Its principal subsidiary, MGE, generates and distributes electricity to more than 128,000 customers in Dane County, Wisconsin (250 square miles) and purchases, transports and distributes natural gas to nearly 123,000 customers in seven south-central and western Wisconsin counties (1,375 square miles). (Press Release)

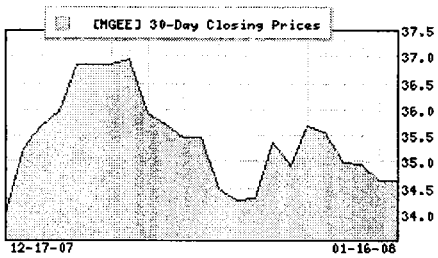
General Information

MGE ENERGY INC
133 South Blair St
Madison, WI 53703
Phone: 608 252-7000
Fax: 608 252-7098
Web: www.mge.com
Email: investor@mgeenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	N/A

Price and Volume Information

Zacks Rank	
Yesterday's Close	34.63
52 Week High	37.24
52 Week Low	29.40
Beta	0.77
20 Day Moving Average	78,566.10
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	-2.97	4 Week	2.67
12 Week	4.21	12 Week	15.04
YTD	-2.37	YTD	3.33

Share Information		Dividend Information	
Shares Outstanding (millions)	21.87	Dividend Yield	4.10%
		Annual Dividend	$1.42
Market Capitalization (millions)	757.32	Payout Ratio	0.00
Short Ratio	21.30	Change in Payout Ratio	0.00
Last Split Date	02/21/1996	Last Dividend Payout / Amount	11/28/2007 / $0.35

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	N/A	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	N/A	30 Days Ago	0.00
Estimated Long-Term EPS Growth Rate	N/A	60 Days Ago	0.00
Next EPS Report Date	N/A	90 Days Ago	0.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	-	vs. Previous Year	14.52%	vs. Previous Year	5.13%
Trailing 12 Months:	14.99	vs. Previous Quarter	51.06%	vs. Previous Quarter:	5.21%
PEG Ratio	-				

Price Ratios		ROE		ROA	
Price/Book	1.79	09/30/07	-	09/30/07	-

Price/Cash Flow	9.63	06/30/07	12.31	06/30/07	4.89
Price / Sales	-	03/31/07	12.06	03/31/07	4.75
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	0.80	06/30/07	0.49	06/30/07	9.17
03/31/07	1.06	03/31/07	0.69	03/31/07	8.74
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	14.47	06/30/07	14.47	06/30/07	19.31
03/31/07	13.84	03/31/07	13.84	03/31/07	19.26
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	6.03	06/30/07	0.55	06/30/07	35.61
03/31/07	5.96	03/31/07	0.58	03/31/07	36.74

Zacks.com Quotes and Research

NISOURCE INC HLDG CO (NYSE)

Scottrade

NI	18.41	▼-0.16	(-0.86%)	Vol. 717,630	12:41 ET

NiSource Inc., formerly NIPSCO Industries, Inc., is an energyand utility-based holding company headquartered in Merrillville, Indiana, that provides natural gas, electricity and water to the public for residential, commercial and industrial uses. NiSource operating companies deliver energy to millions of customers located within the high-demand energy corridor stretching from the Gulf Coast through the Midwest to New England.

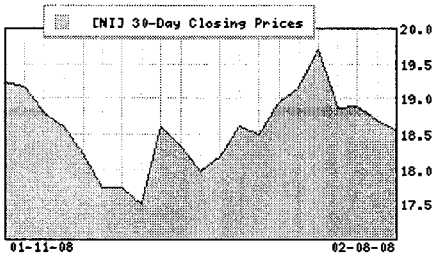
General Information

NISOURCE INC
801 East 86th Avenue
Merrillville, IN 46410
Phone: 877 647-5990
Fax: 219-647-5589
Web: www.nisource.com
Email: questions@nisource.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	05/08/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	18.57
52 Week High	25.43
52 Week Low	16.78
Beta	0.45
20 Day Moving Average	2,779,183.00
Target Price Consensus	21.13



% Price Change		% Price Change Relative to S&P 500	
4 Week	-3.48	4 Week	1.57
12 Week	3.34	12 Week	13.23
YTD	-1.69	YTD	8.43

Share Information		Dividend Information	
Shares Outstanding (millions)	274.17	Dividend Yield	4.95%
		Annual Dividend	$0.92
Market Capitalization (millions)	5,091.38	Payout Ratio	0.67
Short Ratio	3.72	Change in Payout Ratio	0.05
Last Split Date	02/23/1998	Last Dividend Payout / Amount	01/29/2008 / $0.23

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.81	Current (1=Strong Buy, 5=Strong Sell)	3.10
Current Year EPS Consensus Estimate	1.31	30 Days Ago	3.10
Estimated Long-Term EPS Growth Rate	2.80	60 Days Ago	3.10
Next EPS Report Date	05/08/2008	90 Days Ago	3.11

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.15	vs. Previous Year	0.00%	vs. Previous Year	9.81%
Trailing 12 Months:	13.56	vs. Previous Quarter	437.50%	vs. Previous Quarter:	259.40%
PEG Ratio	5.15				

Price Ratios		ROE		ROA	
Price/Book	1.02	12/31/07	7.48	12/31/07	2.16

Price/Cash Flow	5.36	09/30/07	7.47	09/30/07	2.13
Price / Sales	0.92	06/30/07	7.66	06/30/07	2.17
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	-	12/31/07	-	12/31/07	6.86
09/30/07	0.84	09/30/07	0.50	09/30/07	7.09
06/30/07	0.66	06/30/07	0.53	06/30/07	7.20
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	10.02	09/30/07	10.02	09/30/07	18.25
06/30/07	10.50	06/30/07	10.50	06/30/07	18.52
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	7.20	09/30/07	1.18	09/30/07	54.21
06/30/07	7.37	06/30/07	1.01	06/30/07	50.24

Zacks.com Quotes and Research

NSTAR (NYSE)

Scottrade

NST	31.64	▼-0.50	(-1.56%)	Vol. 197,736	12:43 ET

NSTAR was formed through a merger of BEC Energy and Commonwealth Energy System. The company, headquartered in Boston, Massachusetts provides regulated electric and gas utility services and is also engaged intelecommunications and other non-regulated activities. NSTAR, through its subsidiaries, Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company and Commonwealth Gas Company, serves approximately 1.3 million customers throughout Massachusetts. (Press Release)

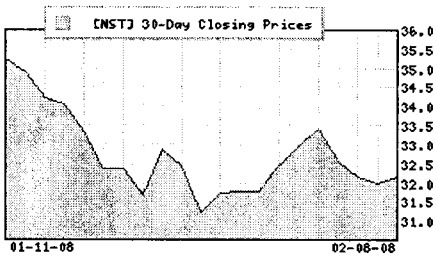
General Information

NSTAR
800 Boylston Street
Boston, MA 02199
Phone: 617 424-2000
Fax: 617 424-4032
Web: www.nstaronline.com
Email: ir@nstar.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	04/24/2008

Price and Volume Information

Zacks Rank	2
Yesterday's Close	32.14
52 Week High	37.37
52 Week Low	30.14
Beta	0.71
20 Day Moving Average	609,503.50
Target Price Consensus	35.78



% Price Change		% Price Change Relative to S&P 500	
4 Week	-8.82	4 Week	-4.05
12 Week	-7.11	12 Week	1.78
YTD	-11.26	YTD	-2.13

Share Information		Dividend Information	
Shares Outstanding (millions)	106.81	Dividend Yield	4.36%
		Annual Dividend	$1.40
Market Capitalization (millions)	3,432.81	Payout Ratio	0.63
Short Ratio	5.59	Change in Payout Ratio	-0.01
Last Split Date	06/06/2005	Last Dividend Payout / Amount	01/08/2008 / $0.35

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.48	Current (1=Strong Buy, 5=Strong Sell)	2.43
Current Year EPS Consensus Estimate	2.23	30 Days Ago	2.38
Estimated Long-Term EPS Growth Rate	6.20	60 Days Ago	2.38
Next EPS Report Date	04/24/2008	90 Days Ago	2.29

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.43	vs. Previous Year	-2.63%	vs. Previous Year	-6.82%
Trailing 12 Months:	15.45	vs. Previous Quarter	-53.16%	vs. Previous Quarter:	-7.15%
PEG Ratio	2.33				

Price Ratios	ROE	ROA

Price/Book	2.02	12/31/07	13.31	12/31/07	2.89
Price/Cash Flow	6.02	09/30/07	13.53	09/30/07	2.89
Price / Sales	1.05	06/30/07	13.31	06/30/07	2.80
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	-	12/31/07	-	12/31/07	6.79
09/30/07	0.72	09/30/07	0.63	09/30/07	6.71
06/30/07	0.72	06/30/07	0.65	06/30/07	6.20
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	10.58	09/30/07	10.58	09/30/07	15.92
06/30/07	9.77	06/30/07	9.77	06/30/07	15.44
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	18.09	09/30/07	1.01	09/30/07	50.28
06/30/07	19.22	06/30/07	1.04	06/30/07	50.42

Zacks.com Quotes and Research

PNM RES INC (HLDG) (NYSE)

Scottrade

PNM	20.06	▼-0.08	(-0.40%)	Vol. 779,500	13:01 ET

PNM Resources is an energy holding company based in Albuquerque, New Mexico. Its principal subsidiary is Public Service Company of New Mexico, which provides electric power and natural gas utility services to more than 1.3 million people in New Mexico. The company also sells power on the wholesale market in the Western U.S.

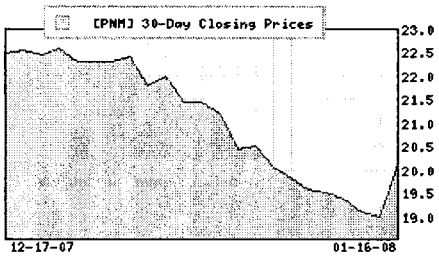
General Information

PNM RESOURCES
Alvarado Square
Albuquerque, NM 87158
Phone: 505 241-2700
Fax: 505 241-4311
Web: www.pnmresources.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	02/12/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	20.14
52 Week High	34.28
52 Week Low	18.75
Beta	0.89
20 Day Moving Average	1,421,115.00
Target Price Consensus	24.33



% Price Change		% Price Change Relative to S&P 500	
4 Week	-10.29	4 Week	-5.08
12 Week	-14.81	12 Week	-5.95
YTD	-6.11	YTD	-5.36

Share Information		Dividend Information	
Shares Outstanding (millions)	76.78	Dividend Yield	4.57%
		Annual Dividend	$0.92
Market Capitalization (millions)	1,546.29	Payout Ratio	0.00
Short Ratio	10.36	Change in Payout Ratio	0.00
Last Split Date	06/14/2004	Last Dividend Payout / Amount	10/30/2007 / $0.23

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.31	Current (1=Strong Buy, 5=Strong Sell)	2.43
Current Year EPS Consensus Estimate	1.27	30 Days Ago	2.71
Estimated Long-Term EPS Growth Rate	8.50	60 Days Ago	2.57
Next EPS Report Date	02/12/2008	90 Days Ago	2.57

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.63	vs. Previous Year	-34.92%	vs. Previous Year	-3.19%
Trailing 12 Months:	13.89	vs. Previous Quarter	215.38%	vs. Previous Quarter:	8.40%
PEG Ratio	1.37				

Price Ratios		ROE		ROA	
Price/Book	0.90	09/30/07	-	09/30/07	-

Price/Cash Flow	5.04	06/30/07	6.49	06/30/07	1.85
Price / Sales	-	03/31/07	7.59	03/31/07	2.06
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	0.40	06/30/07	0.36	06/30/07	4.46
03/31/07	0.58	03/31/07	0.53	03/31/07	4.92
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	4.02	06/30/07	4.02	06/30/07	22.26
03/31/07	6.15	03/31/07	6.15	03/31/07	22.51
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	27.13	06/30/07	0.72	06/30/07	41.79
03/31/07	26.05	03/31/07	0.89	03/31/07	46.85

Zacks.com Quotes and Research

PINNACLE WEST CAP (NYSE)

Scottrade

PNW	37.05	▼-0.11	(-0.30%)	Vol. 435,646	12:46 ET

Pinnacle West Capital is engaged, through its subsidiaries, in the generation, transmission, and distribution of electricity and selling energy, products and services; in real estate development; and in venture capital investment. Its primary subsidiary is Arizona Public Service Company. The company's other subsidiaries include SunCor, El Dorado, APSEnergy Services and Pinnacle West Energy.

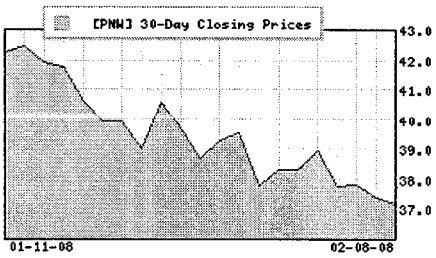
General Information

PINNACLE WEST
400 North Fifth Street
P.O. Box 53999
Phoenix, AZ 85072-3999
Phone: 602 250-1000
Fax: 602 250-2789
Web: www.pinnaclewest.com
Email: elisa.malagon@pinnaclewest.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	04/23/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	37.16
52 Week High	50.68
52 Week Low	36.79
Beta	0.65
20 Day Moving Average	941,397.13
Target Price Consensus	39.22



% Price Change		% Price Change Relative to S&P 500	
4 Week	-12.07	4 Week	-7.46
12 Week	-13.38	12 Week	-5.09
YTD	-12.38	YTD	-3.36

Share Information		Dividend Information	
Shares Outstanding (millions)	100.39	Dividend Yield	5.65%
		Annual Dividend	$2.10
Market Capitalization (millions)	3,730.31	Payout Ratio	0.73
Short Ratio	9.46	Change in Payout Ratio	0.05
Last Split Date	N/A	Last Dividend Payout / Amount	01/30/2008 / $0.52

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.16	Current (1=Strong Buy, 5=Strong Sell)	3.13
Current Year EPS Consensus Estimate	2.63	30 Days Ago	3.13
Estimated Long-Term EPS Growth Rate	6.70	60 Days Ago	3.14
Next EPS Report Date	04/23/2008	90 Days Ago	3.14

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.14	vs. Previous Year	0.00%	vs. Previous Year	3.98%
Trailing 12 Months:	12.99	vs. Previous Quarter	-98.41%	vs. Previous Quarter:	-37.05%
PEG Ratio	2.12				

Price Ratios	ROE	ROA

Price/Book	1.04	12/31/07	8.30	12/31/07	2.58
Price/Cash Flow	5.27	09/30/07	8.29	09/30/07	2.56
Price / Sales	1.06	06/30/07	8.20	06/30/07	2.50
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	-	12/31/07	-	12/31/07	8.19
09/30/07	0.82	09/30/07	0.68	09/30/07	8.24
06/30/07	0.78	06/30/07	0.65	06/30/07	8.35
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	12.81	09/30/07	12.81	09/30/07	35.58
06/30/07	13.02	06/30/07	13.02	06/30/07	34.15
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	8.92	09/30/07	0.90	09/30/07	47.51
06/30/07	9.11	06/30/07	0.94	06/30/07	48.57

Zacks.com Quotes and Research

PPL CORP (NYSE)

Scottrade

PPL	47.57	▲1.16	(2.50%)	Vol. 2,957,212	12:51 ET

PPL Corporation is an energy and utility holding company. PPL controls about 11,500 megawatts of generating capacity in the United States, sells energy in key U.S. markets and delivers electricity to customers in Pennsylvania, the United Kingdom and Latin America.

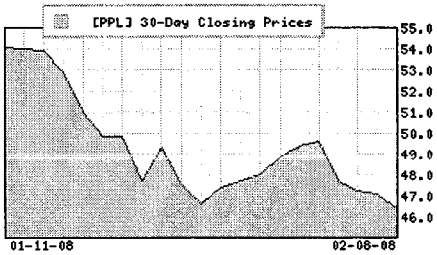
General Information

PPL CORP
Two North Ninth Street
Allentown, PA 18101-1179
Phone: 610 774-5151
Fax: 610 774-5106
Web: www.pplweb.com
Email: invrel@pplweb.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	05/08/2008

Price and Volume Information

Zacks Rank	2
Yesterday's Close	46.41
52 Week High	55.23
52 Week Low	36.46
Beta	0.37
20 Day Moving Average	2,679,921.00
Target Price Consensus	58.44



% Price Change		% Price Change Relative to S&P 500	
4 Week	-14.17	4 Week	-9.67
12 Week	-5.57	12 Week	3.46
YTD	-10.90	YTD	-1.73

Share Information		Dividend Information	
Shares Outstanding (millions)	372.20	Dividend Yield	2.63%
		Annual Dividend	$1.22
Market Capitalization (millions)	17,273.62	Payout Ratio	0.47
Short Ratio	2.25	Change in Payout Ratio	0.00
Last Split Date	08/25/2005	Last Dividend Payout / Amount	12/06/2007 / $0.31

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.68	Current (1=Strong Buy, 5=Strong Sell)	1.78
Current Year EPS Consensus Estimate	2.42	30 Days Ago	1.67
Estimated Long-Term EPS Growth Rate	10.30	60 Days Ago	1.67
Next EPS Report Date	05/08/2008	90 Days Ago	1.89

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	19.17	vs. Previous Year	27.66%	vs. Previous Year	-6.84%
Trailing 12 Months:	17.85	vs. Previous Quarter	-16.67%	vs. Previous Quarter:	-8.91%
PEG Ratio	1.86				

Price Ratios		ROE		ROA	
Price/Book	3.45	12/31/07	19.12	12/31/07	5.04

Price/Cash Flow	10.99	09/30/07	18.35	09/30/07	4.82
Price / Sales	2.61	06/30/07	17.23	06/30/07	4.57
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	-	12/31/07	-	12/31/07	15.21
09/30/07	1.31	09/30/07	1.20	09/30/07	14.24
06/30/07	1.34	06/30/07	1.23	06/30/07	13.35
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	18.67	09/30/07	18.67	09/30/07	13.47
06/30/07	16.46	06/30/07	16.46	06/30/07	13.91
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	6.64	09/30/07	1.39	09/30/07	56.86
06/30/07	7.26	06/30/07	1.27	06/30/07	57.17

Zacks.com Quotes and Research

PROGRESS ENERGY INC (NYSE)

Scottrade

PGN	46.91	-0.84	(-1.76%)	Vol. 1,213,400	14:33 ET

CP & L Energy, Inc. is primarily engaged in the generation, transmission,distribution and sale of electricity in portions of North and South Carolina and Florida and the transmission, distribution and sale of natural gas in portions of North Carolina. The company provides these and other services through its business segments: electric, natural gas and other.

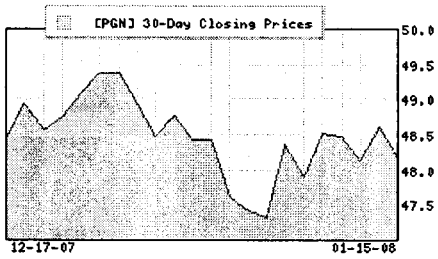
General Information

PROGRESS ENERGY
410 South Wilmington Street
Raleigh, NC 27601-1748
Phone: 919 546-6111
Fax: 919 546-2920
Web: www.progress-energy.com
Email: investor.relations@pgnmail.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	02/14/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	47.75
52 Week High	52.75
52 Week Low	43.12
Beta	0.71
20 Day Moving Average	1,089.392.88
Target Price Consensus	49.52



% Price Change		% Price Change Relative to S&P 500	
4 Week	-1.71	4 Week	4.00
12 Week	4.42	12 Week	15.27
YTD	-1.40	YTD	4.16

Share Information		Dividend Information	
Shares Outstanding (millions)	259.20	Dividend Yield	5.15%
		Annual Dividend	$2.46
Market Capitalization (millions)	12,376.90	Payout Ratio	0.00
Short Ratio	4.76	Change in Payout Ratio	0.00
Last Split Date	02/01/1993	Last Dividend Payout / Amount	01/08/2008 / $0.62

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.51	Current (1=Strong Buy, 5=Strong Sell)	2.67
Current Year EPS Consensus Estimate	2.86	30 Days Ago	2.67
Estimated Long-Term EPS Growth Rate	5.20	60 Days Ago	2.67
Next EPS Report Date	02/14/2008	90 Days Ago	2.75

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.77	vs. Previous Year	30.11%	vs. Previous Year	6.42%
Trailing 12 Months:	15.86	vs. Previous Quarter	105.08%	vs. Previous Quarter:	28.84%
PEG Ratio	3.03				

Price Ratios		ROE		ROA	
Price/Book	1.47	09/30/07	-	09/30/07	-

Price/Cash Flow	6.88	06/30/07	9.19	06/30/07	2.97
Price / Sales	-	03/31/07	8.36	03/31/07	2.68
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	1.10	06/30/07	0.79	06/30/07	7.60
03/31/07	0.95	03/31/07	0.60	03/31/07	6.96
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	10.83	06/30/07	10.83	06/30/07	32.54
03/31/07	9.61	03/31/07	9.61	03/31/07	31.95
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	4.88	06/30/07	1.09	06/30/07	52.06
03/31/07	4.90	03/31/07	1.02	03/31/07	50.42

Zacks.com Quotes and Research

SCANA CP NEW (NYSE)

Scottrade

SCG	39.83	▼-0.66	(-1.63%)	Vol. 776,400	14:39 ET

SCANA Corporation is an energy-based holding company whose businesses include regulated electric and natural gas utility operations, telecommunications and other non-regulated energy-related businesses. SCANA?s subsidiaries serve electric customers in South Carolina, North Carolina and Georgia.

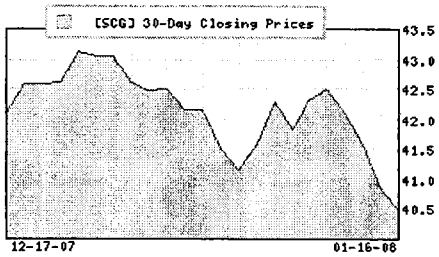
General Information

SCANA CORP
1426 Main Street
Columbia, SC 29201
Phone: 803 217-9000
Fax: 803 748-2344
Web: www.scana.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	02/12/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	40.49
52 Week High	45.49
52 Week Low	32.93
Beta	0.39
20 Day Moving Average	582,665.63
Target Price Consensus	43



% Price Change		% Price Change Relative to S&P 500	
4 Week	-4.91	4 Week	0.62
12 Week	2.33	12 Week	12.96
YTD	-3.94	YTD	4.66

Share Information		Dividend Information	
Shares Outstanding (millions)	116.67	Dividend Yield	4.35%
		Annual Dividend	$1.76
Market Capitalization (millions)	4,723.77	Payout Ratio	0.00
Short Ratio	2.01	Change in Payout Ratio	0.00
Last Split Date	05/26/1995	Last Dividend Payout / Amount	12/06/2007 / $0.44

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.71	Current (1=Strong Buy, 5=Strong Sell)	2.83
Current Year EPS Consensus Estimate	2.70	30 Days Ago	2.60
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	2.60
Next EPS Report Date	02/12/2008	90 Days Ago	2.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.99	vs. Previous Year	3.95%	vs. Previous Year	1.60%
Trailing 12 Months:	15.45	vs. Previous Quarter	68.09%	vs. Previous Quarter:	7.15%
PEG Ratio	2.80				

Price Ratios		ROE		ROA	
Price/Book	1.61	09/30/07	-	09/30/07	-

Price/Cash Flow	6.97	06/30/07	10.55	06/30/07	3.14
Price / Sales	-	03/31/07	10.55	03/31/07	3.14
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	0.81	06/30/07	0.49	06/30/07	6.61
03/31/07	0.84	03/31/07	0.53	03/31/07	6.57
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	9.44	06/30/07	9.44	06/30/07	25.11
03/31/07	8.91	03/31/07	8.91	03/31/07	24.81
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	7.02	06/30/07	1.01	06/30/07	49.28
03/31/07	7.17	03/31/07	1.02	03/31/07	49.66

Zacks.com Quotes and Research

SOUTHERN CO (NYSE)

Scottrade

SO	35.65	▼-0.10	(-0.28%)	Vol. 1,803,047	12:58 ET

Southern Energy acquires, develops, builds, owns and operates power production and delivery facilities and provides a broad range ofenergy-related services to utilities and industrial companies in selectedcountries around the world. Southern Energy businesses include independent power projects, integrated utilities, a distribution company, and energy trading and marketing businesses outside the southeastern United States.

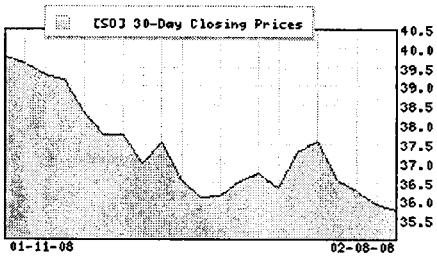
General Information

SOUTHN COMPANY
30 Ivan Allen Jr. Boulevard, N.W.
Atlanta, GA 30308
Phone: 404 506-5000
Fax: -
Web: www.southerncompany.com
Email: investors@southerncompany.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	04/24/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	35.75
52 Week High	40.60
52 Week Low	33.16
Beta	0.40
20 Day Moving Average	5,707,479.00
Target Price Consensus	37.78



% Price Change		% Price Change Relative to S&P 500	
4 Week	-10.09	4 Week	-5.38
12 Week	-3.43	12 Week	5.81
YTD	-7.74	YTD	1.76

Share Information		Dividend Information	
Shares Outstanding (millions)	759.48	Dividend Yield	4.50%
		Annual Dividend	$1.61
Market Capitalization (millions)	27,151.38	Payout Ratio	0.72
Short Ratio	4.39	Change in Payout Ratio	0.00
Last Split Date	03/01/1994	Last Dividend Payout / Amount	01/31/2008 / $0.40

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.45	Current (1=Strong Buy, 5=Strong Sell)	2.53
Current Year EPS Consensus Estimate	2.31	30 Days Ago	2.57
Estimated Long-Term EPS Growth Rate	4.60	60 Days Ago	2.57
Next EPS Report Date	04/24/2008	90 Days Ago	2.72

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.50	vs. Previous Year	8.00%	vs. Previous Year	5.96%
Trailing 12 Months:	15.96	vs. Previous Quarter	-72.73%	vs. Previous Quarter:	-30.88%
PEG Ratio	3.37				

Price Ratios		ROE		ROA	
Price/Book	2.19	12/31/07	14.24	12/31/07	3.83

Price/Cash Flow	8.82	09/30/07	14.26	09/30/07	3.82
Price / Sales	1.77	06/30/07	14.51	06/30/07	3.87
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	-	12/31/07	-	12/31/07	11.01
09/30/07	0.89	09/30/07	0.65	09/30/07	11.05
06/30/07	0.87	06/30/07	0.60	06/30/07	11.19
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	17.18	09/30/07	17.18	09/30/07	16.32
06/30/07	17.08	06/30/07	17.08	06/30/07	15.68
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	5.42	09/30/07	1.12	09/30/07	51.31
06/30/07	5.45	06/30/07	1.19	06/30/07	52.90

Zacks.com Quotes and Research

TECO ENERGY INC (NYSE)

Scottrade

TE	16.20	▼-0.02	(-0.12%)	Vol. 713,000	13:03 ET

TECO Energy, Inc. is a diversified, energy-related holding company. Its principal businesses are Tampa Electric, Peoples Gas, Florida's largest natural gas distributor; TECO Power Services, an independent power company; TECO Transport, a river and ocean transportation company; TECO Coal, producer of coal and synthetic fuel; and TECO Solutions, an energy services/engineering company. (Company Press Release)

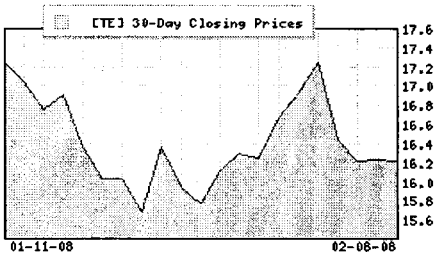
General Information

TECO ENERGY
702 N. Franklin Street
Tampa, FL 33602
Phone: 813-228-1111
Fax: 813-228-1670
Web: www.tecoenergy.com
Email: investorrelations@tecoenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	05/06/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	16.22
52 Week High	18.58
52 Week Low	14.84
Beta	0.68
20 Day Moving Average	1,986,913.38
Target Price Consensus	17.72



% Price Change		% Price Change Relative to S&P 500	
4 Week	-5.92	4 Week	-0.99
12 Week	-5.15	12 Week	3.93
YTD	-5.75	YTD	3.95

Share Information		Dividend Information	
Shares Outstanding (millions)	210.68	Dividend Yield	4.81%
		Annual Dividend	$0.78
Market Capitalization (millions)	3,417.20	Payout Ratio	0.75
Short Ratio	6.43	Change in Payout Ratio	-0.01
Last Split Date	08/31/1993	Last Dividend Payout / Amount	11/13/2007 / $0.19

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.22	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.05	30 Days Ago	2.71
Estimated Long-Term EPS Growth Rate	7.30	60 Days Ago	2.71
Next EPS Report Date	05/06/2008	90 Days Ago	2.71

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.49	vs. Previous Year	11.11%	vs. Previous Year	3.89%
Trailing 12 Months:	15.60	vs. Previous Quarter	-47.37%	vs. Previous Quarter:	-13.30%
PEG Ratio	2.11				

Price Ratios		ROE		ROA	
Price/Book	1.83	12/31/07	12.01	12/31/07	3.01

Price/Cash Flow	6.85	09/30/07	11.86	09/30/07	2.93
Price / Sales	0.97	06/30/07	12.07	06/30/07	2.88
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	-	12/31/07	-	12/31/07	6.17
09/30/07	1.35	09/30/07	1.11	09/30/07	6.08
06/30/07	1.24	06/30/07	0.99	06/30/07	6.15
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	9.04	09/30/07	9.04	09/30/07	8.88
06/30/07	9.12	06/30/07	9.12	06/30/07	8.67
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	15.82	09/30/07	1.85	09/30/07	64.89
06/30/07	14.95	06/30/07	1.90	06/30/07	65.57

Zacks.com Quotes and Research

UIL HLDG CORP (NYSE)

Scottrade

UIL	34.16	▼-0.82	(-2.34%)	Vol. 112,100	14:50 ET

UIL Holdings Corporation is the holding company for The United Illuminating Company and United Resources. United Illuminating Company is aNew Haven-based regional distribution utility that provides electricity and energy-related services to customers in municipalities in the Greater New Haven and Greater Bridgeport areas.(PR)

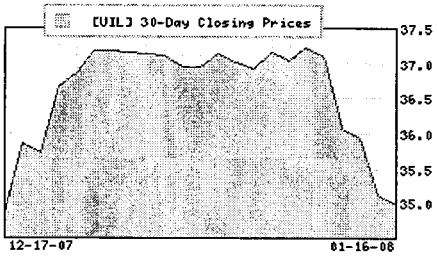
General Information

UIL HOLDINGS CP
157 Church Street
New Haven, CT 06506
Phone: 203 499-2000
Fax: 203 499-2414
Web: www.uil.com
Email: Susan.Allen@uinet.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	02/19/2008

Price and Volume Information

Zacks Rank	2
Yesterday's Close	34.98
52 Week High	41.24
52 Week Low	27.02
Beta	1.06
20 Day Moving Average	136,190.50
Target Price Consensus	36.38



% Price Change		% Price Change Relative to S&P 500	
4 Week	-2.07	4 Week	3.62
12 Week	6.16	12 Week	17.19
YTD	-5.33	YTD	2.31

Share Information		Dividend Information	
Shares Outstanding (millions)	25.16	Dividend Yield	4.94%
		Annual Dividend	$1.73
Market Capitalization (millions)	880.10	Payout Ratio	0.00
Short Ratio	11.49	Change in Payout Ratio	0.00
Last Split Date	07/05/2006	Last Dividend Payout / Amount	12/03/2007 / $0.43

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.23	Current (1=Strong Buy, 5=Strong Sell)	2.33
Current Year EPS Consensus Estimate	1.74	30 Days Ago	2.33
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	2.33
Next EPS Report Date	02/19/2008	90 Days Ago	2.33

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	17.32	vs. Previous Year	19.74%	vs. Previous Year	2.58%
Trailing 12 Months:	22.00	vs. Previous Quarter	139.47%	vs. Previous Quarter:	23.60%
PEG Ratio	-				

Price Ratios		ROE		ROA	
Price/Book	1.90	09/30/07	-	09/30/07	-

Price/Cash Flow	6.21	06/30/07	8.69	06/30/07	2.37
Price / Sales	-	03/31/07	7.67	03/31/07	2.16
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	1.18	06/30/07	1.16	06/30/07	4.70
03/31/07	1.02	03/31/07	1.01	03/31/07	4.26
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	18.20	06/30/07	18.20	06/30/07	18.45
03/31/07	18.31	03/31/07	18.31	03/31/07	18.01
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/07	-	09/30/07	-	09/30/07	-
06/30/07	181.28	06/30/07	1.09	06/30/07	52.07
03/31/07	205.45	03/31/07	0.89	03/31/07	47.16

Zacks.com Quotes and Research

VECTREN CORP (NYSE)

Scottrade

VVC	27.93	▼-0.11	(-0.39%)	Vol. 141,200	13:08 ET

Vectren Corp., through its regulated subsidiaries Indiana Gas and SIGECO, offers gas and/or electricity to customers in adjoining service areas that cover nearly two-thirds of Indiana. Vectren's non-regulated subsidiaries currently offer energy-related products and services, including energy marketing, fiber-optic based communication services, and utility related services including materials management, debt collections, locating, meter reading and trenching services to customers throughout the surrounding region. (PRESS RELEASE)

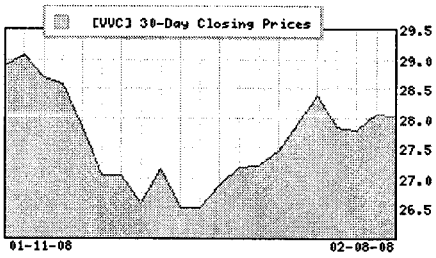
General Information

VECTREN CORP
One Vectren Square
Evansville, IN 47708
Phone: 812 491-4000
Fax: -
Web: www.vectren.com
Email: sschein@vectren.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	04/22/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	28.04
52 Week High	30.50
52 Week Low	24.85
Beta	0.53
20 Day Moving Average	432,051.19
Target Price Consensus	32.33



% Price Change		% Price Change Relative to S&P 500	
4 Week	-2.91	4 Week	2.18
12 Week	-2.47	12 Week	6.87
YTD	-3.34	YTD	6.61

Share Information		Dividend Information	
Shares Outstanding (millions)	76.52	Dividend Yield	4.64%
		Annual Dividend	$1.30
Market Capitalization (millions)	2,145.54	Payout Ratio	0.70
Short Ratio	26.68	Change in Payout Ratio	-0.02
Last Split Date	10/05/1998	Last Dividend Payout / Amount	11/13/2007 / $0.32

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.92	Current (1=Strong Buy, 5=Strong Sell)	1.88
Current Year EPS Consensus Estimate	1.95	30 Days Ago	1.83
Estimated Long-Term EPS Growth Rate	4.70	60 Days Ago	1.83
Next EPS Report Date	04/22/2008	90 Days Ago	1.83

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.35	vs. Previous Year	7.27%	vs. Previous Year	5.86%
Trailing 12 Months:	15.07	vs. Previous Quarter	227.78%	vs. Previous Quarter:	69.06%
PEG Ratio	3.07				

Price Ratios	ROE	ROA

Price/Book	1.77	12/31/07	11.65	12/31/07	3.57
Price/Cash Flow	7.44	09/30/07	11.46	09/30/07	3.46
Price / Sales	0.94	06/30/07	11.46	06/30/07	3.46
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	-	12/31/07	-	12/31/07	6.22
09/30/07	0.61	09/30/07	0.39	09/30/07	6.16
06/30/07	0.60	06/30/07	0.43	06/30/07	6.18
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	8.84	09/30/07	8.84	09/30/07	15.85
06/30/07	8.09	06/30/07	8.09	06/30/07	15.94
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	9.17	09/30/07	1.00	09/30/07	49.92
06/30/07	9.30	06/30/07	0.99	06/30/07	49.79

Zacks.com Quotes and Research

XCEL ENERGY INC (NYSE)

Scottrade

XEL	20.58	▼-0.03	(-0.15%)	Vol. 1,184,829	13:10 ET

Xcel Energy Inc. is predominantly an operating public utility engaged in the generation, transmission and distribution of electricity and the transportation, storage and distribution of natural gas. The company has two significant subsidiaries, Northern States Power Company, a Wisconsin corporation, and NRG Energy, Inc.

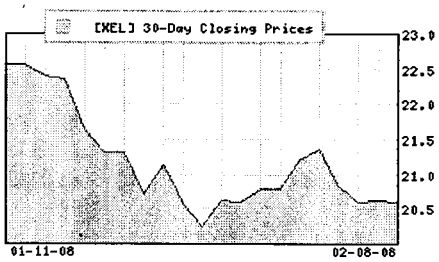
General Information

XCEL ENERGY INC
414 Nicollet Mall
Minneapolis, MN 55401
Phone: 612 330-5500
Fax: 612 330-2900
Web: www.xcelenergy.com
Email: Paul.A.Johnson@xcelenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/07
Next EPS Date	04/23/2008

Price and Volume Information

Zacks Rank	
Yesterday's Close	20.61
52 Week High	25.03
52 Week Low	19.59
Beta	0.72
20 Day Moving Average	2,947,012.50
Target Price Consensus	23.67



% Price Change		% Price Change Relative to S&P 500	
4 Week	-8.64	4 Week	-3.86
12 Week	-6.95	12 Week	1.96
YTD	-8.68	YTD	0.72

Share Information		Dividend Information	
Shares Outstanding (millions)	419.93	Dividend Yield	4.46%
		Annual Dividend	$0.92
Market Capitalization (millions)	8,654.76	Payout Ratio	0.63
Short Ratio	11.51	Change in Payout Ratio	-0.03
Last Split Date	06/02/1998	Last Dividend Payout / Amount	12/24/2007 / $0.23

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.29	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	1.51	30 Days Ago	2.43
Estimated Long-Term EPS Growth Rate	5.20	60 Days Ago	2.43
Next EPS Report Date	04/23/2008	90 Days Ago	2.43

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.65	vs. Previous Year	36.36%	vs. Previous Year	5.53%
Trailing 12 Months:	14.02	vs. Previous Quarter	-46.43%	vs. Previous Quarter:	8.47%
PEG Ratio	2.62				

Price Ratios		ROE		ROA	
Price/Book	1.40	12/31/07	10.59	12/31/07	2.84

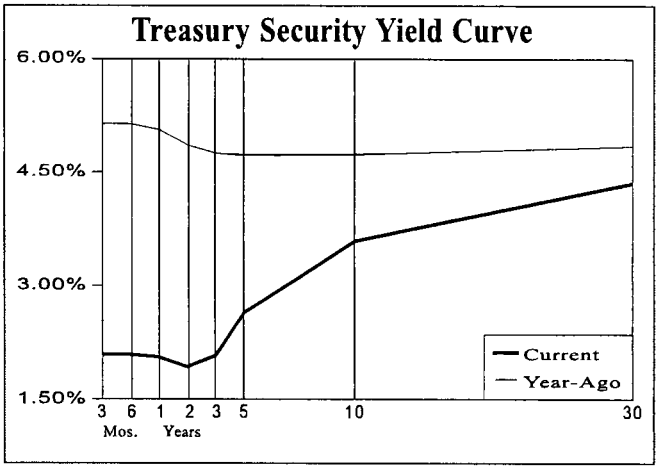
Price/Cash Flow	5.69	09/30/07	10.10	09/30/07	2.70
Price / Sales	0.86	06/30/07	9.93	06/30/07	2.65
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/07	-	12/31/07	-	12/31/07	6.34
09/30/07	1.07	09/30/07	0.84	09/30/07	6.08
06/30/07	0.87	06/30/07	0.72	06/30/07	5.85
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	8.65	09/30/07	8.65	09/30/07	14.68
06/30/07	7.88	06/30/07	7.88	06/30/07	14.66
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/07	-	12/31/07	-	12/31/07	-
09/30/07	10.20	09/30/07	1.18	09/30/07	53.65
06/30/07	10.02	06/30/07	1.10	06/30/07	52.03

ATTACHMENT C

Selected Yields

	Recent (2/06/08)	3 Months Ago (11/07/07)	Year Ago (2/07/07)
TAXABLE			
Market Rates			
Discount Rate	3.50	5.00	6.25
Federal Funds	3.00	4.50	5.25
Prime Rate	6.00	7.50	8.25
30-day CP (A1/P1)	3.04	4.53	5.24
3-month LIBOR	3.13	4.90	5.36
Bank CDs			
6-month	2.30	2.83	3.27
1-year	2.39	3.55	3.86
5-year	2.86	3.90	3.91
U.S. Treasury Securities			
3-month	2.09	3.44	5.15
6-month	2.09	3.73	5.15
1-year	2.06	3.83	5.07
5-year	2.65	3.88	4.73
10-year	3.59	4.31	4.74
10-year (inflation-protected)	1.26	1.91	2.38
30-year	4.36	4.65	4.85
30-year Zero	4.40	4.66	4.80

	Recent (2/06/08)	3 Months Ago (11/07/07)	Year Ago (2/07/07)
Mortgage-Backed Securities			
GNMA 6.5%	4.31	5.53	5.72
FHLMC 6.5% (Gold)	4.68	5.75	5.82
FNMA 6.5%	4.21	5.58	5.76
FNMA ARM	5.19	5.90	5.62
Corporate Bonds			
Financial (10-year) A	5.54	5.81	5.56
Industrial (25/30-year) A	6.12	5.89	5.79
Utility (25/30-year) A	6.02	6.07	5.81
Utility (25/30-year) Baa/BBB	6.20	6.15	6.07
Foreign Bonds (10-Year)			
Canada	3.79	4.28	4.11
Germany	3.90	4.15	4.03
Japan	1.43	1.57	1.74
United Kingdom	4.46	4.83	4.96
Preferred Stocks			
Utility A	6.09	6.38	6.14
Financial A	6.95	7.84	6.44
Financial Adjustable A	5.51	5.51	5.51



	Recent (2/06/08)	3 Months Ago (11/07/07)	Year Ago (2/07/07)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.39	4.40	4.31
25-Bond Index (Revs)	4.76	4.73	4.59
General Obligation Bonds (GOs)			
1-year Aaa	1.65	3.30	3.60
1-year A	1.75	3.34	3.70
5-year Aaa	2.66	3.46	3.62
5-year A	2.96	3.76	3.90
10-year Aaa	3.34	3.84	3.76
10-year A	3.63	4.14	4.17
25/30-year Aaa	4.26	4.52	4.10
25/30-year A	4.39	4.67	4.42
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.40	4.72	4.48
Electric AA	4.40	4.72	4.41
Housing AA	4.70	4.95	4.65
Hospital AA	4.80	4.90	4.65
Toll Road Aaa	4.45	4.72	4.52

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	1/30/08	1/16/08	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1460	1710	-250	1701	2145	1861
Borrowed Reserves	390	1377	-987	1699	1291	729
Net Free/Borrowed Reserves	1070	333	737	2	854	1133

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	1/21/08	1/14/08	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1372.3	1345.8	26.5	1.2%	0.6%	-0.0%
M2 (M1+savings+small time deposits)	7491.7	7441.3	50.4	6.6%	5.9%	5.7%

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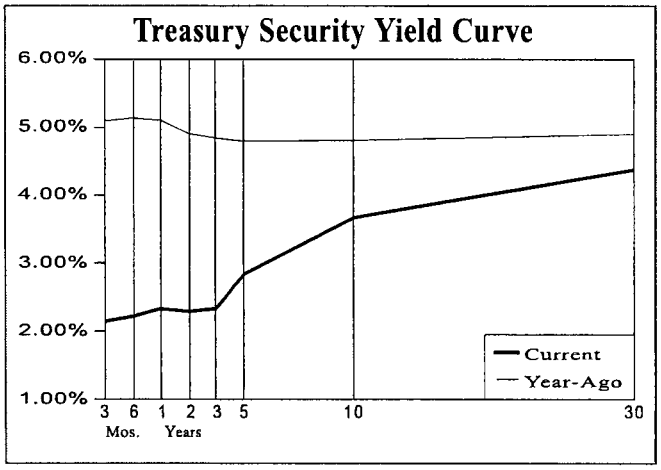
Selected Yields

	Recent (1/30/08)	3 Months Ago (10/31/07)	Year Ago (1/31/07)
TAXABLE			
Market Rates			
Discount Rate	3.50	5.00	6.25
Federal Funds	3.00	4.50	5.25
Prime Rate	6.00	7.50	8.25
30-day CP (A1/P1)	3.06	4.53	5.24
3-month LIBOR	3.24	4.89	5.36
Bank CDs			
6-month	2.50	2.89	3.30
1-year	2.60	3.57	3.86
5-year	3.01	3.90	3.91
U.S. Treasury Securities			
3-month	2.15	3.91	5.10
6-month	2.22	4.07	5.14
1-year	2.33	3.98	5.11
5-year	2.84	4.17	4.80
10-year	3.67	4.47	4.81
10-year (inflation-protected)	1.25	2.13	2.38
30-year	4.38	4.75	4.91
30-year Zero	4.46	4.74	4.86



	Recent (1/30/08)	3 Months Ago (10/31/07)	Year Ago (1/31/07)
Mortgage-Backed Securities			
GNMA 6.5%	4.38	5.65	5.79
FHLMC 6.5% (Gold)	4.65	5.79	5.91
FNMA 6.5%	4.28	5.64	5.84
FNMA ARM	5.30	5.91	5.63
Corporate Bonds			
Financial (10-year) A	5.60	5.88	5.63
Industrial (25/30-year) A	6.15	5.96	5.84
Utility (25/30-year) A	6.06	6.13	5.88
Utility (25/30-year) Baa/BBB	6.15	6.22	6.14
Foreign Bonds (10-Year)			
Canada	3.90	4.31	4.18
Germany	4.02	4.24	4.10
Japan	1.44	1.61	1.70
United Kingdom	4.57	4.93	4.98
Preferred Stocks			
Utility A	6.01	6.22	6.10
Financial A	7.08	6.95	6.43
Financial Adjustable A	5.55	5.50	5.50
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.29	4.33	4.32
25-Bond Index (Revs)	4.71	4.67	4.59
General Obligation Bonds (GOs)			
1-year Aaa	2.06	3.32	3.61
1-year A	2.52	3.42	3.71
5-year Aaa	2.73	3.47	3.69
5-year A	2.98	3.77	3.88
10-year Aaa	3.34	3.81	3.86
10-year A	3.72	4.11	4.28
25/30-year Aaa	4.27	4.40	4.17
25/30-year A	4.48	4.58	4.50
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.60	4.55	4.60
Electric AA	4.60	4.65	4.57
Housing AA	4.70	4.80	4.66
Hospital AA	4.75	4.80	4.68
Toll Road Aaa	4.55	4.65	4.58

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	1/16/08	1/2/08	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1713	2393	-680	1606	2160	1867
Borrowed Reserves	1377	5308	-3931	1682	1284	720
Net Free/Borrowed Reserves	336	-2915	3251	-76	876	1147

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	1/14/08	1/7/08	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1345.7	1361.8	-16.1	-7.6%	-3.7%	-2.5%
M2 (M1+savings+small time deposits)	7440.8	7457.7	-16.9	4.3%	4.8%	5.0%

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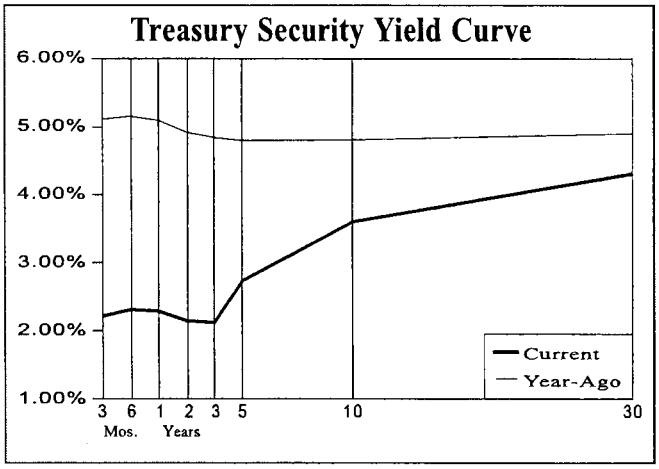
Selected Yields

	Recent (1/23/08)	3 Months Ago (10/24/07)	Year Ago (1/24/07)
TAXABLE			
Market Rates			
Discount Rate	4.00	5.25	6.25
Federal Funds	3.50	4.75	5.25
Prime Rate	6.50	7.75	8.25
30-day CP (A1/P1)	3.12	4.72	5.25
3-month LIBOR	3.33	5.07	5.36
Bank CDs			
6-month	2.64	2.89	3.30
1-year	2.96	3.62	3.86
5-year	3.35	3.91	3.91
U.S. Treasury Securities			
3-month	2.22	3.87	5.12
6-month	2.31	4.00	5.16
1-year	2.29	4.01	5.10
5-year	2.74	3.99	4.80
10-year	3.60	4.34	4.81
10-year (inflation-protected)	1.32	2.05	2.41
30-year	4.31	4.64	4.91
30-year Zero	4.39	4.66	4.86

	Recent (1/23/08)	3 Months Ago (10/24/07)	Year Ago (1/24/07)
Mortgage-Backed Securities			
GNMA 6.5%	4.57	5.56	5.75
FHLMC 6.5% (Gold)	4.97	5.76	5.83
FNMA 6.5%	4.61	5.61	5.76
FNMA ARM	5.28	5.88	5.58
Corporate Bonds			
Financial (10-year) A	5.86	5.68	5.62
Industrial (25/30-year) A	6.05	5.86	5.83
Utility (25/30-year) A	6.13	6.03	5.87
Utility (25/30-year) Baa/BBB	6.20	6.09	6.14
Foreign Bonds (10-Year)			
Canada	3.88	4.29	4.17
Germany	3.89	4.15	4.04
Japan	1.36	1.58	1.67
United Kingdom	4.42	4.84	4.91
Preferred Stocks			
Utility A	6.03	6.23	6.12
Financial A	7.35	6.91	6.47
Financial Adjustable A	5.50	5.50	5.50



	Recent (1/23/08)	3 Months Ago (10/24/07)	Year Ago (1/24/07)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.15	4.39	4.25
25-Bond Index (Revs)	4.63	4.73	4.55
General Obligation Bonds (GOs)			
1-year Aaa	2.10	3.35	3.57
1-year A	2.20	3.45	3.67
5-year Aaa	2.60	3.42	3.64
5-year A	2.70	3.72	3.92
10-year Aaa	3.17	3.71	3.80
10-year A	3.37	4.01	4.20
25/30-year Aaa	4.11	4.27	4.13
25/30-year A	4.31	4.45	4.45
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.40	4.50	4.50
Electric AA	4.45	4.50	4.43
Housing AA	4.55	4.65	4.60
Hospital AA	4.60	4.60	4.60
Toll Road Aaa	4.45	4.50	4.49

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	1/16/08	1/2/08	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1712	2382	-670	1604	2160	1867
Borrowed Reserves	1377	5308	-3931	1682	1284	720
Net Free/Borrowed Reserves	335	-2926	3261	-78	875	1147

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	1/7/08	12/31/07	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1363.0	1363.2	-0.2	-0.8%	-0.6%	0.0%
M2 (M1+savings+small time deposits)	7455.6	7461.5	-5.9	5.1%	5.7%	5.5%

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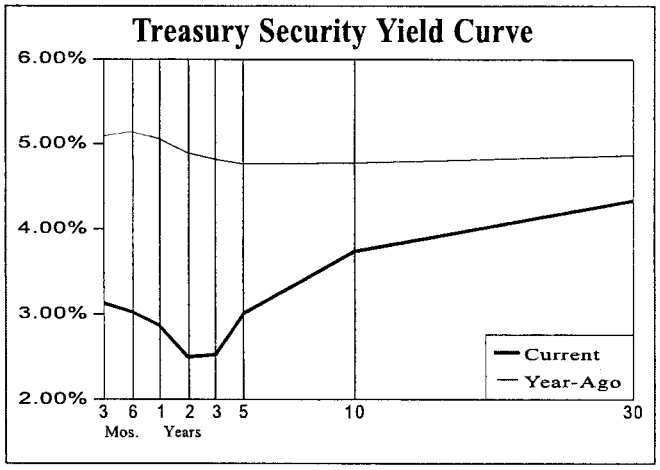
Selected Yields

	Recent (1/16/08)	3 Months Ago (10/17/07)	Year Ago (1/17/07)
TAXABLE			
Market Rates			
Discount Rate	4.75	5.25	6.25
Federal Funds	4.25	4.75	5.25
Prime Rate	7.25	7.75	8.25
30-day CP (A1/P1)	3.99	4.86	5.24
3-month LIBOR	3.95	5.20	5.36
Bank CDs			
6-month	2.80	2.90	3.30
1-year	3.22	3.61	3.85
5-year	3.58	3.91	3.91
U.S. Treasury Securities			
3-month	3.13	3.99	5.10
6-month	3.03	4.16	5.15
1-year	2.87	4.26	5.06
5-year	3.01	4.21	4.77
10-year	3.74	4.55	4.78
10-year (inflation-protected)	1.45	2.25	2.48
30-year	4.34	4.83	4.87
30-year Zero	4.42	4.82	4.82

	Recent (1/16/08)	3 Months Ago (10/17/07)	Year Ago (1/17/07)
Mortgage-Backed Securities			
GNMA 6.5%	4.69	5.70	5.68
FHLMC 6.5% (Gold)	5.10	5.85	5.81
FNMA 6.5%	4.75	5.80	5.75
FNMA ARM	5.34	5.89	5.58
Corporate Bonds			
Financial (10-year) A	5.79	5.93	5.62
Industrial (25/30-year) A	6.03	6.01	5.83
Utility (25/30-year) A	6.07	6.21	5.86
Utility (25/30-year) Baa/BBB	6.22	6.27	6.14
Foreign Bonds (10-Year)			
Canada	3.82	4.43	4.16
Germany	3.98	4.39	4.04
Japan	1.39	1.66	1.69
United Kingdom	4.38	5.03	4.90
Preferred Stocks			
Utility A	5.96	6.23	6.01
Financial A	7.39	6.85	6.42
Financial Adjustable A	5.49	5.49	5.49



	Recent (1/16/08)	3 Months Ago (10/17/07)	Year Ago (1/17/07)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.21	4.48	4.21
25-Bond Index (Revs)	4.66	4.78	4.55
General Obligation Bonds (GOs)			
1-year Aaa	2.60	3.36	3.57
1-year A	2.65	3.46	3.67
5-year Aaa	2.88	3.50	3.63
5-year A	3.18	3.80	3.82
10-year Aaa	3.36	3.80	3.79
10-year A	3.65	4.10	4.21
25/30-year Aaa	4.12	4.37	4.14
25/30-year A	4.25	4.55	4.47
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.25	4.50	4.58
Electric AA	4.25	4.60	4.54
Housing AA	4.50	4.75	4.63
Hospital AA	4.55	4.70	4.65
Toll Road Aaa	4.30	4.60	4.53

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	1/2/08	12/19/07	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	2393	1169	1224	1667	2189	1885
Borrowed Reserves	5308	3833	1475	1518	1199	676
Net Free/Borrowed Reserves	-2915	-2664	-251	150	990	1209

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	12/31/07	12/24/07	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1364.3	1355.2	9.1	2.4%	-0.5%	0.5%
M2 (M1+savings+small time deposits)	7471.9	7467.6	4.3	4.8%	5.6%	5.7%

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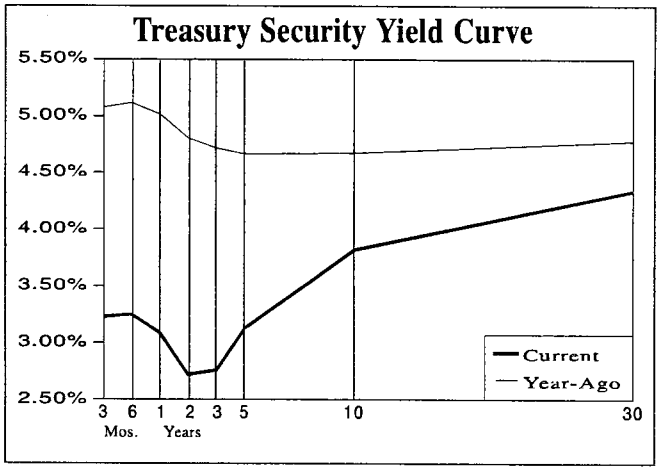
Selected Yields

	Recent (1/09/08)	3 Months Ago (10/10/07)	Year Ago (1/10/07)
TAXABLE			
Market Rates			
Discount Rate	4.75	5.25	6.25
Federal Funds	4.25	4.75	5.25
Prime Rate	7.25	7.75	8.25
30-day CP (A1/P1)	4.28	4.84	5.24
3-month LIBOR	4.44	5.25	5.36
Bank CDs			
6-month	2.77	2.90	3.30
1-year	3.38	3.61	3.85
5-year	3.73	3.92	3.91
U.S. Treasury Securities			
3-month	3.23	4.04	5.08
6-month	3.25	4.26	5.12
1-year	3.09	4.23	5.02
5-year	3.13	4.37	4.67
10-year	3.82	4.65	4.68
10-year (inflation-protected)	1.53	2.35	2.42
30-year	4.34	4.87	4.78
30-year Zero	4.39	4.85	4.72

	Recent (1/09/08)	3 Months Ago (10/10/07)	Year Ago (1/10/07)
Mortgage-Backed Securities			
GNMA 6.5%	5.04	5.90	5.61
FHLMC 6.5% (Gold)	5.28	5.98	5.73
FNMA 6.5%	5.18	5.92	5.64
FNMA ARM	5.36	5.90	5.58
Corporate Bonds			
Financial (10-year) A	5.79	5.97	5.53
Industrial (25/30-year) A	5.98	6.06	5.74
Utility (25/30-year) A	5.99	6.27	5.76
Utility (25/30-year) Baa/BBB	6.17	6.34	6.06
Foreign Bonds (10-Year)			
Canada	3.87	4.45	4.08
Germany	4.09	4.35	4.02
Japan	1.48	1.74	1.76
United Kingdom	4.40	4.98	4.81
Preferred Stocks			
Utility A	6.00	6.23	6.03
Financial A	7.61	6.83	6.41
Financial Adjustable A	5.48	5.49	5.49



	Recent (1/09/08)	3 Months Ago (10/10/07)	Year Ago (1/10/07)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.32	4.42	4.15
25-Bond Index (Revs)	4.72	4.72	4.50
General Obligation Bonds (GOs)			
1-year Aaa	2.70	3.38	3.50
1-year A	2.80	3.48	3.60
5-year Aaa	2.97	3.53	3.54
5-year A	3.07	3.83	3.82
10-year Aaa	3.43	3.84	3.72
10-year A	3.73	4.14	4.12
25/30-year Aaa	4.14	4.43	4.06
25/30-year A	4.34	4.61	4.38
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.45	4.55	4.41
Electric AA	4.50	4.65	4.39
Housing AA	4.60	4.80	4.50
Hospital AA	4.65	4.78	4.53
Toll Road Aaa	4.50	4.65	4.47

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	1/2/08	12/19/07	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	2392	1174	1218	1668	2189	1886
Borrowed Reserves	35307	3833	31474	5803	3342	1787
Net Free/Borrowed Reserves	-32915	-2659	-30256	-4135	-1153	98

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	12/24/07	12/17/07	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1355.1	1361.0	-5.9	1.5%	0.7%	-1.4%
M2 (M1+savings+small time deposits)	7468.3	7460.2	8.1	4.8%	5.6%	5.9%

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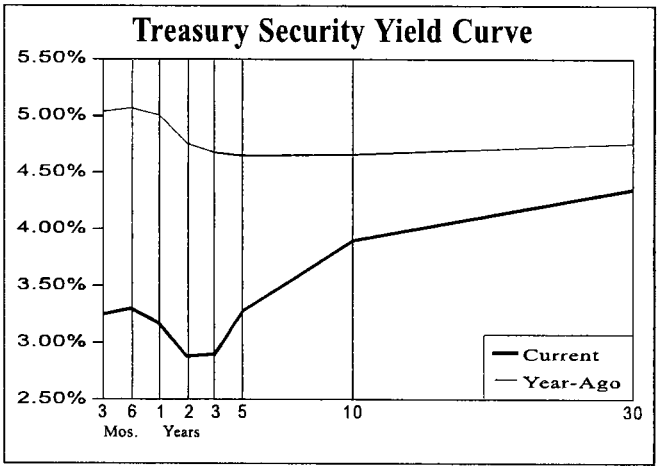
Selected Yields

	Recent (1/02/08)	3 Months Ago (10/03/07)	Year Ago (1/03/07)
TAXABLE			
Market Rates			
Discount Rate	4.75	5.25	6.25
Federal Funds	4.25	4.75	5.25
Prime Rate	7.25	7.75	8.25
30-day CP (A1/P1)	4.40	4.82	5.24
3-month LIBOR	4.68	5.24	5.36
Bank CDs			
6-month	2.81	2.91	3.30
1-year	3.43	3.70	3.85
5-year	3.73	3.92	3.91
U.S. Treasury Securities			
3-month	3.25	3.94	5.04
6-month	3.30	4.15	5.07
1-year	3.17	4.10	5.01
5-year	3.28	4.25	4.65
10-year	3.90	4.56	4.66
10-year (inflation-protected)	1.56	2.29	2.36
30-year	4.35	4.80	4.76
30-year Zero	4.38	4.80	4.71

	Recent (1/02/08)	3 Months Ago (10/03/07)	Year Ago (1/03/07)
Mortgage-Backed Securities			
GNMA 6.5%	5.36	5.81	5.53
FHLMC 6.5% (Gold)	5.44	5.96	5.67
FNMA 6.5%	5.37	5.88	5.60
FNMA ARM	5.38	5.89	5.58
Corporate Bonds			
Financial (10-year) A	5.86	5.97	5.50
Industrial (25/30-year) A	5.92	6.02	5.73
Utility (25/30-year) A	5.94	6.22	5.79
Utility (25/30-year) Baa/BBB	6.11	6.31	6.06
Foreign Bonds (10-Year)			
Canada	3.91	4.36	4.05
Germany	4.21	4.33	3.95
Japan	1.51	1.69	1.69
United Kingdom	4.44	4.97	4.79
Preferred Stocks			
Utility A	6.31	6.32	6.07
Financial A	8.12	6.87	6.40
Financial Adjustable A	5.48	5.48	5.48



	Recent (1/02/08)	3 Months Ago (10/03/07)	Year Ago (1/03/07)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.44	4.48	4.17
25-Bond Index (Revs)	4.80	4.77	4.56
General Obligation Bonds (GOs)			
1-year Aaa	2.88	3.38	3.50
1-year A	2.92	3.48	3.60
5-year Aaa	3.19	3.48	3.54
5-year A	3.49	3.58	3.83
10-year Aaa	3.61	3.76	3.72
10-year A	3.90	4.26	4.14
25/30-year Aaa	4.26	4.38	4.06
25/30-year A	4.37	4.68	4.39
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.40	4.67	4.50
Electric AA	4.40	4.65	4.44
Housing AA	4.65	4.85	4.55
Hospital AA	4.65	4.83	4.58
Toll Road Aaa	4.50	4.68	4.42

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	12/19/07	12/5/07	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1173	1848	-675	1608	2125	1850
Borrowed Reserves	3833	199	3634	954	836	487
Net Free/Borrowed Reserves	-2660	1649	-4309	653	1290	1363

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	12/17/07	12/10/07	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1361.2	1371.3	-10.1	-0.7%	0.7%	-0.3%
M2 (M1+savings+small time deposits)	7460.2	7456.6	3.6	4.6%	5.6%	6.2%

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ATTACHMENT D

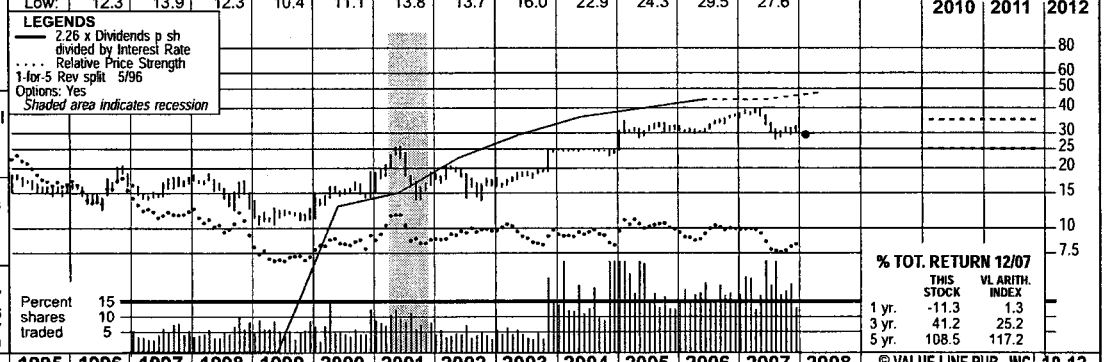
UNISOURCE ENERGY NYSE-UNS

RECENT PRICE 29.41 | P/E RATIO 17.0 (Trailing: 20.4 Median: 16.0) | RELATIVE P/E RATIO 1.06 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 4 Raised 8/17/07
SAFETY 3 New 12/31/04
TECHNICAL 2 Raised 2/1/08
BETA .60 (1.00 = Market)

High:	20.8	18.3	18.9	13.9	19.3	26.0	20.8	24.9	24.9	34.8	37.5	40.0
Low:	12.3	13.9	12.3	10.4	11.1	13.8	13.7	16.0	22.9	24.3	29.5	27.6

Target Price Range 2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+20%)	8%
Low	25	(-15%)	Nil

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	4	0	0	1	0	0	2
to Sell	1	0	4	0	0	0	0	0	1

Institutional Decisions

	1Q2007	2Q2007	3Q2007
to Buy	87	73	56
to Sell	67	81	87
Hld's(000)	31380	30634	31880

% TOT. RETURN 12/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	-11.3	1.3
3 yr.	41.2	25.2
5 yr.	108.5	117.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
114.58	19.56	20.61	21.51	20.87	22.28	22.71	23.83	24.85	31.12	43.12	25.50	28.71	34.13	35.26	37.42	38.65	40.60	Revenues per sh	45.60
d12.43	d.30	2.06	3.44	4.58	6.82	5.29	3.48	3.96	4.23	5.41	4.80	5.20	5.29	5.21	5.68	5.40	5.70	"Cash Flow" per sh	6.35
d28.05	d12.40	d.25	.65	1.70	3.76	2.60	.68	1.08	1.27	1.79	.97	1.30	1.31	1.30	1.85	1.60	1.75	Earnings per sh A	1.90
--	--	--	--	--	--	--	--	--	.32	.40	.50	.60	.64	.76	.84	.90	.96	Div'd Decl'd per sh B ■ †	1.14
8.75	1.08	1.50	1.95	1.84	2.07	2.22	2.52	2.87	3.19	3.63	3.36	4.06	4.49	5.83	6.77	5.55	6.50	Cap'l Spending per sh	7.75
d37.31	d1.19	d1.96	d1.31	.39	4.15	6.75	7.65	10.02	11.20	12.68	13.05	15.97	16.95	17.68	18.59	19.55	20.85	Book Value per sh C	22.25
5.14	32.09	32.14	32.14	32.13	32.13	32.14	32.26	32.35	33.22	33.50	33.58	33.79	34.26	34.87	35.19	35.70	36.20	Common Shs Outst'g D	37.70
--	--	--	26.7	9.6	4.3	6.1	23.3	10.8	11.8	10.8	18.2	14.6	18.7	23.9	17.7	18.4		Avg Ann'l P/E Ratio	16.0
--	--	--	1.75	.64	.27	.35	1.21	.62	.77	.55	.99	.83	.99	1.27	.96	.97		Relative P/E Ratio	1.05
--	--	--	--	--	--	--	--	--	2.1%	2.1%	2.8%	3.2%	2.6%	2.5%	2.6%	3.1%		Avg Ann'l Div'd Yield	3.8%

CAPITAL STRUCTURE as of 9/30/07
Total Debt $1607.2 mill. **Due in 5 Yrs** $1079.6 mill.
LT Debt $1532.3 mill. **LT Interest** $145.6 mill.
Incl. $528.9 mill. capitalized leases.

(LT interest earned: 1.6x)

Pension Assets-12/06 $176 mill. **Oblig.** $218 mill.
Pfd Stock None

Common Stock 35,338,420 shs. **as of 10/31/07**
MARKET CAP: $1.1 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
729.9	768.7	803.8	1033.7	1444.7	856.2	969.9	1169.0	1229.5	1316.9	1380	1470	Revenues ($mill)	1720
83.6	21.9	35.5	26.3	60.9	33.3	45.2	45.9	46.1	69.2	57.0	63.0	Net Profit ($mill)	71.0
--	45.6%	46.8%	32.9%	43.8%	33.7%	19.7%	42.5%	41.4%	38.8%	39.0%	39.0%	Income Tax Rate	39.0%
--	--	--	--	--	--	2.2%	--	2.2%	2.9%	3.0%	3.0%	AFUDC % to Net Profit	3.0%
90.7%	89.4%	86.1%	84.2%	79.6%	81.5%	79.2%	77.1%	75.3%	72.9%	68.5%	67.0%	Long-Term Debt Ratio	61.0%
9.3%	10.6%	13.9%	15.8%	20.4%	18.5%	20.8%	22.9%	24.7%	27.1%	31.5%	33.0%	Common Equity Ratio	39.0%
2322.3	2320.6	2340.5	2362.4	2081.3	2368.8	2589.0	2540.3	2494.9	2414.1	2230	2245	Total Capital ($mill)	2290
1935.5	1915.6	1729.9	1706.3	1677.7	1668.4	2069.2	2081.1	2171.5	2259.6	2320	2415	Net Plant ($mill)	2545
5.0%	2.5%	2.9%	2.5%	4.4%	2.8%	4.9%	5.1%	5.1%	5.9%	5.5%	5.5%	Return on Total Cap'l	6.0%
38.5%	8.9%	11.0%	7.1%	14.3%	7.6%	8.4%	7.9%	7.5%	10.6%	8.0%	8.5%	Return on Shr. Equity	8.5%
38.5%	8.9%	11.0%	7.1%	14.3%	7.6%	8.4%	7.9%	7.5%	10.6%	8.0%	8.5%	Return on Com Equity E	8.5%
38.5%	8.9%	11.0%	4.3%	11.2%	3.8%	4.6%	4.1%	3.2%	6.1%	3.5%	3.5%	Retained to Com Eq	3.5%
--	--	--	39%	22%	51%	45%	48%	57%	43%	56%	55%	All Div'ds to Net Prof	60%

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+3.2	+3.9	+3.7
Avg. Indust. Use (MWH)	3293	3421	3431
Avg. Indust. Revs. per KWH (¢)	6.50	6.60	6.60
Capacity at Peak (Mw)	2275	2567	2696
Peak Load, Summer (Mw)	2458	2792	2913
Annual Load Factor (%)	64.6	63.9	64.0
% Change Customers (yr-end)	+2.1	+2.6	+1.8
Fixed Charge Cov. (%)	130	131	157

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	5.0%	1.5%	4.0%
"Cash Flow"	1.0%	3.5%	3.0%
Earnings	-3.0%	1.5%	4.0%
Dividends	--	NMF	7.0%
Book Value	32.5%	9.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	270.1	290.1	335.3	273.5	1169.0
2005	260.9	300.6	349.3	318.7	1229.5
2006	305.0	318.4	375.6	317.9	1316.9
2007	317.8	329.8	398.2	334.2	1380
2008	345	360	415	350	1470

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.18	.37	.68	.08	1.31
2005	d.11	.27	.49	.65	1.30
2006	.52	.28	.73	.32	1.85
2007	.14	.33	.66	.47	1.60
2008	.25	.35	.75	.40	1.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.16	.16	.16	.16	.64
2005	.19	.19	.19	.19	.76
2006	.21	.21	.21	.21	.84
2007	.225	.225	.225	.225	.90
2008					

BUSINESS: UniSource Energy Corp., parent of Tucson Electric Power Company, supplies electricity in Tucson, Arizona and the surround. area (serv. area: 1,155 sq. miles). Nonutility subsidiaries engage in plant construction, fuel supply, and related businesses. Revenue sources: residential, 44%; commercial, 26%; industrial, 21%; other, 9%. Copper mining is largest industry served. Fuels: coal, 81%; gas, 6%; purchased power, 13%. Fuel: 46% of electric revenues; labor costs: 9%. '06 depreciation rate: 3.1%. Estimated plant age: 10 years. Has 1,260 employees. Chairman, President, and CEO: James S. Pignatelli. Inc.: AZ. Address: One South Church Ave. Suite 1820, Tucson, AZ 85701. Tel.: 520-884-3650. Internet: www.unisourceenergy.cbm.

UniSource seeks higher rates. A 1999 agreement froze electric rates through the end of 2008. As required by regulators, UNS filed for new rates that would take effect in January, 2009. It recommended that the commission use one of three methods in setting new tariffs. In all three cases, transmission and distribution rates are based on historic cost-based calculations. But rates for generated power are figured differently under each approach. In the first instance, charges would be based on wholesale market prices. An alternative ties rates to historic costs, subject to a separate charge. Either procedure would raise annual rates by about 22%. A third option blends the first two and results in lesser rates. All proposals reward customers for energy conservation. An order on the application will take effect January 1, 2009.

Financial indicators will remain weak for a while. Though long-term debt has been reduced steadily since 1996, it still accounts for about 70% of total capital. What's more, meaningful reductions are unlikely for a while because of the need to finance the capital spending program. That, in turn, keeps pressure on fixed charges, which have been barely earned since 1997. Too, though a large percentage of profits are being plowed back into retained earnings, this account still had a negative balance last September, 30th. Finally, UNS is having difficulty earning its allowed return on equity. In view of these negatives, we rate the company's Financial Strength a below-average C++.

Earnings should improve in 2008. Planned and unplanned plant outages, which took a toll in last year's first quarter, are behind the company. UNS should also benefit from an order on a filing for $9 million in higher posted gas tariffs. In all, we think 2008 earnings will rise 9% over last year's estimated $1.60 a share. An order on the aforementioned electric rate filing suggests a further gain next year. The stock is untimely.

These shares offer an even balance of pluses and minuses. Above-average dividend growth prospects to 2010-2012 might interest income-oriented investors. But those of a conservative bent may hesitate because of the company's weak finances.

Arthur H. Medalie *February 8, 2008*

(A) EPS diluted. Next earnings report due late Feb. Excl. nonrecur. gains (losses): '91, ($12.49); '92, 18¢; '93, ($0.11); '98, 19¢; '99, $1.35; '00, 48¢; '03, $2.00. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '06: $6.38/sh. (D) In millions, adjusted for split. (E) Rate base: fair value. Rate allowed on com. eq. in '94: 11.0%; earned on avg. com. eq., '06: 10.3%. Regulatory Climate: Avg.

Company's Financial Strength	C++
Stock's Price Stability	90
Price Growth Persistence	90
Earnings Predictability	40

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TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-07-0402
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TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
COST OF CAPITAL SUMMARY

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 1

WEIGHTED COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) CAPITAL RATIO	(E) RUCO COST	(F) WEIGHTED COST
1	LONG-TERM DEBT	$ 805,636	$ -	$ 805,636	55.00%	6.39%	3.51%
2	COMMON EQUITY	659,157	-	659,157	45.00%	9.44%	4.25%
3	TOTAL CAPITALIZATION	$ 1,464,793	$ -	$ 1,464,793	100.00%		
4	**WEIGHTED COST OF CAPITAL**						7.76%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1, PAGE 1
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) - COLUMN (B)
COLUMN (D): LINE 1 ÷ LINE 3
LINE 2 ÷ LINE 3
COLUMN (E): LINE 1 - SCHEDULE WAR-1, PAGE 2, LINE 37
LINE 2 - SCHEDULE WAR-1, PAGE 3, LINE 7
COLUMN (F): COLUMN (D) x COLUMN (E)

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
COST OF CAPITAL SUMMARY

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 1

COST OF LONG-TERM DEBT

LINE NO.	(A) DESCRIPTION	(B) OUTSTANDING BALANCE ($000)	(C) ANNUAL INTEREST ($000)	(D) COST RATE (%)
1	MORTGAGE BONDS			
2	7.50% SERIES FIRST COLLATERAL TRUST BONDS	$ 138,300	$ 10,373	
3	TOTAL FIRST MORTGAGE BONDS	$ 138,300	$ 10,373	7.50%
4				
5	VARIABLE RATE-TAX EXEMPT BONDS			
6	VARIABLE 1982 PIMA A IRVINGTON	$ 38,700	$ 1,872	
7	VARIABLE 1982 PIMA A IRVINGTON & FOUR CORNERS	39,900	1,889	
8	VARIABLE 1982 APACHE A SPRINGERVILLE	100,000	4,786	
9	VARIABLE 1983 APACHE B SPRINGERVILLE	80,000	3,788	
10	VARIABLE 1983 APACHE C SPRINGERVILLE	50,000	2,340	
11	VARIABLE 1985 APACHE A SPRINGERVILLE	20,000	956	
12	TOTAL VARIABLE RATE-TAX EXEMPT BONDS	$ 328,600	$ 15,631	4.76%
13				
14				
15	FIXED RATE-TAX EXEMPT BONDS			
16	6.10% 1997 PIMA A	$ 22,460	$ 1,370	
17	5.85% 1998 APACHE C	16,500	965	
18	6.95% 1997 FARMINGTON A	80,410	5,588	
19	7.125% 1997 COCONINO A	36,700	2,615	
20	7.00% 1997 COCONINO B	14,700	1,029	
21	5.85% 1998 APACHE A	83,700	4,896	
22	5.85% 1998 APACHE B	99,800	5,863	
23	TOTAL FIXED RATE-TAX EXEMPT BONDS	$ 354,270	$ 22,326	6.30%
24				
25	TOTAL LONG-TERM DEBT	$ 821,170	$ 48,330	5.89%
26				
27	UNAMORTIZED DEBT DISCOUNT, PREMIUM AND			
28	EXPENSE AND LOSS ON REAQUIRED DEBT	$ (15,534)		
29				
30	AMORTIZATION OF DEBT DISCOUNT AND			
31	EXPENSE AND LOSS ON REAQUIRED DEBT		2,971	
32				
33	CREDIT FACILITY COMMITMENT FEES		165	
34				
35	TOTAL LONG-TERM DEBT - NET	$ 805,636	$ 51,466	
36				
37	TOTAL COST OF LONG-TERM DEBT			6.39%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-2, PAGE 1
COLUMN (B): COMPANY SCHEDULE D-2, PAGE 1
COLUMN (C): COMPANY SCHEDULE D-2, PAGE 1

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
COST OF CAPITAL SUMMARY

COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	8.62%	SCHEDULE WAR-2, COLUMN (C), LINE 27
3	**CAPM METHODOLOGY**		
4	CAPM - GEOMETRIC MEAN ESTIMATE	9.42%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 27
5	CAPM - ARITHMETIC MEAN ESTIMATE	11.08%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 27
6	AVERAGE OF CAPM ESTIMATES	10.25%	(LINE 4 + LINE 5) ÷ 2
7	**AVERAGE**	9.44%	(LINE 2 + LINE 6) ÷ 2

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DCF COST OF EQUITY CAPITAL

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	ALE	ALLETTE, INC.	4.26%	+	5.45%	=	9.71%
2	LNT	ALLIANT ENERGY	3.53%	+	5.25%	=	8.78%
3	AEE	AMEREN CORP.	5.05%	+	2.52%	=	7.57%
4	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	3.57%	+	6.03%	=	9.60%
5	CHG	CH ENERGY GROUP, INC.	5.29%	+	2.50%	=	7.79%
6	CV	CENTRAL VERMONT PUBLIC SERVICE CORPORATION	3.06%	+	3.73%	=	6.78%
7	CNL	CLECO CORPORATION	3.35%	+	4.48%	=	7.83%
8	ED	CONSOLIDATED EDISON, INC.	4.97%	+	3.38%	=	8.36%
9	DTE	DTE ENERGY COMPANY	4.79%	+	2.50%	=	7.29%
10	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	5.66%	+	3.97%	=	9.63%
11	FE	FIRSTENERGY CORP.	2.74%	+	7.26%	=	10.00%
12	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	5.50%	+	2.41%	=	7.91%
13	IDA	IDACORP, INC.	3.54%	+	3.63%	=	7.17%
14	MGEE	MGE ENERGY, INC.	4.11%	+	7.05%	=	11.16%
15	NI	NISOURCE, INC.	4.91%	+	2.00%	=	6.91%
16	NST	NSTAR	4.05%	+	6.01%	=	10.06%
17	PNM	PNM RESOURCES	4.46%	+	2.70%	=	7.16%
18	PNW	PINNACLE WEST CAPITAL CORPORATION	5.11%	+	2.02%	=	7.13%
19	PPL	PPL CORPORATION	2.39%	+	11.26%	=	13.65%
20	PGN	PROGRESSS ENERGY	5.17%	+	2.33%	=	7.50%
21	SCG	SCANA CORPORATION	4.33%	+	4.03%	=	8.36%
22	SO	SOUTHERN COMPANY	4.23%	+	5.01%	=	9.23%
23	TE	TECO ENERGY, INC.	4.62%	+	4.72%	=	9.34%
24	UIL	UIL HOLDINGS	4.89%	+	2.56%	=	7.44%
25	VVC	VECTREN	4.56%	+	4.81%	=	9.37%
26	XEL	XCEL ENERGY INC.	4.19%	+	4.24%	=	8.43%
27	**AVERAGE**						8.62%

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND YIELD CALCULATION

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND (PER SHARE)	÷	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	ALE	ALLETTE, INC.	$ 1.64	÷	$ 38.50	=	4.26%
2	LNT	ALLIANT ENERGY	1.40	÷	39.68	=	3.53%
3	AEE	AMEREN CORP.	2.54	÷	50.32	=	5.05%
4	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	1.64	÷	45.92	=	3.57%
5	CHG	CH ENERGY GROUP, INC.	2.16	÷	40.81	=	5.29%
6	CV	CENTRAL VERMONT PUBLIC SERVICE CORPORATION	0.92	÷	30.10	=	3.06%
7	CNL	CLECO CORPORATION	0.90	÷	26.88	=	3.35%
8	ED	CONSOLIDATED EDISON, INC.	2.32	÷	46.68	=	4.97%
9	DTE	DTE ENERGY COMPANY	2.12	÷	44.27	=	4.79%
10	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	1.28	÷	22.60	=	5.66%
11	FE	FIRSTENERGY CORP.	2.00	÷	72.89	=	2.74%
12	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	1.24	÷	22.53	=	5.50%
13	IDA	IDACORP, INC.	1.20	÷	33.87	=	3.54%
14	MGEE	MGE ENERGY, INC.	1.42	÷	34.51	=	4.11%
15	NI	NISOURCE, INC.	0.92	÷	18.74	=	4.91%
16	NST	NSTAR	1.40	÷	34.53	=	4.05%
17	PNM	PNM RESOURCES	0.92	÷	20.61	=	4.46%
18	PNW	PINNACLE WEST CAPITAL CORPORATION	2.10	÷	41.08	=	5.11%
19	PPL	PPL CORPORATION	1.22	÷	51.13	=	2.39%
20	PGN	PROGRESSS ENERGY	2.44	÷	47.20	=	5.17%
21	SCG	SCANA CORPORATION	1.76	÷	40.61	=	4.33%
22	SO	SOUTHERN COMPANY	1.61	÷	38.15	=	4.23%
23	TE	TECO ENERGY, INC.	0.78	÷	16.88	=	4.62%
24	UIL	UIL HOLDINGS	1.73	÷	35.35	=	4.89%
25	VVC	VECTREN	1.30	÷	28.50	=	4.56%
26	XEL	XCEL ENERGY INC.	0.92	÷	21.98	=	4.19%
27	**AVERAGE**						4.32%

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 12/10/2007 TO 02/08/2008
STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) ÷ COLUMN (B)

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 4

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	ALE	ALLETTE, INC.	5.00%	+	0.45%	=	5.45%
2	LNT	ALLIANT ENERGY	5.25%	+	0.00%	=	5.25%
3	AEE	AMEREN CORP.	2.25%	+	0.27%	=	2.52%
4	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	5.65%	+	0.38%	=	6.03%
5	CHG	CH ENERGY GROUP, INC.	2.50%	+	0.00%	=	2.50%
6	CV	CENTRAL VERMONT PUBLIC SERVICE CORPORATION	3.25%	+	0.48%	=	3.73%
7	CNL	CLECO CORPORATION	3.50%	+	0.98%	=	4.48%
8	ED	CONSOLIDATED EDISON, INC.	2.75%	+	0.63%	=	3.38%
9	DTE	DTE ENERGY COMPANY	2.50%	+	0.00%	=	2.50%
10	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	2.25%	+	1.72%	=	3.97%
11	FE	FIRSTENERGY CORP.	7.25%	+	0.01%	=	7.26%
12	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	1.75%	+	0.66%	=	2.41%
13	IDA	IDACORP, INC.	3.25%	+	0.38%	=	3.63%
14	MGEE	MGE ENERGY, INC.	5.50%	+	1.55%	=	7.05%
15	NI	NISOURCE, INC.	2.00%	+	0.00%	=	2.00%
16	NST	NSTAR	6.00%	+	0.01%	=	6.01%
17	PNM	PNM RESOURCES	2.75%	+	-0.05%	=	2.70%
18	PNW	PINNACLE WEST CAPITAL CORPORATION	2.00%	+	0.02%	=	2.02%
19	PPL	PPL CORPORATION	11.25%	+	0.01%	=	11.26%
20	PGN	PROGRESSS ENERGY	2.00%	+	0.33%	=	2.33%
21	SCG	SCANA CORPORATION	4.00%	+	0.03%	=	4.03%
22	SO	SOUTHERN COMPANY	3.50%	+	1.51%	=	5.01%
23	TE	TECO ENERGY, INC.	4.50%	+	0.22%	=	4.72%
24	UIL	UIL HOLDINGS	2.00%	+	0.56%	=	2.56%
25	VVC	VECTREN	3.50%	+	1.31%	=	4.81%
26	XEL	XCEL ENERGY INC.	3.50%	+	0.74%	=	4.24%
27	**AVERAGE**						4.30%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 4
PAGE 2 OF 2

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) SHARE GROWTH	x	{ [((M ÷ B) + 1) ÷ 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
					(B)		
1	ALE	ALLETTE, INC.	1.40%	x	{ [((1.65) + 1) ÷ 2] - 1 }	=	0.45%
2	LNT	ALLIANT ENERGY	0.01%	x	{ [((1.77) + 1) ÷ 2] - 1 }	=	0.00%
3	AEE	AMEREN CORP.	1.00%	x	{ [((1.54) + 1) ÷ 2] - 1 }	=	0.27%
4	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	0.90%	x	{ [((1.84) + 1) ÷ 2] - 1 }	=	0.38%
5	CHG	CH ENERGY GROUP, INC.	0.01%	x	{ [((1.23) + 1) ÷ 2] - 1 }	=	0.00%
6	CV	CENTRAL VERMONT PUBLIC SERVICE CORPORATION	1.50%	x	{ [((1.64) + 1) ÷ 2] - 1 }	=	0.48%
7	CNL	CLECO CORPORATION	3.00%	x	{ [((1.65) + 1) ÷ 2] - 1 }	=	0.98%
8	ED	CONSOLIDATED EDISON, INC.	3.50%	x	{ [((1.36) + 1) ÷ 2] - 1 }	=	0.63%
9	DTE	DTE ENERGY COMPANY	0.01%	x	{ [((1.26) + 1) ÷ 2] - 1 }	=	0.00%
10	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	8.50%	x	{ [((1.40) + 1) ÷ 2] - 1 }	=	1.72%
11	FE	FIRSTENERGY CORP.	0.01%	x	{ [((2.52) + 1) ÷ 2] - 1 }	=	0.01%
12	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	2.00%	x	{ [((1.66) + 1) ÷ 2] - 1 }	=	0.66%
13	IDA	IDACORP, INC.	2.50%	x	{ [((1.30) + 1) ÷ 2] - 1 }	=	0.38%
14	MGEE	MGE ENERGY, INC.	3.00%	x	{ [((2.03) + 1) ÷ 2] - 1 }	=	1.55%
15	NI	NISOURCE, INC.	0.30%	x	{ [((1.01) + 1) ÷ 2] - 1 }	=	0.00%
16	NST	NSTAR	0.01%	x	{ [((2.21) + 1) ÷ 2] - 1 }	=	0.01%
17	PNM	PNM RESOURCES	1.25%	x	{ [((0.92) + 1) ÷ 2] - 1 }	=	-0.05%
18	PNW	PINNACLE WEST CAPITAL CORPORATION	0.25%	x	{ [((1.16) + 1) ÷ 2] - 1 }	=	0.02%
19	PPL	PPL CORPORATION	0.01%	x	{ [((3.68) + 1) ÷ 2] - 1 }	=	0.01%
20	PGN	PROGRESSS ENERGY	1.50%	x	{ [((1.44) + 1) ÷ 2] - 1 }	=	0.33%
21	SCG	SCANA CORPORATION	0.10%	x	{ [((1.60) + 1) ÷ 2] - 1 }	=	0.03%
22	SO	SOUTHERN COMPANY	2.25%	x	{ [((2.34) + 1) ÷ 2] - 1 }	=	1.51%
23	TE	TECO ENERGY, INC.	0.50%	x	{ [((1.89) + 1) ÷ 2] - 1 }	=	0.22%
24	UIL	UIL HOLDINGS	1.25%	x	{ [((1.89) + 1) ÷ 2] - 1 }	=	0.56%
25	VVC	VECTREN	3.75%	x	{ [((1.70) + 1) ÷ 2] - 1 }	=	1.31%
26	XEL	XCEL ENERGY INC.	3.00%	x	{ [((1.50) + 1) ÷ 2] - 1 }	=	0.74%
27	**AVERAGE**						0.47%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (C): COLUMN (A) x COLUMN (B)

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND GROWTH COMPONENTS

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 5

LINE NO.	STOCK SYMBOL	COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	ALE	ALLETTE, INC.	2002	NMF		-		NMF	-	-	
2			2003	NMF		-		NMF	-	-	
3			2004	0.7778		6.10%		4.74%	21.23	29.70	
4			2005	0.4960		11.30%		5.60%	20.03	30.10	
5			2006	0.4765		11.60%		5.53%	21.90	30.40	
6			GROWTH 2002 - 2006					5.29%	-		0.58%
7			2007	0.4533		11.50%		5.21%		30.85	1.48%
8			2008	0.3778		10.00%		3.78%		31.30	1.47%
9			2010-12	0.4857		10.50%		5.10%	5.50%	32.50	1.34%
10											
11	LNT	ALLIANT ENERGY	2002	-0.6949		5.80%		NMF	19.89	92.30	
12			2003	0.3631		6.70%		2.43%	21.37	110.96	
13			2004	0.4486		8.20%		3.68%	22.13	115.74	
14			2005	0.5249		13.10%		6.88%	20.85	117.07	
15			2006	0.4417		9.10%		4.02%	22.83	116.13	
16			GROWTH 2002 - 2006					4.25%	-2.50%		5.91%
17			2007	0.5115		12.00%		6.14%		107.20	-7.69%
18			2008	0.4717		11.00%		5.19%		108.00	-3.56%
19			2010-12	0.4035		10.50%		4.24%	4.00%	111.00	-0.90%
20											
21	AEE	AMEREN CORP.	2002	0.0451		9.90%		0.45%	24.93	154.10	
22			2003	0.1911		11.60%		2.22%	26.73	162.90	
23			2004	0.0993		9.10%		0.90%	29.71	195.20	
24			2005	0.1885		9.70%		1.83%	31.09	204.70	
25			2006	0.0451		8.10%		0.37%	31.86	206.60	
26			GROWTH 2002 - 2006					1.15%	5.50%		7.60%
27			2007	0.2185		10.00%		2.18%		208.80	1.06%
28			2008	0.2303		10.00%		2.30%		210.80	1.01%
29			2010-12	0.2529		9.00%		2.28%	3.00%	216.80	0.97%
30											
31	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	2002	0.1608		13.70%		2.20%	20.85	338.84	
32			2003	0.3478		12.40%		4.31%	19.93	395.02	
33			2004	0.4636		12.20%		5.66%	21.32	395.86	
34			2005	0.4621		11.30%		5.22%	23.08	393.72	
35			2006	0.4755		12.00%		5.71%	23.73	396.67	
36			GROWTH 2002 - 2006					4.62%	-2.50%		4.02%
37			2007	0.4357		11.00%		4.79%		400.50	0.97%
38			2008	0.4698		12.00%		5.64%		404.00	0.92%
39			2010-12	0.4500		12.50%		5.63%	6.00%	413.00	0.81%

REFERENCES: RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007.
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND GROWTH COMPONENTS

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 5

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	CHG	CH ENERGY GROUP, INC.	2002	-0.0189		7.10%		NMF	30.31	16.06	
2			2003	0.2230		9.10%		2.03%	30.80	15.76	
3			2004	0.1970		8.60%		1.69%	31.31	15.76	
4			2005	0.2313		8.80%		2.04%	31.97	15.76	
5			2006	0.1563		7.90%		1.23%	32.54	15.76	
6			GROWTH 2002 - 2006					1.75%	1.50%		-0.47%
7			2007	0.1692		8.00%		1.35%		15.76	0.00%
8			2008	0.2286		8.50%		1.94%		15.76	0.00%
9			2010-12	0.3046		9.00%		2.74%	2.00%	15.00	-0.98%
10											
11	CV	CENTRAL VERMONT PUBLIC SERVICE CORPORATION	2002	0.4286		9.30%		3.99%	16.83	11.74	
12			2003	0.3759		8.10%		3.04%	17.89	11.81	
13			2004	0.2640		6.80%		1.80%	18.49	12.19	
14			2005	-10.5000		0.50%		NMF	17.70	12.28	
15			2006	0.4356		10.10%		4.40%	17.70	10.13	
16			GROWTH 2002 - 2006					3.31%	2.00%		-3.62%
17			2007	0.3429		7.50%		2.57%		10.30	1.68%
18			2008	0.3867		8.00%		3.09%		10.40	1.32%
19			2010-12	0.4424		8.00%		3.54%	3.00%	10.70	1.10%
20											
21	CNL	CLECO CORPORATION	2002	0.4079		13.10%		5.34%	11.77	47.04	
22			2003	0.2857		12.50%		3.57%	10.09	47.18	
23			2004	0.3182		11.90%		3.79%	10.83	49.62	
24			2005	0.3662		10.70%		3.92%	13.69	49.99	
25			2006	0.3382		8.30%		2.81%	15.22	57.57	
26			GROWTH 2002 - 2006					3.89%	5.50%		5.18%
27			2007	0.3077		8.00%		2.46%		60.00	4.22%
28			2008	0.4000		9.00%		3.60%		61.00	2.94%
29			2010-12	0.3500		10.50%		3.68%	6.50%	64.00	2.14%
30											
31	ED	CONSOLIDATED EDISON, INC.	2002	0.2907		11.30%		3.29%	27.68	213.93	
32			2003	0.2085		9.80%		2.04%	28.44	225.84	
33			2004	0.0259		7.80%		0.20%	29.09	242.51	
34			2005	0.2375		9.70%		2.30%	29.80	245.29	
35			2006	0.2203		9.20%		2.03%	31.09	257.46	
36			GROWTH 2002 - 2006					1.97%	3.00%		4.74%
37			2007	0.2970		9.50%		2.82%		272.00	5.65%
38			2008	0.3118		9.50%		2.96%		273.00	2.97%
39			2010-12	0.3143		8.50%		2.67%	5.00%	278.00	1.55%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND GROWTH COMPONENTS

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 5

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	DTE	DTE ENERGY COMPANY	2002	0.4621		13.80%		6.38%	27.26	167.46	
2			2003	0.2772		9.10%		2.52%	31.36	168.61	
3			2004	0.1922		8.00%		1.54%	31.85	174.21	
4			2005	0.3700		10.00%		3.70%	32.44	177.81	
5			2006	0.1510		7.50%		1.13%	33.02	177.14	
6			GROWTH 2002 - 2006					3.05%	3.00%		1.41%
7			2007	0.3049		9.00%		2.74%		162.50	-8.26%
8			2008	0.2351		8.00%		1.88%		157.00	-5.86%
9			2010-12	0.3143		9.00%		2.83%	2.50%	157.00	-2.38%
10											
11	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	2002	-0.0756		7.80%		NMF	14.59	22.57	
12			2003	0.0078		7.80%		0.06%	15.17	24.98	
13			2004	-0.4884		5.80%		NMF	14.76	25.70	
14			2005	-0.3913		6.00%		NMF	15.08	26.08	
15			2006	0.0922		8.50%		0.78%	15.49	30.25	
16			GROWTH 2002 - 2006					0.42%	2.00%		7.60%
17			2007	-0.0240		7.00%		NMF		34.25	13.22%
18			2008	0.1172		8.50%		1.00%		35.80	8.79%
19			2010-12	0.2286		10.50%		2.40%	3.00%	36.00	3.54%
20											
21	FE	FIRSTENERGY CORP.	2002	0.4094		10.50%		4.30%	23.92	297.64	
22			2003	-0.0204		5.40%		NMF	25.13	329.84	
23			2004	0.3105		10.60%		3.29%	26.04	329.84	
24			2005	0.3979		10.20%		4.06%	27.86	329.84	
25			2006	0.5157		13.90%		7.17%	28.30	319.21	
26			GROWTH 2002 - 2006					4.70%	4.50%		1.76%
27			2007	0.5224		15.00%		7.84%		304.80	-4.51%
28			2008	0.5000		14.00%		7.00%		304.80	-2.28%
29			2010-12	0.5238		13.50%		7.07%	6.00%	304.80	-0.92%
30											
31	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	2002	0.2346		11.30%		2.65%	14.21	73.62	
32			2003	0.2152		10.80%		2.32%	14.36	75.84	
33			2004	0.0882		8.90%		0.79%	15.01	80.69	
34			2005	0.1507		9.70%		1.46%	15.02	80.98	
35			2006	0.0677		9.90%		0.67%	13.44	81.46	
36			GROWTH 2002 - 2006					1.58%	2.00%		2.56%
37			2007	-0.3778		6.50%		NMF		83.50	2.50%
38			2008	0.0080		9.00%		0.07%		85.50	2.45%
39			2010-12	0.1733		11.00%		1.91%	-0.50%	87.00	1.32%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	IDA	IDACORP, INC.	2002	-0.1411		7.00%		NMF	23.01	38.02	
2			2003	-0.9375		4.20%		NMF	22.54	38.34	
3			2004	0.1053		7.20%		0.76%	23.88	42.22	
4			2005	0.3143		6.20%		1.95%	24.04	42.66	
5			2006	0.4894		8.90%		4.36%	25.76	43.63	
6			GROWTH 2002 - 2006					2.35%	2.50%		3.50%
7			2007	0.4000		7.50%		3.00%		45.00	3.14%
8			2008	0.4419		7.50%		3.31%		46.30	3.01%
9			2010-12	0.4667		7.00%		3.27%	4.00%	47.50	1.71%
10											
11	MGEE	MGE ENERGY, INC.	2002	0.2071		12.80%		2.65%	12.94	17.57	
12			2003	0.2105		11.60%		2.44%	14.34	18.34	
13			2004	0.2316		10.00%		2.32%	16.59	20.39	
14			2005	0.1274		9.30%		1.18%	16.81	20.45	
15			2006	0.3252		11.30%		3.68%	17.89	20.98	
16			GROWTH 2002 - 2006					2.45%	7.00%		4.53%
17			2007	0.4000		12.50%		5.00%		21.90	4.39%
18			2008	0.4042		13.50%		5.46%		21.90	2.17%
19			2010-12	0.4231		14.00%		5.92%	7.00%	21.90	0.86%
20											
21	NI	NISOURCE, INC.	2002	0.3927		9.70%		3.81%	16.78	248.86	
22			2003	0.3082		9.40%		2.90%	16.81	262.63	
23			2004	0.4321		9.00%		3.89%	17.69	270.63	
24			2005	0.1481		6.00%		0.89%	18.09	272.62	
25			2006	0.1930		6.30%		1.22%	18.32	273.65	
26			GROWTH 2002 - 2006					2.54%	4.00%		2.40%
27			2007	0.2333		6.50%		1.52%		274.75	0.40%
28			2008	0.2640		6.50%		1.72%		275.50	0.34%
29			2010-12	0.3333		7.50%		2.50%	2.00%	277.00	0.24%
30											
31	NST	NSTAR	2002	0.3669		13.80%		5.06%	12.25	106.07	
32			2003	0.3736		13.70%		5.12%	12.84	106.07	
33			2004	0.3580		13.10%		4.69%	13.52	106.55	
34			2005	0.5246		12.80%		6.71%	14.37	106.81	
35			2006	0.2021		13.10%		2.65%	14.82	106.81	
36			GROWTH 2002 - 2006					4.85%	2.50%		0.17%
37			2007	0.3571		13.50%		4.82%		106.81	0.00%
38			2008	0.3644		14.00%		5.10%		106.81	0.00%
39			2010-12	0.4167		14.50%		6.04%	5.50%	106.81	0.00%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	PNM	PNM RESOURCES	2002	0.4673		6.50%		3.04%	16.60	58.68	
2			2003	0.4696		6.30%		2.96%	17.84	60.39	
3			2004	0.5594		8.00%		4.48%	18.19	60.46	
4			2005	0.5031		8.20%		4.13%	18.70	68.79	
5			2006	0.5000		7.20%		3.60%	22.09	76.65	
6			GROWTH 2002 - 2006					3.64%	4.50%		6.91%
7			2007	0.3111		5.50%		1.71%		77.00	0.46%
8			2008	0.4121		7.00%		2.88%		80.00	2.16%
9			2010-12	0.4108		7.00%		2.88%	4.50%	80.00	0.86%
10											
11	PNW	PINNACLE WEST CAPITAL CORPORATION	2002	0.3557		8.00%		2.85%	29.44	91.26	
12			2003	0.3135		8.10%		2.54%	31.00	91.29	
13			2004	0.2907		8.00%		2.33%	32.14	91.79	
14			2005	0.1384		6.50%		0.90%	34.57	99.08	
15			2006	0.3596		9.20%		3.31%	34.47	99.96	
16			GROWTH 2002 - 2006					2.38%	4.00%		2.30%
17			2007	0.2857		8.50%		2.43%		100.40	0.44%
18			2008	0.1686		7.00%		1.18%		100.50	0.27%
19			2010-12	0.2271		8.00%		1.82%	2.00%	100.80	0.17%
20											
21	PPL	PPL CORPORATION	2002	0.5325		21.10%		11.24%	6.71	331.47	
22			2003	0.5815		19.60%		11.40%	9.19	354.72	
23			2004	0.5615		16.30%		9.15%	11.21	378.14	
24			2005	0.5000		16.70%		8.35%	11.62	380.15	
25			2006	0.5197		17.30%		8.99%	13.30	385.04	
26			GROWTH 2002 - 2006					9.83%	14.00%		3.82%
27			2007	0.5564		20.50%		11.41%		372.00	-3.39%
28			2008	0.4531		16.50%		7.48%		372.00	-1.71%
29			2010-12	0.5111		23.50%		12.01%	8.50%	360.00	-1.34%
30											
31	PGN	PROGRESSS ENERGY	2002	0.4323		12.10%		5.23%	28.73	232.43	
32			2003	0.3372		10.90%		3.68%	30.26	246.00	
33			2004	0.2516		9.90%		2.49%	30.90	247.00	
34			2005	0.1905		9.00%		1.71%	31.90	252.00	
35			2006	-0.1805		6.10%		NMF	32.37	256.00	
36			GROWTH 2002 - 2006					3.28%	5.00%		2.44%
37			2007	0.1552		9.00%		1.40%		260.00	1.56%
38			2008	0.1767		9.00%		1.59%		264.00	1.55%
39			2010-12	0.2333		9.50%		2.22%	1.50%	274.00	1.37%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	SCG	SCANA CORPORATION	2002	0.4538		11.60%		5.26%	19.64	110.83	
2			2003	0.4480		12.10%		5.42%	20.82	110.74	
3			2004	0.4532		12.20%		5.53%	21.69	113.00	
4			2005	0.4388		11.80%		5.18%	23.28	115.00	
5			2006	0.3514		10.50%		3.69%	24.32	117.00	
6			GROWTH 2002 - 2006					5.02%	2.50%		1.36%
7			2007	0.3481		10.50%		3.66%		117.00	0.00%
8			2008	0.3724		11.00%		4.10%		117.00	0.00%
9			2010-12	0.3846		11.00%		4.23%	4.50%	117.00	0.00%
10											
11	SO	SOUTHERN COMPANY	2002	0.2649		15.10%		4.00%	12.15	716.90	
12			2003	0.2944		14.80%		4.36%	13.13	734.80	
13			2004	0.3107		14.90%		4.63%	13.86	741.80	
14			2005	0.3052		14.90%		4.55%	14.41	741.60	
15			2006	0.2667		13.80%		3.68%	15.23	746.60	
16			GROWTH 2002 - 2006					4.24%	1.00%		1.02%
17			2007	0.2727		13.50%		3.68%		765.00	2.46%
18			2008	0.2783		13.00%		3.62%		783.00	2.41%
19			2010-12	0.2600		13.00%		3.38%	5.00%	805.00	1.52%
20											
21	TE	TECO ENERGY, INC.	2002	0.2769		9.90%		2.74%	14.86	175.80	
22			2003	0.1389		NMF		NMF	8.93	187.80	
23			2004	-0.0704		10.70%		NMF	6.43	199.70	
24			2005	0.2400		13.30%		3.19%	7.65	208.20	
25			2006	0.3504		14.10%		4.94%	8.25	209.50	
26			GROWTH 2002 - 2006					3.62%	-9.50%		4.48%
27			2007	0.4222		15.00%		6.33%		210.50	0.48%
28			2008	0.3043		12.50%		3.80%		211.50	0.48%
29			2010-12	0.3120		11.50%		3.59%	6.50%	215.00	0.52%
30											
31	UIL	UIL HOLDINGS	2002	0.0649		9.10%		0.59%	20.28	23.79	
32			2003	-0.3952		6.00%		NMF	20.65	23.86	
33			2004	-0.1234		6.70%		NMF	22.84	24.01	
34			2005	-0.3308		5.80%		NMF	22.39	24.32	
35			2006	0.0699		9.90%		0.69%	18.53	24.86	
36			GROWTH 2002 - 2006					0.64%	1.00%		1.11%
37			2007	0.0649		9.50%		0.62%		25.20	1.37%
38			2008	0.1128		10.00%		1.13%		25.40	1.08%
39			2010-12	0.1953		10.50%		2.05%	-1.00%	26.60	1.36%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 02/08/2008, 12/28/2007 AND 11/30/2007
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COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

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COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	VVC	VECTREN	2002	0.3631		13.10%		4.76%	12.79	68.01	
2			2003	0.2885		10.40%		3.00%	14.18	75.60	
3			2004	0.1901		9.90%		1.88%	14.42	75.90	
4			2005	0.3425		12.00%		4.11%	15.01	76.19	
5			2006	0.1458		9.30%		1.36%	15.43	76.10	
6			GROWTH 2002 - 2006					3.02%	4.50%		2.85%
7			2007	0.3135		11.00%		3.45%		80.80	6.18%
8			2008	0.3282		11.00%		3.61%		81.00	3.17%
9			2010-12	0.3024		10.50%		3.18%	4.50%	81.60	1.41%
10											
11	XEL	XCEL ENERGY INC.	2002	-1.6905		3.70%		NMF	11.70	398.71	
12			2003	0.3902		9.80%		3.82%	12.95	398.96	
13			2004	0.3622		10.00%		3.62%	12.99	400.46	
14			2005	0.2917		9.20%		2.68%	13.37	403.39	
15			2006	0.3481		9.70%		3.38%	14.28	407.30	
16			GROWTH 2002 - 2006					3.38%	-4.50%		0.53%
17			2007	0.3259		9.00%		2.93%		427.00	4.84%
18			2008	0.3667		10.00%		3.67%		429.00	2.63%
19			2010-12	0.3714		10.00%		3.71%	0.40%	435.00	1.32%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
GROWTH RATE COMPARISON

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 6

LINE NO.	STOCK SYMBOL		(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) DPS	(C) BVPS	(D) VALUE LINE HISTORIC EPS	(D) DPS	(D) BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) DPS	(F) BVPS
1	ALE	ALLETTE, INC.	5.45%	5.00%	8.00%	NMF	5.50%	-	-	-	6.17%	-	-	-
2	LNT	ALLIANT ENERGY	5.25%	6.00%	5.50%	8.00%	4.00%	-3.00%	-11.50%	-2.50%	0.93%	14.95%	-12.92%	3.51%
3	AEE	AMEREN CORP.	2.52%	6.20%	3.00%	NMF	3.00%	-2.00%	-	5.50%	3.14%	0.00%	0.00%	6.32%
4	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	6.03%	5.40%	6.50%	7.50%	6.00%	3.00%	-9.50%	-2.50%	2.34%	0.00%	-11.09%	3.29%
5	CHG	CH ENERGY GROUP, INC.	2.50%	-	3.00%	1.00%	2.00%	-2.50%	-	1.50%	1.00%	4.83%	0.00%	1.79%
6	CV	CENTRAL VERMONT PUBLIC SERVICE CORPORATION	3.73%	-	9.00%	NMF	3.00%	-2.50%	1.00%	2.00%	2.50%	1.43%	1.12%	1.27%
7	CNL	CLECO CORPORATION	4.48%	9.50%	6.50%	6.50%	6.50%	-	1.00%	5.50%	5.92%	-2.74%	0.00%	6.64%
8	ED	CONSOLIDATED EDISON, INC.	3.38%	3.20%	4.00%	1.00%	5.00%	-2.00%	1.00%	3.00%	2.17%	-1.47%	0.89%	2.95%
9	DTE	DTE ENERGY COMPANY	2.50%	6.00%	4.00%	2.50%	2.50%	-1.00%	-	3.00%	2.83%	-10.57%	0.24%	4.91%
10	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	3.97%	-	8.50%	1.00%	3.00%	1.00%	-	2.00%	3.10%	4.33%	0.00%	1.51%
11	FE	FIRSTENERGY CORP.	7.26%	7.50%	9.00%	5.50%	6.00%	3.50%	4.00%	4.50%	5.71%	10.74%	5.38%	4.29%
12	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	2.41%	4.50%	1.50%	NMF	-0.50%	-1.00%	-	2.00%	1.30%	-4.81%	0.00%	-1.38%
13	IDA	IDACORP, INC.	3.63%	5.00%	2.00%	NMF	4.00%	-8.50%	-8.50%	2.50%	-0.58%	9.58%	-10.38%	2.86%
14	MGEE	MGE ENERGY, INC.	7.05%	-	6.00%	0.50%	7.00%	2.50%	1.00%	7.00%	4.00%	5.07%	0.92%	8.43%
15	NI	NISOURCE, INC.	2.00%	2.80%	2.50%	1.50%	2.00%	0.50%	-1.50%	4.00%	1.69%	-12.10%	-5.63%	2.22%
16	NST	NSTAR	6.01%	6.20%	8.50%	7.00%	5.50%	3.50%	3.00%	2.50%	5.17%	3.38%	9.53%	4.88%
17	PNM	PNM RESOURCES	2.70%	8.50%	2.50%	6.00%	4.50%	-2.50%	7.50%	4.50%	4.43%	12.60%	10.83%	7.40%
18	PNW	PINNACLE WEST CAPITAL CORPORATION	2.02%	6.70%	1.50%	3.00%	2.00%	-5.00%	6.00%	4.00%	2.60%	5.80%	5.64%	4.02%
19	PPL	PPL CORPORATION	11.26%	10.30%	14.00%	15.00%	8.50%	6.50%	13.00%	14.00%	11.61%	10.43%	11.18%	18.65%
20	PGN	PROGRESSS ENERGY	2.33%	5.20%	3.50%	1.00%	1.50%	-0.50%	2.50%	5.00%	2.60%	-14.52%	2.65%	3.03%
21	SCG	SCANA CORPORATION	4.03%	5.00%	3.50%	4.00%	4.50%	7.00%	5.00%	2.50%	4.50%	2.14%	6.62%	5.49%
22	SO	SOUTHERN COMPANY	5.01%	4.60%	3.00%	4.00%	5.00%	3.00%	2.00%	1.00%	3.23%	3.22%	3.16%	5.81%
23	TE	TECO ENERGY, INC.	4.72%	7.30%	4.50%	2.00%	6.50%	-13.00%	-10.50%	-9.50%	-1.81%	-11.99%	-14.32%	-13.68%
24	UIL	UIL HOLDINGS	2.56%	-	5.50%	NMF	-1.00%	-8.50%	-	1.00%	-0.75%	0.13%	0.00%	-2.23%
25	VVC	VECTREN	4.81%	4.70%	4.50%	3.00%	4.50%	4.50%	4.00%	4.50%	4.24%	-3.78%	3.55%	4.80%
26	XEL	XCEL ENERGY INC.	4.24%	5.20%	5.50%	4.50%	0.40%	-6.50%	-10.50%	-4.50%	-0.84%	33.90%	-6.06%	5.11%
27					5.21%	3.88%	3.88%	-1.10%	-0.05%	2.50%		2.42%	0.05%	3.68%
28	AVERAGES		4.30%	5.94%		4.32%			0.45%		2.97%		2.05%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 02/08/2008, 12/28/2007 AND 11/30/2007
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1, 3, 5 AND 7
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 02/08/2008, 12/28/2007 AND 11/30/2007

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
CAPM COST OF EQUITY CAPITAL

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 7
PAGE 1 OF 2

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f	+	[	ß	x	(	r_m	-	r_f	)	]	=	(A)	(B) EXPECTED RETURN
1	ALE	ALLETTE, INC.	k	=	2.68%	+	[	0.95	x	(	10.40%	-	2.68%	)	]	=		10.01%
2	LNT	ALLIANT ENERGY	k	=	2.68%	+	[	0.80	x	(	10.40%	-	2.68%	)	]	=		8.86%
3	AEE	AMEREN CORP.	k	=	2.68%	+	[	0.80	x	(	10.40%	-	2.68%	)	]	=		8.86%
4	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	k	=	2.68%	+	[	0.95	x	(	10.40%	-	2.68%	)	]	=		10.01%
5	CHG	CH ENERGY GROUP, INC.	k	=	2.68%	+	[	0.90	x	(	10.40%	-	2.68%	)	]	=		9.63%
6	CV	CENTRAL VERMONT PUBLIC SERVICE CORPORATION	k	=	2.68%	+	[	1.00	x	(	10.40%	-	2.68%	)	]	=		10.40%
7	CNL	CLECO CORPORATION	k	=	2.68%	+	[	1.15	x	(	10.40%	-	2.68%	)	]	=		11.56%
8	ED	CONSOLIDATED EDISON, INC.	k	=	2.68%	+	[	0.75	x	(	10.40%	-	2.68%	)	]	=		8.47%
9	DTE	DTE ENERGY COMPANY	k	=	2.68%	+	[	0.80	x	(	10.40%	-	2.68%	)	]	=		8.86%
10	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	k	=	2.68%	+	[	0.85	x	(	10.40%	-	2.68%	)	]	=		9.24%
11	FE	FIRSTENERGY CORP.	k	=	2.68%	+	[	0.85	x	(	10.40%	-	2.68%	)	]	=		9.24%
12	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	k	=	2.68%	+	[	0.75	x	(	10.40%	-	2.68%	)	]	=		8.47%
13	IDA	IDACORP, INC.	k	=	2.68%	+	[	0.95	x	(	10.40%	-	2.68%	)	]	=		10.01%
14	MGEE	MGE ENERGY, INC.	k	=	2.68%	+	[	0.95	x	(	10.40%	-	2.68%	)	]	=		10.01%
15	NI	NISOURCE, INC.	k	=	2.68%	+	[	0.90	x	(	10.40%	-	2.68%	)	]	=		9.63%
16	NST	NSTAR	k	=	2.68%	+	[	0.75	x	(	10.40%	-	2.68%	)	]	=		8.47%
17	PNM	PNM RESOURCES	k	=	2.68%	+	[	0.90	x	(	10.40%	-	2.68%	)	]	=		9.63%
18	PNW	PINNACLE WEST CAPITAL CORPORATION	k	=	2.68%	+	[	0.80	x	(	10.40%	-	2.68%	)	]	=		8.86%
19	PPL	PPL CORPORATION	k	=	2.68%	+	[	0.90	x	(	10.40%	-	2.68%	)	]	=		9.63%
20	PGN	PROGRESSS ENERGY	k	=	2.68%	+	[	0.85	x	(	10.40%	-	2.68%	)	]	=		9.24%
21	SCG	SCANA CORPORATION	k	=	2.68%	+	[	0.85	x	(	10.40%	-	2.68%	)	]	=		9.24%
22	SO	SOUTHERN COMPANY	k	=	2.68%	+	[	0.70	x	(	10.40%	-	2.68%	)	]	=		8.08%
23	TE	TECO ENERGY, INC.	k	=	2.68%	+	[	0.95	x	(	10.40%	-	2.68%	)	]	=		10.01%
24	UIL	UIL HOLDINGS	k	=	2.68%	+	[	0.95	x	(	10.40%	-	2.68%	)	]	=		10.01%
25	VVC	VECTREN	k	=	2.68%	+	[	0.90	x	(	10.40%	-	2.68%	)	]	=		9.63%
26	XEL	XCEL ENERGY INC.	k	=	2.68%	+	[	0.80	x	(	10.40%	-	2.68%	)	]	=		8.86%
27	**AVERAGE**							0.87										9.42%

REFERENCES:

COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 01/11/2008 THROUGH 02/15/2008 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE GEOMETRIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2006 PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR, INC.'S STOCKS, BONDS, BILLS AND INFLATION: 2007 YEARBOOK .

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
CAPM COST OF EQUITY CAPITAL

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 7
PAGE 2 OF 2

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f	+ [	ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
							(A)								
1	ALE	ALLETTE, INC.	k	=	2.68%	+ [	0.95	x	(	12.30%	-	2.68%	)]	=	11.82%
2	LNT	ALLIANT ENERGY	k	=	2.68%	+ [	0.80	x	(	12.30%	-	2.68%	)]	=	10.38%
3	AEE	AMEREN CORP.	k	=	2.68%	+ [	0.80	x	(	12.30%	-	2.68%	)]	=	10.38%
4	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	k	=	2.68%	+ [	0.95	x	(	12.30%	-	2.68%	)]	=	11.82%
5	CHG	CH ENERGY GROUP, INC.	k	=	2.68%	+ [	0.90	x	(	12.30%	-	2.68%	)]	=	11.34%
6	CV	CENTRAL VERMONT PUBLIC SERVICE CORPORATION	k	=	2.68%	+ [	1.00	x	(	12.30%	-	2.68%	)]	=	12.30%
7	CNL	CLECO CORPORATION	k	=	2.68%	+ [	1.15	x	(	12.30%	-	2.68%	)]	=	13.74%
8	ED	CONSOLIDATED EDISON, INC.	k	=	2.68%	+ [	0.75	x	(	12.30%	-	2.68%	)]	=	9.89%
9	DTE	DTE ENERGY COMPANY	k	=	2.68%	+ [	0.80	x	(	12.30%	-	2.68%	)]	=	10.38%
10	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	k	=	2.68%	+ [	0.85	x	(	12.30%	-	2.68%	)]	=	10.86%
11	FE	FIRSTENERGY CORP.	k	=	2.68%	+ [	0.85	x	(	12.30%	-	2.68%	)]	=	10.86%
12	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	k	=	2.68%	+ [	0.75	x	(	12.30%	-	2.68%	)]	=	9.89%
13	IDA	IDACORP, INC.	k	=	2.68%	+ [	0.95	x	(	12.30%	-	2.68%	)]	=	11.82%
14	MGEE	MGE ENERGY, INC.	k	=	2.68%	+ [	0.95	x	(	12.30%	-	2.68%	)]	=	11.82%
15	NI	NISOURCE, INC.	k	=	2.68%	+ [	0.90	x	(	12.30%	-	2.68%	)]	=	11.34%
16	NST	NSTAR	k	=	2.68%	+ [	0.75	x	(	12.30%	-	2.68%	)]	=	9.89%
17	PNM	PNM RESOURCES	k	=	2.68%	+ [	0.90	x	(	12.30%	-	2.68%	)]	=	11.34%
18	PNW	PINNACLE WEST CAPITAL CORPORATION	k	=	2.68%	+ [	0.80	x	(	12.30%	-	2.68%	)]	=	10.38%
19	PPL	PPL CORPORATION	k	=	2.68%	+ [	0.90	x	(	12.30%	-	2.68%	)]	=	11.34%
20	PGN	PROGRESSS ENERGY	k	=	2.68%	+ [	0.85	x	(	12.30%	-	2.68%	)]	=	10.86%
21	SCG	SCANA CORPORATION	k	=	2.68%	+ [	0.85	x	(	12.30%	-	2.68%	)]	=	10.86%
22	SO	SOUTHERN COMPANY	k	=	2.68%	+ [	0.70	x	(	12.30%	-	2.68%	)]	=	9.41%
23	TE	TECO ENERGY, INC.	k	=	2.68%	+ [	0.95	x	(	12.30%	-	2.68%	)]	=	11.82%
24	UIL	UIL HOLDINGS	k	=	2.68%	+ [	0.95	x	(	12.30%	-	2.68%	)]	=	11.82%
25	VVC	VECTREN	k	=	2.68%	+ [	0.90	x	(	12.30%	-	2.68%	)]	=	11.34%
26	XEL	XCEL ENERGY INC.	k	=	2.68%	+ [	0.80	x	(	12.30%	-	2.68%	)]	=	10.38%
27	**AVERAGE**						0.87								11.08%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [ß (r_m - r_f)]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 01/11/2008 THROUGH 02/15/2008 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2006 PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR, INC.'S STOCKS, BONDS, BILLS AND INFLATION: 2007 YEARBOOK.

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. E-01933A-07-0402
SCHEDULE WAR - 8

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.40%	1.90%	10.01%	6.98%	8.10%	7.50%	7.49%	9.86%	10.06%
2	1991	4.21%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.01%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.99%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.56%	4.00%	7.14%	3.60%	4.21%	4.25%	4.25%	8.31%	8.63%
6	1995	2.83%	2.50%	8.83%	5.21%	5.83%	5.49%	5.49%	7.89%	8.29%
7	1996	2.95%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	1.70%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.60%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.70%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.40%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	1.60%	0.80%	6.92%	3.41%	3.88%	3.40%	5.95%	7.59%	8.02%
13	2002	2.40%	1.60%	4.67%	1.17%	1.67%	1.61%	5.38%	7.41%	7.98%
14	2003	1.90%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	3.30%	3.90%	4.34%	2.34%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.40%	3.20%	6.16%	4.19%	3.22%	3.15%	4.57%	5.38%	5.78%
17	2006	2.50%	3.30%	7.97%	5.96%	4.97%	4.73%	4.91%	5.94%	6.30%
18	2007	4.10%	2.20%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	CURRENT	4.10%	2.20%	6.00%	3.50%	3.00%	2.09%	4.36%	6.02%	6.20%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (F): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 02/15/2008
COLUMN (G) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 02/15/2008
COLUMN (H) THROUGH (J): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2006
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. E-01933A-07-04
SCHEDULE WAR - 9

LINE NO.		ALE	PCT.	LNT	PCT.	AEE	PCT.	AEP	PCT.
1	DEBT	$ 359.8	35.1%	$ 2,651.3	62.9%	$ 5,285.0	44.5%	$ 12,429.0	56.7%
2									
3	PREFERRED STOCK	0.0	0.0%	243.8	5.8%	18.0	0.2%	61.0	0.3%
4									
5	COMMON EQUITY	665.8	64.9%	1,323.3	31.4%	6,583.0	55.4%	9,412.0	43.0%
6									
7	TOTALS	$ 1,025.6	100%	$ 4,218.4	100%	$ 11,886.0	100%	$ 21,902.0	100%
8									
9									
10		CHG	NST	CV	PCT.	CNL	PCT.	ED	PCT.
11									
12	DEBT	$ 337,889.0	38.8%	$ 123.0	39.2%	$ 619,341.0	40.9%	$ 8,298.0	50.2%
13									
14	PREFERRED STOCK	21,027.0	2.4%	12.0	3.8%	20,092.0	1.3%	213.0	1.3%
15									
16	COMMON EQUITY	512,862.0	58.8%	179.0	57.0%	876,129.0	57.8%	8,004.0	48.5%
17									
18	TOTALS	$ 871,778.0	100%	$ 314.0	100%	$ 1,515,562.0	100%	$ 16,515.0	100%
19									
20									
21		DTE	NST	EDE	PCT.	FE	PCT.	HE	PCT.
22									
23	DEBT	$ 7,474.0	56.1%	$ 462,437.0	49.7%	$ 8,535.0	48.6%	$ 1,133,185.0	50.9%
24									
25	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
26									
27	COMMON EQUITY	5,849.0	43.9%	468,609.0	50.3%	9,035.0	51.4%	1,095,240.0	49.1%
28									
29	TOTALS	$ 13,323.0	100%	$ 931,046.0	100%	$ 17,570.0	100%	$ 2,228,425.0	100%
30									
31									
32		IDA	PCT.	MGEE	PCT.	NI	PCT.	NST	PCT.
33									
34	DEBT	$ 928,648.0	45.2%	$ 237,284.0	38.7%	$ 5,146.2	50.7%	$ 2,444,774.0	60.1%
35									
36	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	43,000.0	1.1%
37									
38	COMMON EQUITY	1,124,183.0	54.8%	375,348.0	61.3%	5,013.6	49.3%	1,582,563.0	38.9%
39									
40	TOTALS	$ 2,052,831.0	100%	$ 612,632.0	100%	$ 10,159.8	100%	$ 4,070,337.0	100%
41									
42									
43		PNM	PCT.	PNW	PCT.	PPL	PCT.	PGN	PCT.
44									
45	DEBT	$ 1,765,907.0	50.9%	$ 3,232,633.0	48.4%	$ 6,728.0	55.4%	$ 8,845.0	51.4%
46									
47	PREFERRED STOCK	11,529.0	0.3%	0.0	0.0%	301.0	2.5%	93.0	0.5%
48									
49	COMMON EQUITY	1,693,296.0	48.8%	3,446,116.0	51.6%	5,122.0	42.2%	8,286.0	48.1%
50									
51	TOTALS	$ 3,470,732.0	100%	$ 6,678,749.0	100%	$ 12,151.0	100%	$ 17,224.0	100%
52									
53									
54		SCG	PCT.	SO	PCT.	TE	PCT.	UIL	PCT.
55									
56	DEBT	$ 3,067.0	50.9%	$ 12,503.0	50.8%	$ 3,212.6	65.0%	$ 408,603.0	47.0%
57									
58	PREFERRED STOCK	114.0	1.9%	744.0	3.0%	0.0	0.0%	0.0	0.0%
59									
60	COMMON EQUITY	2,846.0	47.2%	11,371.0	46.2%	1,729.0	35.0%	460,581.0	53.0%
61									
62	TOTALS	$ 6,027.0	100%	$ 24,618.0	100%	$ 4,941.6	100%	$ 869,184.0	100%
63									
64						ELECTRIC COMPANY SAMPLE			
65		VVC	PCT.	VVC	PCT.	AVERAGE	PCT.	UNS	PCT.
66									
67	DEBT	$ 1,208.0	50.7%	$ 1,208.0	50.7%	$ 448,375.9	49.7%	$ 1,759,941.0	72.9%
68									
69	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	3,748.0	0.4%	0.0	0.0%
70									
71	COMMON EQUITY	1,174.2	49.3%	1,174.2	49.3%	450,488.2	49.9%	654,149.0	27.1%
72									
73	TOTALS	$ 2,382.2	100%	$ 2,382.2	100%	$ 902,612.1	100%	$ 2,414,090.0	100%

REFERENCE:
MOST RECENT SEC 10(k) FILINGS OR COMPANY ANNUAL REPORTS

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-07-0402
DOCKET NO. E-01933A-05-0650

DIRECT TESTIMONY

OF

BEN JOHNSON, PH.D.

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 29, 2008

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Critique of TEP's Generation Proposals 15

Recommendations 32

TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of

The Residential Utility Consumer Office

Before the

Arizona Corporation Commission

Docket No. E-01933A-07-0402

Docket No. E-01933A-05-0650

Introduction

Q. Would you please state your name and address?

A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

Q. What is your present occupation?

A. I am a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation.

Q. Have you prepared an appendix that describes your qualifications in regulatory and utility economics?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. What is your purpose in making your appearance at this hearing?

A. Our firm has been retained by the Residential Utility Consumer Office ("RUCO") to assist with

RUCO's evaluation of the three methodologies proposed by Tuscon Electric Power Company (TEP) for setting rates related to generating electricity.

Following this introduction, my testimony has four sections. In the first section, I briefly summarize some of the history leading to this proceeding. In the second section, I summarize the three rate setting methodologies proposed by TEP, focusing on the development of rates for generation services. In the third section, I discuss several problems with TEP's filing. In this section I point out how TEP's forecasted rates are flawed, and could lead the Commission to the wrong conclusion when evaluating the merits of TEP's proposed rate-setting methodologies. I also discuss how market-based generation rates may result in rates that are not just and reasonable – a problem that also applies to TEP's hybrid proposal. In the fourth and final section, I summarize my conclusions and recommendations.

Q. As background information, can you please briefly summarize the history of this Commission's Electric Competition rules?

A. The Commission adopted its Electric Competition Rules (Rules) in 1996. [See, Decision No. 59943] The Rules were intended to "set forth a framework for the inevitable transition from a non-competitive to a competitive environment". [Id., p. 2]

Among other things, the Rules required TEP to file estimates of its stranded costs, and required commission approval of any charges intended to recover stranded costs. [R14-2-1607(G) and (H)] In September 1999, the Commission revised the Rules to require TEP to divest its generation assets and to purchase its power for Standard Offer Service from the competitive market. [R14-2-1615(A) and R14-2-1606(B)] The Rules also declare that rates set by the market for competitive services are deemed just and reasonable. [R14-2-1611(A)]

Q. Now, can you briefly summarize this Commission's efforts to foster competition as they relate specifically to Tucson Electric Power?

A. On June 22, 1998 the Commission issued it's Stranded Cost Order, which required TEP to file a plan for stranded cost recovery. [Decision No. 60977] On August 10, 1998, TEP filed its Stranded Cost Recovery Plan. On June 9, 1999, TEP, RUCO and several other parties entered into Settlement Proposal, which was intended to resolve various disputed issues concerning TEP's proposed Stranded Cost Recovery Plan. [See, Decision 62103, p. 2] On November 30, 1999, the Commission adopted the Settlement Agreement, with modifications. [Decision 62103]

The Settlement Agreement required TEP to transfer its generation assets to a subsidiary by December 31, 2002. [Settlement Agreement § 3.1] The Settlement Agreement also reaffirmed rate reductions of 1 percent in 1999 and again in 2000, and a rate freeze thereafter through December 31, 2008. [Settlement Agreement § 5.1] In exchange, the Settlement Agreement provided mechanisms for the recovery of TEP's stranded costs, thereby shielding TEP from the anticipated adverse financial impact of allowing competitors to supply electricity in TEP's service area.

Q. Can you explain how TEP's stranded costs were to be recovered under the Settlement Agreement?

A. Yes. TEP's frozen rates would include a fixed Competitive Transition Charge (CTC) and a floating CTC. [Settlement Agreement § 2.1] The fixed CTC was set at 0.93 cents/kWh and would terminate after recovery of $450 million of stranded costs, or on December 31, 2008, whichever occurred first. [Id.] The floating CTC was intended to recover an estimated additional $233 million in stranded costs. The floating CTC would be determined in part by a Market Generation Credit (MGC) based upon a market-index futures price. The MGC and CTC were inversely related; an increase in the MGC results in a decrease in the CTC, and vice versa.

In other words, the floating CTC would decrease as the market price of power increased (as estimated by the MGC market index). The Settlement Agreement acknowledged that the floating CTC could actually be negative, if short term wholesale prices increase, in which case "the negative value would be credited to the customers' monthly bill". [Decision 62103, p. 5] The Settlement Agreement provides for termination of the floating CTC on December 31, 2008. [Id.]

Q. Are there any other major provisions of the Settlement Agreement that you would like to mention at this point?

A. Yes. The Settlement Agreement also provided for a review of TEP's rates in 2004. The purpose was to facilitate a Commission investigation into whether TEP's Standard Offer rates, or its overall unbundled rates had been set too high, and should be reduced. [Settlement Agreement, § 5.2]

Q. Can you now discuss the next significant event leading up to this proceeding?

A. On September 10, 2002 the Commission issued its "Track A Order", which modified portions of the Rules and Decision 62103. [Decision No. 65154] Specifically, the Track A Order granted TEP a waiver from the requirement to divest its generation assets and the requirement to purchase energy on the competitive market. [Id., pp. 32-33] The Commission stated:

> In retrospect, it was a good idea to delay divestiture and competitive procurement in the APS and TEP Settlement Agreements, given what has happened in the last two or so years, including the experience in California; the market volatility and illiquidity; and the lack of public confidence in the transition to electric deregulation and ability of regulators to prevent price spikes, ensure reliable service, and prevent bankruptcies. Even today, there is not agreement amongst economists, much less regulators, as to why ...what happened in California, happened, and how to prevent a similar or related occurrence.
>
> It is clear that the Commission and all parties expected benefits from retail competition, yet there is no active retail Competition, so actual benefits are still unknown. It is said that consumers will benefit from wholesale competition, but not without the proper market structure and regulatory framework that will support it. It was anticipated that at the time that APS and

> TEP divested, ESPs would be providing direct access to retail customers. In actuality, no retail competition exists; market power is held by the incumbent utilities; no RTO is in effect; transmission constraints exist that potentially exacerbate market abuse; the GAO has issued a negative report on FERC's ability to manage competitive markets; both TEP and APS recognize a problem - one wants to postpone its divestiture while the other is affected by its parent's and affiliates' adverse financial considerations; proposed new generation may be cancelled if it is not able to find a market; more protections are needed against self-dealing and inappropriate affiliate transactions; and investigations are ongoing into market manipulations and improprieties. Contrary to what APS argues, these changes relate to the question of divestiture, especially to our willingness to transfer our ratemaking jurisdiction over generation assets to FERC, given its recent history regulating the wholesale market and the conclusions contained in the recent GAO report. [Id., p. 22]

Q. Have the Commission's Competition Rules also been the subject of some controversy?

A. Yes. Various parties challenged the Rules, and several Certificates of Convenience and Necessity (CC&Ns) that were issued to potential competitors pursuant to the Rules. Primarily at issue was Rule R14-2-1611 which provides: "Market determined rates for Competitive Services, as defined in R14-2-1601 shall be deemed to be just and reasonable."

In resolving this dispute, the Court of Appeals of Arizona noted that the Arizona Constitution requires the Commission to "prescribe ... just and reasonable rates and charges to be made and collected by public service corporations" and to "ascertain the fair value of the property within the State of every public service corporation doing business therein." [Phelps Dodge v. AEPCO, 83 P.3d 573, ¶ 18 (App. 2004)] The Court of Appeals concluded that the Commission violated these portions of the Arizona Constitution by approving CC&N's for competitive electric providers without first determining and considering fair value. [Id., ¶ 24] As well, the Court rejected the Commission's sweeping replacement of traditional ratemaking principles with market-based pricing, concluding that "the Commission may not abdicate its constitutional responsibility to set just and reasonable rates by allowing competitive market forces alone to do so". [Id., ¶ 32]

1 **Q. Previously you mentioned that TEP's rates were supposed to be reviewed in 2004. Did**
2 **that review occur?**
3 A. Yes. In 2004 TEP filed the rate review required by Decision No. 62103, claiming a revenue
4 deficiency of $111 million. The Staff, RUCO and other parties disputed TEP's alleged revenue
5 deficiency, contending that this computation was greatly overstated. However, no party
6 concluded that TEP was over-earning, which was the key issue under consideration. Hence, the
7 proceeding was suspended and no action was taken by the Commission.
8
9 **Q. What happened after the 2004 rate review?**
10 A. In 2005, TEP filed a Motion for Declaratory Order, seeking clarification of whether TEP would
11 be entitled to charge Standard Offer generation rates based on the MGC in 2009 and beyond.
12 After several parties filed opposition to the Motion for Declaratory Order, the Administrative
13 Law Judge issued a procedural order suggesting TEP file its request for relief in a different
14 form. TEP then filed a Motion to Amend Decision No. 62103. That Motion was assigned
15 Docket No. E-01933A-05-0650. In April 2006, the Commission issued Decision No. 68669,
16 which ordered that a hearing be held to consider amending Decision No. 62103 and the
17 Settlement Agreement. TEP then filed testimony in which it claimed that the Settlement
18 Agreement provided that TEP could begin charging market-based rates beginning in 2009 in
19 accordance with the MGC provisions of the Settlement Agreement. TEP's testimony also
20 presented two proposals for generation rates beginning in 2009, a market-phase in proposal and
21 a traditional cost of service proposal that included an $850 million regulatory asset.
22
23 **Q. What was RUCO's position on TEP's Motion to Amend Decision No. 62103?**
24 A. RUCO opposed TEP's claim that the Settlement Agreement required the use of the MGC
25 mechanism to establish Standard Offer generation rates in 2009. RUCO also opposed the two
26 alternatives TEP had proposed, and suggested that the Commission should establish rates based

on a traditional cost of service rate case, to be effective in 2009. RUCO filed testimony and a legal memorandum in support of its position[1]. Other parties likewise disagreed with TEP's contention that generation rates for Standard Offer service would be based on the MGC in 2009. During the hearing on the Motion to Amend in March 2007, TEP offered another alternative for setting generation rates based on a hybrid of cost-based and market-based rates.

Q. What was the disposition of TEP's Motion to Amend?

A. The Commission issued Decision No. 69568 in May 2007. The Commission did not decide the issue of how rates would be established in 2009, but ordered TEP to file a rate application that included all of its rate proposals for side-by-side comparison. The Commission ordered that the rate application would be consolidated with the docket on the Motion to Amend. In July 2007, TEP filed the rate application that is the subject of my testimony.

Q. How does your testimony differ from that RUCO offered in response to the Motion to Amend?

A. The testimony and legal memorandum RUCO presented in the Motion to Amend docket explained why the Commission was not required to establish TEP's rates based on the MGC methodology beginning in 2009. My testimony is meant to evaluate the relative merits of TEP's various proposals based on the assumption that the Commission agrees it is not required to use the MGC methodology as TEP has claimed it is.

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1 Direct Testimony of Marylee Diaz Cortez, filed January 7, 2007 in Docket No. E-0933A-05-0650 (with attached legal memorandum); and Surrebuttal Testimony of Marylee Diaz Cortez, filed February 8, 2007 in the same docket. Ms. Diaz Cortez also testified at the hearing in March 2007. The entire record in Docket No. E-01933A-05-0650 has been consolidated with the Rate Application, per Decision No. 69568.

TEP's Generation Proposals

Q. Could you now summarize TEP's proposals regarding the treatment of generation assets and its proposals for rates related to generating electricity?

A. TEP proposes three different rate making methodologies, which differ in their treatment of TEP's generating plants, and in the development of rates related to generation. The methods are: the "Market Methodology", the "Cost-of-Service Methodology", and the "Hybrid Methodology".

Q. Can you briefly describe TEP's proposed Market Methodology?

A. Yes. TEP claims that, beginning January 1, 2009, it is entitled to charge market-based rates for generation service.[2]

> TEP has presented the Market Methodology to the Commission because it believes that when the rate increase moratorium in the 1999 Settlement Agreement is lifted on January 1, 2009, it is entitled to (i) a rate increase for transmission and distribution service; and (ii) charge rates for generation service based upon the market-based methodology set forth in the 1999 Settlement Agreement. [Pignatelli Direct Testimony, p. ii]

The Market Methodology put forward by TEP is premised on this interpretation of the 1999 Settlement Agreement. TEP seems to be claiming it has a legal right to charge customers for generation based on a "market-based proxy, the Market Generation Credit ("MGC")" as set forth in the 1999 Settlement Agreement". TEP's support for its Market proposal is based almost entirely on its legal theory and its claims concerning the 1999 Settlement Agreement. In its direct case, TEP made no real effort to demonstrate that its Market proposal is in the public interest, treats customers fairly, or results in fair and reasonable rates.

While TEP claims it is entitled to charge market-based rates consistent with its Market proposal, it does provide two alternatives for Commission consideration. The Cost-of-Service

2 As discussed above, RUCO disagrees with TEP's position and has set forth the basis for that disagreement in Docket No. E-01933A-05-0650.

and Hybrid Methodologies are presented to "help the Commission evaluate our proposals for amending the 1999 Settlement Agreement and Decision No. 62103 in furtherance of settlement discussions and negotiations among the parties to the 1999 Settlement Agreement". [Id., p. 7]

Q. How would rates for transmission and distribution services be developed under the Market Methodology?

A. Transmission and distribution rates would be based on a traditional cost of service approach recovering TEP's actual costs and allowing it to earn a fair return on the transmission and distribution portion of its fair value rate base. [See, Id., p. i]

Q. Can you now explain how rates for generation service would be determined under the Market Methodology?

A. Under the Market Methodology, TEP proposes to set prices for generation service using the MGC computations set forth in its Settlement Agreement.

> Market prices for generation service would be calculated using the existing Market Generation Credit ("MGC") rate schedule (Rate Schedule MGC-1) from TEP's 1999 Settlement Agreement as modified by Decision No. 65754 (March 20, 2003). This Schedule is attached to my testimony as Exhibit DGH-11, and incorporated herein. This MGC value is derived from a Palo Verde market index published by Platts, a McGraw-Hill publication. [Hutchins Direst Testimony, p. 47]

The Settlement Agreement provides that the MGC is calculated 30 days prior to each calendar estimation month using the most recent 3 day average of the Platts Long-Term Forward Assessment for Palo Verde Forward prices. [See, Schedule MGC-1, p. 2] These are "spot" prices for large blocks of electricity transferred from one utility to another on a short term basis.

Q. Are there any other aspects of the Market Methodology you would like to mention at this point?

A. Yes. There is one other point I would like to mention. Under the Market Methodology, TEP's

rate base would include an Implementation Cost Regulatory Asset (ICRA) of $14.2 million to recover "direct costs incurred to implement competition in compliance with the 1999 Settlement Agreement". [Id., p. 5] The largest component of the $14.2 million ICRA is computer software costs. [Kissinger Direct Testimony, p. 8] The $14.2 million ICRA also includes costs incurred by funding and developing two entities (Desert Star and WestConnect) which were formed to provide more open access to the Arizona transmission grid. [Id., p. 10] Other costs include consulting fees, and accounting, legal, administrative, and payroll expenses. [Id., pp. 8-10]

Q. What is the rate impact of TEP's proposed Market Methodology?

A. By the Company's calculations, the Market Methodology would result in an immediate 21.9% increase "based on current projections for wholesale market power prices". [TEP Application, p. 2]

Q. Can you now summarize TEP's proposed Cost-of-Service Methodology?

A. If the Commission rejects the Market Methodology (e.g. because it would result in unreasonably high rates), TEP nevertheless wants a rate increase of a similar magnitude. It proposes to accomplish this by implementing a modified version of traditional rate making. Nominally, transmission, distribution and generation rates would all be based on cost of service principles. [Id.] Significantly, however, TEP proposes to include both a $47.5 Million ICRA in its rate base, and to recover an additional $788 million which it refers to as a Termination Cost Regulatory Asset (TCRA) [Id., p. 7]. The effect of the proposed TCRA, if approved, would be to increase rates to nearly the same level as its Market proposal.

Q. What is included in the $47.5 million ICRA?

A. The $47.5 million ICRA includes the $14.2 million discussed previously, plus additional costs that TEP incurred in buying out certain coal contracts, and refinancing costs associated with

certain generation assets. [Id., pp. 11-12]

Q. Can you now explain the $788 million TCRA?

A. TEP claims that the TCRA reflects it's estimate of the "financial impact of meeting its obligations under the 1999 Settlement Agreement and transitioning back to cost-of-service ratemaking in 2009". [TEP Application, p. 7] The TCRA would be recovered through a TCRA Charge at an average rate of $0.0126 per kWh. [Id.] TEP explains the TCRA as follows:

> The TCRA represents economic harm that will have been suffered by TEP if the 1999 Settlement Agreement is not honored and generation service rates are based solely on cost-of-service principles. The TCRA will place TEP in the position it would have been but for the 1999 Settlement Agreement. The amount of the TCRA included in the Company's rate request under the Cost-of-Service Methodology is $788 million, which is based on the $111 million revenue deficiency proved in the 2004 Rate Review. Applying this revenue deficiency, the Company has determined that it will have foregone revenues in an amount that will reach $788 million by May 2008. The cumulative balance of the foregone revenues will grow to $921 million by December 2008. However, because TEP believes that the continuation of the collection of CTC revenues beyond May 2008 is a partial mitigation of the losses that TEP has suffered as a result of the 1999 Settlement Agreement not being honored in full, the Company is proposing the lower $788 million balance for the TCRA. [Pignatelli Direct Testimony, p. 20]

Q. Are there any other aspects of TEP's proposed Cost-of-Service Methodology that you would like to mention?

A. Yes. Under this methodology TEP is proposing to implement a Purchased Power and Fuel Adjustment Clause (PPFAC). Mr. Pignatelli explains:

> TEP does not currently employ a PPFAC. However, in light of the volatile fuel and purchased power costs experienced in recent years, TEP should have a PPFAC mechanism in place to provide for the timely recovery of fuel and purchased power costs incurred in serving its customers. A PPFAC would serve the best interests of TEP and its customers. [Id.]

Mr. Hutchens further explains:

> TEP relies on significant quantities of natural gas and purchased power to meet its retail load. Although TEP has served the majority of its load with company-owned generating resources, it relies on natural gas and purchased power to meet a growing percentage of its customer demand. This gas and power is

> purchased at market prices, so TEP should be allowed to recover these costs. [Hutchens Direct Testimony, p. 30]

In addition, TEP proposed that its Certificate of Convenience and Necessity ("CC&N") be restored to its former exclusive status.

Q. What is the rate impact of TEP's proposed Cost-of-Service Methodology?

A. By the Company's calculations, the Cost-of-Service Methodology would result in a 23.0% increase "based on current expectations for future power supply costs". [TEP Application, p. 3] As I will discuss later in my testimony, a large portion of this proposed increase is directly attributable to the proposed TCRA.

Q. Can you describe the Company's proposed Hybrid Methodology?

A. TEP's Hybrid Methodology selectively combines elements of the Cost of Service and Market Methodologies. Under this approach, transmission, distribution and <u>some</u> generation rates would be based on traditional cost of service principles. However, TEP's interest in certain generation assets would be removed from rate base and designated as wholesale assets. [Id.]

> The assets excluded from rate base under the Hybrid Methodology are (i) the Company's interest in Navajo Generating Station Units 1, 2 and 3, and (ii) the Company's interest in Four Corners Generating Station Units 4 and 5 (the "excluded generation assets"). These excluded generation assets will be dedicated to wholesale market transactions, although the power could be used to supply TEP's retail customers at prices reflecting wholesale market conditions. In that circumstance, the cost to supply TEP's retail customers from those excluded generation assets would be recovered through the PPFAC and not base rates. [Id., p. 7]

Notably, TEP is not seeking recovery of any portion of the proposed $788 million TCRA under its proposed Hybrid Methodology, although it does seek recovery of the full $47.5 Million ICRA. The Hybrid Methodology also includes a PPFAC. [Pignatelli Direct Testimony, p. ii] Further, TEP proposes that if its Hybrid Methodology is adopted, TEP's exclusive CC&N would be partially restored. Specifically, TEP proposes that only customers with a demand in excess of 3MW would be permitted to obtain generation service from a competitive provider.

Q. What is the rate impact of TEP's proposed Hybrid Methodology?

A. By the Company's calculations, the Hybrid method would result in a 14.9% increase "based on current expectations for future power supply costs". [TEP Application, p. 3] This is much less than the impact of the Cost of Service Approach, primarily because the Hybrid Approach doesn't include the TCRA. It is less than the impact of the Market Approach, because fewer generating plants would be moved out of the rate base and thus a larger portion of its generation-related rates would continue to be based on traditional rate setting principles – a much smaller fraction of its generating costs would be tied to the MGC calculations.

Q. Has TEP provided a comparison of the rate effects of the three different methodologies?

A. Yes. In response to Staff data request 5.11, TEP provided a forecast of unbundled rates for the three methodologies for the years 2009 through 2015, in comparison to the test year unbundled rates. As shown in the following table, TEP's total test year unbundled rates were 8.42 cents per kWh. Total 2009 rates under the Cost-of-Service, Market and Hybrid Methodologies are forecast to be 23.4%, 21.4% and 15.3% greater than the current unbundled rates, respectively.

	TEP's	2009 Forecast Rates		
¢ / kWh	Test Year	Cost of Service	Market	Hybrid
Distribution	1.98	1.58	1.58	1.58
Transmission	0.78	0.70	0.70	0.70
Must-Run & Ancillary	0.64	0.55	0.55	0.55
Fixed CTC	0.97	NA	NA	NA
Floating CTC	(2.67)	NA	NA	NA
MGC	6.66	NA	7.39	NA
DSM	0.06	NA	NA	NA
Generation Non-Fuel	NA	2.99	NA	2.62
PPFAC	NA	3.31	NA	4.25
TCRAC	NA	1.26	NA	NA
Total	8.42	10.39	10.22	9.71
Percent Increase		23.4%	21.4%	15.3%

As shown in the following table, total 2015 rates under the Cost-of-Service, Market and Hybrid Methodologies are forecast by TEP to be 34.5%, 16.6% and 25.0% greater than test year rates, respectively.

¢ / kWh	TEP's Test Year	2015 Forecast Rates Cost of Service	Market	Hybrid
Distribution	1.98	1.58	1.58	1.58
Transmission	0.78	0.70	0.70	0.70
Must-Run & Ancillary	0.64	0.55	0.55	0.55
Fixed CTC	0.97	NA	NA	NA
Floating CTC	(2.67)	NA	NA	NA
MGC	6.66	NA	6.99	NA
DSM	0.06	NA	NA	NA
Generation Non-Fuel	NA	2.99	NA	2.62
PPFAC	NA	4.24	NA	5.07
TCRAC	NA	1.26	NA	NA
Total	8.42	11.33	9.82	10.53
Percent Increase		34.5%	16.6%	25.0%

This forecast suggests the market approach will be less onerous in future years than it is initially. However, this is tied to the forecast (or assumption) that the MGC will only slightly increase from the test year level of 6.66 cents to 6.99 cents in 2015. Needless to say, there is no assurance that this forecast will come to pass. If natural gas prices continue to escalate, or growth in demand for electricity in California and the Western United States outstrips growth in new supply, spot market prices at Palo Verde could increase dramatically, causing the MGC to escalate far above the level shown in this forecast.

Critique of TEP's Generation Proposals

Q. Let's turn to the next section of your testimony. As you offer your critique of TEP's proposals regarding generation rates, to what degree do you consider the aspects of TEP's proposals relating to the exclusivity of its CC&N?

A. My comments below are applicable to the aspects of TEP's proposals relating to the pricing of generation regardless of whether the Commission were to decide to restore any exclusivity to TEP's and CC&N. Essentially, I have set aside those aspects of TEP's proposal relating to its CC&N, and I am evaluating only the generation pricing of its proposals. I understand that the issue of whether the Commission wants to maintain a competitive retail generation market structure is under consideration in other dockets, and I do not believe that it would be necessary for the Commission to resolve that issue for TEP in this proceeding. The determination of how TEP's Standard Offer Service is priced is not dependent on any particular resolution of the CC&N question, and any of TEP's pricing mechanisms could theoretically exist whether TEP's CC&N was exclusive or not. While I recognize that the issue of whether the Commission will permit retail electric competition is a significant one, the Commission can evaluate TEP's proposed generation pricing alternatives without having decided whether retail competition will be permitted or not. I recommend that the Commission not make a decision on the future status of TEP's CC&N in this proceeding.

Q. Can you briefly identify some of your concerns with respect to TEP's proposals relating to market-based generation rates?

A. Yes. TEP's proposed Market Methodology is based on some incorrect assumptions – that it is entitled to charge market-based generation rates, and that the resulting rates will be just and reasonable. Moreover, TEP's forecast rate comparisons are flawed, and could lead the Commission to incorrect conclusions when evaluating the relative merits of the the proposals.

Finally, TEP's Market Methodology will result in widely fluctuating rates that can easily exceed levels that are just and reasonable. And, even if rates were to average out to a reasonable level over a long period of time (something that has not been demonstrated), the very fact that the rates would fluctuate so widely from month-to-month and year-to-year is a reason for concluding that the proposed Market-based rates would not be just and reasonable.

Q. Can you briefly explain your first concern, TEP's assumption that it is entitled to charge market-based generation rates?

A. TEP contends that it has the right to charge customers for electrical generation on the basis of the MGC formula set forth in the 1999 Settlement Agreement. Since it assumes it already has the right to do this, TEP makes little or no effort to argue that this is would be fair, or that the resulting rates would be just and reasonable. As the Commission knows, RUCO strongly disagrees with this assumption. As explained in various pleadings submitted to the Commission, RUCO has a fundamentally different interpretation of the 1999 Settlement Agreement; and, even if TEP's interpretation had some validity, it would not negate the need to demonstrate that the resulting rates will be just and reasonable – something TEP has not even attempted.

Q. Doesn't the MGC portion of the 1999 Settlement Agreement expire on December 31, 2008?

A. Yes, it certainly appears that way to me in my reading of the Agreement as a non-lawyer. The purpose of the MGC was to develop the floating CTC, and under the terms of the Settlement Agreement, the floating CTC will expire on December 31, 2008. Logically, after the CTC expires, the MGC will become unnecessary, and thus the provisions relating to the MGC would become moot. I don't see any provisions in the Settlement Agreement that specifically contemplate using the MGC for any purpose other than developing the floating CTC.

Q. Does TEP agree that the Settlement Agreement calls for the expiration of the MGC at the end of 2008?

A. No. TEP contends that the Settlement Agreement is silent as to the expiration of the MGC. "While the Floating CTC terminates on December 31, 2008, the agreement set no expiration date for the MGC rate". [Pignatelli Direct Testimony, p. 14] Perhaps more importantly, TEP claims that the MGC is of general applicability – it isn't simply a component used in computing the floating CTC, and that the Settlement Agreement "requires TEP to charge the MGC rate for generation service". [Id.]

In searching the text of the Settlement Agreement, I did not find any references to the MGC except in the section 2, "Stranded Cost Recovery" (pages 4-7 of Attachment No. 1 to Decision 62103). For instance, it says: "The Floating CTC shall be calculated using a Market Generation Credit CMGC") methodology ... and will terminate on December 31, 2008." Similarly, I did not find any statement in the Settlement Agreement concerning how standard offer generation service would be priced, or that prices would be based on spot market prices. In fact, at page 8, under Section 4 Unbundled Rates, there is a provision that states

> TEP's rates shall be fully unbundled into separate charges for: (a) distribution; (b) transmission; (c) metering: (d) billing; (e) ancillary services; (f) fixed must-run generation; (g) system benefits; and (h) standard offer generation, the sum of TEP's standard offer which shall not exceed a customer's current bundled rates.

This language certainly doesn't provide support for the view that the Settlement Agreement mandates a substantial increase in rates above the then-existing level of bundled rates. To the contrary, my impression of this language as a non-lawyer is that the intent was to ensure that standard offer customers (those who continue to purchase energy from TEP) would not face any increase in their rates as a result of the unbundling process or other provisions of the Agreement.

1 **Q. Can you explain your concern that TEP is simply assuming that rates under its market**
2 **approach would be fair and reasonable?**
3 A. Yes. Even if one interpreted the Settlement Agreement as the Commission's expression of
4 support for Standard Offer rates being based on market-priced generation, this policy does not,
5 and cannot, override the constitutional requirement for fair and reasonable rates. Nor does a
6 policy preference for competition automatically ensure that competition will, in fact, exist. Nor
7 is there anything about this policy that would require the Commission to adopt TEP's proposed
8 "market" approach.
9 It is clear from the decision of the Court of Appeals in the *Phelps Dodge* case that the
10 Commission is responsible for ensuring that all of the rates charged by TEP are just and
11 reasonable – including generation rates. The Commission has broad discretion in deciding
12 whether to implement competitive retail generation rates, but any such action to move in that
13 direction must be consistent with the requirements of the Arizona constitution – the
14 Commission must ensure that rates remain just and reasonable. Yet there is no assurance that
15 market prices will be just and reasonable. The Commission cannot simply assume that market
16 rates will satisfy the just and reasonable standard, particularly under a proposal that will result
17 in a substantial increase in rates above levels that were previously found to be just and
18 reasonable.
19
20 **Q. Can you now explain how TEP's rate forecasts might lead the Commission to the wrong**
21 **conclusion regarding the relative merits of each approach?**
22 A. Yes. As I explained earlier, TEP estimates that its proposed Market, Cost-of-Service and Hybrid
23 methods will result in rate increases of 21.9%, 23.0% and 14.9%, respectively. TEP's rate
24 comparisons give the impression that the Hybrid approach is less costly for consumers. The
25 hybrid approach appears to be the most favorable because it doesn't include the $788 million
26 TCRA. The Cost of Service approach would show even lower costs, if the TCRA were excluded

from that approach as well. Clearly, these comparisons hinge on the relevance, appropriateness, and magnitude of the TCRA. If the TCRA were rejected the comparison would shift in favor of the cost of service approach; similarly, even if the concept of a TCRA were accepted, but TEP's calculations were rejected, and a much smaller TCRA were approved, the comparison would look strikingly different.

Q. Are there other flaws in TEP's comparison of forecast rates?

A. Yes. The rates forecast by TEP under each of its proposed methodologies are based upon a particular view of disputed facts, and they are based on a particular set of market projections, and they do not adequately portray the potential for significantly different outcomes, depending on future market volatility and uncertainties.

Q. Can you please explain how the forecast rates are based on the Company's particular view of disputed facts?

A. Yes. Key components of each forecast are dependent on a variety of different revenue requirement and ratemaking calculations that are disputed by other parties. These disputes are particularly significant with regard to the proposed TCRA that TEP proposes to include as part of the Cost-of-Service Methodology. The TCRA is based entirely on calculations that are inherently controversial and speculative. As TEP's witness explains, the $788 million TCRA "is based on the $111 million revenue deficiency *proved* in the 2004 Rate Review". [Pignatelli Direct Testimony, p. 20, emphasis added] However, the $111 million revenue deficiency was merely alleged by TEP, it was never proven, nor did the Commission ever make any findings of fact concerning the existence, or magnitude of a revenue deficiency at that time. In fact, the Staff and RUCO provided evidence which suggested a revenue deficiency of $111 million did *not* exist. To the extent these other parties believed a revenue deficiency existed, they believed it was significantly less than the amount claimed by TEP. The Commission concluded that

proceeding without making any determination regarding TEP's revenue requirements.

Q. What would be the effect of removing the TCRA from TEP's cost of service rate forecast?

A. As shown in the table below, removing the TCRA would bring rates down to levels that are much closer to the existing rates. Rates would increase by 8.4% in 2009, gradually trending up to a total 19.5% increase by 2015. It should be noted that these calculations assume that TEP prevails on all disputed revenue requirement issues, and that the proposed PPFAC is accepted – contrary to RUCO's recommendations in this proceeding. If RUCO's positions were adopted instead, rates would be substantially lower throughout this time period, and much closer to the existing level of rates.

	TEP's	Cost of Service Forecast Rates		
¢ / kWh	Test Year	2009	2012	2015
Distribution	1.98	1.58	1.58	1.58
Transmission	0.78	0.70	0.70	0.70
Must-Run & Ancillary	0.64	0.55	0.55	0.55
Fixed CTC	0.97	NA	NA	NA
Floating CTC	(2.67)	NA	NA	NA
MGC	6.66	NA	NA	NA
DSM	0.06	NA	NA	NA
Generation Non-Fuel	NA	2.99	2.99	2.99
PPFAC	NA	3.31	3.72	4.24
Total	8.42	9.13	9.54	10.07
Percent Increase		8.4%	13.3%	19.5%

Q. Can you please comment on TEP's request that it be "compensated" for harm it allegedly suffered as a result of the 1999 Settlement Agreement – the underlying premise of the TCRA proposal?

A. Yes. TEP's TCRA calculations are based purely on its perspective, without considering the perspective of customers. The Court of Appeals in *Phelps Dodge* has clearly stated that a "just and reasonable" analysis must ensure that rates are fair to both consumers and the regulated

1 Company.

2 Even if the Commission were willing to compensate TEP for any impacts of a perceived
3 failure to abide by the 1999 Settlement Agreement, it should not rely on TEP's claims
4 concerning its revenue deficiency during past years. Those calculations are highly speculative
5 and they are inconsistent with the analogous calculations developed during the 2004 rate review
6 by the Staff and other parties. There is simply no way of knowing whether, in the absence of
7 the rate freeze provided by the 1999 Settlement Agreement, the Commission would have
8 approved a rate increase during this time period, and if so what the magnitude of such an
9 increase would have been.

10 There is no "entitlement" to increase rates in the future merely because TEP believes
11 rates were too low in the past, or that a revenue deficiency existed during portions of the time
12 period when its rates were frozen. Furthermore, it is a matter of pure speculation to conjecture
13 whether the Commission would have computed any specific revenue deficiency, or that it would
14 have approved a rate increase, or what the magnitude of such an increase would have been, if
15 rates had not been frozen during this time period.

16

17 **Q. You mentioned that TEP's rate forecasts don't adequately portray significant differences**
18 **in volatility and risk. Can you please explain this concern?**

19 A. Yes. As I explained, under TEP's proposed Market Methodology, generation rates would be
20 based on the MGC, which will fluctuate from month to month. Under the proposed Market
21 Methodology, rates paid by TEP's customers' will depend heavily on a rate component that will
22 fluctuate from month to month; in fact, according to TEP's forecasts, the MGC will represent
23 approximately 70% of the total rate paid by TEP's customers. Yet, the MGC can fluctuate
24 dramatically, in response to fluctuations in natural gas prices, and imbalances in supply and
25 demand conditions. Recent history has shown the magnitude of these fluctuations can be very
26 dramatic, despite the fact that the fact that the actual cost of generating most of the power used

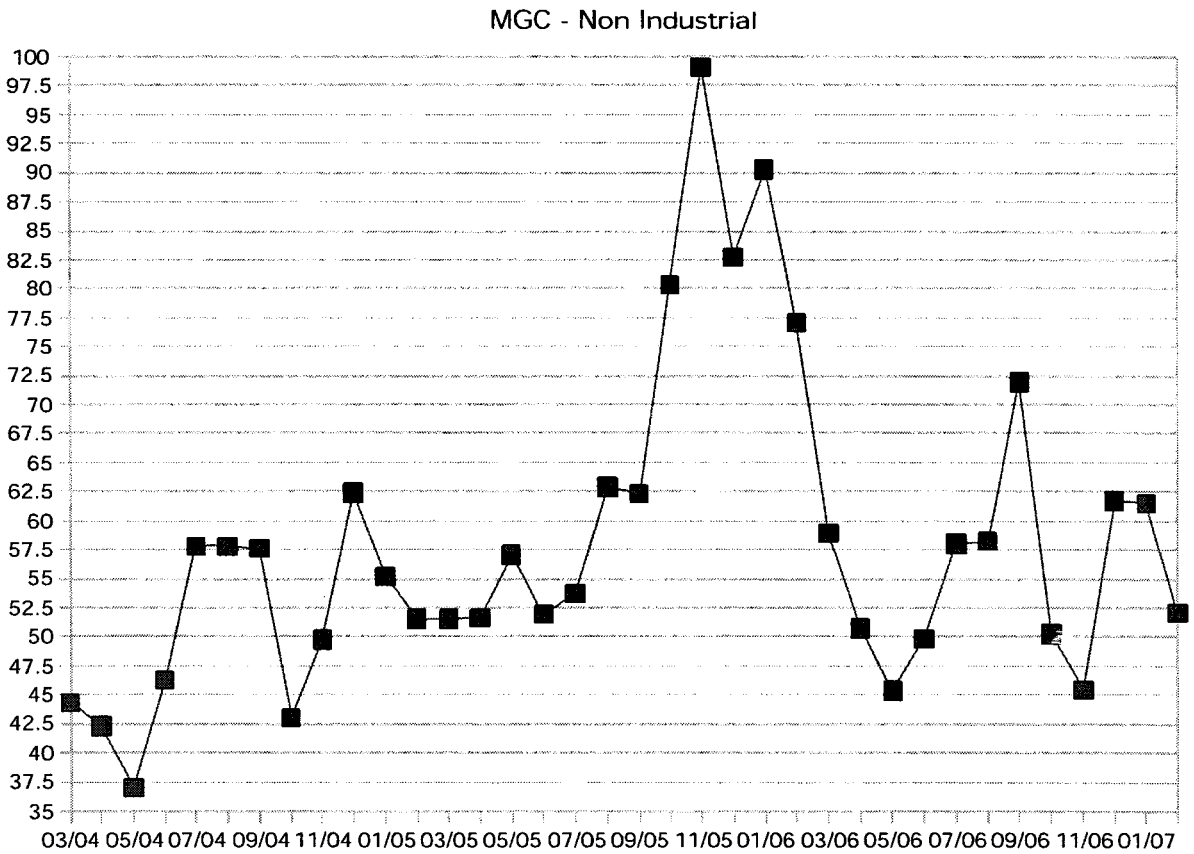
1 by TEP's customers is relatively stable.

2 Exhibit DGH-12, attached to Mr. Hutchen's direct testimony, shows monthly MGC
3 values from January 2000 through February 2007. For convenience, I've reproduced the data in
4 the table below. As shown, during this time period the MGC for non-industrial customers has
5 been as low as $18.56 per month in March 2002, and as high as $315.63 per month in August
6 2001 – a difference of more than 1,500%.

Date	MGC Industrial	MGC Other	Date	MGC Industrial	MGC Other
01/00	24.17	25.10	08/03	51.02	52.96
02/00	22.78	23.65	09/03	42.43	44.04
03/00	21.37	22.17	10/03	41.23	42.81
04/00	29.21	30.30	11/03	38.37	39.84
05/00	27.14	28.15	12/03	37.19	38.62
06/00	28.57	29.62	01/04	39.90	41.43
07/00	54.37	56.36	02/04	45.46	47.20
08/00	73.47	76.22	03/04	42.69	44.33
09/00	60.99	63.27	04/04	40.71	42.26
10/00	75.40	78.24	05/04	35.71	37.06
11/00	51.61	53.55	06/04	44.61	46.30
12/00	55.63	57.71	07/04	55.68	57.79
01/01	60.67	62.97	08/04	55.68	57.80
02/01	59.58	61.84	09/04	55.47	57.58
03/01	52.51	54.50	10/04	41.46	43.05
04/01	201.36	209.07	11/04	47.91	49.75
05/01	170.89	177.42	12/04	60.08	62.39
06/01	176.53	183.25	01/05	53.17	55.20
07/01	272.88	283.31	02/05	49.60	51.50
08/01	304.02	315.63	03/05	49.60	51.50
09/01	193.18	200.57	04/05	49.74	51.64
10/01	33.16	34.41	05/05	54.94	57.04
11/01	33.87	35.14	06/05	50.01	51.91
12/01	35.87	37.23	07/05	51.76	53.73
01/02	25.44	26.39	08/05	60.60	62.90
02/02	22.03	22.85	09/05	60.04	62.33
03/02	17.90	18.56	10/05	77.38	80.34
04/02	20.08	20.83	11/05	95.49	99.15
05/02	24.08	24.96	12/05	79.70	82.76
06/02	28.56	29.60	01/06	86.97	90.31
07/02	31.02	32.15	02/06	74.26	77.11
08/02	36.45	37.78	03/06	56.70	58.88
09/02	30.16	31.27	04/06	48.86	50.74
10/02	28.61	29.68	05/06	43.69	45.37
11/02	28.34	29.40	06/06	47.99	49.83
12/02	33.11	34.35	07/06	55.86	58.01
01/03	32.65	33.87	08/06	56.08	58.24
02/03	39.38	40.87	09/06	69.32	71.98
03/03	42.12	43.71	10/06	48.37	50.23
04/03	56.18	58.31	11/06	43.80	45.48
05/03	39.03	40.49	12/06	59.44	61.73
06/03	37.34	38.75	01/07	59.25	61.51
07/03	50.89	52.82	02/07	50.14	52.06

Admittedly, these extreme fluctuations occurred during an unusual time period, which everyone hopes will never be repeated. But, there are no guarantees that a milder version of the supply/demand imbalances that occurred during during the 2001 California energy crisis will

never occur again. In fact, even during the past few years, when market conditions have been relatively calm, the MGC has demonstrated a tendency to fluctuate rather dramatically. The graph below shows the MGC data for the most recent 3 year period – a period which excludes the 2001 California energy crisis. During this time period, the MGC for non industrial customers fluctuated from a low of $37.06 per month in May of 2004, to a high of $99.15 in October, 2005. This period includes month to month price increases of more than 30%, month to month price decreases of more than 25%, and an overall increase from May 2004 to October 2005 of more than 160%



1 **Q. Why are you concerned about volatility of the MGC?**

2 A. Under the Company's market proposal, the majority of consumers' rates would be determined
3 by the MGC, and thus fluctuations in the MGC would translate into widely fluctuating rates to
4 be paid by TEP's customers. Even if the average level of MGC-based generation rates were
5 comparable to those that would be charged under traditional cost of service ratemaking over a
6 ten or twenty year period, the instability and unpredictability of rates on a month-to-month or
7 year-to-year basis would still make the market approach completely unacceptable to the vast
8 majority of customers.

9 It is important to realize that most people are risk averse most of the time – they prefer
10 stability and predictability, and they particularly dislike unpleasant surprises. While some
11 people enjoy gambling small amounts in the hope of gaining a large amount, this is a limited
12 exception to the more general rule: given a choice, most people prefer stability and certainty
13 when it comes to important financial matters – that's why there is a thriving market for
14 insurance, and that's why investors demand higher returns where risk and uncertainty exists.

15 Given that electricity is such a vital service – one that customers cannot simply do
16 without if the price is too high, or too volatile, it is not reasonable to force customers to pay
17 rates that fluctuate widely. Fluctuating rates would wreak havoc on the budgets of both
18 residential and business customers – making it difficult to plan ahead, and potentially forcing
19 them into dire straits if prices suddenly escalate above anticipated levels. While some local
20 businesses may be able to recoup higher electric costs by simply raising their prices, others
21 would find this impossible to do. Unlike TEP, many local businesses do not enjoy any
22 substantial degree of monopoly power; firms will experience a sharp drop in sales if they
23 attempt to increase prices, as customers buy less of their products, or purchase from businesses
24 located in Phoenix or elsewhere. Thus, they would not be in a position to simply increase or
25 decrease their prices each month, in response to increases or decreases in TEP's rates.

26 Similarly, widely fluctuating electric rates would create problems for many residential

customers. Volatile electric rates would obviously have an adverse impact on senior citizens who are living on a fixed income, but they would also cause a problem for the vast majority of residential customers, who cannot expect their employer to increase their pay every time electric rates increase. And, even if the highs and lows eventually average out, it simply isn't fair to force customers to deal with this sort of extreme uncertainty with respect to something as important, and unavoidable, as their monthly electric bill. Customers need a reasonable degree of predictability with respect to the cost of electricity; so they can make reasonable plans, know how much of their monthly budget they need to set aside for their electric bill, and how much will be available for food, clothing, and other expenses.

As noted by the Court of Appeals in *Phelps Dodge*, Arizona courts "have consistently held that 'just and reasonable rates' are those that are fair to both consumers and public service corporations". [83 P. 3d 573, ¶ 30] The Arizona Supreme Court has held:

> In determining what is a reasonable price to be charged for services by a public service corporation, an examination must be made not only from the point of view of the corporation, but from that of the one served, also. A reasonable rate is not one ascertained solely from considering the bearing of the facts upon the profits of the corporation. The effect of the rate upon persons to whom services are rendered is as deep a concern in the fixing thereof as is the effect upon the stockholders or bondholders. A reasonable rate is one which is as fair as possible to all whose interests are involved. [Id.]

When considering whether rates are just and reasonable, the Commission should not only be concerned with the overall magnitude or average level of rates. It must take all relevant factors into consideration, including the degree of volatility and predictability of the rates. From the consumers' perspective, rates that can vary 10, 20 or 30 percent from one month to the next cannot be considered just and reasonable. The Commission has recently expressed its concern about volatility in electric rates. In APS's most recent rate case, the Commission retained an annual 4 mil per kWh cap on the amount APS' power supply adjustor could change, and rejected Staff's proposal to allow the adjustor to move an unlimited amount each month. [See,

Decision No. 69663 at p. 112]

Q. What about from TEP's perspective? Is the Company facing severe fluctuations in its generation costs from month-to-month?

A. No. As explained by RUCO witness Marylee Diaz Cortez, the primary source of TEP's power is from coal plants that it owns, or leases on a long term basis. During the test year, TEP generated 81% of power from coal fired plants. [Diaz Cortez Direct Testimony, f.n. 5, p. 27] Another 6.3% was generated from plants that are fueled with natural gas, and just 12.6% was acquired through open market purchases. [Id.]

Clearly, the vast majority of TEP's generating costs are relatively stable and predictable, compared to the MGC rate. To the extent TEP faces uncertainties with respect to the cost of generating electricity from coal, that uncertainty primarily exists during the years when a plant is being planned and constructed, and a source of coal is being obtained. Once the plant is built and contracts have been signed for a long term coal supply, the cost of generating power is quite stable and predictable.

Admittedly, the costs of generating electricity with natural gas is not as predictable on a long term basis – natural gas cannot generally be purchased on a fixed-price, long term basis, and the cost of fuel is a larger proportion of the total cost of a gas plant (the cost of plant construction is generally lower). But, as I said, only a small minority of TEP's generation is subject to this uncertainty – because the vast majority of its power comes from coal plants, where costs are much more predictable.

In effect, TEP's market proposal would force its customers to suffer from precisely the sort of volatility that TEP itself has prudently avoided. While there have been periods when natural gas may have looked very attractive from a total cost of production perspective, TEP has not bet heavily on this fuel source, and thus it has minimized the risks and uncertainties of natural gas prices, which fluctuate widely from month to month and year to year in response to

global energy markets. Gas prices are strongly influenced by crude oil prices, as well as energy supply and demand conditions around the globe, and thus by political developments in Russia, Venezuela and the Middle East – factors that are completely beyond the control of TEP, this Commission, or Arizona rate payers. Yet, TEP is asking its customers to pay electric prices that are tied directly to volatile market indexes that are heavily influenced by those same uncertainties.

Q. You have been discussing the potential volatility of prices under the Market proposal. Would electric prices also vary under the two alternative approaches proposed by TEP?

A. Yes. Both the Cost-of-Service and Hybrid Methodologies include a PPFAC, which would vary over time. However, the PPFAC would be updated annually, while the MGC is modified every month. Also, as shown in the table above, the PPFAC under both the Cost-of-Service and Hybrid Methodologies would comprise a significantly smaller percentage of overall rates than the MGC under the Market Methodology, and thus rates would not be nearly as volatile, even if the PPFAC is approved. However, it is worth noting that RUCO does not agree with the PPFAC proposal. As explained by Ms. Diaz Cortez, RUCO believes the proposed PPFAC does not meet the Arizona Court of Appeals' eligibility requirements for an automatic adjustment mechanism. RUCO therefore recommends the Commission reject TEP's request for a PPFAC.

Q. Can competitive market data be used to determine just and reasonable rates?

A. I doubt it, at least given the current status of competitive markets. In its FERC Form 1 TEP has admitted that retail electric competition is essentially non-existent in its service area. As explained by TEP:

> As a result of the energy crisis in California in 2000 and 2001 and the volatility of natural gas prices, the competitive retail market in Arizona that was anticipated in 1999 did not materialize. In addition, a 2005 Arizona Court of Appeals ruling held certain portions of the ACC's retail competition rules invalid. Currently, none of TEP or UNS Electric's customers are receiving energy from other providers; however we cannot predict if retail competition

> will enter the Arizona market. [TEP FERC Form 1, p. K-18]

TEP paints a more encouraging picture of competition at the wholesale level:

> Competition in wholesale markets has greatly escalated due to increased participation by utilities, non-utility generators, independent power producers and other wholesale power marketers and brokers. [id.]

But, even if competition in wholesale spot markets is escalating, that doesn't mean the wholesale market is fully mature, or that the Commission can rely entirely on market price information to establish retail prices that are fair and reasonable.

Among other problems, there is not sufficient market data available for the price of power generated over long time periods, stretching 10 or more years into the future. For instance, the data included in the MGC calculations is focused on short term, or spot-market, transactions; none of the underlying index data extends even 5 years into the future. Yet, the actual costs incurred by TEP are being incurred on a long term, relatively stable basis extending over multiple decades. For instance, the typical base load generating plant has a useful life of 40 or more years, and it is not unheard of for a generating plant to be still operating 60 or more years after it was constructed.

The Commission must ensure that rates are fair to both producers and consumers, that rates are reasonably adequate to cover the full cost of producing power over a typical plant's entire life cycle, and that rates do not greatly exceed those fully compensatory levels, in order to ensure that customers are also treated fairly. It is hard to see how the Commission can reconcile all of these concerns if it were going to tie rates purely to short term market prices – prices that only extend a few years into the future, leaving great uncertainty about the adequacy or excessiveness of price levels in future years – during the later part of the life cycle of a newly constructed plant.

In any event, regardless of whether or not it is theoretically possible to develop just and reasonable rates by relying in part on wholesale market price data, the specific proposal offered

by TEP is clearly not up to the task.

Q. Should the Commission also consider the actual circumstances facing TEP and its customers – including the specific history and costs associated with its generating plants, in determining whether rates are just and reasonable?

A. Yes, I believe it should. TEP's existing generating plants were all constructed as part of an integrated Generation, Transmission and Distribution utility. This is particularly significant with respect to its coal plants, which required long construction lead times and involve very long operating lives. While these plants offer cost stability, they require investments that stretch over many decades – risks that have historically been borne in part by TEP's customers under the traditional rate making process.

Under the traditional ratemaking process, TEP's customers have been required to reimburse the reasonable and prudent costs incurred by the utility, including the cost of plants that were constructed by the utility to serve its native load, regardless of whether those plants happened to have higher or lower costs than other plants built by other utilities during the same time period, and regardless of whether the resulting total cost of electricity happened to be higher or lower than the spot market price of electricity available for short term purchase from other utilities. Thus, for example, customers were required to pay the full cost of coal-based power, even if short term blocks of natural gas-based power happened to be available on the open market at a lower cost during at a particular point in time.

The equitable principles behind this long-standing arrangement helps explain why the Commission was concerned about the possibility of "stranded" costs, and why it provided the CTC mechanism, to ensure that customers – not TEP – would be responsible for paying for any costs that otherwise might have been "stranded" during a transition to retail competition. In effect, customers were expected to be "guarantors" to ensure that TEP would have an adequate opportunity to recover the full cost of its existing generating plants, even if the cost of power

generated by those plants happened to be higher than the going market price.

Moreover, traditional rate making shifts a disproportionate share of the costs of plants onto customers during the early years of a plant's operating life cycle, through the depreciation and return on rate base procedures. Rather than charging a "levelized" price which remains constant over the plant's entire life cycle, or an escalating price that increases with the general level of prices, under traditional cost-based ratemaking principles, rates are highest in the early years, and lowest in the final year's of the plant's life cycle – when the plant is largely, if not entirely depreciated. In a sense, under standard rate making practices, the cost of newly constructed plants is "front-loaded" onto customers, forcing them to pay a disproportionately high portion of the life cycle cost in years right after a new plant goes into service. This burden was offset by the expectation that customers would get the benefit of lower prices in the final years of the plant's life cycle, when the plant is almost entirely depreciated, and thus a relatively small amount would appear in the rate base.

Given this historical practice, it would clearly be unfair and unreasonable to force customers to pay high spot-market based rates now, despite having helped share the burdens and risks associated with TEP's existing generating plants, and despite having paid higher-than-average rates during the early years immediately after these plants went into operation. Stated another way, just as it would not have been fair to TEP to simply ignore the problem of stranded costs if spot market prices are much lower than TEP's actual costs, it would not be fair to customers to simply ignore the analogous problem in the other direction, if spot market prices are high relative to TEP's actual costs.

1 **Recommendations**

2

3 **Q. Let's turn to the final section of your testimony. What do you recommend the**
4 **Commission do with regard to TEP's proposed treatment of generating costs?**

5 A. I recommend that the Commission reject both the Market and Hybrid Methodologies. The
6 linchpin for all of TEP's generation proposals is its claim that it is entitled to charge MGC-based
7 rates for generation starting on January 1, 2009. Yet, the 1999 Settlement Agreement does not
8 say anything about how rates will be computed after 2008 – it only indicates that the rate freeze
9 will end, suggesting an opportunity for TEP to request changes in its rates, and an opportunity
10 for other parties to submit evidence concerning what they believe would be reasonable for the
11 Commission to do in response to such a request.

12 Significantly, TEP ties its claim to provisions in the 1999 Settlement Agreement
13 concerning the MGC, but the MGC is only used to calculate the floating CTC, which provided a
14 mechanism for recovery of stranded costs from customers who start purchasing from
15 competitive energy providers. Since the MGC is not mentioned elsewhere in the Agreement
16 and is not used for any other purpose, there is no logical basis for assuming that the MGC will
17 live on, after the floating CTC expires. It would be doubly unreasonable for the MGC to live on
18 indefinitely, and to effectively control the level of rates paid by captive customers, considering
19 that TEP never even experienced a rush of customers leaving its system to purchase from
20 competing energy providers, and thus it never actually suffered from the problem of stranded
21 costs which led to creation of both the MGC and the CTC in the first place.

22 I would also note that, the Commission should keep in mind that its responsibilities go
23 far beyond simply resolving a dispute over language in a legal document. There are overriding
24 public policy considerations which must concern the Commission, and the proper resolution of
25 this issue should take those public policy considerations into account. However the 1999
26 Settlement Agreement is interpreted, it cannot, and should not, be the only factor considered by

1 the Commission, because that document does not in any way supersede this Commission's
2 obligations to ensure that rates are just and reasonable. That constitutional obligation requires
3 the Commission to take appropriate steps to ensure that customers are treated fairly, regardless
4 of how that document is worded.
5
6 **Q. What methodology should the Commission use to set generation rates?**
7 A. The Market and Hybrid methodologies should not be used, because they will result in
8 excessive, unreasonably volatile rates, which would impose an unnecessary and unreasonable
9 burden on customers.
10 I recommend the Commission use a traditional cost-of-service methodology in setting
11 all rates, including generation rates. However, RUCO recommend the Commission reject TEP's
12 proposed TCRA Charge, because it is based upon incorrect premises is further explained by
13 RUCO witness Marylee Diaz Cortez. Further, TEP's TCRA calculations are highly speculative,
14 and they are based upon disputed claims regarding an alleged revenue deficiency – claims that
15 were never resolved by the Commission. For all these reasons, the TCRA proposal should be
16 rejected.
17
18 **Q. Does this conclude your testimony prefiled on February 29, 2008?**
19 A. Yes, it does.

Appendix A

Qualifications

Present Occupation

Q. What is your present occupation?

A. I am a consulting economist and President of Ben Johnson Associates, Inc.®, a firm of economic and analytic consultants specializing in the area of public utility regulation.

Educational Background

Q. What is your educational background?

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. The title of my Master's Thesis is a "A Critique of Economic Theory as Applied to the Regulated Firm." Finally, I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics. The title of my doctoral dissertation is "Executive Compensation, Size, Profit, and Cost in the Electric Utility Industry."

Clients

Q. What types of clients employ your firm?

A Much of our work is performed on behalf of public agencies at every level of government involved in utility regulation. These agencies include state regulatory

commissions, public counsels, attorneys general, and local governments, among others. We are also employed by various private organizations and firms, both regulated and unregulated. The diversity of our clientele is illustrated below.

Regulatory Commissions

Alabama Public Service Commission—Public Staff for Utility Consumer Protection
Alaska Public Utilities Commission
Arizona Corporation Commission
Arkansas Public Service Commission
Connecticut Department of Public Utility Control
District of Columbia Public Service Commission
Idaho Public Utilities Commission
Idaho State Tax Commission
Iowa Department of Revenue and Finance
Kansas State Corporation Commission
Maine Public Utilities Commission
Minnesota Department of Public Service
Missouri Public Service Commission
National Association of State Utility Consumer Advocates
Nevada Public Service Commission
New Hampshire Public Utilities Commission
North Carolina Utilities Commission—Public Staff
Oklahoma Corporation Commission
Ontario Ministry of Culture and Communications
Staff of the Delaware Public Service Commission
Staff of the Georgia Public Service Commission
Texas Public Utilities Commission
Virginia State Corporation Commission
Washington Utilities and Transportation Commission

West Virginia Public Service Commission—Division of Consumer Advocate

Wisconsin Public Service Commission

Wyoming Public Service Commission

Public Counsels

Arizona Residential Utility Consumers Office

Colorado Office of Consumer Counsel

Colorado Office of Consumer Services

Connecticut Consumer Counsel

District of Columbia Office of People's Counsel

Florida Public Counsel

Georgia Consumers' Utility Counsel

Hawaii Division of Consumer Advocacy

Illinois Small Business Utility Advocate Office

Indiana Office of the Utility Consumer Counselor

Iowa Consumer Advocate

Maryland Office of People's Counsel

Minnesota Office of Consumer Services

Missouri Public Counsel

New Hampshire Consumer Counsel

Ohio Consumer Counsel

Pennsylvania Office of Consumer Advocate

Utah Department of Business Regulation—Committee of Consumer Services

Attorneys General

Arkansas Attorney General

Florida Attorney General—Antitrust Division

Idaho Attorney General

Kentucky Attorney General

Michigan Attorney General

Minnesota Attorney General

Nevada Attorney General's Office of Advocate for Customers of Public Utilities

South Carolina Attorney General

Utah Attorney General

Virginia Attorney General

Washington Attorney General

Local Governments

City of Austin, TX

City of Corpus Christi, TX

City of Dallas, TX

City of El Paso, TX

City of Galveston, TX

City of Norfolk, VA

City of Phoenix, AZ

City of Richmond, VA

City of San Antonio, TX

City of Tucson, AZ

County of Augusta, VA

County of Henrico, VA

County of York, VA

Town of Ashland, VA

Town of Blacksburg, VA

Town of Pecos City, TX

1 Other Government Agencies

2

3 Canada—Department of Communications
4 Hillsborough County Property Appraiser
5 Provincial Governments of Canada
6 Sarasota County Property Appraiser
7 State of Florida—Department of General Services
8 United States Department of Justice—Antitrust Division
9 Utah State Tax Commission

10

11 Regulated Firms

12

13 Alabama Power Company
14 Americall LDC, Inc.
15 BC Rail
16 CommuniGroup
17 Florida Association of Concerned Telephone Companies, Inc.
18 LDDS Communications, Inc.
19 Louisiana/Mississippi Resellers Association
20 Madison County Telephone Company
21 Montana Power Company
22 Mountain View Telephone Company
23 Nevada Power Company
24 Network I, Inc.
25 North Carolina Long Distance Association
26 Northern Lights Public Utility
27 Otter Tail Power Company
28 Pan-Alberta Gas, Ltd.
29 Resort Village Utility, Inc.
30 South Carolina Long Distance Association
31 Stanton Telephone

Teleconnect Company
Tennessee Resellers' Association
Westel Telecommunications
Yelcot Telephone Company, Inc.

Other Private Organizations

Arizona Center for Law in the Public Interest
Black United Fund of New Jersey
Casco Bank and Trust
Coalition of Boise Water Customers
Colorado Energy Advocacy Office
East Maine Medical Center
Georgia Legal Services Program
Harris Corporation
Helca Mining Company
Idaho Small Timber Companies
Independent Energy Producers of Idaho
Interstate Securities Corporation
J.R. Simplot Company
Merrill Trust Company
MICRON Semiconductor, Inc.
Native American Rights Fund
PenBay Memorial Hospital
Rosebud Enterprises, Inc.
Skokomish Indian Tribe
State Farm Insurance Company
Twin Falls Canal Company
World Center for Birds of Prey

1 ***Prior Experience***

2

3 **Q. Before becoming a consultant, what was your employment experience?**

4 A. From August 1975 to September 1977, I held the position of Senior Utility Analyst
5 with Office of Public Counsel in Florida. From September 1974 until August 1975, I
6 held the position of Economic Analyst with the same office. Prior to that time, I was
7 employed by the law firm of Holland and Knight as a corporate legal assistant.

8

9 **Q. In how many formal utility regulatory proceedings have you been involved?**

10 A. As a result of my experience with the Florida Public Counsel and my work as a
11 consulting economist, I have been actively involved in approximately 400 different
12 formal regulatory proceedings concerning electric, telephone, natural gas, railroad, and
13 water and sewer utilities.

14

15 **Q. Have you done any independent research and analysis in the field of regulatory**
16 **economics?**

17 A. Yes, I have undertaken extensive research and analysis of various aspects of utility
18 regulation. Many of the resulting reports were prepared for the internal use of the
19 Florida Public Counsel. Others were prepared for use by the staff of the Florida
20 Legislature and for submission to the Arizona Corporation Commission, the Florida
21 Public Service Commission, the Canadian Department of Communications, and the
22 Provincial Governments of Canada, among others. In addition, as I already mentioned,
23 my Master's thesis concerned the theory of the regulated firm.

24

Q. Have you testified previously as an expert witness in the area of public utility regulation?

A. Yes. I have provided expert testimony on more than 250 occasions in proceedings before state courts, federal courts, and regulatory commissions throughout the United States and in Canada. I have presented or have pending expert testimony before 35 state commissions, the Interstate Commerce Commission, the Federal Communications Commission, the District of Columbia Public Service Commission, the Alberta, Canada Public Utilities Board, and the Ontario Ministry of Culture and Communication.

Q. What types of companies have you analyzed?

A. My work has involved more than 425 different telephone companies, covering the entire spectrum from AT&T Communications to Stanton Telephone, and more than 55 different electric utilities ranging in size from Texas Utilities Company to Savannah Electric and Power Company. I have also analyzed more than 30 other regulated firms, including water, sewer, natural gas, and railroad companies.

Teaching and Publications

Q. Have you ever lectured on the subject of regulatory economics?

A. Yes, I have lectured to undergraduate classes in economics at Florida State University on various subjects related to public utility regulation and economic theory. I have also addressed conferences and seminars sponsored by such institutions as the National Association of Regulatory Utility Commissioners (NARUC), the Marquette University College of Business Administration, the Utah Division of Public Utilities and the University of Utah, the Competitive Telecommunications Association (COMPTEL), the

International Association of Assessing Officers (IAAO), the Michigan State University Institute of Public Utilities, the National Association of State Utility Consumer Advocates (NASUCA), the Rural Electrification Administration (REA), North Carolina State University, and the National Society of Rate of Return Analysts.

Q. Have you published any articles concerning public utility regulation?

A. Yes, I have authored or co-authored the following articles and comments:

"Attrition: A Problem for Public Utilities—Comment." *Public Utilities Fortnightly*, March 2, 1978, pp. 32-33.

"The Attrition Problem: Underlying Causes and Regulatory Solutions." *Public Utilities Fortnightly*, March 2, 1978, pp. 17-20.

"The Dilemma in Mixing Competition with Regulation." *Public Utilities Fortnightly,* February 15, 1979, pp. 15-19.

"Cost Allocations: Limits, Problems, and Alternatives." *Public Utilities Fortnightly,* December 4, 1980, pp. 33-36.

"AT&T is Wrong." *The New York Times,* February 13, 1982, p. 19.

"Deregulation and Divestiture in a Changing Telecommunications Industry," with Sharon D. Thomas. *Public Utilities Fortnightly*, October 14, 1982, pp. 17-22.

"Is the Debt-Equity Spread Always Positive?" *Public Utilities Fortnightly,* November 25, 1982, pp. 7-8.

"Working Capital: An Evaluation of Alternative Approaches." *Electric Rate-Making,* December 1982/January 1983, pp. 36-39.

"The Staggers Rail Act of 1980: Deregulation Gone Awry," with Sharon D. Thomas. *West Virginia Law Review,* Coal Issue 1983, pp. 725-738.

"Bypassing the FCC: An Alternative Approach to Access Charges." *Public Utilities Fortnightly*, March 7, 1985, pp. 18-23.

"On the Results of the Telephone Network's Demise—Comment," with Sharon D. Thomas. *Public Utilities Fortnightly*, May 1, 1986, pp. 6-7.

"Universal Local Access Service Tariffs: An Alternative Approach to Access Charges." In *Public Utility Regulation in an Environment of Change,* edited by Patrick C. Mann and Harry M. Trebing, pp. 63-75. Proceedings of the Institute of Public Utilities Seventeenth Annual Conference. East Lansing, Michigan: Michigan State University Public Utilities Institute, 1987.

With E. Ray Canterbery. Review of *The Economics of Telecommunications: Theory and Policy* by John T. Wenders. *Southern Economic Journal* 54.2 (October 1987).

"The Marginal Costs of Subscriber Loops," A Paper Published in the Proceedings of the Symposia on Marginal Cost Techniques for Telephone Services. The National Regulatory Research Institute, July 15-19, 1990 and August 12-16, 1990.

With E. Ray Canterbery and Don Reading. "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." *Southern Economic Journal,* January 1996.

Professional Memberships

Q. Do you belong to any professional societies?

A. Yes. I am a member of the American Economic Association.

TUCSON ELECTRIC POWER COMPANY

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DIRECT TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 29, 2008

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INTRODUCTION

Q. Please state your name, position, employer and address.

A. Rodney L. Moore, Public Utilities Analyst V
Residential Utility Consumer Office ("RUCO")
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix 1, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding the "Cost of Service" proposal in Tucson Electric Power Company's ("Company" or "TEP") application for the establishment of just and reasonable rates and charges designed to realize a reasonable rate of return on the fair value of its operations throughout the state of Arizona. The test year utilized by the Company in connection with the preparation of this application is the 12-month period that ended December 31, 2006.

BACKGROUND

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's filing as it relates to operating income, rate base and the Company's overall revenue requirement. My recommendations are based on these analyses. Procedures performed include the in-house formulation and analysis of eleven sets of data requests, the review and analysis of Company responses to Arizona Corporation Commission ("Commission" or "ACC") Staff data requests, conversations with Company personnel and the review of prior ACC dockets related to TEP.

In Decision No. 62103, dated November 30, 1999, the Commission approved a Settlement Agreement, which approved rate reductions for residential and business customers; set the amount, method and recovery period of stranded costs that TEP can collect in customer charges; and established unbundled rates.

Q. What areas will you address in your testimony?

A. I will address issues related to rate base, operating income and revenue requirements.

RUCO's witness Mr. William Rigsby will provide an analysis of the cost of capital.

RUCO's witness Ms. Marylee Diaz Cortez will address issues related to rate base, operating income and revenue requirements.

RUCO consultant Mr. Glen Gregory will address issues related to the cost of service study and rate design.

RUCO consultant Mr. Ben Johnson will also address additional issues related with the two alternate ratemaking methodologies, the "Market Methodology" and the "Hybrid Methodology".

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules numbered RLM-1 through RLM-18.

SUMMARY OF ADJUSTMENTS

Q. Please summarize the adjustments to rate base and operating income issues addressed in your testimony.

A. My testimony addresses the following issues:

Rate Base

Accumulated Depreciation - This adjustment is the difference in the computation of the accumulated depreciation produced by the implementation of different depreciation rates between the Company and RUCO.

Springerville Unit 1 – RUCO witness Ms. Diaz Cortez addresses this adjustment.

Luna Plant – RUCO witness Ms. Diaz Cortez addresses this adjustment.

Implementation Cost Regulatory Asset – RUCO witness Ms. Diaz Cortez addresses this adjustment.

FAS 143 Accumulated Depreciation Write-Off - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Allowance For Working Capital – This adjustment is the difference in the level of expense recommendations calculated by the Company and RUCO.

Operating Income

Springerville Unit 1 Costs - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Annualized Depreciation and Amortization Expenses– This adjustment reflects the level of test-year depreciation expense based on RUCO's adjusted gross plant in service and the Company–proposed depreciation rates.

Disallowance Of Inappropriate/Unnecessary Expenses – RUCO's adjustment to operating expenses removes inappropriate expenditures not necessary in the provisioning of electric service.

Supplemental Executive Retirement Plan – RUCO's adjustment reflects disallowing the costs for the supplemental executive retirement plan.

Incentive Compensation – This adjustment splits the incentive compensation expenses on a 50/50 basis to conform to the recent Commission Decision in the UNS Gas rate case.

Rate-Case Expense – This adjustment is based on RUCO's determination of the fair and reasonable cost to TEP ratepayers for this application process.

Property Tax – This adjustment reflects the appropriate level of property tax expense given RUCO's recommended level of net plant in service.

Normalization Of Overhead Line Maintenance Expense – RUCO's adjustment normalizes the test-year level of overhead line maintenance expense.

Penalty and Fine Expenses – RUCO's adjustment to operating expenses removes expenditures not prudent in the provisioning of electric service.

Luna Plant Costs - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Implementation Costs Regulatory Assets - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Payroll – This adjustment maintains RUCO's strict adherence to the historical test-year principle and disagrees with the Company's proposed proforma adjustment, which averages the payroll expenses for two years.

Payroll Tax – This is a companion adjustment to the payroll expense and is adjusted for same reasons as stated above.

Renewable Resources – This is a conforming adjustment corresponding to the Company's acknowledgment of an omission of $19,274 in expenses to the original filing.

Bad Debt Expense – RUCO witness Ms. Diaz Cortez addresses this adjustment.

Navajo Coal Contract - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Customer Care and Billing – This adjustment removes the cost increase associated with the implementation of a new customer information system.

Gain On Sale of SO2 Allowances - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Employee Recognition – RUCO's adjustment removes costs recorded in the test year associated with employee recognition expenses.

Employee Benefits – RUCO's adjustment removes costs recorded in the test year associated with some employee benefit expenses.

Lime Usage Costs - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Short-Term Sales - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Generating Facilities – Operating Lease - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Miscellaneous Revenues - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Wholesale Trading Activity - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Rate-Case Expenses Associated With Docket No. E-01933A-05-0650 - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Income Tax – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

REVENUE REQUIREMENTS

Q. Please summarize the results of RUCO's analysis of the Company's filing and state RUCO's recommended revenue requirement.

A. As outlined in Schedule RLM-1, based on the "Cost of Service" model RUCO is recommending that the increase in the Company's revenue requirement not exceed:

TEP	RUCO	DIFFERENCE
$158,186,000	$36,254,000	($121,932,000)

My recommended revenue requirement percentage increase versus the Company's proposal is as follows:

TEP	RUCO	DIFFERENCE
22.19 %	4.04 %	-18.15 %

RUCO's recommended increase in Fair Value Rate Base ("FVRB") based on the equal weighting of a 50/50 split between Original Cost Rate Base ("OCRB") and Reconstruction Cost New Depreciated Rate Base ("RCND") is summarized on Schedule RLM-1:

TEP	RUCO	DIFFERENCE
$1,416,014,000	$1,359,709,000	($56,305,000)

The detail supporting RUCO's recommended rate base is presented on Schedules RLM-2, RLM-3, RLM-4, RLM-5 and RLM-6.

RUCO's recommended required operating income is shown on Schedule RLM-1 as:

TEP	RUCO	DIFFERENCE
$82,069,000	$72,667,000	($9,402,000)

Schedule RLM-1 presents the calculation of RUCO's recommended revenue requirement.

RATE BASE

Determination Of Fair Value Rate Base

Q. Please explain the basis for your determination of the FVRB as shown on Schedule RLM-1.

A. RUCO's determination of the FVRB consists of three elements. First, the value of the OCRB was restated to reflect RUCO's adjustments to the

various rate base determinants. Second, the value of the RCND was computed. As shown on supporting Schedule RLM-2, RUCO computed RCND by multiplying RUCO's OCRB by the ratio of the Company's OCRB to its RCND as filed. Third, the FVRB was computed on an equally weighted basis (50/50 split) between RUCO's OCRB and RCND.

Q. Please elaborate on the first element of RUCO's FVRB determination.

A. The first element consists of several adjustments to the OCRB. The aggregate adjustment was corroborated between myself and RUCO witness Ms. Diaz Cortez. As shown on Schedule RLM-4, I was responsible in part for Adjustment No. 1 and for Adjustment No. 6. Ms. Diaz Cortez analyzed the remaining rate base adjustments.

<u>RUCO Rate Base Adjustment No. 1 – Accumulated Depreciation</u>

Q. Please explain RUCO's adjustment to the accumulated depreciation balance.

A. The full explanation of this adjustment is a coordinated effort between myself and RUCO witness Ms. Diaz Cortez. I will provide clarification of the various computations involved in this adjustment. Ms. Diaz Cortez will illuminate the background, rationale and ratemaking principles involved in this adjustment.

Q. Please continue with the explanation of your portion of this adjustment.

A. During the initial stage of Discovery, I identified a significant irreconcilable difference in the test-year accumulated depreciation balance between the Company's filing and RUCO's computation. Through extensive discussions with the Company the reason for the discrepancy was identified.

The difference was mainly due to the Company's decision to utilize depreciation rates that differed from those previously authorized for its production/generation plant. My adjustment quantifies the amount of accumulated depreciation the Company failed to record as a result of these inappropriate depreciation rates.

Q. Please explain the methodology of your computation to quantify the Company's inappropriate shortfall.

A. My adjustment concentrates only on the plant associated with electrical production/generation (FERC Accounts 310 through 346); since this is the plant related to the significant irreconcilable difference in the test-year accumulated depreciation balance. First I calculated the accumulated depreciation using the authorized depreciation rates, and then I calculated the accumulated depreciation using the lower depreciation rates the Company had utilized. The difference between the two calculations was then reduced by an adjustment factor.

Q. Please explain this adjustment factor.

A. Through the extensive discovery period on the issue of accumulated depreciation the Company criticized RUCO's methodology to adjust for the Company's use of non-approved depreciation rates and identified several key components in the computation of accumulated depreciation being overlooked by RUCO. Some of these components of concern for the Company included:

1. The Company contends computing depreciation provisions is a highly complicated and time-consuming process;
2. Computing depreciation using an annual-averaging convention versus a monthly convention does not reflect actual account balance; and
3. Computing depreciation based on composite plant account rates versus individual asset unique rates also distorts actual account balance.

Therefore, to reduce the issues in this adjustment, I acknowledged these concerns and refined my adjustment. To recognize the Company's concerns, I calculated the percent difference between the Company's requested level of accumulated depreciation in this filing and the level of accumulated depreciation derived from RUCO's computation based on the Company's "OCRB Adjusted Gross Plant In Service" minus the plant associated with production/generation, which forms the bases for this

adjustment. This percentage (-0.74%) represents an adjustment factor, which accurately reconciles the difference between the Company's computation and RUCO's methodology.

Q. Please continue with the explanation of your adjustment to the accumulated depreciation.

A. By removing the portion of my accumulated depreciation adjustment associated with the two different methodologies used between RUCO and the Company, I am able to provide a quantified level of accumulated depreciation directly attributable to the unauthorized depreciation rates implemented by the Company. This quantified level of accumulated depreciation is $49,503,835.

Q. Is there any other element to this adjustment required to conform to all ratemaking principles?

A. Yes, to recognize all the ramifications of this adjustment to increase the accumulated depreciation balance, an additional adjustment must be made to the accumulated deferred income tax ("ADIT") account. Therefore, I increased the ADIT account in an amount equal to the product of multiplying the effective federal and state income tax rate by the adjustment to increase the accumulated depreciation balance. The increase to the ADIT is 39.5% X $49,503,835 = $19,554,498.

Q. Please summarize your adjustment to the test-year accumulated depreciation balance.

A. As mentioned at the beginning of this adjustment, I was responsible for calculation and quantification of this adjustment and the Direct Testimony of RUCO witness Ms. Diaz Cortez supports the principles and theory for this adjustment.

As shown on Schedule RLM-4, column (B) and supported in my Work papers designated as "Dep Rate Study", my total adjustment decreases adjusted test-year rate base by (-$49,503,835) + $19,554,498 = $29,949,337.

RUCO Rate Base Adjustment No. 6 – Allowance For Working Capital

Q. Have you reviewed the Company's working capital calculations?

A. Yes. The Company's working capital request is comprised of a thirteen-month average balance for its prepayment and material and supplies accounts, and its cash working capital request is based on a lead/lag study.

Q. Do you agree with the Company's methodology?

A. Yes. Further, I have reviewed the Company's individual lag day calculations and find them to be reasonable. The only difference between the Company's calculation and RUCO's is the different level of expense

recommendations. These adjustments result in a net increase in cash working capital of $3,946,134.

OPERATING INCOME

Operating Income Summary

Q. Is RUCO recommending any changes to the Company's proposed operating expenses?

A. Yes. The Company proposed forty-three adjustments to its historical test-year operating income. RUCO analyzed the Company's adjustments and made several additional adjustments to the operating income as filed by the Company. The testimony of RUCO witness Ms. Diaz Cortez discusses a portion of these adjustments, RUCO consultants address some of these adjustments and I was responsible for reviewing the remainder of the adjustments the Company proposes to its test-year operating income. Finally, as a result of its discovery, RUCO recommends other adjustments. My review, analysis and adjustments are explained below.

Operating Income Adjustment No. 2 – Depreciation Expenses

Q. Please explain your adjustment to increase depreciation expenses.

A. The adjustment is primarily attributable to RUCO's rate base adjustments. RUCO agrees with the set of depreciation rates that TEP is proposing to implement on a going forward basis. However, since RUCO does not

have the plant data in as fine a detail as the Company provided in its depreciation study, I computed a composite depreciation rate. These depreciation rates reflect FERC account balances the Company provided in its response to RUCO Data Request 2.13. The actual depreciation rates shown on Schedule RLM-9 were calculated by dividing each FERC account's "test-year depreciation" balance by the "end-of-test-year plant in service" balance. I then computed test-year depreciation by multiplying RUCO's level of test-year gross plant in service by the composite depreciation rates.

As shown on Schedule RLM-8, column (C) and supporting Schedule RLM-9, my adjustment increases adjusted test-year expenses by $4,067,209.

<u>Operating Income Adjustment No. 3 – Disallowance of Inappropriate and/or Unnecessary Expenses</u>

Q. Please explain your analysis of the various operating expense accounts that result in your removal of inappropriate or unnecessary costs for the provisioning of electric service.

A After review of all the journal entries in various FERC accounts and the Company's response to RUCO Data Request 5.17, I determined there were numerous expenditures that were questionable, inappropriate, extravagant and/or unnecessary.

Therefore, as shown on Schedule RLM-10 and supporting workpapers designated as Revised Exhibit A (not attached to this testimony, but provided to the Company simultaneously with this testimony), I have made an adjustment to remove test-year expenses related to payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events, advertising and for various meals, lodging and refreshments, which are not necessary in the provisioning of electric service. The back-up documentation denoting each individual expense removed is recorded in Revised Exhibit A: FERC Account Code 921, pages 1 to 28, FERC Account 923, page 1, FERC Account 930.1, page 1, and FERC Account 930.2, pages 1 to 6.

RUCO provided TEP with a copy of the original Exhibit A in a data request to the Company. The Company responded with comments as to the appropriateness and necessity of each expense. After analyzing the Company's response, RUCO removed $1,396,419 from the $1,910,151 test-year expenses submitted on the original Exhibit A.

However, of the 1,449 questionable invoices originally submitted by RUCO on Exhibit A there still remain expenditures that seem questionable, inappropriate, extravagant and/or unnecessary that the Company deem as "valid charges".

Such "valid charges" include:

1. Invoices for the UNS 2006 Board Retreat held September 12 – 16. The Board retreat is held annually in order to strategically plan, discuss and organize the companies current and future; therefore, the directors and spouses were secluded high in the Wasatch Mountains, somewhere around Park City, Utah. The allocated cost to the TEP ratepayers was: 1) $35,816 for lodging at the Stein Eriksen Lodge; 2) $7,489.87 for food services; 3) $6,408.94 for planning and coordination; 4) $5,170.00 for dinners for the directors and their spouses; 5) $2,000.00 for transportation to and from the retreat; 6) $1,168.40 for floral arrangements; and 7) $6,566.38 for embroidered jackets. This UNS 2006 Board Retreat would burden the ratepayers with a total of $64,620.04.
2. Invoices for $130,369.11 recorded by the Company as "Meals and Entertainment – Discretionary".
3. Invoices for $125,000 to the Tucson Regional Economic Opportunities, Inc. to support the creation of new businesses.
4. Invoices for purchases at: Albertson's, Basha's, Food City, Fry's, Safeway's, Walgreen's and Wal Mart totaled $10,987.94.
5. Invoices at Lowns Costumes for $1,757.30 and Party America for $518.34, totaling $2,275.64.
6. Invoices for flowers, gifts, trophies, hams, steaks, toys and clothing totaling $14,942.27.

7. Invoices for various chamber of commerce, community organizations and public relations organizations totaling $28,094.89.

As shown on Schedule RLM-8, column (D) and supporting Schedule RLM-10, this adjustment decreased test-year expenses by $531,731.

Operating Income Adjustment No. 4 – Supplemental Executive Retirement Plan

Q. Please explain the basis for the adjustment you made to the Pension and Benefits operating expenses.

A. I made an adjustment to the Supplemental Executive Retirement Plan ("SERP") portion of the pension and benefits operating expenses.

Q. Please explain your adjustment to the SERP.

A. As explained in the Company's responses to Staff data request 1.81, TEP's test-year payroll loadings include the cost of a SERP. The Company's test-year operating expenses include $927,925 related to the SERP. The SERP is a retirement plan that is provided to a small select group of high-ranking officers of the Company. The high-ranking officers who are covered under the SERP receive these benefits in addition to the regular retirement plan.

Q. Should ratepayers be required to pay the cost of supplemental benefits for the high-ranking officers of the Company?

A. No. The cost of supplemental benefits for high-ranking officers is not a necessary cost of providing electric service. These individuals are already fairly compensated for their work and are provided with a wide array of benefits including a medical plan, dental plan, life insurance, long term disability, paid absence time, and a retirement plan. If the Company feels it is necessary to provide additional perks to a select group of employees it should do so at its own expense.

Q. In recent ACC Decisions did the Commissioners determine whether SERP expenses were recoverable?

A. Yes. Recently, the Commission agreed with RUCO that SERP expenses should not be the burden of ratepayers. In Southwest Gas' latest rate case, (Decision No. 68487, dated February 23, 2006) the Commission agreed with RUCO that SERP should be excluded from operating expenses. In Arizona Public Service's most recent rate case, (Decision No. 69663, dated June 28, 2007), the Commission voted to disallow SERP. Moreover, the Commission voted to disallow SERP in the UNS Gas rate case (Decision No. 70011, dated November 27,2007). I see no reason to depart from this precedent; therefore, RUCO recommends the removal of the test-year cost of the SERP from operating expenses.

As shown on Schedule RLM-8, column (E), this adjustment decreased test-year expenses by $927,925.

Operating Income Adjustment No. 5 – Incentive Compensation

Q. Please provide an explanation for RUCO's adjustment to the incentive compensation expenses.

A. After reviewing the Commission's position on incentive compensation expense as authorized in Decision No. 70011, dated November 27, 2007 (the recent UNS Gas rate case); RUCO recommends a 50/50 sharing as a reasonable balancing of the interests between ratepayers and shareholders. The incentive program is comprised of elements that relate to the Company's financial performance and cost containment goals, matters that primarily benefit shareholders; plus elements based on meeting customer service goals, which offers opportunity for the Company's customers to benefit from improved performance.

RUCO does not generally vary from the strict implementation of the Historical Test-Year principle to avoid mismatches in the ratemaking elements. RUCO determined in the instant case the test year was not abnormal; and therefore, RUCO dismisses the Company's proposal to a four-year average of the incentive compensation expenses.

Q. Please explain the elements of your adjustment to the incentive compensation expenses.

A. As shown on Schedule RLM-11, this adjustment consists of two elements. First, I restated the Company's adjusted level of the incentive compensation expense from its proposed four-year average to the actual historical test-year expense level. Second, I split the historical expense level on a 50/50 basis.

As shown on Schedule RLM-8, column (F) and supporting Schedule RLM-11, this adjustment decreased test-year expenses by $1,525,378.

Operating Income Adjustment No. 6 – Rate-Case Expense

Q. Please discuss your review of the Company's proposed rate-case expenses.

A. The Company has budgeted $900,000 for rate-case expenses for outside services and proposes to amortize that amount over four years. RUCO has a concern over the reasonableness of such a large financial burden to the ratepayers from this requested adjustment. RUCO believes the Company's proposed rate-case expense of nearly a million dollars is excessive and should be reduced significantly when compared with rate-case expense allowances in a long line of cases that have come before the Commission.

Unlike the rate-case expenses for TEP's affiliates UNS Gas and UNS Electric where a significant portion of the costs incurred were due to the allocation of TEP personnel assigned to perform tasks associated with those individual rate cases; in the instant case TEP is requesting recovery of $900,000 from outside services. TEP labor costs allocated to UNS Gas' rate case was $476,602 and $256,734 was allocated to UNS Electric.

With consideration of the Commission's authorized level of rate-case expense in the recent UNS Gas rate case (Decision No. 70011) of $300,000, RUCO believes the instant case warrants a reduced level of rate-case expense and recommends a 50 percent adjustment. RUCO has no disagreement with the Company's proposal to amortize the rate-case expense over four years.

Therefore, this adjustment reduces annual rate-case expense from the Company's proposed level of $225,000 ($900,000 / 4 years) to RUCO's recommended level of $112,500 ($450,000 / 4 years).

As shown on Schedule RLM-8, Column (G), this adjustment decreased test-year expenses by $112,500.

Operating Income Adjustment No. 7 – Property Tax

Q. Do you agree with TEP's methodology for computing property taxes?

A. Yes. I have used the same methodology to compute RUCO's recommended level of property taxes.

Q. Please explain the reasons for RUCO's property tax adjustment.

A. My adjustment consists of two elements. First, RUCO's property tax adjustment reflects several adjustments to the net plant in service. Second, RUCO's property tax computation uses a different assessment ratio than the Company.

Q. Please explain the first element of RUCO's property tax adjustment.

A. RUCO made several adjustments to net plant in service. The value of the net plant in service is the initial component in the calculation of the appropriate level of property tax expenses. These net plant adjustments are depicted on Schedule RLM-4. Moreover, to avoid a double count in its calculation of total net plant in service, RUCO reversed additional journal entries for transactions associated with RUCO's plant adjustments. These additional components were identified by the Company in its response to RUCO data request 10.1 in which the Company, by reconciling the rate base, illuminated additional transactions directly related to RUCO's plant adjustments. These additional transactions are depicted on Schedule RLM-12, lines 2 through 7.

Q. Please explain the second element of RUCO's property tax adjustment.

A. The second element of this adjustment results from RUCO's use of an assessment ratio of 23 percent, versus the Company use of a 23.5 percent assessment ratio. RUCO's use of the 23 percent ratio accurately reflects the ratio which will be valid when the authorized rates in this case become effective (January 2009). RUCO's recommendation is also consistent with recent Commission decisions in the Southwest Gas rate case (Decision No. 68487, dated February 23, 2006) and the UNS Gas rate case (Decision No. 70011, dated November 27,2007).

The decreasing assessment ratios as authorized in the Arizona Revised Statues relating to property taxes states the effective rate from December 31, 2008 through December 31, 2009 to be 23 percent. The assessment ratio will continue to decline by one-half percent each year until it reaches 20 percent on December 31, 2014.

As shown on Schedule RLM-8, column (H) and supporting Schedule RLM-12, this adjustment decreased test-year expenses by $1,800,201.

Adjustments To Operating Expenses No. 8 – Overhead Line Maintenance

Q. Please explain the basis for the adjustment you made to overhead line maintenance expense.

A. Through discovery I reviewed and analyzed five years of expenses recorded in FERC account 593 – overhead line maintenance from 2002 through 2006.

My analysis indicated this expense was sufficiently volatile to recommend a test-year adjustment to acknowledge the wide variation in annual costs.

Therefore, my adjusted test-year expense in the instant case is the calculated five-year average of the "inflation adjusted" annual overhead line maintenance expenses for 2002 through 2006.

My adjustment is necessary to normalize the test-year level of overhead maintenance expenses.

As shown on Schedule RLM-8, column (I) and supporting Schedule RLM-13, this adjustment decreased test-year expenses by $126,584.

Adjustments To Operating Expenses No. 9 – Penalties and Fines

Q. Please explain the basis for the adjustment you made to remove expenses for penalties and fines.

A. Through discovery I reviewed the Company's response to Staff Data Request 1.114. My analysis indicated there were three invoices for penalties and fines imposed on TEP that were recorded in test-year operating expenses.

RUCO believes if the Company does not prudently handle its affairs and consequently is imposed penalties and fines imposed, these costs are not the financial responsibility of the ratepayers.

Therefore, as shown on Schedule RLM-8, column (J), this adjustment decreased test-year expenses by $9,433.

Adjustments To Operating Expenses No. 12 – Payroll Expense

Q. Please explain the basis for your adjustment to payroll expenses.

A. RUCO does not generally vary from the strict implementation of the Historical Test-Year principle to avoid mismatches in the ratemaking elements.

Since RUCO determined the test year was not abnormal the Company's proposal to average the payroll expense over a two-year period was dismissed.

Therefore, as shown on Schedule RLM-14, I restated the Company's proposed allocation of payroll expenses to reflect the actual historical test-year level of payroll expense.

As shown on Schedule RLM-8, column (M) and supporting Schedule RLM-14, this adjustment restated the Company's proposed allocation of payroll expenses to reflect the actual historical test-year level of payroll expense and thus increased test-year expenses by $19,651.

Adjustments To Operating Expenses No. 13 – Payroll Tax Expense

Q. Please explain the basis for your adjustment to payroll tax expenses.

A. This is a companion adjustment to the payroll expense adjustment and reflects the actual historical test-year level of payroll tax expense.

As shown on Schedule RLM-8, column (N) and supporting Schedule RLM-15, this adjustment restated the Company's proposed allocation of payroll tax expenses to reflect the actual historical test-year level of payroll tax expense and thus increased test-year expenses by $2,689.

Adjustments To Operating Expenses No. 14 – Renewable Resources

Q. Please explain the basis for your adjustment to renewable resources expenses.

A. This is a conforming adjustment corresponding to the Company's response to Staff Data Request 1.85, which acknowledged a failure to remove $19,274 in expenses in the Company's original filing.

Therefore, as shown on Schedule RLM-8, column (O), this adjustment decreased test-year expenses by $19,274.

Adjustments To Operating Expenses No. 17 – Customer Care and Billing

Q. Please explain the basis for your adjustment to normalize the customer care and billing expenses.

A. This adjustment removes the computed incremental cost increase associated with the implementation of a new customer information system, designated as the Customer Care and Billing system ("CC&B").

Q. Please explain why RUCO disallowed increased customer service costs.

A. RUCO is disallowing this expenditure because evidence provided by the Commission Consumer Services Section indicates the quality of customer service has not improved since the CC&B has been implemented. As shown on Attachment A filed at the end of my testimony, the Commission Consumer Services Section Report ("Report") on TEP states, in 2004,

there were 9 consumer complaints recorded based on "quality of service" issues. In 2005, there were 25 consumer complaints recorded based on "quality of service" issues. In 2006, the year in which the CC&B was implemented, there were 95 consumer complaints recorded based on "quality of service" issues. In 2007, through to December 3rd, there were 111 consumer complaints recorded based on "quality of service" issues.

Since the Report does not demonstrate the improvements, enhancements and synergy promoted by the Company as justification for the increased expenditure has translated into increased customer satisfaction, RUCO is removing any increase in this expense until the Company provides documentation that the overall customer satisfaction level has improved.

Moreover, this scenario of attempting to improve customer service by implementing a new system to consolidate call centers and customer service functions among UNS Gas, UNS Electric and TEP has not yet proven to provide the significantly enhanced benefit to the ratepayers. As I have previously testified in both the recent UNS Gas and UNS Electric rate cases the additional costs incurred to improve the quality of customer service has not translated into a better level of service; to the contrary, the evidence shows a higher degree of frustration in the quality of service customers received.

Therefore, as shown on Schedule RLM-8, column (R) and supporting Schedule RLM-16, this adjustment decreased test-year expenses by $296,230.

Adjustments To Operating Expenses No. 19 – Employee Recognition

Q. Please explain the basis for your adjustment to operating expenses for the removal of costs associated with employee recognition.

A. As previously explained in Operating Expense Adjustment No. 3, RUCO believes it is inappropriate to burden ratepayers with expenses related to payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events, advertising and for various meals, lodging and refreshments, which are not necessary in the provisioning of electric service.

Therefore, RUCO requested the Company to identify costs recorded in the test year associated with employee recognition expenses. In the Company's response to RUCO data request 6.1, TEP acknowledged $76,125 was recorded in the test-year general ledger for employee recognition. The recognition program is administered by the OC Tanner Recognition Company wherein an employee selects his/her service-award gift from a catalogue.

RUCO analyzed the information in the Company's response and determined no portion of the $76,125 has been removed in any other adjustment.

As shown on Schedule RLM-8, column (T), this adjustment decreased test-year expenses by $76,125.

Adjustments To Operating Expenses No. 20 – Employee Benefits

Q. Please explain the basis for your adjustment to operating expenses for the removal of costs associated with some employee benefits.

A. As previously explained in Operating Expense Adjustment No. 3, RUCO believes it is inappropriate to burden ratepayers with expenses related to payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events, advertising and for various meals, lodging and refreshments, which are not necessary in the provisioning of electric service.

Meanwhile, Staff had requested that the Company identify costs recorded in the test year associated with employee benefit expenses. In the Company's response to Staff data request 1.79, TEP recognized $54,442 were recorded in the test-year general ledger for employee benefits, such as; gifts, awards, luncheons, dinners, picnics, parties and social events. RUCO analyzed the information provided in the Company's response and

determined that of the $54,442, TEP had removed $14,659 from the test-year expenses, RUCO had removed $16,618 from of test-year expenses in previous Adjustment No. 3; thus, leaving $23,165 ($54,442 - $14,659 - $16,618 = $23,165) in costs recorded in the test year associated with employee benefit expenses.

Therefore, as shown on Schedule RLM-8, column (U), this adjustment decreased test-year expenses by $23,165.

Operating Income Adjustment No. 28 – Income Tax Expense – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

As shown on Schedule RLM-7, column (D) and supporting Schedule RLM-17, this adjustment increased test-year expenses by $32,062,674.

COST OF CAPITAL

Q. Is RUCO proposing any adjustments to the Company proposed cost of capital?

A. Yes. As shown on Schedule RLM-18, this adjustment decreases the Company's cost of common equity and therefore its weighted cost of capital by 59 basis points from 8.35 to 7.76 percent to reflect current market conditions.

This adjustment is fully explained in the testimony of RUCO witness Mr. Rigsby.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ATTACHMENT A

M E M O R A N D U M

TO: Rodney Moore
Rate Analyst
Residential Consumer Utility Office

FROM: John La Porta
Public Utilities Consumer Analyst I
Utilities Division

DATE: December 4, 2007

RE: Tucson Electric Power Company – Quality of Service Complaints

Per your request, a research of the Consumer Services database represents the number of Quality of Service complaints that were filed against Tucson Electric Power Company ("TEP" or "Company") since 2004.

2004 – Nine Complaints -	1 TEP Response Time, 1 Misinformation from Company, 3 Customer Service Contact, 2 Outages, 2 Other
2005 – 25 Complaints -	2 TEP Response Time, 6 Misinformation from Company, 2 Customer Service Contact, 7 Outages, 2 Can't Reach Company, 2 Pressure or Voltage Issues, 4 Other
2006 – 95 Complaints -	5 TEP Response Time, 1 Misinformation from Company, 2 Customer Service Contact, 3 Field Visits by Company, 9 Outages, 69 Can't Reach Company, 2 Pressure or Voltage Issues, 4 Other
2007 – 111 Complaints (thru December 3, 2007)	2 TEP Response Time, 14 Outages, 92 Can't Reach Company, 3 Other

If you need any further information regarding the numbers above, please feel free to call me at (602) 542-0819.

APPENDIX 1

Qualifications of Rodney Lane Moore

EDUCATION: Athabasca University
Bachelor's Degree in Business Administration - 1993

EXPERIENCE: Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona 85007
May 2001 - Present

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

Auditor
Arizona Corporation Commission
Phoenix, Arizona 85007
October 1999 - May 2001

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.
Rio Verde Utilities, Inc	WS-02156A-00-0321
Black Mountain Gas Company	G-03703A-01-0283
Green Valley Water Company	W-02025A-01-0559
New River Utility Company	W-01737A-01-0662

Utility Company	Docket No.
Dragoon Water Company	W-01917A-01-0851
Roosevelt Lake Resort, Inc.	W-01958A-02-0283
Southwest Gas Company	G-01551A-02-0425
Arizona-American Water Company	W-01303A-02-0867 et al.
Rio Rico Utilities, Inc.	WS-02676A-03-0434
Qwest Corporation	T-01051B-03-0454
Chaparral City Water Company	W-02113A-04-0616
Southwest Gas Company	G-01551A-04-0876
Arizona-American Water Company	W-01303A-05-0405
Far West Water and Sewer Company	WS-03478A-05-0801
Gold Canyon Sewer Company	SW-02519A-06-0015
Arizona-American Water Company	WS-01303A-06-0403
UNS Gas, Inc.	G-04204A-06-0463 et al.
UNS Electric, Inc.	E-04204A-06-0783

EXHIBIT A

TUCSON ELECTRIC POWER COMPANY

DATA RESPONSE 1.20 (a): FERC 921 A&G Expense - Office Supplies

TEST YEAR ENDING DECEMBER 31, 2006

Source: Transaction Detail - Co: 002, GL Period Name: %06, FERC: 0921

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
51500	123	Materials Purchased	ALCPA *DUES LB	185.00		185.00		
51500	123	Materials Purchased	AMAZON.COM	69.95		69.95		
51500	123	Materials Purchased	AMY'S HALLMARK #899	7.87		7.87		
51500	123	Materials Purchased	AMZ*SUPERSTORE	46.92		46.92		
51500	123	Materials Purchased	BRUEGGERS BAGEL BAKERY	84.31		84.31		
51500	123	Materials Purchased	GENL INJECTABLES/VACCI	309.33		309.33		
51500	123	Materials Purchased	GONE SCRAPPIN INC	450.00		450.00		
51500	123	Materials Purchased	HARRY & DAVID #830	277.52		277.52		
51500	123	Materials Purchased	HENRY SCHEIN*	128.54		128.54		
51500	123	Materials Purchased	ISTOCKPHOTO	10.00		10.00		
51500	123	Materials Purchased	JASON'S DELI	123.67		123.67		
51500	123	Materials Purchased	JUST SPORTS 244	107.65		107.65		
51500	123	Materials Purchased	MICHAELS #2758	23.16		23.16		
51500	123	Materials Purchased	MICHAELS #5206	160.15		160.15		
51500	123	Materials Purchased	MICHAELS #9530	113.31		113.31		
51500	123	Materials Purchased	MINKUS ADVERTISING	270.20		270.20		
51500	123	Materials Purchased	MISTERART.COM LP	34.24		34.24		
51500	123	Materials Purchased	MOUNTAIN VIEW SPORTS	190.34		190.34		
51500	123	Materials Purchased	NELLIS AFB EXCHANGE	49.95		49.95		
51500	123	Materials Purchased	NEW BEGINNINGS	150.00		150.00		
51500	123	Materials Purchased	OMAHASTEAKS.COM INC	747.96		747.96		
51500	123	Materials Purchased	ORIENTAL TRADING CO	187.91		187.91		
51500	123	Materials Purchased	OSCO DRUG 9215	276.88		276.88		
51500	123	Materials Purchased	OSCO DRUG 9254	10.21		10.21		
51500	123	Materials Purchased	OSCO DRUG 9277	21.07		21.07		
51500	123	Materials Purchased	PARADIES WASH NAT L	4.70		4.70		
51500	123	Materials Purchased	PARADIES-TUCSON	6.21		6.21		
51500	123	Materials Purchased	PARK PLACE	101.50		101.50		
51500	123	Materials Purchased	PARTY AMERICA #1404	89.81		89.81		
51500	123	Materials Purchased	PARTY AMERICA 1405	186.09		186.09		
51500	123	Materials Purchased	PARTY CITY OF TUCSON I	449.15		449.15		
51500	123	Materials Purchased	PEN*POWERGEN	95.00		95.00		
51500	123	Materials Purchased	PLAYHARD, INC	78.80		78.80		
51500	123	Materials Purchased	POSITIVE PROMOTIONS IN	1,049.80		1,049.80		
51500	123	Materials Purchased	PRIMERA WEB STORE	284.86		284.86		
51500	123	Materials Purchased	ROCKY MT ELEC LEAGUE	410.00		410.00		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
51500	123	Materials Purchased	SAFEWAY STORE00015214	54.95		54.95		
51500	123	Materials Purchased	SAFEWAY STORE 00019SC9	648.77		648.77		
51500	123	Materials Purchased	SAHUARO TROPHY	107.60		107.60		
51500	123	Materials Purchased	SCHLOTZSKY S	9.71		9.71		
51500	123	Materials Purchased	SEARS ROEBUCK 1338	69.93		69.93		
51500	123	Materials Purchased	SKYLINE GALLERY	500.00		500.00		
51500	123	Materials Purchased	SONARE 20075396	429.25		429.25		
51500	123	Materials Purchased	SPINKEEPER.COM	569.94		569.94		
51500	123	Materials Purchased	STARBAND	1,439.88		1,439.88		
51500	123	Materials Purchased	TARGET 00001792	43.22		43.22		
51500	123	Materials Purchased	TARGET 00002113	64.82		64.82		
51500	123	Materials Purchased	TARGET 00008540	98.67		98.67		
51500	123	Materials Purchased	TARGET 00008557	10.75		10.75		
51500	123	Materials Purchased	TARGET 00013169	247.28		247.28		
51500	123	Materials Purchased	TARGET 00014399	317.86		317.86		
51500	123	Materials Purchased	TARGET 00018630	14.04		14.04		
51500	123	Materials Purchased	TAYLOR DISTRIBUTOR INC	163.55		163.55		
51500	123	Materials Purchased	THE GIFT BASKET STOP	99.45		99.45		
51500	123	Materials Purchased	THE SPORTS AUTHORITY #	87.54		87.54		
51500	123	Materials Purchased	THRIFT CITY & OUTLET	27.15		27.15		
51500	123	Materials Purchased	TOYS R US #5646	27.01		27.01		
51500	123	Materials Purchased	TUCSON MALL	1,081.50		1,081.50		
51500	123	Materials Purchased	TUCSONS MAP AND FLAG C	64.45		64.45		
51500	123	Materials Purchased	TULLER TROPHY'S & AWAR	229.19		229.19		
51500	123	Materials Purchased	WAL MART	155.47		155.47		
51500	123	Materials Purchased	WALGREEN 00002Q39	77.34		77.34		
51500	123	Materials Purchased	WALGREEN 00038Q39	21.26		21.26		
51500	123	Materials Purchased	WALGREEN 00040Q39	10.21		10.21		
51500	123	Materials Purchased	WALGREEN 00047Q39	3.76		3.76		
51500	123	Materials Purchased	WALGREEN 00052Q39	13.92		13.92		
51500	123	Materials Purchased	WALGREEN 00053Q39	15.80		15.80		
51500	123	Materials Purchased	WALGREEN 00065Q39	24.70		24.70		
51500	123	Materials Purchased	WALGREEN 00067Q39	615.70		615.70		
51500	123	Materials Purchased	WALGREEN 00070Q39	5.53		5.53		
51500	123	Materials Purchased	WAL-MART #1175	5.00		5.00		
51500	123	Materials Purchased	WAL-MART #1291	90.12		90.12		
51500	123	Materials Purchased	WAL-MART #1325	82.25		82.25		
51500	123	Materials Purchased	WAL-MART #2922 SE2	15.44		15.44		
51500	123	Materials Purchased	WORLD MKT 00001370	217.44		217.44		
51500	123	Materials Purchased	WORLD MKT 00002691	129.99		129.99		
51500	123	Materials Purchased		263.00		263.00	VOLUNTEERS OF	062706 26300
79010	282	Meals & Ent - Discretionary	ALBERTSONS #959 S9H	284.97		284.97		
79010	282	Meals & Ent - Discretionary	ALBERTSONS #963	27.27		27.27		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	282	Meals & Ent - Discretionary	ALBERTSONS #988 S9H	127.97		127.97		
79010	282	Meals & Ent - Discretionary	ALVERNON DONUT SHOP	52.07		52.07		
79010	282	Meals & Ent - Discretionary	ALVERNON DONUTS	19.76		19.76		
79010	282	Meals & Ent - Discretionary	AMC VALLEY VIE01001Q02	9.00		9.00		
79010	282	Meals & Ent - Discretionary	APPLEBEE'S #602	62.95		62.95		
79010	282	Meals & Ent - Discretionary	APPLEBEE'S MEN00164087	27.89		27.89		
79010	282	Meals & Ent - Discretionary	ASSOCTD BLDRS/CNTRC ED	136.00		136.00		
79010	282	Meals & Ent - Discretionary	AZ DIAMONDBACKS BX OFC	780.00		780.00		
79010	282	Meals & Ent - Discretionary	AZ DIAMONDBACKS SPRING	1,483.00		1,483.00		
79010	282	Meals & Ent - Discretionary	BAGGINS STORE #10	645.57		645.57		
79010	282	Meals & Ent - Discretionary	BAHAMA BREEZE 00030114	13.84		13.84		
79010	282	Meals & Ent - Discretionary	BAL O'S DSA	54.00		54.00		
79010	282	Meals & Ent - Discretionary	BAMBOO TEMPE	13.57		13.57		
79010	282	Meals & Ent - Discretionary	BAMBOO TERRACE RESTAUR	87.00		87.00		
79010	282	Meals & Ent - Discretionary	BAMBOO TUCSON	69.75		69.75		
79010	282	Meals & Ent - Discretionary	BARLEY BROTHERS BREWER	129.18		129.18		
79010	282	Meals & Ent - Discretionary	BASHA S #88 SYW	17.59		17.59		
79010	282	Meals & Ent - Discretionary	BASHAS #100	35.75		35.75		
79010	282	Meals & Ent - Discretionary	BASHAS #100 SYW	119.79		119.79		
79010	282	Meals & Ent - Discretionary	BASKIN ROBBINS #251	56.90		56.90		
79010	282	Meals & Ent - Discretionary	BEDROXX	137.21		137.21		
79010	282	Meals & Ent - Discretionary	BENNIGANS GRILL AND TA	24.11		24.11		
79010	282	Meals & Ent - Discretionary	BOOGA REDS	63.99		63.99		
79010	282	Meals & Ent - Discretionary	BRUEGGERS BAGEL BAKERY	10.58		10.58		
79010	282	Meals & Ent - Discretionary	BRUEGGER'S BAGELS -Q50	36.87		36.87		
79010	282	Meals & Ent - Discretionary	BURGER KING # 1002 Q07	9.49		9.49		
79010	282	Meals & Ent - Discretionary	BURGER KING #8615 Q07	9.34		9.34		
79010	282	Meals & Ent - Discretionary	BUSY B S BAKERY	22.37		22.37		
79010	282	Meals & Ent - Discretionary	CAFE POCA COSA	148.00		148.00		
79010	282	Meals & Ent - Discretionary	CALIFORNIA PIZZA 058	79.79		79.79		
79010	282	Meals & Ent - Discretionary	CALLAWAY INN FRONT DES	117.72		117.72		
79010	282	Meals & Ent - Discretionary	CAPITAL GRILLE 800	44.85		44.85		
79010	282	Meals & Ent - Discretionary	CASA BONITA	44.39		44.39		
79010	282	Meals & Ent - Discretionary	CHA-BONES	20.00		20.00		
79010	282	Meals & Ent - Discretionary	CHARIOT PIZZA	657.68		657.68		
79010	282	Meals & Ent - Discretionary	CHARLIECLARK'SSTEAKHOU	119.86		119.86		
79010	282	Meals & Ent - Discretionary	CHEVRON 0092528 Q61	12.21		12.21		
79010	282	Meals & Ent - Discretionary	CHILI'S GRI16100011619	9.88		9.88		
79010	282	Meals & Ent - Discretionary	CHILI'S GRI56300005637	233.77		233.77		
79010	282	Meals & Ent - Discretionary	CIRCLE K 00424 Q04	7.56		7.56		
79010	282	Meals & Ent - Discretionary	CITY OF TCSN RAND CLBH	50.00		50.00		
79010	282	Meals & Ent - Discretionary	CLAIM JUMPER #35	1,307.93		1,307.93		
79010	282	Meals & Ent - Discretionary	COFFEE POT RESTAURANT	9.71		9.71		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	282	Meals & Ent - Discretionary	COUNTY LINE RIVERWALK	24.36		24.36		
79010	282	Meals & Ent - Discretionary	CRACKER BARREL #416	9.45		9.45		
79010	282	Meals & Ent - Discretionary	DELECTABLES RESTAURANT	945.78		945.78		
79010	282	Meals & Ent - Discretionary	DENNY'S #6608 Q67	12.01		12.01		
79010	282	Meals & Ent - Discretionary	DESERT DIAMOND CASINO	28.90		28.90		
79010	282	Meals & Ent - Discretionary	DISCOUNT COFFEE COM	555.86		555.86		
79010	282	Meals & Ent - Discretionary	DORAL EAGLEWOOD	38.21		38.21		
79010	282	Meals & Ent - Discretionary	EAT AT JOE'S AIRPORT	7.05		7.05		
79010	282	Meals & Ent - Discretionary	EL MINUTO CAFE	29.00		29.00		
79010	282	Meals & Ent - Discretionary	EL MOLINITO	833.15		833.15		
79010	282	Meals & Ent - Discretionary	EL PARADOR	477.78		477.78		
79010	282	Meals & Ent - Discretionary	EL PASO BAR B QUE	29.40		29.40		
79010	282	Meals & Ent - Discretionary	EL PASO BAR-B-QUE 555	313.01		313.01		
79010	282	Meals & Ent - Discretionary	ELA THE FAT BURRITO	10.98		10.98		
79010	282	Meals & Ent - Discretionary	ELEPHANT & CASTLE	52.16		52.16		
79010	282	Meals & Ent - Discretionary	ELEPHANT BAR # 219	36.16		36.16		
79010	282	Meals & Ent - Discretionary	ENOTECA PIZZARIA WINE	73.81		73.81		
79010	282	Meals & Ent - Discretionary	FAMOUS SAMS #17	18.28		18.28		
79010	282	Meals & Ent - Discretionary	FIRECRACKER	91.41		91.41		
79010	282	Meals & Ent - Discretionary	FLEMINGS #1350	254.44		254.44		
79010	282	Meals & Ent - Discretionary	FRIDAYS_AM_BAR #0806	10.77		10.77		
79010	282	Meals & Ent - Discretionary	FRYS-FOOD-DRG #0090SXN	141.61		141.61		
79010	282	Meals & Ent - Discretionary	FRYS-FOOD-DRG #058 SXN	498.95		498.95		
79010	282	Meals & Ent - Discretionary	GASLIGHT THEATRE	720.06		720.06		
79010	282	Meals & Ent - Discretionary	GOLDEN CORRAL 29724Q15	25.46		25.46		
79010	282	Meals & Ent - Discretionary	GREATER TUCSON LEADER	35.00		35.00		
79010	282	Meals & Ent - Discretionary	GREER LODGE	16.11		16.11		
79010	282	Meals & Ent - Discretionary	Gross Pay	46,485.77		46,485.77		
79010	282	Meals & Ent - Discretionary	GUILLERMOS DOUBLE L RE	80.33		80.33		
79010	282	Meals & Ent - Discretionary	HMS HOST-ORD-AIRPT #55	9.46		9.46		
79010	282	Meals & Ent - Discretionary	HMSHOST-LAS-AIRPT #008	8.06		8.06		
79010	282	Meals & Ent - Discretionary	HMSHOST-PHX-AIR #05	11.97		11.97		
79010	282	Meals & Ent - Discretionary	HOMETOWN BUFFE00103Q31	43.21		43.21		
79010	282	Meals & Ent - Discretionary	HONEYBAKED-HAM #0053	157.99		157.99		
79010	282	Meals & Ent - Discretionary	HOOTERS OF SAN DIEGO	18.33		18.33		
79010	282	Meals & Ent - Discretionary	HOTEL CONTESSA	13.89		13.89		
79010	282	Meals & Ent - Discretionary	HOTEL CONTESSA-HOTEL	63.43		63.43		
79010	282	Meals & Ent - Discretionary	HUDDLE HOUSE #358	17.93		17.93		
79010	282	Meals & Ent - Discretionary	HYATT HOTELS F & B	24.87		24.87		
79010	282	Meals & Ent - Discretionary	HYATT HOTELS DENVER CC	47.08		47.08		
79010	282	Meals & Ent - Discretionary	IHOP #3033	14.92		14.92		
79010	282	Meals & Ent - Discretionary	IHOP#3036	75.75		75.75		
79010	282	Meals & Ent - Discretionary	IN-N-OUT BURGER 000000	9.49		9.49		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	282	Meals & Ent - Discretionary	IN-N-OUT BURGERS	6.94		6.94		
79010	282	Meals & Ent - Discretionary	JACKSONS GRILL	210.60		210.60		
79010	282	Meals & Ent - Discretionary	JASON'S DELI	1,223.56		1,223.56		
79010	282	Meals & Ent - Discretionary	JB'S RESTAURANT 35	19.28		19.28		
79010	282	Meals & Ent - Discretionary	JOE'S ON SULLIVAN	36.56		36.56		
79010	282	Meals & Ent - Discretionary	JOHNNY ROCKETS	48.85		48.85		
79010	282	Meals & Ent - Discretionary	KFC #10 Q20	16.25		16.25		
79010	282	Meals & Ent - Discretionary	KMART 00049Q	21.96		21.96		
79010	282	Meals & Ent - Discretionary	KOFA CAFE	7.58		7.58		
79010	282	Meals & Ent - Discretionary	KRISPY KREME 15 05	88.13		88.13		
79010	282	Meals & Ent - Discretionary	LA CASITA CAFE	31.71		31.71		
79010	282	Meals & Ent - Discretionary	LA HACIENDA EXPRESS	6.51		6.51		
79010	282	Meals & Ent - Discretionary	LESLEE'S CAFE Q99	5.25		5.25		
79010	282	Meals & Ent - Discretionary	LEVY @BANK1 BPARK CON	225.00		225.00		
79010	282	Meals & Ent - Discretionary	LEVY GRP SALE 90085002	831.03		831.03		
79010	282	Meals & Ent - Discretionary	LIGHTNING RIDGE CAFE	1,160.61		1,160.61		
79010	282	Meals & Ent - Discretionary	LIONS DEN, THE	10.50		10.50		
79010	282	Meals & Ent - Discretionary	LITTLE MEXICO RESTAURA	184.17		184.17		
79010	282	Meals & Ent - Discretionary	LODGE ON THE DESERT	445.46		445.46		
79010	282	Meals & Ent - Discretionary	LOEWS #698 FOOTHILLS	102.00		102.00		
79010	282	Meals & Ent - Discretionary	MACARONI GR16300001636	336.56		336.56		
79010	282	Meals & Ent - Discretionary	MANUEL'S AMIGOS CA	29.78		29.78		
79010	282	Meals & Ent - Discretionary	MCALISTER'S DELI #1205	21.93		21.93		
79010	282	Meals & Ent - Discretionary	MCDONALD'S F18788 Q17	11.22		11.22		
79010	282	Meals & Ent - Discretionary	MCDONALDS F5012 Q17	3.49		3.49		
79010	282	Meals & Ent - Discretionary	MCDONALD'S F6045 Q17	16.62		16.62		
79010	282	Meals & Ent - Discretionary	METRO GRILL PARK PLACE	95.94		95.94		
79010	282	Meals & Ent - Discretionary	MICHAS	127.49		127.49		
79010	282	Meals & Ent - Discretionary	MOODY GARDENS, INC	12.77		12.77		
79010	282	Meals & Ent - Discretionary	NADINES PASTRY SHOPPE	70.20		70.20		
79010	282	Meals & Ent - Discretionary	NEW YORK PIZZA DEPT	7.73		7.73		
79010	282	Meals & Ent - Discretionary	OAK CREEK BREWERY & GR	33.92		33.92		
79010	282	Meals & Ent - Discretionary	OAXACA RESTAURANTE	29.73		29.73		
79010	282	Meals & Ent - Discretionary	OISHI SUSHI & TERIYAKI	91.50		91.50		
79010	282	Meals & Ent - Discretionary	OLD CHICAGO PASTA & PI	23.68		23.68		
79010	282	Meals & Ent - Discretionary	OLD PUEBLO GRILLE	1,373.94		1,373.94		
79010	282	Meals & Ent - Discretionary	OMNI HOTELS INTERLOCKE	73.15		73.15		
79010	282	Meals & Ent - Discretionary	PALO VERDE BAR & GRILL	85.70		85.70		
79010	282	Meals & Ent - Discretionary	PEI WEI ASIAN DINER-00	185.55		185.55		
79010	282	Meals & Ent - Discretionary	PIZZA HUT #14357500Q34	515.59		515.59		
79010	282	Meals & Ent - Discretionary	PIZZA HUT #14357543Q	45.38		45.38		
79010	282	Meals & Ent - Discretionary	QUIZNOS SUB #3255 Q22	16.80		16.80		
79010	282	Meals & Ent - Discretionary	RAINFOREST-GALVSTN RST	18.57		18.57		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	282	Meals & Ent - Discretionary	RENDEZVOUS DINER	26.84		26.84		
79010	282	Meals & Ent - Discretionary	RINCON MARKET	1,688.26		1,688.26		
79010	282	Meals & Ent - Discretionary	RINCON MARKET SRI	18.07		18.07		
79010	282	Meals & Ent - Discretionary	RISKY BUSINESS #4	805.37		805.37		
79010	282	Meals & Ent - Discretionary	RUDYS CARLISLE#9102Q23	11.45		11.45		
79010	282	Meals & Ent - Discretionary	SACHIKO SUSHI II	131.00		131.00		
79010	282	Meals & Ent - Discretionary	SAFEWAY STORE00012294	38.27		38.27		
79010	282	Meals & Ent - Discretionary	SAFEWAY STORE00012SC9	10.18		10.18		
79010	282	Meals & Ent - Discretionary	SAFEWAY STORE00017491	49.47		49.47		
79010	282	Meals & Ent - Discretionary	SAFEWAY STORE00017SC9	92.19		92.19		
79010	282	Meals & Ent - Discretionary	SAFEWAY STORE00018SC9	604.31		604.31		
79010	282	Meals & Ent - Discretionary	SAFEWAY STORE 00019SC9	197.73		197.73		
79010	282	Meals & Ent - Discretionary	SA-ING THAI CUISINE	19.36		19.36		
79010	282	Meals & Ent - Discretionary	SALT WATER GRILL	104.56		104.56		
79010	282	Meals & Ent - Discretionary	SALTGRASS-GALVESTON	153.75		153.75		
79010	282	Meals & Ent - Discretionary	SAM HUGHES PLACE	44.80		44.80		
79010	282	Meals & Ent - Discretionary	SAUSAGE DELI	120.30		120.30		
79010	282	Meals & Ent - Discretionary	SHEPSOFCHLORIDE	31.88		31.88		
79010	282	Meals & Ent - Discretionary	SILVER SADDLE STEAKHOU	40.38		40.38		
79010	282	Meals & Ent - Discretionary	SPICES	29.65		29.65		
79010	282	Meals & Ent - Discretionary	STAGE COACH GRILL AND	35.05		35.05		
79010	282	Meals & Ent - Discretionary	STARBUCKS USA 00063Q48	8.02		8.02		
79010	282	Meals & Ent - Discretionary	STARR PASS GOLF CLUB	548.76		548.76		
79010	282	Meals & Ent - Discretionary	SUBWAY 34169 00341Q16	32.50		32.50		
79010	282	Meals & Ent - Discretionary	SULLIVAN'S STE00085258	444.03		444.03		
79010	282	Meals & Ent - Discretionary	SUSHI CHO	24.27		24.27		
79010	282	Meals & Ent - Discretionary	SUSHI TEN	118.62		118.62		
79010	282	Meals & Ent - Discretionary	SWEET TOMATOES #48	38.22		38.22		
79010	282	Meals & Ent - Discretionary	TACO BELL PIZZ49695Q34	5.94		5.94		
79010	282	Meals & Ent - Discretionary	TED'S COUNTRY STORE	4,731.83		4,731.83		
79010	282	Meals & Ent - Discretionary	TERRIBLES #148	14.90		14.90		
79010	282	Meals & Ent - Discretionary	TEXAS LAND & CATTLE#71	58.62		58.62		
79010	282	Meals & Ent - Discretionary	THE GOOD EGG WILLIAMS	23.97		23.97		
79010	282	Meals & Ent - Discretionary	THE MONKEY BOX	37.82		37.82		
79010	282	Meals & Ent - Discretionary	THE OLIVE GARD00016220	25.30		25.30		
79010	282	Meals & Ent - Discretionary	THE PASTA HOUSE	35.00		35.00		
79010	282	Meals & Ent - Discretionary	THE PINES GOLF CLUB AT	74.59		74.59		
79010	282	Meals & Ent - Discretionary	THE SAN LUIS HOTEL	9.50		9.50		
79010	282	Meals & Ent - Discretionary	TIERRA LINDA DESIGNS I	1,168.40		1,168.40		
79010	282	Meals & Ent - Discretionary	Transfer costs from O&M to capital		3,988.44	(3,988.44)		
79010	282	Meals & Ent - Discretionary	TUBAC MANAGEMENT C	29.72		29.72		
79010	282	Meals & Ent - Discretionary	TUCSON CONVENTION CTR	153.00		153.00		
79010	282	Meals & Ent - Discretionary	UNO CHICAGO BAR & GRIL	42.98		42.98		
79010	282	Meals & Ent - Discretionary	VILLAGE-INN-REST #0394	17.83		17.83		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	282	Meals & Ent - Discretionary	WHATABURGER 813 Q26	8.74		8.74		
79010	282	Meals & Ent - Discretionary	ZUNI GRILL	26.68		26.68		
79010	282	Meals & Ent - Discretionary		17,388.66		17,388.66		
79010	282	Meals & Ent - Discretionary			17,388.66	(17,388.66)		
79010	282	Meals & Ent - Discretionary			100.69	(100.69)		
79010	282	Meals & Ent - Discretionary		7,489.87		7,489.87		
79010	282	Meals & Ent - Discretionary		100.69		100.69		
79010	282	Meals & Ent - Discretionary		450.00		450.00	CEREMONY	102706 45000
79010	282	Meals & Ent - Discretionary		3,968.84		3,968.84	AT REID PARK LLC L	062006 396884
79010	282	Meals & Ent - Discretionary		761.56		761.56	CLUB	21362
79010	282	Meals & Ent - Discretionary		100.69		100.69	CLUB	19098
79010	282	Meals & Ent - Discretionary		1,264.60		1,264.60	CLUB	120406 126460
79010	282	Meals & Ent - Discretionary		243.16		243.16	CLUB	110206 24316
79010	282	Meals & Ent - Discretionary		1,850.00		1,850.00	CLUB	100206 185000
79010	282	Meals & Ent - Discretionary		475.74		475.74	CLUB	090106 47574
79010	282	Meals & Ent - Discretionary		42.85		42.85	CLUB	080206 4285
79010	282	Meals & Ent - Discretionary		224.67		224.67	CLUB	070306 22467
79010	282	Meals & Ent - Discretionary		219.50		219.50	CLUB	22599
79010	282	Meals & Ent - Discretionary		580.18		580.18	CLUB	010406 58018
79010	282	Meals & Ent - Discretionary		360.21		360.21	CLUB	030306 36021
79010	282	Meals & Ent - Discretionary		90.00		90.00	PETTY CASH	RPC43268NICKERSON
79010	282	Meals & Ent - Discretionary		1,115.77		1,115.77	LLC	454
79010	282	Meals & Ent - Discretionary		35,816.45		35,816.45	STEIN ERIKSEN LODGE	2850
79010	282	Meals & Ent - Discretionary		25.00		25.00	APPRENTICESHIP	122906 2500
79010	284	Meals & Ent - NonDiscretionary	BENNIGANS	87.06		87.06		
79010	284	Meals & Ent - NonDiscretionary	CAFE POCA COSA	113.29		113.29		
79010	284	Meals & Ent - NonDiscretionary	EINSTEIN BROS #3064	12.72		12.72		
79010	284	Meals & Ent - NonDiscretionary	EL MOLINITO	200.00		200.00		
79010	284	Meals & Ent - NonDiscretionary	EL PASO BAR-B-QUE 555	77.89		77.89		
79010	284	Meals & Ent - NonDiscretionary	FOX & HOUND #65057	52.37		52.37		
79010	284	Meals & Ent - NonDiscretionary	JASON'S DELI	147.87		147.87		
79010	284	Meals & Ent - NonDiscretionary	LIGHTNING RIDGE CAFE	390.60		390.60		
79010	284	Meals & Ent - NonDiscretionary	LUCKY WISHBONE NO.	64.56		64.56		
79010	284	Meals & Ent - NonDiscretionary	MAINSTREET GRILL,	37.19		37.19		
79010	284	Meals & Ent - NonDiscretionary	OLD PUEBLO GRILLE	25.94		25.94		
79010	284	Meals & Ent - NonDiscretionary	PARTY AMERICA	76.34		76.34		
79010	284	Meals & Ent - NonDiscretionary	SILVER SADDLE STEAKHOU	20.00		20.00		
79010	284	Meals & Ent - NonDiscretionary	WM SUPERCENTER SE2	15.00		15.00		
79020	252	Member Dues - Individual	100 CLUB	560.00		560.00		
79020	252	Member Dues - Individual	88-CRIME INC	1,000.00		1,000.00		
79020	252	Member Dues - Individual	9210150190MB	211.35		211.35		
79020	252	Member Dues - Individual	9210150190MB 4026	339.40		339.40		
79020	252	Member Dues - Individual	9210150350MB	160.00		160.00		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79020	252	Member Dues - Individual	9210250151MB	252.00		252.00		
79020	252	Member Dues - Individual	9210250190MB	456.35		456.35		
79020	252	Member Dues - Individual	9210250340MB	315.00		315.00		
79020	252	Member Dues - Individual	9210250350MB	145.00		145.00		
79020	252	Member Dues - Individual	ACFE	280.00		280.00		
79020	252	Member Dues - Individual	ACGIH	159.00		159.00		
79020	252	Member Dues - Individual	ALCPA *DUES LB	185.00		185.00		
79020	252	Member Dues - Individual	AMERICAN ASSO OF OC	205.00		205.00		
79020	252	Member Dues - Individual	AMERICAN HEART ASSOCIA	500.00		500.00		
79020	252	Member Dues - Individual	ARIZONA ASSOCIATION OF	780.00		780.00		
79020	252	Member Dues - Individual	ARIZONA CHAMBER OF COM	4,825.00		4,825.00		
79020	252	Member Dues - Individual	ARTHRITIS FOUNDATION	2,000.00		2,000.00		
79020	252	Member Dues - Individual	ASID	415.00		415.00		
79020	252	Member Dues - Individual	ASID ONLINE	435.00		435.00		
79020	252	Member Dues - Individual	ASIS	855.00		855.00		
79020	252	Member Dues - Individual	ASSOCIATION OF00 OF 00	1,590.00		1,590.00		
79020	252	Member Dues - Individual	AZ MX COMMISSION	133.37		133.37		
79020	252	Member Dues - Individual	BIG BROTHERS BIG SISTE	3,000.00		3,000.00		
79020	252	Member Dues - Individual	CASA DE LOS NINOS	1,000.00		1,000.00		
79020	252	Member Dues - Individual	CFA INSTITUTE (INT)	600.00		600.00		
79020	252	Member Dues - Individual	CHICAHOS POR LA CAUSA	175.00		175.00		
79020	252	Member Dues - Individual	EPILEPSY FONDATION OF	250.00		250.00		
79020	252	Member Dues - Individual	IEEE-RENEW	162.00		162.00		
79020	252	Member Dues - Individual	IFMA	327.00		327.00		
79020	252	Member Dues - Individual	IIDA	872.00		872.00		
79020	252	Member Dues - Individual	IOMA	301.95		301.95		
79020	252	Member Dues - Individual	ISACA/ITGI	150.00		150.00		
79020	252	Member Dues - Individual	MOTHERS AGAINST DRUNK	120.00		120.00		
79020	252	Member Dues - Individual	NATIONAL SAFETY COUNCI	100.00		100.00		
79020	252	Member Dues - Individual	NATIONAL SAFETY MANAGE	70.00		70.00		
79020	252	Member Dues - Individual	NCIDQ	52.00		52.00		
79020	252	Member Dues - Individual	OUR TOWN FAMILY CENTER	250.00		250.00		
79020	252	Member Dues - Individual	PASSONLINE.COM	59.95		59.95		
79020	252	Member Dues - Individual	PHOENIX CHAMBER OF COM	1,000.00		1,000.00		
79020	252	Member Dues - Individual	PIMA AIR MUSEUM	350.00		350.00		
79020	252	Member Dues - Individual	PIMA COUNTY BAR ASSOCI	110.00		110.00		
79020	252	Member Dues - Individual	PROJECT MANAGEMENT INS	844.00		844.00		
79020	252	Member Dues - Individual	RESNET	1,250.00		1,250.00		
79020	252	Member Dues - Individual	SHRM ORG	210.00		210.00		
79020	252	Member Dues - Individual	THE AP NETWORK	595.00		595.00		
79020	252	Member Dues - Individual	THE NATURE CONSERVANCY	25.00		25.00		
79020	252	Member Dues - Individual	TUCSON HISPANIC CHAMBE	3,100.00		3,100.00		
79020	252	Member Dues - Individual	TUCSON METRO CHMBR CMM	108.00		108.00		
79020	252	Member Dues - Individual	U OF A FOUNDATION	395.00		395.00		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79020	252	Member Dues - Individual	WESTERN GOVERNORS' ASS	550.00		550.00		
79020	252	Member Dues - Individual	YALE CLUB OF NYC	569.31		569.31		
79020	252	Member Dues - Individual		150.00		150.00	BG'S	082806 15000
79020	252	Member Dues - Individual		240.00		240.00	BREAKFAST CLUB	071006 24000
79020	252	Member Dues - Individual		240.00		240.00	BREAKFAST CLUB	062806 24000
79020	252	Member Dues - Individual		240.00		240.00	BREAKFAST CLUB	010406 24000
79020	252	Member Dues - Individual		500.00		500.00	DM 50	121806 50000
79020	252	Member Dues - Individual		500.00		500.00	DM 50	040406 50000
79020	252	Member Dues - Individual		1,500.00		1,500.00	RESNET	030906 150000
79020	252	Member Dues - Individual		15,000.00		15,000.00	RMEL_ENDATED	121906 1500000
79020	252	Member Dues - Individual		5,000.00		5,000.00	ALLIANCE_ENDATED	010506 500000
79200	299	Miscellaneous	1-800-FLOWERS.COM,INC.	83.22		83.22		
79200	299	Miscellaneous	ARIZONA CORPORATION CO	738.00		738.00		
79200	299	Miscellaneous	BRUEGGERS BAGEL BAKERY	87.64		87.64		
79200	299	Miscellaneous	CAMPBELL FLORAL&PLA	79.94		79.94		
79200	299	Miscellaneous	CASAS ADOBES FLOWER SH	87.19		87.19		
79200	299	Miscellaneous	CITY OF TUCSON DLNQ AC	187.53		187.53		
79200	299	Miscellaneous	DELIGHTFUL DELIVERIES	81.97		81.97		
79200	299	Miscellaneous	DISCOUNT COFFEE COM	265.36		265.36		
79200	299	Miscellaneous	DOLRTREE 2635 00026351	32.43		32.43		
79200	299	Miscellaneous	EVERGREEN FLOWERS	31.18		31.18		
79200	299	Miscellaneous	FCC-	230.00		230.00		
79200	299	Miscellaneous	FRAN'S FLOWERS	65.00		65.00		
79200	299	Miscellaneous	FRYS-FOOD-DRG #058 SXN	459.87		459.87		
79200	299	Miscellaneous	FTD*FLOWERS ACROSS AME	58.94		58.94		
79200	299	Miscellaneous	FTD*FTD.COM/1-800-SEND	83.79		83.79		
79200	299	Miscellaneous	FTD*ROSES & MORE INC	68.76		68.76		
79200	299	Miscellaneous	GIFTARIA	106.00		106.00		
79200	299	Miscellaneous	INGLIS BROADWAY FLORIS	196.01		196.01		
79200	299	Miscellaneous	INTERNATIONAL CORPORAT	407.54		407.54		
79200	299	Miscellaneous	MAYFIELD FLORIST	132.69		132.69		
79200	299	Miscellaneous	MICHAELS #5206	414.28		414.28		
79200	299	Miscellaneous	PARK PLACE	148.00		148.00		
79200	299	Miscellaneous	PARKS/REC RANDOLPH PRO	529.39		529.39		
79200	299	Miscellaneous	PARTY AMERICA	94.34		94.34		
79200	299	Miscellaneous	PAYPAL *BOSTIC WS	565.49		565.49		
79200	299	Miscellaneous	PROFLOWERS.COM	52.40		52.40		
79200	299	Miscellaneous	reclass SPRGPAY PA3231206	1,368.95		1,368.95		
79200	299	Miscellaneous	SAFEWAY STORE00015214	52.51		52.51		
79200	299	Miscellaneous	SAFEWAY STORE 00019869	16.20		16.20		
79200	299	Miscellaneous	SALLIE MAE - SLM GWU A	60.00		60.00		
79200	299	Miscellaneous	TIERRA LINDA DESIGNS I	387.45		387.45		
79200	299	Miscellaneous	TLF*CASAS ADOBES FLOWE	169.24		169.24		

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79200	299	Miscellaneous	TLF*FLORAL ORIGINALS B	113.35		113.35		
79200	299	Miscellaneous	TLF*INGLIS BROADWAY FL	868.48		868.48		
79200	299	Miscellaneous	TLF*MAYFIELD FLST	321.58		321.58		
79200	299	Miscellaneous	TLF*TELEFLORA.COM	73.93		73.93		
79200	299	Miscellaneous	TLF*THE BALLOON FACTOR	45.25		45.25		
79200	299	Miscellaneous	USGOVT PRINTING OFC 3-	62.00		62.00		
79200	299	Miscellaneous	USGPO/PUBLICATIONS/ND-	70.50		70.50		
79200	299	Miscellaneous	V SATTUI WINERY RETAIL	61.36		61.36		
79200	299	Miscellaneous	VILLA FELIZ FLOWERS	134.91		134.91		
79200	299	Miscellaneous	WALGREEN 00070Q39	37.19		37.19		
79200	299	Miscellaneous	WAL-MART #1291	34.49		34.49		
51500	206	Office Supplies	ALBERTSONS #964 S9H	11.97		11.97		
51500	206	Office Supplies	BAGGINS STORE #8	43.78		43.78		
51500	206	Office Supplies	BRUEGGER'S BAGELS -Q51	17.64		17.64		
51500	206	Office Supplies	DISCOUNT COFFEE COM	388.56		388.56		
51500	206	Office Supplies	DIZZY GS RESTAURANT	37.00		37.00		
51500	206	Office Supplies	FRYS-FOOD-DRG #020 SXN	2.99		2.99		
51500	206	Office Supplies	FRYS-FOOD-DRG #033 SXN	50.26		50.26		
51500	206	Office Supplies	FRYS-FOOD-DRG #042 SXN	19.08		19.08		
51500	206	Office Supplies	FRYS-FOOD-DRG #058 SXN	129.02		129.02		
51500	206	Office Supplies	HALLMARK CREATIONS #56	41.48		41.48		
51500	206	Office Supplies	HERITAGE PRODUCTS INC	550.88		550.88		
51500	206	Office Supplies	KMART 00049SZI	45.40		45.40		
51500	206	Office Supplies	PARTY AMERICA #1404	71.76		71.76		
51500	206	Office Supplies	SAFEWAY STORE00018747	35.80		35.80		
51500	206	Office Supplies	SAFEWAY STORE00018SC9	77.35		77.35		
51500	206	Office Supplies	SAFEWAY STORE 00019893	28.00		28.00		
51500	206	Office Supplies	TARGET 00014399	97.27		97.27		
51500	206	Office Supplies	WAL MART	102.18		102.18		
51500	206	Office Supplies	WALGREEN 00051Q39	3.98		3.98		
51500	206	Office Supplies	WALGREEN 00067Q39	10.77		10.77		
51500	206	Office Supplies	WAL-MART #1291	8.33		8.33		
51500	206	Office Supplies	WAL-MART #1612 SE2	2.56		2.56		
51500	206	Office Supplies	WM SUPERCENTER SE2	105.84		105.84		
52100	160	Outside Serv - Meals & Enter	AJ S 122	256.93		256.93		
52100	160	Outside Serv - Meals & Enter	ALBERTSONS #972	9.99		9.99		
52100	160	Outside Serv - Meals & Enter	BAGGINS STORE #10	25.63		25.63		
52100	160	Outside Serv - Meals & Enter	BASKIN ROBBINS	28.59		28.59		
52100	160	Outside Serv - Meals & Enter	BEER BOTTOM'S BISTRO	54.94		54.94		
52100	160	Outside Serv - Meals & Enter	BENNIGANS	40.20		40.20		
52100	160	Outside Serv - Meals & Enter	BEYOND BREAD-CAMPB	29.73		29.73		
52100	160	Outside Serv - Meals & Enter	BIG APPLE GOODYEAR	12.41		12.41		
52100	160	Outside Serv - Meals & Enter	BISON WITCHES BAR & DE	32.57		32.57		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
52100	160	Outside Serv - Meals & Enter	CAFE JASPER	24.32		24.32		
52100	160	Outside Serv - Meals & Enter	CANOA HILLS GOLF COURS	102.92		102.92		
52100	160	Outside Serv - Meals & Enter	CANOA HILLS GOLF F/B	10.00		10.00		
52100	160	Outside Serv - Meals & Enter	CHILI'S GRI56300005637	95.16		95.16		
52100	160	Outside Serv - Meals & Enter	CHIPOTLE #0085 Q82	15.67		15.67		
52100	160	Outside Serv - Meals & Enter	CLAIM JUMPER #35	141.48		141.48		
52100	160	Outside Serv - Meals & Enter	COACHES CORNER	26.17		26.17		
52100	160	Outside Serv - Meals & Enter	DENNY'S #6614 Q67	8.05		8.05		
52100	160	Outside Serv - Meals & Enter	DENNY'S #6716 Q67	7.15		7.15		
52100	160	Outside Serv - Meals & Enter	DESERT DIAMOND CASINO	243.70		243.70		
52100	160	Outside Serv - Meals & Enter	DONUT WHEEL	9.80		9.80		
52100	160	Outside Serv - Meals & Enter	EL CHARO	31.48		31.48		
52100	160	Outside Serv - Meals & Enter	EL CHARRO-ORIGINAL	95.09		95.09		
52100	160	Outside Serv - Meals & Enter	EL PASO BAR-B-QUE 555	233.26		233.26		
52100	160	Outside Serv - Meals & Enter	EL SABROSO	90.60		90.60		
52100	160	Outside Serv - Meals & Enter	ENOTECA PIZZARIA WINE	31.53		31.53		
52100	160	Outside Serv - Meals & Enter	FAMOUS SAMS #28	43.95		43.95		
52100	160	Outside Serv - Meals & Enter	HIFALUTIN	25.99		25.99		
52100	160	Outside Serv - Meals & Enter	JB'S RESTAURANT 11	41.46		41.46		
52100	160	Outside Serv - Meals & Enter	JERRY BOB'S	8.48		8.48		
52100	160	Outside Serv - Meals & Enter	LA PARILLA SUIZA	67.68		67.68		
52100	160	Outside Serv - Meals & Enter	LA PARRILLA SUIZA #3	58.76		58.76		
52100	160	Outside Serv - Meals & Enter	LAS CAZUELITAS DE TUCS	48.45		48.45		
52100	160	Outside Serv - Meals & Enter	LUKES ITALIAN BEEF	17.48		17.48		
52100	160	Outside Serv - Meals & Enter	MACARONI GR16300001636	31.24		31.24		
52100	160	Outside Serv - Meals & Enter	MARISCOS CHIHUAHUA	67.10		67.10		
52100	160	Outside Serv - Meals & Enter	MICHAS	87.42		87.42		
52100	160	Outside Serv - Meals & Enter	OMNI HOTELS F/B	52.44		52.44		
52100	160	Outside Serv - Meals & Enter	OREGANO S	47.46		47.46		
52100	160	Outside Serv - Meals & Enter	P.F. CHANG'S #8000	43.05		43.05		
52100	160	Outside Serv - Meals & Enter	PARRILLA DEL REY	23.26		23.26		
52100	160	Outside Serv - Meals & Enter	RED LOBSTER US00008698	43.47		43.47		
52100	160	Outside Serv - Meals & Enter	SAFEWAY STORE00015SC9	21.98		21.98		
52100	160	Outside Serv - Meals & Enter	SAFEWAY STORE 00019877	22.99		22.99		
52100	160	Outside Serv - Meals & Enter	SAM HUGHES PLACE	144.75		144.75		
52100	160	Outside Serv - Meals & Enter	SILVER SADDLE STEAKHOU	60.51		60.51		
52100	160	Outside Serv - Meals & Enter	SPROUTS FARMERS MARSPR	6.88		6.88		
52100	160	Outside Serv - Meals & Enter	TEXAS ROADHOUSE #2204	35.21		35.21		
52100	160	Outside Serv - Meals & Enter	THE GALLERY RESTAURANT	28.86		28.86		
52100	160	Outside Serv - Meals & Enter	THE GOOD EGG WILLIAMS	72.15		72.15		
52100	160	Outside Serv - Meals & Enter	TUCSON GOLF/CONF GOLF	549.12		549.12		
55020	354	Software Licenses	ASPEN	150.00		150.00		
55020	354	Software Licenses	BEER BOTTOM'S BISTRO	48.44		48.44		
55020	354	Software Licenses	CHILI'S GRI56300005637	55.94		55.94		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
55020	354	Software Licenses	CHUMBO.COM	70.99		70.99		
79200	205	Subs & Ref Materials	WWW.COSTCO.COM	53.80		53.80		
79200	205	Subs & Ref Materials		243.17		243.17	COSTCO WHOLESALE	021606 835964
55000	403	Transportation Usage		2,310.41		2,310.41		
79010	272	Travel	9210150201BT	2,259.89		2,259.89		
79010	272	Travel	9210150350BT	6,227.93		6,227.93		
79010	272	Travel	9210250151BT	4,905.23		4,905.23		
79010	272	Travel	9210250151BT E-0101	2,875.19		2,875.19		
79010	272	Travel	9210250201BT	3,301.77		3,301.77		
79010	272	Travel	9210250350BT	3,207.64		3,207.64		
79010	272	Travel	9210400840BT	3,749.14		3,749.14		
79010	272	Travel	9210400840BT 4026	2,746.34		2,746.34		
79010	272	Travel	ALL RESORT EXPRESS	2,000.00		2,000.00		
79010	272	Travel	COURTYARD BY MARRIOTT-	2,669.55		2,669.55		
79010	272	Travel	EXPEDIA*TRAVEL	4,675.55		4,675.55		
79010	272	Travel	HERTZ RENT-A-CAR	2,361.14		2,361.14		
79010	272	Travel	HILTON HOTELS	3,878.46		3,878.46		
79010	272	Travel	HILTON HOTELS LINC CTR	2,969.14		2,969.14		
79010	272	Travel	HYATT HOTELS SAN FRANC	2,544.70		2,544.70		
79010	272	Travel	HYATT REGENCY WASHINGT	2,706.81		2,706.81		
79010	272	Travel	MARRIOTT 337E4 DESERT	3,248.14		3,248.14		
79010	272	Travel	MARRIOTT HOTELS UNIVER	2,261.98		2,261.98		
79010	272	Travel	OMNI HOTELS INTERLOCKE	3,197.22		3,197.22		
79010	272	Travel	SOIREE PRODUCTIONS WHI	3,043.17		3,043.17		
79010	272	Travel	THOROUGHBRED PAINT & B	2,439.84		2,439.84		
79010	281	Travel - Discretionary	CLAIM JUMPER #35	86.80		86.80		
79010	281	Travel - Discretionary		259.30		259.30		
79010	274	Travel - Lodging	THE BENJAMIN	3,916.04		3,916.04		
79010	275	Travel - Meals & Enter	1410 BIER MARKET RESTA	16.65		16.65		
79010	275	Travel - Meals & Enter	4TH AVE VINTAGE HIDEAW	46.25		46.25		
79010	275	Travel - Meals & Enter	9210150190ET	28.35		28.35		
79010	275	Travel - Meals & Enter	9210150201ET	535.43		535.43		
79010	275	Travel - Meals & Enter	9210150201ET 4026	90.40		90.40		
79010	275	Travel - Meals & Enter	9210150350ET	1,434.71		1,434.71		
79010	275	Travel - Meals & Enter	9210150350ET E-0044	78.16		78.16		
79010	275	Travel - Meals & Enter	9210150360ET	90.31		90.31		
79010	275	Travel - Meals & Enter	9210150360ET E-0295	37.07		37.07		
79010	275	Travel - Meals & Enter	9210150360ET E-0353	46.55		46.55		
79010	275	Travel - Meals & Enter	9210150360ET E-0475	57.85		57.85		
79010	275	Travel - Meals & Enter	9210250151ET	331.00		331.00		
79010	275	Travel - Meals & Enter	9210250151ET E-0101	433.53		433.53		
79010	275	Travel - Meals & Enter	9210250190ET	548.60		548.60		
79010	275	Travel - Meals & Enter	9210250201ET	540.83		540.83		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	275	Travel - Meals & Enter	9210250340ET	652.80		652.80		
79010	275	Travel - Meals & Enter	9210250341ET	38.19		38.19		
79010	275	Travel - Meals & Enter	9210250341ET		38.19	(38.19)		
79010	275	Travel - Meals & Enter	9210250350ET	561.61		561.61		
79010	275	Travel - Meals & Enter	9210250360ET	552.99		552.99		
79010	275	Travel - Meals & Enter	9210400360ET	240.00		240.00		
79010	275	Travel - Meals & Enter	9210400840ET	1,200.00		1,200.00		
79010	275	Travel - Meals & Enter	9210400840ET 4026	312.08		312.08		
79010	275	Travel - Meals & Enter	AJ S 122 SYM	119.60		119.60		
79010	275	Travel - Meals & Enter	AKIKO'S SUSHI BAR	20.76		20.76		
79010	275	Travel - Meals & Enter	ALADDIN-SPICE MARKET B	29.93		29.93		
79010	275	Travel - Meals & Enter	ALBERTSONS #961 S9H	17.16		17.16		
79010	275	Travel - Meals & Enter	ALBERTSONS #964	84.56		84.56		
79010	275	Travel - Meals & Enter	ALBERTSONS #972	28.08		28.08		
79010	275	Travel - Meals & Enter	ALBERTSONS #972 S9H	14.98		14.98		
79010	275	Travel - Meals & Enter	ALBUQUERQUE INT'L AIRP	21.25		21.25		
79010	275	Travel - Meals & Enter	ALEJANDRO'S CAFE	160.25		160.25		
79010	275	Travel - Meals & Enter	ALEXIS	42.50		42.50		
79010	275	Travel - Meals & Enter	AMERICA	26.57		26.57		
79010	275	Travel - Meals & Enter	APPLEBEE'S #17NEIGHBOR	19.83		19.83		
79010	275	Travel - Meals & Enter	APPLEBEES #511	163.30		163.30		
79010	275	Travel - Meals & Enter	APPLEBEE'S #602	184.34		184.34		
79010	275	Travel - Meals & Enter	APPLEBEE'S #605	10.47		10.47		
79010	275	Travel - Meals & Enter	APPLEBEE'S MEN00164087	52.46		52.46		
79010	275	Travel - Meals & Enter	ARBY'S #1180 00011Q52	9.74		9.74		
79010	275	Travel - Meals & Enter	ARBY'S #7019 Q52	11.92		11.92		
79010	275	Travel - Meals & Enter	ASIA GARDEN REST	22.32		22.32		
79010	275	Travel - Meals & Enter	ASPECT COMM STORE Q79	139.37		139.37		
79010	275	Travel - Meals & Enter	ASU-PANDINI'S 30012Q20	6.90		6.90		
79010	275	Travel - Meals & Enter	AU BON PAIN	7.07		7.07		
79010	275	Travel - Meals & Enter	AU BON PAIN #4	18.19		18.19		
79010	275	Travel - Meals & Enter	AU BON PAINS	17.76		17.76		
79010	275	Travel - Meals & Enter	AUNT CHILADAS	28.67		28.67		
79010	275	Travel - Meals & Enter	AUNTIE ANNE'S PRETZQ29	1.72		1.72		
79010	275	Travel - Meals & Enter	AVENUE GRILL	100.00		100.00		
79010	275	Travel - Meals & Enter	AZ MX COMMISSION	500.00		500.00		
79010	275	Travel - Meals & Enter	BACI RESTAURANT	35.25		35.25		
79010	275	Travel - Meals & Enter	BACK YARD BURGERS #032	6.98		6.98		
79010	275	Travel - Meals & Enter	BAGGINS STORE #10	1,159.07		1,159.07		
79010	275	Travel - Meals & Enter	BAGGINS STORE #8	1,248.69		1,248.69		
79010	275	Travel - Meals & Enter	BAGGINS STORE #9	8.43		8.43		
79010	275	Travel - Meals & Enter	BAHAMA BREEZE 00030114	39.33		39.33		
79010	275	Travel - Meals & Enter	BAMBOO TERRACE RESTAUR	121.88		121.88		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	275	Travel - Meals & Enter	BAMBOO TUCSON	648.68		648.68		
79010	275	Travel - Meals & Enter	BARNES & NOBLE #2060	4.28		4.28		
79010	275	Travel - Meals & Enter	BARRIO	528.41		528.41		
79010	275	Travel - Meals & Enter	BASHAS #160	19.16		19.16		
79010	275	Travel - Meals & Enter	BASHAS #86 SYW	55.86		55.86		
79010	275	Travel - Meals & Enter	BCG@LITTLE FIGS	23.78		23.78		
79010	275	Travel - Meals & Enter	BEAVER STREET BREW	82.70		82.70		
79010	275	Travel - Meals & Enter	BEER BOTTOM'S BISTRO	510.58		510.58		
79010	275	Travel - Meals & Enter	BELLAGIO HOTEL & CASIN	154.91		154.91		
79010	275	Travel - Meals & Enter	BENIHANA #OR	87.16		87.16		
79010	275	Travel - Meals & Enter	BENNIGANS	28.99		28.99		
79010	275	Travel - Meals & Enter	BEST WESTERN CENTRAL P	39.05		39.05		
79010	275	Travel - Meals & Enter	BEYOND BREAD	24.26		24.26		
79010	275	Travel - Meals & Enter	BEYOND BREAD-CAMPB	14.59		14.59		
79010	275	Travel - Meals & Enter	BIANCHIS ITALIAN	71.95		71.95		
79010	275	Travel - Meals & Enter	BIG CITY BBQ & GRILL	12.79		12.79		
79010	275	Travel - Meals & Enter	BIGFOOT BARBECUE	32.43		32.43		
79010	275	Travel - Meals & Enter	BLACK JACK PIZZA ST MA	44.70		44.70		
79010	275	Travel - Meals & Enter	BOB DOBBS	35.80		35.80		
79010	275	Travel - Meals & Enter	BOB THE FISH	20.01		20.01		
79010	275	Travel - Meals & Enter	BON APPETIT@ 51153Q99	19.36		19.36		
79010	275	Travel - Meals & Enter	BOOGA REDS	72.11		72.11		
79010	275	Travel - Meals & Enter	BOSTON MARKET #0444Q98	38.90		38.90		
79010	275	Travel - Meals & Enter	BOWLINS PICACHO PEAK P	3.38		3.38		
79010	275	Travel - Meals & Enter	BROOKLYNS	210.17		210.17		
79010	275	Travel - Meals & Enter	BRUEGGERS BAGEL BAKERY	344.15		344.15		
79010	275	Travel - Meals & Enter	BRUEGGER'S BAGELS -Q51	175.41		175.41		
79010	275	Travel - Meals & Enter	BRUEGGER'S BAGELS -Q55	11.69		11.69		
79010	275	Travel - Meals & Enter	BRUEGGERS BAGELS#29-02	31.11		31.11		
79010	275	Travel - Meals & Enter	BUBBA GUMP REST #344	65.00		65.00		
79010	275	Travel - Meals & Enter	BUDDY S GRILL	31.00		31.00		
79010	275	Travel - Meals & Enter	BUDDY'S	38.00		38.00		
79010	275	Travel - Meals & Enter	BUN HUGGERS WEST	20.64		20.64		
79010	275	Travel - Meals & Enter	BURGER KING #3109 Q07	6.25		6.25		
79010	275	Travel - Meals & Enter	BURGER KING #9759 Q07	4.61		4.61		
79010	275	Travel - Meals & Enter	BUSTER S RESTAURANT	50.84		50.84		
79010	275	Travel - Meals & Enter	BUSTERS	49.06		49.06		
79010	275	Travel - Meals & Enter	BUSY B S BAKERY	33.07		33.07		
79010	275	Travel - Meals & Enter	BUZZARDS-BOTTLESCREW B	28.17		28.17		
79010	275	Travel - Meals & Enter	CAFE A LA CART	1,479.48		1,479.48		
79010	275	Travel - Meals & Enter	CAFE METRO - CM -	33.55		33.55		
79010	275	Travel - Meals & Enter	CAFE METRO - CM - QAE	10.28		10.28		
79010	275	Travel - Meals & Enter	CAFE POCA COSA	560.68		560.68		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	275	Travel - Meals & Enter	CAFE TIRAMISU	26.70		26.70		
79010	275	Travel - Meals & Enter	CAFETERIA	33.02		33.02		
79010	275	Travel - Meals & Enter	CAFFE MILANO LLC	361.26		361.26		
79010	275	Travel - Meals & Enter	CALIFORNIA PIZZA 150	21.59		21.59		
79010	275	Travel - Meals & Enter	CANTINA GRILL B CONCOU	33.00		33.00		
79010	275	Travel - Meals & Enter	CAPITAL GRILLE 802	75.58		75.58		
79010	275	Travel - Meals & Enter	CAPPELLOS ITALIAN	77.55		77.55		
79010	275	Travel - Meals & Enter	CASA DEL FOOD SERVIQ44	9.50		9.50		
79010	275	Travel - Meals & Enter	CASA RIO MEXICAN FOODS	13.50		13.50		
79010	275	Travel - Meals & Enter	CASA SANCHEZ MOM'S MEX	36.05		36.05		
79010	275	Travel - Meals & Enter	CATTLEMEN'S #9	42.01		42.01		
79010	275	Travel - Meals & Enter	CATTLETOWN STEAKHOUSE	36.10		36.10		
79010	275	Travel - Meals & Enter	CB & POTTS #11	21.09		21.09		
79010	275	Travel - Meals & Enter	CHACO'S CAFE	143.52		143.52		
79010	275	Travel - Meals & Enter	CHAFFINS FAMILY RESTAU	21.22		21.22		
79010	275	Travel - Meals & Enter	CHALO S CASA DE REYNOS	30.24		30.24		
79010	275	Travel - Meals & Enter	CHARIOT PIZZA	481.09		481.09		
79010	275	Travel - Meals & Enter	CHARLESTON S CHANDLER	13.25		13.25		
79010	275	Travel - Meals & Enter	CHARLIECLARK'SSTEAKHOU	216.81		216.81		
79010	275	Travel - Meals & Enter	CHARLIE'S GRILLED SUBS	14.99		14.99		
79010	275	Travel - Meals & Enter	CHAYA BRASSERIE (SF)	122.42		122.42		
79010	275	Travel - Meals & Enter	CHEESECAKE DENVER	184.45		184.45		
79010	275	Travel - Meals & Enter	CHEESECAKE LAS VEGAS	38.50		38.50		
79010	275	Travel - Meals & Enter	CHEESECAKE NO SCOTTSDA	22.59		22.59		
79010	275	Travel - Meals & Enter	CHEESECAKE PHOENIX	27.46		27.46		
79010	275	Travel - Meals & Enter	CHEESECAKE STONEBRIAR	56.52		56.52		
79010	275	Travel - Meals & Enter	CHESAPEAKE BAGEL &BAKE	1.68		1.68		
79010	275	Travel - Meals & Enter	CHEVRON 0208629 Q61	3.66		3.66		
79010	275	Travel - Meals & Enter	CHILI'S GRI04600010462	166.16		166.16		
79010	275	Travel - Meals & Enter	CHILI'S GRI09500010959	45.79		45.79		
79010	275	Travel - Meals & Enter	CHILI'S GRI38100003814	21.32		21.32		
79010	275	Travel - Meals & Enter	CHILI'S GRI41600004168	34.79		34.79		
79010	275	Travel - Meals & Enter	CHILI'S GRI42700004275	92.58		92.58		
79010	275	Travel - Meals & Enter	CHILI'S GRI56300005637	461.32		461.32		
79010	275	Travel - Meals & Enter	CHINA GARDEN	30.86		30.86		
79010	275	Travel - Meals & Enter	CHINATOWN BUFFET	31.91		31.91		
79010	275	Travel - Meals & Enter	CHIPOTLE #0742 Q26	16.11		16.11		
79010	275	Travel - Meals & Enter	CHOPSTIX	113.15		113.15		
79010	275	Travel - Meals & Enter	CHRIS' CAFE	50.59		50.59		
79010	275	Travel - Meals & Enter	CHRISTMASTREE REST	211.67		211.67		
79010	275	Travel - Meals & Enter	CHU S MONGOLIAN BARBEQ	35.20		35.20		
79010	275	Travel - Meals & Enter	CHUCK WAGON STEAKH	90.05		90.05		
79010	275	Travel - Meals & Enter	CINNABON	31.97		31.97		

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79010	275	Travel - Meals & Enter	CINNABON #177 Q66	1.90		1.90		
79010	275	Travel - Meals & Enter	CIRCLE K 00423 Q04	4.56		4.56		
79010	275	Travel - Meals & Enter	CIRCLE K 01383 Q04	8.72		8.72		
79010	275	Travel - Meals & Enter	CLAIM JUMPER #35	3,558.78		3,558.78		
79010	275	Travel - Meals & Enter	CLIFF CASTLE CASINO	22.65		22.65		
79010	275	Travel - Meals & Enter	COCOS BAKERY RESTAURAN	20.03		20.03		
79010	275	Travel - Meals & Enter	CODYS BEEF AND BEANS	32.86		32.86		
79010	275	Travel - Meals & Enter	COFFEE PLANTATION	2.30		2.30		
79010	275	Travel - Meals & Enter	COFFEE POT RESTAURANT	16.89		16.89		
79010	275	Travel - Meals & Enter	COOKIES BY DESIGN OF T	80.85		80.85		
79010	275	Travel - Meals & Enter	COPPER SQUARE GRILL	25.38		25.38		
79010	275	Travel - Meals & Enter	CORKY'S BAR-B-Q	16.66		16.66		
79010	275	Travel - Meals & Enter	COSI # 48 Q83	4.38		4.38		
79010	275	Travel - Meals & Enter	COURTYARD BY MARRIOTT-	11.85		11.85		
79010	275	Travel - Meals & Enter	COYOTE CAFE & BISTRO A	16.95		16.95		
79010	275	Travel - Meals & Enter	COYOTE CREEK STEAK HOU	291.64		291.64		
79010	275	Travel - Meals & Enter	CRACKER BARREL #344	54.44		54.44		
79010	275	Travel - Meals & Enter	CRACKER BARREL #388	20.00		20.00		
79010	275	Travel - Meals & Enter	CRACKER BARREL #416	31.64		31.64		
79010	275	Travel - Meals & Enter	CRAVINGS RESTAURANT	190.00		190.00		
79010	275	Travel - Meals & Enter	CREWS OF CALIFORNI	1.99		1.99		
79010	275	Travel - Meals & Enter	CROSSCORNER	28.28		28.28		
79010	275	Travel - Meals & Enter	CROSSROADS RESTAURAN	74.00		74.00		
79010	275	Travel - Meals & Enter	CUVEE WORLD BISTRO	536.94		536.94		
79010	275	Travel - Meals & Enter	DAGLIOS CHEESESTEAKS &	59.45		59.45		
79010	275	Travel - Meals & Enter	DAISY MAE'S STRONGHOLD	33.15		33.15		
79010	275	Travel - Meals & Enter	DAVE & BUSTER'S #24	148.22		148.22		
79010	275	Travel - Meals & Enter	DAVE & BUSTER'S #29	38.33		38.33		
79010	275	Travel - Meals & Enter	DCA MARKETS	4.88		4.88		
79010	275	Travel - Meals & Enter	DE ANZA RESTAURANT & C	78.75		78.75		
79010	275	Travel - Meals & Enter	DEBS CONEY CAFE	26.49		26.49		
79010	275	Travel - Meals & Enter	DELECTABLES RESTAURANT	1,391.51		1,391.51		
79010	275	Travel - Meals & Enter	DENNY'S 00867432	243.08		243.08		
79010	275	Travel - Meals & Enter	DENNY'S #6534 Q67	20.91		20.91		
79010	275	Travel - Meals & Enter	DENNY'S #6614 Q67	41.02		41.02		
79010	275	Travel - Meals & Enter	DENNY'S #6716	21.06		21.06		
79010	275	Travel - Meals & Enter	DENNY'S #7297 Q67	50.00		50.00		
79010	275	Travel - Meals & Enter	DENNY'S #7415 Q67	14.76		14.76		
79010	275	Travel - Meals & Enter	DENNY'S INC Q67	86.76		86.76		
79010	275	Travel - Meals & Enter	DESERT DIAMOND CASINO	192.80		192.80		
79010	275	Travel - Meals & Enter	DIAMONDS CHINESE RESTA	38.75		38.75		
79010	275	Travel - Meals & Enter	DINING ARTISTS PT	138.16		138.16		
79010	275	Travel - Meals & Enter	DISNEY HILTON RESTRNT	15.99		15.99		

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79010	275	Travel - Meals & Enter	DIZZY GS RESTAURANT	34.39		34.39		
79010	275	Travel - Meals & Enter	DOMINOES PIZZA #7634	206.83		206.83		
79010	275	Travel - Meals & Enter	DON ALEJANDROS TEXAN G	28.00		28.00		
79010	275	Travel - Meals & Enter	DONOVANS STEAK AND	225.00		225.00		
79010	275	Travel - Meals & Enter	DOUBE D'S SPORTS GRILL	48.85		48.85		
79010	275	Travel - Meals & Enter	DOUBLETREE HOTEL F&B	85.54		85.54		
79010	275	Travel - Meals & Enter	DRAGON VILLAGE RES	43.10		43.10		
79010	275	Travel - Meals & Enter	DUCK & DECANTER	187.53		187.53		
79010	275	Travel - Meals & Enter	DUNKIN DONUTS	22.36		22.36		
79010	275	Travel - Meals & Enter	DUNKIN DONUTS #306705	5.89		5.89		
79010	275	Travel - Meals & Enter	DURANTS	35.87		35.87		
79010	275	Travel - Meals & Enter	EAGLEWOOD RESORT AND S	3.20		3.20		
79010	275	Travel - Meals & Enter	EAST SIDE MARIOS	9.03		9.03		
79010	275	Travel - Meals & Enter	ECLECTIC CAFE	31.67		31.67		
79010	275	Travel - Meals & Enter	EEGEE S	427.38		427.38		
79010	275	Travel - Meals & Enter	EINSTEIN BROS #3064	78.02		78.02		
79010	275	Travel - Meals & Enter	EL CHARO	204.00		204.00		
79010	275	Travel - Meals & Enter	EL CHARRO-ORIGINAL	293.81		293.81		
79010	275	Travel - Meals & Enter	EL CORRAL RESTAURANT	3.75		3.75		
79010	275	Travel - Meals & Enter	EL GUERO CANELO	92.18		92.18		
79010	275	Travel - Meals & Enter	EL MINUTO CAFE	498.03		498.03		
79010	275	Travel - Meals & Enter	EL MOLINITO	170.05		170.05		
79010	275	Travel - Meals & Enter	EL PARADOR	23.10		23.10		
79010	275	Travel - Meals & Enter	EL PASO BAR B QUE	260.58		260.58		
79010	275	Travel - Meals & Enter	EL PASO BAR-B-QUE 555	1,249.71		1,249.71		
79010	275	Travel - Meals & Enter	EL POLLO #3567	8.41		8.41		
79010	275	Travel - Meals & Enter	EL SABROSO	99.14		99.14		
79010	275	Travel - Meals & Enter	EL SAGUARITO	493.35		493.35		
79010	275	Travel - Meals & Enter	EL SUR RESTAURANT	47.67		47.67		
79010	275	Travel - Meals & Enter	EL TACO TOTE #7	48.15		48.15		
79010	275	Travel - Meals & Enter	EL TORERO	99.53		99.53		
79010	275	Travel - Meals & Enter	ELEPHANT BAR # 228	31.24		31.24		
79010	275	Travel - Meals & Enter	ELLE A WINE COUNTRY RE	102.00		102.00		
79010	275	Travel - Meals & Enter	EMERILS NO FISH HOUSE	29.63		29.63		
79010	275	Travel - Meals & Enter	ENOTECA PIZZARIA WINE	1,657.53		1,657.53		
79010	275	Travel - Meals & Enter	F15751 MCDONALD'S Q17	6.27		6.27		
79010	275	Travel - Meals & Enter	FAMOUS DAVE'S BBQ	74.49		74.49		
79010	275	Travel - Meals & Enter	FAMOUS SAMS #17	28.00		28.00		
79010	275	Travel - Meals & Enter	FAMOUS SAMS #28	157.96		157.96		
79010	275	Travel - Meals & Enter	FIESTA MEXICANA #7	44.16		44.16		
79010	275	Travel - Meals & Enter	FINEMONDO	1,208.16		1,208.16		
79010	275	Travel - Meals & Enter	FIRST WATCH #4	11.27		11.27		
79010	275	Travel - Meals & Enter	FISH MARKET SD	26.05		26.05		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	275	Travel - Meals & Enter	FISH MARKET SM	39.00		39.00		
79010	275	Travel - Meals & Enter	FLATIRON CAFE	53.22		53.22		
79010	275	Travel - Meals & Enter	FONTINA RISTORANTE	27.73		27.73		
79010	275	Travel - Meals & Enter	FOOD CITY #147 ST3	205.74		205.74		
79010	275	Travel - Meals & Enter	FOOD CITY #77 SYW	221.23		221.23		
79010	275	Travel - Meals & Enter	FOX & HOUND #65057	226.01		226.01		
79010	275	Travel - Meals & Enter	FRIDAYS_FRONT_ROW #060	19.98		19.98		
79010	275	Travel - Meals & Enter	FROG & FIRKIN	34.08		34.08		
79010	275	Travel - Meals & Enter	FRYS-FOOD-DRG #0090SXN	21.99		21.99		
79010	275	Travel - Meals & Enter	FRYS-FOOD-DRG #017 SXN	29.79		29.79		
79010	275	Travel - Meals & Enter	FRYS-FOOD-DRG #033 SXN	7.00		7.00		
79010	275	Travel - Meals & Enter	FRYS-FOOD-DRG #036 SXN	243.95		243.95		
79010	275	Travel - Meals & Enter	FRYS-FOOD-DRG #042 SXN	81.77		81.77		
79010	275	Travel - Meals & Enter	FRYS-FOOD-DRG #058 SXN	1,041.60		1,041.60		
79010	275	Travel - Meals & Enter	FRYS-FOOD-DRG #119 SXN	399.73		399.73		
79010	275	Travel - Meals & Enter	FRYS-FOOD-DRG #138 SXN	89.25		89.25		
79010	275	Travel - Meals & Enter	FUJI SUSHI RESTA	37.33		37.33		
79010	275	Travel - Meals & Enter	FUNG LUM	32.60		32.60		
79010	275	Travel - Meals & Enter	GALAXY DINER 605	19.83		19.83		
79010	275	Travel - Meals & Enter	GAVI ITALIAN RESTAURAN	126.55		126.55		
79010	275	Travel - Meals & Enter	GEES GARDEN RESTAURANT	27.87		27.87		
79010	275	Travel - Meals & Enter	GENTLE BENS BREWING CO	29.59		29.59		
79010	275	Travel - Meals & Enter	GINAS STROMBOLIS	23.50		23.50		
79010	275	Travel - Meals & Enter	GINSENG BBQ NO 2	39.22		39.22		
79010	275	Travel - Meals & Enter	GODIVA CHOCOLATES #281	228.00		228.00		
79010	275	Travel - Meals & Enter	GODIVA CHOCOLATES #361	194.00		194.00		
79010	275	Travel - Meals & Enter	GOLDEN CORRAL 29724Q15	14.21		14.21		
79010	275	Travel - Meals & Enter	GOLDEN CORRAL 730	58.80		58.80		
79010	275	Travel - Meals & Enter	GONZALEZ Y GONZALEZ	33.11		33.11		
79010	275	Travel - Meals & Enter	GORDON BIERSCH-LAS VEG	31.38		31.38		
79010	275	Travel - Meals & Enter	GORDON BIERSCH-WASH DC	54.64		54.64		
79010	275	Travel - Meals & Enter	GREER LODGE	313.75		313.75		
79010	275	Travel - Meals & Enter	GRILL 417	67.75		67.75		
79010	275	Travel - Meals & Enter	GUILLERMOS DOUBLE L RE	301.56		301.56		
79010	275	Travel - Meals & Enter	HARRAHS CASINO FOOD &	94.50		94.50		
79010	275	Travel - Meals & Enter	HARRAHS FRESH MKT BUFF	20.31		20.31		
79010	275	Travel - Meals & Enter	HILTON HOTELS STS BRNT	23.56		23.56		
79010	275	Travel - Meals & Enter	HILTON SANTA CLARA CAF	3.95		3.95		
79010	275	Travel - Meals & Enter	HILTON SEDONA RESORT F	45.19		45.19		
79010	275	Travel - Meals & Enter	HILTON TUCSON EAST F A	13.49		13.49		
79010	275	Travel - Meals & Enter	HMS HOST - LAS-AIRPT	24.18		24.18		
79010	275	Travel - Meals & Enter	HMS HOST DFW AIRPT #15	4.49		4.49		
79010	275	Travel - Meals & Enter	HMS HOST-LAS-AIRPT #55	37.92		37.92		

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79010	275	Travel - Meals & Enter	HMS HOST-LAS-AIRPT #81	49.38		49.38		
79010	275	Travel - Meals & Enter	HMS HOST-LAS-AIRPT#241	7.09		7.09		
79010	275	Travel - Meals & Enter	HMS HOST-LAS-AIRPT#Q63	5.69		5.69		
79010	275	Travel - Meals & Enter	HMS HOST-ORD AIRPT #6	35.06		35.06		
79010	275	Travel - Meals & Enter	HMS HOST-ORD AIRPT #81	39.57		39.57		
79010	275	Travel - Meals & Enter	HMS HOST-ORD AIRPT #83	36.75		36.75		
79010	275	Travel - Meals & Enter	HMS HOST-PHX AIRPT Q63	7.65		7.65		
79010	275	Travel - Meals & Enter	HMSHOST SAN AIRPT #02	13.10		13.10		
79010	275	Travel - Meals & Enter	HMSHOST-LAS-AIRPT #000	87.24		87.24		
79010	275	Travel - Meals & Enter	HMSHOST-LAX-AIR #00	38.43		38.43		
79010	275	Travel - Meals & Enter	HMSHOST-PHX-AIR #00	42.70		42.70		
79010	275	Travel - Meals & Enter	HMSHOST-PHX-AIR #04	6.47		6.47		
79010	275	Travel - Meals & Enter	HMSHOST-SLC-AIRPT 0820	43.62		43.62		
79010	275	Travel - Meals & Enter	HONEY BEARS BBQ 2	37.70		37.70		
79010	275	Travel - Meals & Enter	HONEYBAKED-HAM #0056	93.14		93.14		
79010	275	Travel - Meals & Enter	HOTEL BRUNSWICK	42.00		42.00		
79010	275	Travel - Meals & Enter	HOUSTON'S 480.922.7775	41.54		41.54		
79010	275	Travel - Meals & Enter	HOUSTON'S 602.957.9700	259.94		259.94		
79010	275	Travel - Meals & Enter	HRC-NEW YORK 10011013	41.35		41.35		
79010	275	Travel - Meals & Enter	HRC-PHOENIX 10011435	24.00		24.00		
79010	275	Travel - Meals & Enter	HRC-SN ANTONIO10011120	50.50		50.50		
79010	275	Travel - Meals & Enter	HUNAN WEST	18.16		18.16		
79010	275	Travel - Meals & Enter	HYATT HOTELS SAN FRANC	31.25		31.25		
79010	275	Travel - Meals & Enter	HYATT REGENCY WASHINGT	4.00		4.00		
79010	275	Travel - Meals & Enter	I LOVE TERIYAKI	6.93		6.93		
79010	275	Travel - Meals & Enter	ICHIBAN SUSHI RESTAURA	35.33		35.33		
79010	275	Travel - Meals & Enter	IHOP #1513 18515130	23.15		23.15		
79010	275	Travel - Meals & Enter	IHOP #1517 21815170	80.95		80.95		
79010	275	Travel - Meals & Enter	IHOP #1522 34615229	47.33		47.33		
79010	275	Travel - Meals & Enter	IKES COFFEE & TEA N ST	48.86		48.86		
79010	275	Travel - Meals & Enter	IL FORNAIO - LAS VEGAS	59.51		59.51		
79010	275	Travel - Meals & Enter	IN-N-OUT BURGER 000000	4.01		4.01		
79010	275	Travel - Meals & Enter	IN-N-OUT BURGERS	32.75		32.75		
79010	275	Travel - Meals & Enter	INTERMEZZO	80.48		80.48		
79010	275	Travel - Meals & Enter	INTERNATIONAL TRANSACTION	8.97		8.97		
79010	275	Travel - Meals & Enter	IRON CACTUS	18.08		18.08		
79010	275	Travel - Meals & Enter	IT'S A GRIND Q21	33.95		33.95		
79010	275	Travel - Meals & Enter	JACKSONS GRILL	17.00		17.00		
79010	275	Travel - Meals & Enter	JACKSONS ON THIRD LLC	49.22		49.22		
79010	275	Travel - Meals & Enter	JALEO	84.31		84.31		
79010	275	Travel - Meals & Enter	JASON'S DELI	2,986.92		2,986.92		
79010	275	Travel - Meals & Enter	JAVA BLUES	262.11		262.11		
79010	275	Travel - Meals & Enter	JAZZMANS 1	3.95		3.95		

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79010	275	Travel - Meals & Enter	JERRY BOB'S	44.56		44.56		
79010	275	Travel - Meals & Enter	JOES CRAB SHACK-LAUGHL	23.65		23.65		
79010	275	Travel - Meals & Enter	JOE'S CRAB SHACK-TEMPE	37.15		37.15		
79010	275	Travel - Meals & Enter	JOE'S CRAB-AURORA, CO	93.21		93.21		
79010	275	Travel - Meals & Enter	JOE'S CRAB-SA #3 RVERW	24.60		24.60		
79010	275	Travel - Meals & Enter	JOE'S CRAB-TUCSON	261.72		261.72		
79010	275	Travel - Meals & Enter	JOES PLACE	12.76		12.76		
79010	275	Travel - Meals & Enter	JOHNNY ROCKETS-TUC	20.26		20.26		
79010	275	Travel - Meals & Enter	JOSEPHINE'S MODERN	113.53		113.53		
79010	275	Travel - Meals & Enter	JUNIOR'S NYC	51.33		51.33		
79010	275	Travel - Meals & Enter	KELLYS COFFEE AND	9.55		9.55		
79010	275	Travel - Meals & Enter	KFC #10 Q20	30.39		30.39		
79010	275	Travel - Meals & Enter	KG'S WESTSIDE CAFE	19.03		19.03		
79010	275	Travel - Meals & Enter	KIM CHI	34.62		34.62		
79010	275	Travel - Meals & Enter	KINCAID S	75.18		75.18		
79010	275	Travel - Meals & Enter	KINGMAN CO STEAKHOUSE	24.00		24.00		
79010	275	Travel - Meals & Enter	KINGMAN DELI, THE	24.00		24.00		
79010	275	Travel - Meals & Enter	KING'S ORIENTAL FAST F	21.05		21.05		
79010	275	Travel - Meals & Enter	KINZIE CHOPHOUSE	58.88		58.88		
79010	275	Travel - Meals & Enter	KMART 00049SZI	334.17		334.17		
79010	275	Travel - Meals & Enter	KOBE STEAKHOUSE - TEMP	71.51		71.51		
79010	275	Travel - Meals & Enter	KONA CAFE	43.75		43.75		
79010	275	Travel - Meals & Enter	KRISPY KREME 15 05	14.36		14.36		
79010	275	Travel - Meals & Enter	LA CANASTA #1	28.39		28.39		
79010	275	Travel - Meals & Enter	LA CANASTA CAPITOLIO	39.28		39.28		
79010	275	Travel - Meals & Enter	LA FONDA MEXICAN FOODS	25.41		25.41		
79010	275	Travel - Meals & Enter	LA PARILLA SUIZA	205.14		205.14		
79010	275	Travel - Meals & Enter	LA PLAYA HOTEL RESTAUR	98.75		98.75		
79010	275	Travel - Meals & Enter	LA SALSA 76	25.87		25.87		
79010	275	Travel - Meals & Enter	LA SANDIA CAFE 1	9.04		9.04		
79010	275	Travel - Meals & Enter	LANDRY'S-SA DOWNTOWN	57.55		57.55		
79010	275	Travel - Meals & Enter	LAS CAZUELITAS LLC	27.95		27.95		
79010	275	Travel - Meals & Enter	LAS VEGAS SPORTS LOUNG	14.00		14.00		
79010	275	Travel - Meals & Enter	LAS VIGAS STEAK RANCH	33.37		33.37		
79010	275	Travel - Meals & Enter	LAWRY'S	134.21		134.21		
79010	275	Travel - Meals & Enter	LAX AIRPORT-PUCKS T7	16.23		16.23		
79010	275	Travel - Meals & Enter	LE CAVES BAKERY	11.98		11.98		
79010	275	Travel - Meals & Enter	LEBANESE TAVERNA	33.80		33.80		
79010	275	Travel - Meals & Enter	LEGENDS OF SAN FRANCIS	20.21		20.21		
79010	275	Travel - Meals & Enter	LERUA'S	41.38		41.38		
79010	275	Travel - Meals & Enter	LEVY GRP SALE 90085002	30.55		30.55		
79010	275	Travel - Meals & Enter	LIGHTNING RIDGE CAFE	2,348.54		2,348.54		
79010	275	Travel - Meals & Enter	LITTLE ANTHONY S DINER	876.36		876.36		

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79010	275	Travel - Meals & Enter	LITTLE CAESARS 3168	12.43		12.43		
79010	275	Travel - Meals & Enter	LITTLE MEXICO RESTAURA	82.60		82.60		
79010	275	Travel - Meals & Enter	LODGE ON THE DESERT	101.00		101.00		
79010	275	Travel - Meals & Enter	LOMBARDI'S RESTAURANT	245.21		245.21		
79010	275	Travel - Meals & Enter	LONE STAR 00128017	15.46		15.46		
79010	275	Travel - Meals & Enter	LONGHORN #248	33.54		33.54		
79010	275	Travel - Meals & Enter	LOS BETOS MEXICAN	19.13		19.13		
79010	275	Travel - Meals & Enter	LOS RANCHOS RESTAURANT	75.03		75.03		
79010	275	Travel - Meals & Enter	LUKES ITALIAN BEEF	28.00		28.00		
79010	275	Travel - Meals & Enter	LV HILTON BUFFET	14.00		14.00		
79010	275	Travel - Meals & Enter	MACARONI GR16300001636	1,037.91		1,037.91		
79010	275	Travel - Meals & Enter	MACARONI GR23300002337	22.13		22.13		
79010	275	Travel - Meals & Enter	MACARONI GR30100003012	97.26		97.26		
79010	275	Travel - Meals & Enter	MACAYO DEPOT	72.38		72.38		
79010	275	Travel - Meals & Enter	MAGPIES GOURMET PIZZA	166.99		166.99		
79010	275	Travel - Meals & Enter	MAIN STREET CATERI	23.00		23.00		
79010	275	Travel - Meals & Enter	MAMA LOUISAS	97.03		97.03		
79010	275	Travel - Meals & Enter	MAMA'S FAMOUS # 2	28.46		28.46		
79010	275	Travel - Meals & Enter	MAMBO CAFE2	45.76		45.76		
79010	275	Travel - Meals & Enter	MANDARIN ORIENTAL SAN	58.21		58.21		
79010	275	Travel - Meals & Enter	MARGARITAVILLE RESTAUR	21.00		21.00		
79010	275	Travel - Meals & Enter	MARIE CALLENDER'S REST	19.26		19.26		
79010	275	Travel - Meals & Enter	MARISCOS CHIHUAHUA	29.71		29.71		
79010	275	Travel - Meals & Enter	MARKET CITY CAFE	25.96		25.96		
79010	275	Travel - Meals & Enter	MARRIOTT 33758 SLC	50.00		50.00		
79010	275	Travel - Meals & Enter	MARRIOTT 337E4 DESERT	11.85		11.85		
79010	275	Travel - Meals & Enter	MATSUTAKE - NATL AIRPO	20.98		20.98		
79010	275	Travel - Meals & Enter	MCCORMICK & SCHMICK #7	122.20		122.20		
79010	275	Travel - Meals & Enter	MCDONALD'S F11538 Q17	11.85		11.85		
79010	275	Travel - Meals & Enter	MCDONALD'S F18788 Q17	11.56		11.56		
79010	275	Travel - Meals & Enter	MCDONALD'S F22627 Q17	16.71		16.71		
79010	275	Travel - Meals & Enter	MCDONALD'S F24530 Q17	6.67		6.67		
79010	275	Travel - Meals & Enter	MCDONALD'S F8010 Q17	36.10		36.10		
79010	275	Travel - Meals & Enter	MCMAHON'S STEAKHOUSE	117.16		117.16		
79010	275	Travel - Meals & Enter	MEI HON	85.18		85.18		
79010	275	Travel - Meals & Enter	MEI WAH RESTAURANT	14.80		14.80		
79010	275	Travel - Meals & Enter	MERLOT BISTRO	44.58		44.58		
79010	275	Travel - Meals & Enter	METRO GRILL PARK PLACE	469.50		469.50		
79010	275	Travel - Meals & Enter	METROPOLITAN GRILL	174.57		174.57		
79010	275	Travel - Meals & Enter	MI AMIGOS-AZ CENTE	59.83		59.83		
79010	275	Travel - Meals & Enter	MI NIDITO	63.24		63.24		
79010	275	Travel - Meals & Enter	MICHAS	1,139.13		1,139.13		
79010	275	Travel - Meals & Enter	MICHAS DEL NORTE	81.51		81.51		

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79010	275	Travel - Meals & Enter	MICROBREWERY	129.74		129.74		
79010	275	Travel - Meals & Enter	MIGUELS ON ORACLE	687.79		687.79		
79010	275	Travel - Meals & Enter	MIMIS CAFE 00000356	80.58		80.58		
79010	275	Travel - Meals & Enter	MING	24.98		24.98		
79010	275	Travel - Meals & Enter	MING'S TABLE	27.62		27.62		
79010	275	Travel - Meals & Enter	MIRAGE HOTEL - STACK	19.00		19.00		
79010	275	Travel - Meals & Enter	MOLLY BUTLER LODGE	186.52		186.52		
79010	275	Travel - Meals & Enter	MONTANA AVENUE	56.23		56.23		
79010	275	Travel - Meals & Enter	MORGANS FOOD & SPIRITS	32.05		32.05		
79010	275	Travel - Meals & Enter	MR. C'S RESTAURANT	118.72		118.72		
79010	275	Travel - Meals & Enter	MRS. FIELDS BAKERY CAF	92.71		92.71		
79010	275	Travel - Meals & Enter	MUDSHARK BREWING CO	89.45		89.45		
79010	275	Travel - Meals & Enter	NADINES PASTRY SHOPPE	405.99		405.99		
79010	275	Travel - Meals & Enter	NAGE RESTAURANT, D.C.	49.00		49.00		
79010	275	Travel - Meals & Enter	NATHAN S FAMOUS HOT DO	11.30		11.30		
79010	275	Travel - Meals & Enter	NAU DINING#94010007	233.74		233.74		
79010	275	Travel - Meals & Enter	NAVY PIER 71229	22.00		22.00		
79010	275	Travel - Meals & Enter	NELLIES KITCHEN	12.18		12.18		
79010	275	Travel - Meals & Enter	NEW YORK LUNCHEONETTE	47.45		47.45		
79010	275	Travel - Meals & Enter	NEW YORK PIZZA DEPT	8.92		8.92		
79010	275	Travel - Meals & Enter	NIJI JAPANESE GRILLE	12.66		12.66		
79010	275	Travel - Meals & Enter	NOTHING BUT NOODLE	33.58		33.58		
79010	275	Travel - Meals & Enter	OAXACA RESTAURANTE	416.48		416.48		
79010	275	Travel - Meals & Enter	O'CHARLEY'S #213	34.27		34.27		
79010	275	Travel - Meals & Enter	OCOTILLO GOLF RESORT	57.67		57.67		
79010	275	Travel - Meals & Enter	OISHI SUSHI & TERIYAKI	15.32		15.32		
79010	275	Travel - Meals & Enter	OLD PEKING CHINESE RES	50.10		50.10		
79010	275	Travel - Meals & Enter	OLD PUEBLO GRILLE	1,387.36		1,387.36		
79010	275	Travel - Meals & Enter	OMARS HIGHWAY CHEF RES	79.81		79.81		
79010	275	Travel - Meals & Enter	ON THE BORD12600001263	247.47		247.47		
79010	275	Travel - Meals & Enter	ON THE BORDER 00000315	34.68		34.68		
79010	275	Travel - Meals & Enter	ORACLE CAFE 2 Q70	17.02		17.02		
79010	275	Travel - Meals & Enter	OREGANO S	60.54		60.54		
79010	275	Travel - Meals & Enter	OREGANOS	44.01		44.01		
79010	275	Travel - Meals & Enter	OREILLYS PUB	42.90		42.90		
79010	275	Travel - Meals & Enter	ORLEANS FR MKT BUFFET	34.75		34.75		
79010	275	Travel - Meals & Enter	OSHA THAI RESTAURANT &	37.47		37.47		
79010	275	Travel - Meals & Enter	OUR DAILY BREAD	15.03		15.03		
79010	275	Travel - Meals & Enter	OUTBACK #0315	60.84		60.84		
79010	275	Travel - Meals & Enter	OUTBACK #0317	58.42		58.42		
79010	275	Travel - Meals & Enter	OUTBACK #3333	43.83		43.83		
79010	275	Travel - Meals & Enter	P.F. CHANG'S #5800	38.68		38.68		
79010	275	Travel - Meals & Enter	P.F. CHANG'S #8000	228.71		228.71		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	275	Travel - Meals & Enter	P.F. CHANG'S CHINA BIS	51.19		51.19		
79010	275	Travel - Meals & Enter	PALM REST VEGAS	308.30		308.30		
79010	275	Travel - Meals & Enter	PANDA EXPRESS 00007Q42	7.60		7.60		
79010	275	Travel - Meals & Enter	PANDA EXPRESS 00011Q42	30.56		30.56		
79010	275	Travel - Meals & Enter	PAOLOS GEORGETOWN	37.19		37.19		
79010	275	Travel - Meals & Enter	PAPA JOHNS #2008	177.43		177.43		
79010	275	Travel - Meals & Enter	PAPA JOHNS #2008.COM	43.10		43.10		
79010	275	Travel - Meals & Enter	PAPA JOHNS #3115.COM	60.41		60.41		
79010	275	Travel - Meals & Enter	PARADIES WASH NAT L	7.01		7.01		
79010	275	Travel - Meals & Enter	PARIS LE VILLAGE BUFFE	92.21		92.21		
79010	275	Travel - Meals & Enter	PARK CENTRAL DELI	38.69		38.69		
79010	275	Travel - Meals & Enter	PARRILLA DEL REY	25.30		25.30		
79010	275	Travel - Meals & Enter	PASTICHE MODERN EATERY	37.60		37.60		
79010	275	Travel - Meals & Enter	PASTO	179.45		179.45		
79010	275	Travel - Meals & Enter	PATS PLACE	20.40		20.40		
79010	275	Travel - Meals & Enter	PEETS SFO #4	13.64		13.64		
79010	275	Travel - Meals & Enter	PEI WEI ASIAN DINER-00	98.42		98.42		
79010	275	Travel - Meals & Enter	PEI WEI ASIAN DINER-01	20.54		20.54		
79010	275	Travel - Meals & Enter	PERSIAN ROOM	160.52		160.52		
79010	275	Travel - Meals & Enter	PETER PIPER PIZZA	19.97		19.97		
79010	275	Travel - Meals & Enter	PETER PIPER PIZZA #162	28.45		28.45		
79010	275	Travel - Meals & Enter	PF CHANGS #9914	27.29		27.29		
79010	275	Travel - Meals & Enter	PHOENIX AIRPORT	8.92		8.92		
79010	275	Travel - Meals & Enter	PINNACLE PEAK	72.00		72.00		
79010	275	Travel - Meals & Enter	PIZZA H011645 01201078	31.53		31.53		
79010	275	Travel - Meals & Enter	PIZZA HUT 07030Q00	25.12		25.12		
79010	275	Travel - Meals & Enter	PIZZA HUT #10557500Q34	54.54		54.54		
79010	275	Travel - Meals & Enter	PIZZA HUT #14357500Q34	240.13		240.13		
79010	275	Travel - Meals & Enter	PIZZA HUT #14357543Q	365.00		365.00		
79010	275	Travel - Meals & Enter	PIZZA HUT C19	4.82		4.82		
79010	275	Travel - Meals & Enter	PIZZA HUT C5	9.02		9.02		
79010	275	Travel - Meals & Enter	PLANET HOLLYWOOD	80.01		80.01		
79010	275	Travel - Meals & Enter	PLAZA CAFE	5.95		5.95		
79010	275	Travel - Meals & Enter	PORT A PIT CATERING	1,349.30		1,349.30		
79010	275	Travel - Meals & Enter	PORTLANDS	91.67		91.67		
79010	275	Travel - Meals & Enter	POTBELLY SANDWCH58 Q86	7.34		7.34		
79010	275	Travel - Meals & Enter	PRIME RIB GRILL	15.73		15.73		
79010	275	Travel - Meals & Enter	QUESADILLIA'S GRILL/ M	14.53		14.53		
79010	275	Travel - Meals & Enter	QUIZNO S ALB	8.84		8.84		
79010	275	Travel - Meals & Enter	QUIZNOS CLASSIC SUBS	7.22		7.22		
79010	275	Travel - Meals & Enter	QUIZNO'S SUB #2515	22.09		22.09		
79010	275	Travel - Meals & Enter	QUIZNOS SUB #3255 Q22	56.47		56.47		
79010	275	Travel - Meals & Enter	QUIZNOS SUB #4297 Q19	28.54		28.54		

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79010	275	Travel - Meals & Enter	QUIZNOS SUB #9515	8.09		8.09		
79010	275	Travel - Meals & Enter	R&G LOUNGE	43.90		43.90		
79010	275	Travel - Meals & Enter	RADISON WILSHIRE	107.00		107.00		
79010	275	Travel - Meals & Enter	RAINFOREST SAN ANTONIO	28.76		28.76		
79010	275	Travel - Meals & Enter	RAINFOREST-AZ REST.	38.62		38.62		
79010	275	Travel - Meals & Enter	RAINFOREST-DISNEY WRLD	36.63		36.63		
79010	275	Travel - Meals & Enter	RAINFOREST-GRAPEVINE	56.34		56.34		
79010	275	Travel - Meals & Enter	RAINFOREST-MGM GRAND	19.99		19.99		
79010	275	Travel - Meals & Enter	RED LOBSTER US00006007	46.48		46.48		
79010	275	Travel - Meals & Enter	RED LOBSTER US00008698	56.56		56.56		
79010	275	Travel - Meals & Enter	RED LOBSTER US00063032	25.75		25.75		
79010	275	Travel - Meals & Enter	RED ROBIN	68.07		68.07		
79010	275	Travel - Meals & Enter	RED ROBIN NO 195	21.58		21.58		
79010	275	Travel - Meals & Enter	RED ROBIN RESTAURANT	127.18		127.18		
79010	275	Travel - Meals & Enter	RENDEZVOUS RANCH INC	5,170.00		5,170.00		
79010	275	Travel - Meals & Enter	RIGO S RESTAURANT	159.78		159.78		
79010	275	Travel - Meals & Enter	RINCON MARKET	758.33		758.33		
79010	275	Travel - Meals & Enter	RINCON MARKET SRI	45.88		45.88		
79010	275	Travel - Meals & Enter	RISKY BUSINESS #4	302.38		302.38		
79010	275	Travel - Meals & Enter	RIVA RISTORANTE	48.68		48.68		
79010	275	Travel - Meals & Enter	ROCK BOTTOM 1077	84.73		84.73		
79010	275	Travel - Meals & Enter	RONS PRODUCE CO INC	261.10		261.10		
79010	275	Travel - Meals & Enter	ROSINELLA	19.75		19.75		
79010	275	Travel - Meals & Enter	ROXANNE CAFE	30.00		30.00		
79010	275	Travel - Meals & Enter	ROYS #2303	143.70		143.70		
79010	275	Travel - Meals & Enter	RUBIO'S AGUA FRIA #52	11.86		11.86		
79010	275	Travel - Meals & Enter	RUBIO'S AHWATUKEE #35	29.78		29.78		
79010	275	Travel - Meals & Enter	RUBY RIVER #405	83.40		83.40		
79010	275	Travel - Meals & Enter	RUBY TUESDAY #2632	14.98		14.98		
79010	275	Travel - Meals & Enter	RUMBI, AZ PROMENADE	11.41		11.41		
79010	275	Travel - Meals & Enter	RUSTY S FAMILY RESTAUR	43.00		43.00		
79010	275	Travel - Meals & Enter	RUSTY'S	82.70		82.70		
79010	275	Travel - Meals & Enter	SABELLA & LATORRE SEAF	15.40		15.40		
79010	275	Travel - Meals & Enter	SACHIKO SUSHI II	224.88		224.88		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00002550	359.60		359.60		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00002683	4.50		4.50		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00002Q	70.24		70.24		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00002SC9	301.94		301.94		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00012559	27.42		27.42		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00012757	28.31		28.31		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00015214	76.33		76.33		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00015SC9	38.66		38.66		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00018747	108.52		108.52		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00018SC9	5.99		5.99		

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79010	275	Travel - Meals & Enter	SAFEWAY STORE00020446	5.01		5.01		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00020768	11.25		11.25		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00020SC9	6.67		6.67		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00026112	33.61		33.61		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00026SC9	89.82		89.82		
79010	275	Travel - Meals & Enter	SAFEWAY STORE 00019851	8.83		8.83		
79010	275	Travel - Meals & Enter	SAFEWAY STORE 00019877	75.27		75.27		
79010	275	Travel - Meals & Enter	SAFEWAY STORE 00019901	33.13		33.13		
79010	275	Travel - Meals & Enter	SAFEWAY STORE 00019Q	15.98		15.98		
79010	275	Travel - Meals & Enter	SAFEWAY STORE 00019SC9	420.68		420.68		
79010	275	Travel - Meals & Enter	SAKURA EAST	179.39		179.39		
79010	275	Travel - Meals & Enter	SALSA FIESTA	29.13		29.13		
79010	275	Travel - Meals & Enter	SAM HUGHES PLACE	1,051.95		1,051.95		
79010	275	Travel - Meals & Enter	SAM'S CAFE-AZ CENTER	42.84		42.84		
79010	275	Travel - Meals & Enter	SAN MARTIN	48.20		48.20		
79010	275	Travel - Meals & Enter	SASSOS PIZZA & DELI	12.13		12.13		
79010	275	Travel - Meals & Enter	SAUCE	47.83		47.83		
79010	275	Travel - Meals & Enter	SAUSAGE DELI	209.35		209.35		
79010	275	Travel - Meals & Enter	SBC GATE 6	4.35		4.35		
79010	275	Travel - Meals & Enter	SCALA'S/CAFFE/STARLIGH	24.34		24.34		
79010	275	Travel - Meals & Enter	SCHLOTZSKY'S DELI #134	7.22		7.22		
79010	275	Travel - Meals & Enter	SCHLOTZSKYS DELI VALEN	218.19		218.19		
79010	275	Travel - Meals & Enter	SEE'S CANDY #404	64.25		64.25		
79010	275	Travel - Meals & Enter	SERIOUS TEXAS BAR B Q	48.00		48.00		
79010	275	Travel - Meals & Enter	SF SOUP CO CROCKER Q35	8.58		8.58		
79010	275	Travel - Meals & Enter	SHOGUN RESTAURANT	33.77		33.77		
79010	275	Travel - Meals & Enter	SHUGRUES RESTAURANT	95.30		95.30		
79010	275	Travel - Meals & Enter	SIAMESE KITCHEN	25.97		25.97		
79010	275	Travel - Meals & Enter	SILVER SADDLE STEAKHOU	648.66		648.66		
79010	275	Travel - Meals & Enter	SIRRICO'S	6.68		6.68		
79010	275	Travel - Meals & Enter	SIZZLER RESTAURANT	21.99		21.99		
79010	275	Travel - Meals & Enter	SKY BLUE WASABI RESTAU	51.90		51.90		
79010	275	Travel - Meals & Enter	SKY SNAX C CONCOURSE	4.32		4.32		
79010	275	Travel - Meals & Enter	SLUGGO'S SPORTS GRILL	26.52		26.52		
79010	275	Travel - Meals & Enter	SOTO'S P/K OUTPOST	25.78		25.78		
79010	275	Travel - Meals & Enter	ST. MARY'S MEXICAN FOO	19.55		19.55		
79010	275	Travel - Meals & Enter	STAR TREK	74.07		74.07		
79010	275	Travel - Meals & Enter	STARBUCKS UCO 00057Q48	7.90		7.90		
79010	275	Travel - Meals & Enter	STARBUCKS USA 00029Q48	9.75		9.75		
79010	275	Travel - Meals & Enter	STARBUCKS USA 00055Q48	20.00		20.00		
79010	275	Travel - Meals & Enter	STARBUCKS USA 00056Q48	7.35		7.35		
79010	275	Travel - Meals & Enter	STARBUCKS USA 00069Q48	23.57		23.57		
79010	275	Travel - Meals & Enter	STARBUCKS USA 00087Q48	19.67		19.67		

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79010	275	Travel - Meals & Enter	STARBUCKS USA 00088Q48	43.24		43.24		
79010	275	Travel - Meals & Enter	STARR PASS GOLF CLUB	673.02		673.02		
79010	275	Travel - Meals & Enter	STOUDEMIRES	29.46		29.46		
79010	275	Travel - Meals & Enter	STROMBOLLI'S PIZZA	81.74		81.74		
79010	275	Travel - Meals & Enter	SUBWAY	134.35		134.35		
79010	275	Travel - Meals & Enter	SUBWAY 00263Q16	11.43		11.43		
79010	275	Travel - Meals & Enter	SUBWAY 34169	17.72		17.72		
79010	275	Travel - Meals & Enter	SUBWAY #1840	18.89		18.89		
79010	275	Travel - Meals & Enter	SUBWAY #25727 Q89	9.49		9.49		
79010	275	Travel - Meals & Enter	SUBWAY #31741 Q16	21.67		21.67		
79010	275	Travel - Meals & Enter	SUBWAY 1840 00018Q16	14.03		14.03		
79010	275	Travel - Meals & Enter	SUBWAY 25070 00250Q16	74.60		74.60		
79010	275	Travel - Meals & Enter	SUBWAY 34169 00341Q16	11.57		11.57		
79010	275	Travel - Meals & Enter	SUBWAY NO. 25070	13.11		13.11		
79010	275	Travel - Meals & Enter	SULLIVAN'S STE00085258	94.23		94.23		
79010	275	Travel - Meals & Enter	SUSHI CHO	90.54		90.54		
79010	275	Travel - Meals & Enter	SUSHI GARDEN, LLC	25.00		25.00		
79010	275	Travel - Meals & Enter	SWEET TOMATOES #48	58.02		58.02		
79010	275	Travel - Meals & Enter	T.G.I. FRIDAY'S COSTA	34.08		34.08		
79010	275	Travel - Meals & Enter	T.G.I. FRIDAY'S TUCSON	209.74		209.74		
79010	275	Travel - Meals & Enter	TADICH GRILL	27.90		27.90		
79010	275	Travel - Meals & Enter	TAQUERIA CANONITA #575	43.83		43.83		
79010	275	Travel - Meals & Enter	TARBELL'S	210.53		210.53		
79010	275	Travel - Meals & Enter	TAYLORS PRIME STEAKS	177.00		177.00		
79010	275	Travel - Meals & Enter	TED'S COUNTRY STOR	1,067.51		1,067.51		
79010	275	Travel - Meals & Enter	TERESA'S MOSAIC CAFE	107.58		107.58		
79010	275	Travel - Meals & Enter	TEXAS LAND & CATTLE#71	56.67		56.67		
79010	275	Travel - Meals & Enter	TGI_FRIDAYS #0792	34.39		34.39		
79010	275	Travel - Meals & Enter	THE ARTIST'S PALATE	18.00		18.00		
79010	275	Travel - Meals & Enter	THE BAGELRY Q17	17.95		17.95		
79010	275	Travel - Meals & Enter	THE BALL PARK CONCESSI	50.00		50.00		
79010	275	Travel - Meals & Enter	THE BOMBAY CLUB	246.20		246.20		
79010	275	Travel - Meals & Enter	THE CHICAGO CHOP HOUSE	60.36		60.36		
79010	275	Travel - Meals & Enter	THE EGG CONNECTION	37.00		37.00		
79010	275	Travel - Meals & Enter	THE GOOD EGG WILLIAMS	318.21		318.21		
79010	275	Travel - Meals & Enter	THE GRAND LUX CAFE	64.17		64.17		
79010	275	Travel - Meals & Enter	THE GREEN FLASH	23.61		23.61		
79010	275	Travel - Meals & Enter	THE JAVA EDGE Q04	8.22		8.22		
79010	275	Travel - Meals & Enter	THE OLIVE GARD00012195	341.75		341.75		
79010	275	Travel - Meals & Enter	THE OLIVE GARD00014514	68.16		68.16		
79010	275	Travel - Meals & Enter	THE OLIVE GARD00016220	442.59		442.59		
79010	275	Travel - Meals & Enter	THE SLANTED DOOR	54.21		54.21		
79010	275	Travel - Meals & Enter	THE STAGE DELI	12.88		12.88		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	275	Travel - Meals & Enter	THE VANS RESTAURANT ON	39.00		39.00		
79010	275	Travel - Meals & Enter	THEDEPOT	15.35		15.35		
79010	275	Travel - Meals & Enter	THUNDER CANYON BREWERY	38.94		38.94		
79010	275	Travel - Meals & Enter	TIDEWATER LANDING	64.99		64.99		
79010	275	Travel - Meals & Enter	TILTED KILT OF ARI	89.54		89.54		
79010	275	Travel - Meals & Enter	TODAI RESTAURANT LAS V	30.06		30.06		
79010	275	Travel - Meals & Enter	TOMBOY'S #2	11.14		11.14		
79010	275	Travel - Meals & Enter	TOMOKAZU JAPANESE CUIS	18.18		18.18		
79010	275	Travel - Meals & Enter	TONY ROMA'S	28.00		28.00		
79010	275	Travel - Meals & Enter	TONY ROMAS #606	80.03		80.03		
79010	275	Travel - Meals & Enter	TORTILLA JO'S 00260323	20.81		20.81		
79010	275	Travel - Meals & Enter	Transfer costs from O&M to capital		361.32	(361.32)		
79010	275	Travel - Meals & Enter	TRATTORIA PINA	113.21		113.21		
79010	275	Travel - Meals & Enter	TRATTORIA PINOCCHIO	52.41		52.41		
79010	275	Travel - Meals & Enter	TREASURE ISLAND - BUFF	16.16		16.16		
79010	275	Travel - Meals & Enter	TREASURE ISLAND LOBBY	7.00		7.00		
79010	275	Travel - Meals & Enter	TREASURE ISLAND PHO RE	23.69		23.69		
79010	275	Travel - Meals & Enter	TROPICANA - SAVANNA	50.10		50.10		
79010	275	Travel - Meals & Enter	TUCSON ELECTRIC PARK	200.00		200.00		
79010	275	Travel - Meals & Enter	TUCSON INTERNATION	30.51		30.51		
79010	275	Travel - Meals & Enter	TUCSON INTERNATIONAL A	22.15		22.15		
79010	275	Travel - Meals & Enter	TUCSON INT'L AIRPORT	50.66		50.66		
79010	275	Travel - Meals & Enter	UNCLE VITOS PIZZA	39.98		39.98		
79010	275	Travel - Meals & Enter	UNO CHICAGO BAR & GRIL	27.74		27.74		
79010	275	Travel - Meals & Enter	VENETO TRATTORIA	29.05		29.05		
79010	275	Travel - Meals & Enter	VILLA MARKET	33.54		33.54		
79010	275	Travel - Meals & Enter	VILLAGE INN RESTAURANT	23.51		23.51		
79010	275	Travel - Meals & Enter	VILLAGE TAVERN #7	164.36		164.36		
79010	275	Travel - Meals & Enter	VINTAGE TERM A-DFW-AIR	24.66		24.66		
79010	275	Travel - Meals & Enter	VIROS ITALIAN BAKERY	112.17		112.17		
79010	275	Travel - Meals & Enter	VIVACE RESTAURANT	158.31		158.31		
79010	275	Travel - Meals & Enter	VOODOO DADDYS MAGIC KI	26.18		26.18		
79010	275	Travel - Meals & Enter	VSA/SBC PARK CONCESSIO	61.25		61.25		
79010	275	Travel - Meals & Enter	WAFFLE HOUSE #1380	18.28		18.28		
79010	275	Travel - Meals & Enter	WALGREEN 00061Q39	5.36		5.36		
79010	275	Travel - Meals & Enter	WAL-MART #1612 SE2	49.83		49.83		
79010	275	Travel - Meals & Enter	WAL-MART #5031 SE2	14.01		14.01		
79010	275	Travel - Meals & Enter	WARWICK DENVER REST	80.67		80.67		
79010	275	Travel - Meals & Enter	WARWICK HOTEL DENVER	72.54		72.54		
79010	275	Travel - Meals & Enter	WASATCH BREW PUB	27.50		27.50		
79010	275	Travel - Meals & Enter	WENDYS #2092 Q25	18.23		18.23		
79010	275	Travel - Meals & Enter	WENDY'S #413 00004Q00	52.29		52.29		
79010	275	Travel - Meals & Enter	WENDYS #8596 Q25	5.92		5.92		

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79010	275	Travel - Meals & Enter	WENDYS NO 413 Q50	13.45		13.45		
79010	275	Travel - Meals & Enter	WESTIN HOTELS F B	40.76		40.76		
79010	275	Travel - Meals & Enter	WESTIN KIERLAND RESORT	110.16		110.16		
79010	275	Travel - Meals & Enter	WHATABURGER 598 Q26	30.40		30.40		
79010	275	Travel - Meals & Enter	WHATABURGER 774 Q26	8.95		8.95		
79010	275	Travel - Meals & Enter	WILDCAT HOUSE	403.70		403.70		
79010	275	Travel - Meals & Enter	WILDFLOWER	57.27		57.27		
79010	275	Travel - Meals & Enter	WINDEMERE HOTEL&CONF C	7.97		7.97		
79010	275	Travel - Meals & Enter	WM SUPERCENTER	219.05		219.05		
79010	275	Travel - Meals & Enter	WM SUPERCENTER SE2	475.96		475.96		
79010	275	Travel - Meals & Enter	WYNN LAS VEGAS HOTEL	11.00		11.00		
79010	275	Travel - Meals & Enter	YANKEE PIER SFO	79.44		79.44		
79010	275	Travel - Meals & Enter	YEAGERS TAP HOUSE	40.81		40.81		
79010	275	Travel - Meals & Enter	YOKOHAMA ASIAN EXPRESS	10.54		10.54		
79010	275	Travel - Meals & Enter	YOYO SUSHI BAR & GRILL	39.39		39.39		
79010	275	Travel - Meals & Enter	Z TEJAS TEMPE #108	56.76		56.76		
79010	275	Travel - Meals & Enter	ZACHARYS PIZZA	98.58		98.58		
79010	275	Travel - Meals & Enter	ZAYTINYA	107.29		107.29		
79010	275	Travel - Meals & Enter	ZEFFIRINOS	45.60		45.60		
79010	275	Travel - Meals & Enter	ZEMAMS	64.88		64.88		
79010	275	Travel - Meals & Enter	ZIVAZ	78.99		78.99		
79010	275	Travel - Meals & Enter	ZONA 78	48.81		48.81		
79010	275	Travel - Meals & Enter	Z'TEJAS CHANDLER	37.15		37.15		
79010	275	Travel - Meals & Enter		1,032.02		1,032.02	SERVICE	042406 103202
79010	275	Travel - Meals & Enter		7,952.16		7,952.16	HOTEL & SUITES	120806 795216
79010	275	Travel - Meals & Enter		2,250.00		2,250.00	LLC	050106 225000
79010	273	Travel - Transportation	CAB-LIMO FARES QAE	70.00		70.00		
79010	273	Travel - Transportation	CHRISTOPHER ROBERT COR	80.00		80.00		
79010	273	Travel - Transportation	DENVER LUXERY LIMOUSIN	85.00		85.00		
79010	273	Travel - Transportation	MAGGIANO'S #8100000810	44.64		44.64		
Sum				414,166.04	21,877.30	**392,288.74**		

TUCSON ELECTRIC POWER COMPANY

DATA RESPONSE 1.20 (b): FERC 923 A&G Expense - Outside Services Employed

TEST YEAR ENDING DECEMBER 31, 2006

Source: Transaction Detail - Co: 002, GL Period Name: %06, FERC: 0923

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
52020	156	Contractor Services	LAMBCHOP STUDIOS	135.00		135.00		
52020	157	Outsourcing Services	JEWISH FAMILY	80.00		80.00		
52020	157	Outsourcing Services	MAGPIES GOURMET PIZZA	95.06		95.06		
52020	157	Outsourcing Services	RAPTOR RESEARCH FOUNDA	822.50		822.50		
52020	157	Outsourcing Services	ROSE HILLS-FLOWER SHOP	135.31		135.31		
52020	157	Outsourcing Services		300.00		300.00	BASEBALL CARDS ETC	030106 30000
52020	157	Outsourcing Services		5,000.00		5,000.00	UA FOUNDATION	061206 500000
79200	271	Training	ASU FOUNDATION	200.00		200.00		
79200	271	Training	FATRABBI SERVICES	185.00		185.00		
Total				6,952.87	0.00	**6,952.87**		

TUCSON ELECTRIC POWER COMPANY

DATA RESPONSE 1.20 (c): FERC 930.1 A&G Expense - General Advertising Expense

TEST YEAR ENDING DECEMBER 31, 2006

Source: Transaction Detail - Co: 002, GL Period Name: %06, FERC: 0930, Exp Types 153, 154, Plus all Exp Types for Task Number: CBU0063

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
52040	153	Advertising		68,427.50		68,427.50	DIAMONDBACKS	D 12941
52040	153	Advertising		68,427.50		68,427.50	DIAMONDBACKS	D 12941
52040	153	Advertising		71,165.59		71,165.59	DIAMONDBACKS	IDBSP0000614
52040	153	Advertising		71,165.59		71,165.59	DIAMONDBACKS	IDBSP0000614
52040	153	Advertising		8,000.00		8,000.00	CONTRIBUTIONS	120106 1600000
52040	153	Advertising		300.00		300.00	PHOTOGRAPHY	040606 30000
52040	153	Advertising		12,500.00		12,500.00	KARTCHNER CAVERNS	050406 2500000
52040	153	Advertising		272.60		272.60	SPECIALTIES	061571
52040	153	Advertising		430.40		430.40	SPECIALTIES	061408
52040	153	Advertising		903.84		903.84	SPECIALTIES	061384
52040	153	Advertising		48.42		48.42	SPECIALTIES	061195
52040	153	Advertising		548.76		548.76	SPECIALTIES	061012
52040	153	Advertising		258.24		258.24	SPECIALTIES	060758
52040	153	Advertising		669.61		669.61	SPECIALTIES	056105
52040	153	Advertising		581.04		581.04	SPECIALTIES	053695
52040	153	Advertising		80.70		80.70	SPECIALTIES	061192
52040	153	Advertising		383.50		383.50	SPECIALTIES	060251
52040	153	Advertising		3,400.00		3,400.00	METROPOLITAN	092006 340000
52040	153	Advertising		20,000.00		20,000.00	METROPOLITAN	033106 286079
52040	153	Advertising		53,500.00		53,500.00	ARIZONA	041706 10700000
52040	153	Advertising		53,500.00		53,500.00	ARIZONA	041706 10700000
52040	153	Advertising Agencies	FINDERBINDER	315.09		315.09		
52040	153	Advertising Agencies	MINKUS ADVERTISING	888.97		888.97		
52040	153	Advertising Agencies	MINKUS ADVERTISING	754.95		754.95		
52040	153	Advertising Agencies	MINKUS ADVERTISING	173.32		173.32		
52040	153	Advertising Agencies	MINKUS ADVERTISING	343.14		343.14		
52040	153	Advertising Agencies	MINKUS ADVERTISING	3,033.53		3,033.53		
52040	153	Advertising Agencies	MINKUS ADVERTISING	1,310.30		1,310.30		
52040	153	Advertising Agencies	MINKUS ADVERTISING	2,222.55		2,222.55		
TOTAL				443,605.14	0.00	**443,605.14**		

TUCSON ELECTRIC POWER COMPANY

DATA RESPONSE 1.20 (d): FERC 930.2 A&G Expense - Misc. General Advertising Expense

TEST YEAR ENDING DECEMBER 31, 2006

Source: Transaction Detail - Co: 002, GL Period Name: %06, FERC: 0930, excluding Exp Types 153, 154, excluding Task Number: CBU0063

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
51500	123	Materials Purchased	LOWN'S COSTUMES	110.00		110.00		
51500	123	Materials Purchased	OSCO DRUG 9207	6.60		6.60		
51500	123	Materials Purchased	PARTY CAROUSEL LLC	161.21		161.21		
51500	123	Materials Purchased	TARGET 00008540	202.07		202.07		
51500	123	Materials Purchased	TARGET 00014399	62.19		62.19		
51500	123	Materials Purchased	THINGS REMEMBERED 0329	110.08		110.08		
51500	123	Materials Purchased	TULLER TROPHY'S & AW	16.21		16.21		
51500	123	Materials Purchased	TULLER TROPHY'S & AW	67.57		67.57		
51500	123	Materials Purchased	TULLER TROPHY'S & AW	18.92		18.92		
51500	123	Materials Purchased	TULLER TROPHY'S & AW	16.22		16.22		
51500	123	Materials Purchased	TULLER TROPHY'S & AWAR	34.97		34.97		
51500	123	Materials Purchased	TULLER TROPHY'S & AWAR	34.97		34.97		
51500	123	Materials Purchased	TULLER TROPHY'S & AWAR	34.97		34.97		
51500	123	Materials Purchased	TULLER TROPHY'S & AWAR	204.44		204.44		
51500	123	Materials Purchased	TULLER TROPHY'S & AWAR	18.83		18.83		
51500	123	Materials Purchased	TULLER TROPHY'S & AWAR	54.05		54.05		
51500	123	Materials Purchased	TULLER TROPHY'S & AWAR	50.03		50.03		
51500	123	Materials Purchased	WAL MART	5.00		5.00		
51500	123	Materials Purchased	WALGREEN 00002Q39	37.88		37.88		
51500	123	Materials Purchased	WALGREEN 00022Q39	18.84		18.84		
51500	123	Materials Purchased	WALGREEN 00058Q39	10.31		10.31		
51500	123	Materials Purchased	WALGREEN 00062Q39	11.69		11.69		
51500	123	Materials Purchased	WALGREEN 00064Q39	9.08		9.08		
51500	123	Materials Purchased	WALGREEN 00073Q39	3.17		3.17		
51500	123	Materials Purchased	WALL STREET GIFTS/COWS	333.12		333.12		
51500	123	Materials Purchased	WALL STREET GIFTS/COWS	21.38		21.38		
51500	123	Materials Purchased		1,314.60		1,314.60	COMMOTION STUDIO	00008837
51500	123	Materials Purchased		1,037.76		1,037.76	SPECIALTIES	065398
51500	123	Materials Purchased		831.40		831.40	SPECIALTIES	065747
51500	123	Materials Purchased		1,037.76		1,037.76	SPECIALTIES	065102
51500	123	Materials Purchased		173.32		173.32	SPECIALTIES	064275
79010	282	Meals & Ent - Discretionary	Gross Pay	40.00		40.00		
79010	282	Meals & Ent - Discretionary	Gross Pay	24.00		24.00		
79010	282	Meals & Ent - Discretionary	Gross Pay	55.51		55.51		
79010	282	Meals & Ent - Discretionary	Gross Pay	59.00		59.00		
79010	282	Meals & Ent - Discretionary	ARIZONA SONORA DESERT	1,800.00		1,800.00		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	282	Meals & Ent - Discretionary	BRUEGGERS BAGEL BAKERY	18.65		18.65		
79010	282	Meals & Ent - Discretionary	BUSY B S BAKERY	23.78		23.78		
79010	282	Meals & Ent - Discretionary	EEGEE S #26	49.53		49.53		
79010	282	Meals & Ent - Discretionary	EL MINUTO CAFE	25.67		25.67		
79010	282	Meals & Ent - Discretionary	LOS BETOS	7.75		7.75		
79010	282	Meals & Ent - Discretionary	SAFEWAY STORE00002SC9	3.78		3.78		
79010	282	Meals & Ent - Discretionary	SUBWAY	16.44		16.44		
79020	251	Member Dues - Corporate			404.66	(404.66)		
79020	251	Member Dues - Corporate	AICPA *DUES ONLINE	185.00		185.00		
79020	251	Member Dues - Corporate	ALCPA *DUES LB	530.00		530.00		
79020	251	Member Dues - Corporate	AMERICAN WELDING SOCIE	80.00		80.00		
79020	251	Member Dues - Corporate	ASSOCTD BLDRS/CNTRC ED	950.00		950.00		
79020	251	Member Dues - Corporate	BBB OF TUCSON	1,082.00		1,082.00		
79020	251	Member Dues - Corporate	BRIGHT FUTURE BUSINESS	450.00		450.00		
79020	251	Member Dues - Corporate	NACM ARIZONA	440.00		440.00		
79020	251	Member Dues - Corporate	NATIONAL SAFETY COUNCI	982.50		982.50		
79020	251	Member Dues - Corporate	ORACLE APPLICATION CON	595.00		595.00		
79020	251	Member Dues - Corporate	PUBLIC RELATIONS SOCIE	300.00		300.00		
79020	251	Member Dues - Corporate	TUCSON METRO CHMBR CMM	350.00		350.00		
79020	251	Member Dues - Corporate		40,304.58		40,304.58		
79020	251	Member Dues - Corporate		40,304.58		40,304.58		
79020	251	Member Dues - Corporate		40,304.58		40,304.58		
79020	251	Member Dues - Corporate		40,304.58		40,304.58		
79020	251	Member Dues - Corporate		40,304.58		40,304.58		
79020	251	Member Dues - Corporate		40,304.58		40,304.58		
79020	251	Member Dues - Corporate		40,304.58		40,304.58		
79020	251	Member Dues - Corporate			176,282.64	(176,282.64)		
79020	251	Member Dues - Corporate		40,303.84		40,303.84		
79020	251	Member Dues - Corporate		40,304.58		40,304.58		
79020	251	Member Dues - Corporate		40,304.58		40,304.58		
79020	251	Member Dues - Corporate			11,632.00	(11,632.00)		
79020	251	Member Dues - Corporate		221,813.15		221,813.15		
79020	251	Member Dues - Corporate			267,067.00	(267,067.00)		
79020	251	Member Dues - Corporate		11,632.00		11,632.00		
79020	251	Member Dues - Corporate		40,304.58		40,304.58		
79020	251	Member Dues - Corporate		166.38		166.38	INC	22536876
79020	251	Member Dues - Corporate		267,067.00		267,067.00	INSTITUTE	1-000038292A
79020	251	Member Dues - Corporate		28,019.00		28,019.00	INSTITUTE	1-000038367D
79020	251	Member Dues - Corporate		25,217.10		25,217.10	INSTITUTE	1-000038367C
79020	251	Member Dues - Corporate		25,217.10		25,217.10	INSTITUTE	1-000038367
79020	251	Member Dues - Corporate		20,691.00		20,691.00	INSTITUTE	1-000045507
79020	251	Member Dues - Corporate		28,019.00		28,019.00	INSTITUTE	1-000038367B
79020	251	Member Dues - Corporate		1,790.00		1,790.00	ASSOCIATION OF	12182218

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79020	251	Member Dues - Corporate		10,000.00		10,000.00	ASSOCIATES	48776
79020	251	Member Dues - Corporate		62.00		62.00	NOTARY BOND AGENCY	042806 6200
79020	251	Member Dues - Corporate		15,000.00		15,000.00	RMEL_ENDATED	10891
79020	251	Member Dues - Corporate		13,500.00		13,500.00	SCIENTECH LLC	IS-2007-778
79020	251	Member Dues - Corporate		25.00		25.00	ARIZONA	042806 2500
79020	251	Member Dues - Corporate		12,000.00		12,000.00	LEADERSHIP COUNCIL	692
79020	251	Member Dues - Corporate		15,010.00		15,010.00	METROPOLITAN	041106 286079
79020	251	Member Dues - Corporate		62,500.00		62,500.00	ECONOMIC	2006-11-TEP
79020	251	Member Dues - Corporate		62,500.00		62,500.00	ECONOMIC	206-08-TEP
79020	251	Member Dues - Corporate		11,632.00		11,632.00	WEST ASSOCIATES	012506 1163200
79020	251	Member Dues - Corporate		216,587.22		216,587.22	COORDINATING	40431
79020	251	Member Dues - Corporate		1,800.00		1,800.00	WESTERN LAMPAC	010506 180000
79200	299	Miscellaneous	FTD*ROSES & MORE INC	16.03		16.03		
79200	262	Sponsorships	TUCSON HISPANIC CHAMBE	40.00		40.00		
79200	262	Sponsorships			2,500.00	(2,500.00)		
79200	262	Sponsorships		2,500.00		2,500.00		
79200	262	Sponsorships		2,500.00		2,500.00	COMMISSION	012306 250000
79200	262	Sponsorships		1,000.00		1,000.00	RESEARCH	1092
79200	262	Sponsorships			210.00	(210.00)	AYSO REGION 922	091505 21000
79200	262	Sponsorships		3,250.00		3,250.00	COMMITTEE	020606 325000
79010	272	Travel	HYATT HOTELS DALLAS	212.75		212.75		
79010	272	Travel	LOWNS COSTUMES AND NOV	825.00		825.00		
79010	272	Travel	LOWNS COSTUMES AND NOV	822.30		822.30		
79010	272	Travel	MARRIOTT HOTELS UNIVER	19.11		19.11		
79010	272	Travel	ORANGE TREE GOLF RESOR	218.39		218.39		
79010	275	Travel - Meals & Enter	ALBERTSONS #960 S9H	53.91		53.91		
79010	275	Travel - Meals & Enter	ALBERTSONS #960 S9H	25.08		25.08		
79010	275	Travel - Meals & Enter	ALBERTSONS #972	58.30		58.30		
79010	275	Travel - Meals & Enter	ALBERTSONS #972	9.98		9.98		
79010	275	Travel - Meals & Enter	ALBERTSONS #972 S9H	8.98		8.98		
79010	275	Travel - Meals & Enter	APPLEBEE'S #603	41.12		41.12		
79010	275	Travel - Meals & Enter	ARIZONA INN RESTAURANT	37.42		37.42		
79010	275	Travel - Meals & Enter	BAGGINS STORE #8	15.90		15.90		
79010	275	Travel - Meals & Enter	BAGGINS STORE #8	18.93		18.93		
79010	275	Travel - Meals & Enter	BAGGINS STORE #8	21.01		21.01		
79010	275	Travel - Meals & Enter	BARRIO	36.54		36.54		
79010	275	Travel - Meals & Enter	BARRIO	42.78		42.78		
79010	275	Travel - Meals & Enter	BARRIO	61.88		61.88		
79010	275	Travel - Meals & Enter	BARRIO	35.00		35.00		
79010	275	Travel - Meals & Enter	BARRIO	42.94		42.94		
79010	275	Travel - Meals & Enter	BEER BOTTOM'S BISTRO	21.00		21.00		
79010	275	Travel - Meals & Enter	BIANCHIS ITALIAN	28.01		28.01		
79010	275	Travel - Meals & Enter	BRUEGGERS BAGEL BAKERY	9.97		9.97		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	275	Travel - Meals & Enter	BURGER KING #2845 Q07	9.81		9.81		
79010	275	Travel - Meals & Enter	BUSY B S BAKERY	9.51		9.51		
79010	275	Travel - Meals & Enter	CAFE A LA CART	31.91		31.91		
79010	275	Travel - Meals & Enter	CAFE A LA CART	24.54		24.54		
79010	275	Travel - Meals & Enter	CAFE A LA CART	23.21		23.21		
79010	275	Travel - Meals & Enter	CAFFE MILANO LLC	6.22		6.22		
79010	275	Travel - Meals & Enter	CAFFE MILANO LLC	10.32		10.32		
79010	275	Travel - Meals & Enter	CAFFE MILANO LLC	59.70		59.70		
79010	275	Travel - Meals & Enter	CHAFFINS FAMILY REST.	18.34		18.34		
79010	275	Travel - Meals & Enter	CHAFFINS FAMILY RESTAU	35.74		35.74		
79010	275	Travel - Meals & Enter	CHAFFINS FAMILY RESTAU	16.89		16.89		
79010	275	Travel - Meals & Enter	CHUYS MESQUITE BROILER	39.77		39.77		
79010	275	Travel - Meals & Enter	CHUYS MESQUITE BROILER	29.29		29.29		
79010	275	Travel - Meals & Enter	CLAIM JUMPER #35	42.92		42.92		
79010	275	Travel - Meals & Enter	DOMINOES PIZZA #7627	228.37		228.37		
79010	275	Travel - Meals & Enter	DOMINOES PIZZA #7634	63.35		63.35		
79010	275	Travel - Meals & Enter	DOWNTOWN DELI	139.94		139.94		
79010	275	Travel - Meals & Enter	EEGEE S #19	13.47		13.47		
79010	275	Travel - Meals & Enter	EEGEE S #20	31.79		31.79		
79010	275	Travel - Meals & Enter	EEGEE S #26	10.35		10.35		
79010	275	Travel - Meals & Enter	EEGEE S #27	92.59		92.59		
79010	275	Travel - Meals & Enter	EL INDIO RESTURANT, IN	20.84		20.84		
79010	275	Travel - Meals & Enter	EL MINUTO CAFE	43.48		43.48		
79010	275	Travel - Meals & Enter	EL MINUTO CAFE	27.66		27.66		
79010	275	Travel - Meals & Enter	EL MINUTO CAFE	25.05		25.05		
79010	275	Travel - Meals & Enter	EL MINUTO CAFE	22.93		22.93		
79010	275	Travel - Meals & Enter	EL MINUTO CAFE	33.97		33.97		
79010	275	Travel - Meals & Enter	EL MINUTO CAFE	36.21		36.21		
79010	275	Travel - Meals & Enter	EL MINUTO CAFE	20.67		20.67		
79010	275	Travel - Meals & Enter	EL POLLO #3567	32.59		32.59		
79010	275	Travel - Meals & Enter	ELLE A WINE COUNTRY RE	52.80		52.80		
79010	275	Travel - Meals & Enter	ELLE A WINE COUNTRY RE	59.20		59.20		
79010	275	Travel - Meals & Enter	ELLE A WINE COUNTRY RE	14.62		14.62		
79010	275	Travel - Meals & Enter	ELLE A WINE COUNTRY RE	27.68		27.68		
79010	275	Travel - Meals & Enter	ELLE A WINE COUNTRY RE	47.46		47.46		
79010	275	Travel - Meals & Enter	ELLE A WINE COUNTRY RE	26.61		26.61		
79010	275	Travel - Meals & Enter	ELLE A WINE COUNTRY RE	36.01		36.01		
79010	275	Travel - Meals & Enter	ELLE A WINE COUNTRY RE	47.48		47.48		
79010	275	Travel - Meals & Enter	ENOTECA PIZZARIA WINE	21.27		21.27		
79010	275	Travel - Meals & Enter	ENOTECA PIZZARIA WINE	11.58		11.58		
79010	275	Travel - Meals & Enter	ENOTECA PIZZARIA WINE	27.90		27.90		
79010	275	Travel - Meals & Enter	ENOTECA PIZZARIA WINE	17.65		17.65		
79010	275	Travel - Meals & Enter	FAMOUS DAVE'S BBQ	62.65		62.65		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	275	Travel - Meals & Enter	FAMOUS SAMS #28	45.59		45.59		
79010	275	Travel - Meals & Enter	FOOD CITY #133	70.69		70.69		
79010	275	Travel - Meals & Enter	FOOD CITY #147 ST3	12.96		12.96		
79010	275	Travel - Meals & Enter	FOOD CITY# 136 ST3	33.73		33.73		
79010	275	Travel - Meals & Enter	FRYS-FOOD-DRG #017 SXN	56.62		56.62		
79010	275	Travel - Meals & Enter	FRYS-FOOD-DRG #036 SXN	105.31		105.31		
79010	275	Travel - Meals & Enter	FRYS-FOOD-DRG #036 SXN	17.28		17.28		
79010	275	Travel - Meals & Enter	FRYS-FOOD-DRG #036 SXN	19.12		19.12		
79010	275	Travel - Meals & Enter	HMSHOST-DFW-AIRPT #007	12.81		12.81		
79010	275	Travel - Meals & Enter	IHOP #1525 04315255	19.90		19.90		
79010	275	Travel - Meals & Enter	JADE GARDEN RESTAURANT	77.28		77.28		
79010	275	Travel - Meals & Enter	KFC 29000Q30	27.22		27.22		
79010	275	Travel - Meals & Enter	LEVY GRP SALE 90085002	1,726.00		1,726.00		
79010	275	Travel - Meals & Enter	LIGHTNING RIDGE CAFE	104.91		104.91		
79010	275	Travel - Meals & Enter	LIGHTNING RIDGE CAFE	14.53		14.53		
79010	275	Travel - Meals & Enter	LITTLE MEXICO RESTAURA	18.21		18.21		
79010	275	Travel - Meals & Enter	LITTLE MEXICO STEAKHOU	38.12		38.12		
79010	275	Travel - Meals & Enter	LOS BETOS	14.85		14.85		
79010	275	Travel - Meals & Enter	LOS BETOS	20.20		20.20		
79010	275	Travel - Meals & Enter	LOS BETOS	27.21		27.21		
79010	275	Travel - Meals & Enter	LOS BETOS MEXICAN FOOD	16.12		16.12		
79010	275	Travel - Meals & Enter	LUCKY WISHBONE #1	43.58		43.58		
79010	275	Travel - Meals & Enter	LUCKY WISHBONE NO	38.27		38.27		
79010	275	Travel - Meals & Enter	MAGPIES GOURMET PIZZA	17.89		17.89		
79010	275	Travel - Meals & Enter	MAMA'S FAMOUS # 2	45.59		45.59		
79010	275	Travel - Meals & Enter	MCDONALD'S F1034 Q17	14.09		14.09		
79010	275	Travel - Meals & Enter	MCDONALD'S F18787 Q17	12.30		12.30		
79010	275	Travel - Meals & Enter	MCDONALD'S M7673 OFQ17	19.09		19.09		
79010	275	Travel - Meals & Enter	MCDONALD'S M7673 OFQ17	18.60		18.60		
79010	275	Travel - Meals & Enter	MICHAS	26.50		26.50		
79010	275	Travel - Meals & Enter	MR. C'S RESTAURANT	51.87		51.87		
79010	275	Travel - Meals & Enter	NADINES PASTRY SHOPPE	61.10		61.10		
79010	275	Travel - Meals & Enter	NADINES PASTRY SHOPPE	8.59		8.59		
79010	275	Travel - Meals & Enter	NADINES PASTRY SHOPPE	42.93		42.93		
79010	275	Travel - Meals & Enter	NEW DRAGON VIEW	23.01		23.01		
79010	275	Travel - Meals & Enter	OLD FATHER INN	53.65		53.65		
79010	275	Travel - Meals & Enter	OLD PUEBLO GRILLE	24.45		24.45		
79010	275	Travel - Meals & Enter	OLD PUEBLO GRILLE	35.05		35.05		
79010	275	Travel - Meals & Enter	OLD PUEBLO GRILLE	11.74		11.74		
79010	275	Travel - Meals & Enter	PARADISE BAKERY	48.65		48.65		
79010	275	Travel - Meals & Enter	PETER PIPER PIZZA STOR	59.56		59.56		
79010	275	Travel - Meals & Enter	R AND R PIZZA EXPRESS	44.14		44.14		
79010	275	Travel - Meals & Enter	RIGO S RESTAURANT	64.52		64.52		

Acct	Exp Type	Exp Type Description	Pa Expenditure Comment	DR	CR	Net Amount	Vendor Name	Invoice Number
79010	275	Travel - Meals & Enter	RIGO S RESTAURANT	21.18		21.18		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00002550	19.52		19.52		
79010	275	Travel - Meals & Enter	SAFEWAY STORE00020SC9	4.50		4.50		
79010	275	Travel - Meals & Enter	SAM HUGHES PLACE	49.55		49.55		
79010	275	Travel - Meals & Enter	SONIC DRIVE IN #399Q63	24.65		24.65		
79010	275	Travel - Meals & Enter	SUBWAY	8.37		8.37		
79010	275	Travel - Meals & Enter	SUBWAY # 1845	4.73		4.73		
79010	275	Travel - Meals & Enter	SUBWAY 1840 00018Q16	95.64		95.64		
79010	275	Travel - Meals & Enter	SUBWAY 1840 00018Q16	133.20		133.20		
79010	275	Travel - Meals & Enter	SUBWAY 25702	15.60		15.60		
79010	275	Travel - Meals & Enter	TANIA 33	42.63		42.63		
79010	275	Travel - Meals & Enter	TANIA 33	34.33		34.33		
79010	275	Travel - Meals & Enter	TANIA 33	24.11		24.11		
79010	275	Travel - Meals & Enter	THE GOOD EGG WILLIAMS	69.51		69.51		
79010	275	Travel - Meals & Enter	THE GOOD EGG WILLIAMS	42.48		42.48		
79010	275	Travel - Meals & Enter	VIVA BURRITO COMPA QAE	35.77		35.77		
79010	275	Travel - Meals & Enter	VIVA BURRITO COMPA QAE	24.23		24.23		
79010	275	Travel - Meals & Enter	VIVA BURRITO COMPA QAE	11.32		11.32		
79010	275	Travel - Meals & Enter	VIVA BURRITO COMPA QAE	5.29		5.29		
79010	275	Travel - Meals & Enter	VIVA BURRITO COMPA QAE	11.89		11.89		
79010	275	Travel - Meals & Enter	VIVACE RESTAURANT	35.15		35.15		
79010	275	Travel - Meals & Enter	WHATABURGER 552	7.76		7.76		
79010	275	Travel - Meals & Enter	WIE NERSCHNITZEL #678	20.69		20.69		
79010	275	Travel - Meals & Enter	WILDCAT HOUSE	42.34		42.34		
79010	275	Travel - Meals & Enter	WILDCAT HOUSE	30.41		30.41		
TOTAL				1,525,400.19	458,096.30	**1,067,303.89**		

EXHIBIT B

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

EXHIBIT B
TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2004

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) AUTH'ZD DEP. RATE	(B) BEGINNING PLANT BALANCE	(C) BEGINNING ACC. DEP. BALANCE	(D) PLANT ADDITIONS	(E) PLANT RETIREM'TS	(F) PLANT ADJUSTM'TS	(G) PLANT TRANSFERS	(H) TOTAL PLANT VALUE	(I) ACCURAL DEPRECIATION	(J) ACCUMULATED DEPRECIATION	(K) NET PLANT VALUE	(L) ACC. DEP. COMPANY WORKPAPERS	(M) ACC. DEP. DIFFERENCE
		INTANGIBLE PLANT													
1	301	Organization	0.00%	$ 29,362	$ -	$ -	$ -	$ -	$ -	$ 29,362	$ -	$ -	$ 29,362		
2	302	Franchises and Consents	0.00%	147,884	-	-	-	-	-	147,884	-	-	147,884		
3	303	Miscellaneous Intangible Plant	0.00%	48,615,887	-	7,746,769	(750,000)	-	-	55,614,656	-	750,000	56,364,656		
4		TOTAL Intangible Plant (Sum L's 1, 2, 3)		$ 48,793,133	$ -	$ 7,746,769	$ (750,000)	$ -	$ -	$ 55,791,902	$ -	$ 750,000	$ 56,541,902	$ -	$ 750,000
		PRODUCTION PLANT													
		Steam Production Plant													
5	310	Land and Land Rights	1.99%	$ 5,878,540	$ (1,633,030)	$ -	$ -	$ -	$ -	$ 5,878,540	$ (118,983)	$ (1,750,013)	$ 4,128,527		
6	311	Structures and Improvements	3.00%	118,388,614	(41,594,244)	1,048,680	(13,834)	-	-	119,423,460	(3,567,181)	(45,147,591)	74,275,869		
7	312	Boiler Plant Equipment	3.29%	664,053,514	(316,829,721)	12,076,681	(2,634,874)	-	-	673,495,321	(22,002,878)	(336,197,525)	337,297,796		
8	313	Engines and Engine-Driven Generators	0.00%	-	-	-	-	-	-	-	-	-	-		
9	314	Turbogenerator Units	2.88%	213,798,200	(105,525,904)	9,346,211	(624,810)	-	-	222,519,601	(6,282,976)	(111,184,070)	111,335,531		
10	315	Accessory Electric Equipment	2.68%	80,972,752	(35,937,406)	133,167	(9,576)	-	-	81,096,343	(2,171,726)	(38,099,556)	42,996,787		
11	316	Misc. Power Plant Equipment	4.05%	17,265,227	(9,181,774)	1,364,565	(69,219)	-	-	18,560,573	(725,472)	(9,838,027)	8,722,546		
12	317	Asset Relm't Costs for Steam Production	2.43%	69,981	(53,568)	22,787	-	-	-	92,768	(1,977)	(55,545)	37,223		
13	114	San Juan Acquisition Adjustment	3.73%	3,124,669	(2,716,293)	-	-	-	-	3,124,669	(116,655)	(2,832,948)	291,721		
14		TOTAL Steam Plant (Sum L's 5 Thru 13)		$1,103,551,497	$ (513,471,940)	$ 23,992,091	$ (3,352,313)	$ -	$ -	$ 1,124,191,275	$ (34,985,649)	$ (545,105,276)	$ 579,085,999	$ (533,775,374)	$ (11,329,902)
		Other Production Plant													
15	340	Land and Land Rights	0.00%	$ 401,628	$ -	$ -	$ -	$ -	$ -	$ 401,628	$ -	$ -	$ 401,828		
16	341	Structures and Improvements	2.02%	1,219,747	(538,047)	-	-	-	-	1,219,747	(24,639)	(562,686)	657,061		
17	342	Fuel Holders, Products, and Accessories	2.35%	1,156,176	(114,044)	8,719	-	-	-	1,164,895	(27,273)	(141,317)	1,023,578		
18	343	Prime Movers	1.48%	354,047	(281,725)	-	-	-	-	354,047	(5,240)	(286,965)	67,082		
19	344	Generators	1.81%	75,805,654	(16,788,626)	-	-	(3,862,639)	-	71,943,015	(1,337,125)	(18,125,751)	53,817,264		
20	345	Accessory Electric Equipment	1.85%	4,125,787	(1,874,255)	349,430	-	-	-	4,475,217	(79,559)	(1,953,814)	2,521,403		
21	346	Misc. Power Plant Equipment	2.72%	682,690	(439,070)	355,620	-	-	-	1,038,310	(23,406)	(462,476)	575,834		
22		TOTAL Other Plant (Sum L's 15 Thru 21)		$ 83,745,729	$ (20,035,767)	$ 713,769	$ -	$ (3,862,639)	$ -	$ 80,596,859	$ (1,497,242)	$ (21,533,009)	$ 59,063,850	$ (21,044,336)	$ (488,873)
23		TOTAL Production Plant (Sum L's 14 & 22)		$1,187,297,226	$ (533,507,707)	$ 24,705,860	$ (3,352,313)	$ (3,862,639)	$ -	$ 1,204,788,134	$ (36,482,891)	$ (566,638,285)	$ 638,149,849	$ (554,819,710)	$ (11,818,575)
		TRANSMISSION PLANT													
		Transmission Non-EHV (138 KV & Below)													
24	350	Land and Land Rights	2.25%	$ 10,926,112	$ (11,350,702)	$ -	$ -	$ -	$ -	$ 10,926,112	$ (245,838)	$ (11,596,540)	$ (670,428)		
25	352	Structures and Improvements	2.44%	6,680,804	(8,210,209)	1,283,968	-	-	-	7,964,772	(178,676)	(8,388,885)	(424,113)		
26	353	Station Equipment	3.52%	117,834,991	(112,620,578)	1,986,425	(1,574,279)	-	-	118,247,137	(4,155,045)	(115,201,344)	3,045,793		
27	354	Towers and Fixtures	3.53%	9,811,270	(104,792,995)	-	-	-	-	9,811,270	(346,338)	(105,139,333)	(95,328,063)		
28	355	Poles and Fixtures	4.54%	16,651,993	(12,268,581)	1,719,967	(81,714)	-	-	18,290,246	(793,189)	(12,980,036)	5,310,210		
29	356	Overhead Conductors and Devices	3.33%	15,905,453	(53,034,553)	80,423	(1,015,917)	-	-	14,969,959	(514,076)	(52,532,712)	(37,562,753)		
30		TOTAL Transmission NOn-EHV (Sum L's 24 Thru 29)		$ 177,810,623	$ (302,277,598)	$ 5,070,783	$ (2,671,910)	$ -	$ -	$ 180,209,496	$ (6,233,161)	$ (305,838,849)	$ (125,629,353)		

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

EXHIBIT B
TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2004

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) AUTH'ZD DEP. RATE	(B) BEGINNING PLANT BALANCE	(C) BEGINNING ACC. DEP. BALANCE	(D) PLANT ADDITIONS	(E) PLANT RETIREM'TS	(F) PLANT ADJUSTM'TS	(G) PLANT TRANSFERS	(H) TOTAL PLANT VALUE	(I) ACCURAL DEPRECIATION	(J) ACCUMULATED DEPRECIATION	(K) NET PLANT VALUE	(L) ACC. DEP. COMPANY WORKPAPERS	(M) ACC. DEP. DIFFERENCE
		Transmission EHV (345 KV & Above)													
31	350	Land and Land Rights	2.25%	$ 15,148,405	$ -	$ -	$ -	$ -	$ -	$ 15,148,405	$ (340,839)	$ (340,839)	$ 14,807,566		
32	352	Structures and Improvements	2.44%	9,178,154	-	892,103	-	-	-	10,070,257	(234,831)	(234,831)	9,835,426		
33	353	Station Equipment	3.52%	110,474,060	-	4,719,833	(36,397)	-	-	115,157,496	(3,971,115)	(3,934,718)	111,222,778		
34	354	Towers and Fixtures	3.53%	145,725,013	-	-	-	(2,540)	-	145,722,473	(5,144,046)	(5,144,046)	140,578,425		
35	355	Poles and Fixtures	4.54%	1,341,221	-	-	-	-	-	1,341,221	(60,891)	(60,891)	1,280,330		
36	356	Overhead Conductors and Devices	3.33%	66,326,769	-	-	-	(1,766)	-	66,325,004	(2,208,652)	(2,208,652)	64,116,352		
37	359	Roads & Trails	2.00%	4,485,615	(2,673,027)	160,601	-	-	-	4,646,216	(91,318)	(2,764,345)	1,881,871		
38		TOTAL Transmission EHV (Sum L's 31 Thru 38)		$ 352,679,237	$ (2,673,027)	$ 5,772,537	$ (36,397)	$ (4,305)	$ -	$ 356,411,072	$ (12,051,695)	$ (14,688,325)	$ 343,722,747		
39		TOTAL Transmission Plant (Sum L's 30 & 37)		$ 530,489,860	$ (304,950,625)	$ 10,843,320	$ (2,708,307)	$ (4,305)	$ -	$ 538,620,568	$ (18,284,856)	$ (320,527,174)	$ 218,093,394	$ (320,865,012)	$ 337,838
		DISTRIBUTION PLANT													
40	360	Land and Land Rights	2.22%	$ 8,761,076	$ (2,289,324)	$ -	$ -	$ -	$ -	$ 8,761,076	$ (194,496)	$ (2,483,820)	$ 6,277,256		
41	361	Structures and Improvements	2.44%	4,142,199	(1,295,749)	815,814	-	-	-	4,958,013	(111,023)	(1,406,772)	3,551,241		
42	362	Station Equipment	4.25%	74,886,825	(51,613,094)	11,658,550	-	-	-	86,525,375	(3,429,584)	(55,042,678)	31,482,697		
43	364	Poles, Towers, and Fixtures	5.48%	91,517,511	(63,729,094)	8,931,864	(184,715)	-	-	100,264,660	(5,254,631)	(68,799,210)	31,465,450		
44	365	Overhead Conductors and Devices	3.66%	95,065,115	(48,553,886)	3,258,292	(153,926)	-	-	98,169,481	(3,536,193)	(51,936,153)	46,233,328		
45	366	Underground Conduit	2.33%	45,860,914	(12,113,190)	3,668,651	(40,394)	-	-	49,489,171	(1,110,828)	(13,183,624)	36,305,547		
46	367	Underground Conductors and Devices	1.63%	175,621,937	(40,117,178)	9,039,591	(325,727)	-	-	184,335,801	(2,933,656)	(42,725,107)	141,610,694		
47	368	Line Transformers	3.38%	183,480,374	(83,256,696)	13,595,044	(1,858,318)	-	-	175,219,100	(5,724,021)	(87,124,399)	108,094,701		
48	369	Services	3.83%	78,009,724	(36,418,284)	3,456,146	(55,014)	-	-	79,410,856	(2,976,304)	(39,339,574)	40,071,282		
49	370	Meters	3.79%	36,855,848	(19,159,888)	1,841,919	(10,734,023)	-	-	27,763,744	(1,224,541)	(9,650,386)	18,113,358		
50	371	Installations on Customer Premises	0.00%	-	-	-	-	-	-	-	-	-	-		
51	373	Street Lighting and Signal Systems	4.48%	8,142,848	(4,729,768)	546,135	(17,274)	-	-	8,671,507	(374,956)	(5,087,450)	3,584,057		
52	374	Asset Retirement Obligation		-	-	-	-	-	-	-	-	-	-		
53		TOTAL Distribution Plant (Sum L's 39 Thru 51)		$ 780,324,169	$ (343,276,131)	$ 56,612,006	$ (13,367,391)	$ -	$ -	$ 823,568,784	$ (26,870,433)	$ (356,779,173)	$ 466,789,611	$ (357,710,354)	$ 931,181
		GENERAL PLANT													
54	389	Land and Land Rights	0.00%	$ 302,740	$ -	$ -	$ -	$ -	$ -	$ 302,740	$ -	$ -	$ 302,740		
55	390	Structures and Improvements	3.38%	28,272,387	(7,992,518)	3,619,230	(214,582)	-	-	31,677,035	(1,013,145)	(8,791,081)	22,885,954		
56	391	Office Furniture and Equipment	13.38%	21,573,813	(11,885,733)	4,081,060	(1,824)	-	-	25,653,049	(3,159,477)	(15,043,386)	10,609,663		
57	392	Transportation Equipment	4.72%	27,621,652	(13,553,832)	4,003,539	(1,102,653)	-	-	30,522,538	(1,372,203)	(13,823,182)	16,699,356		
58	393	Stores Equipment	6.67%	814,671	(719,914)	84,654	-	-	-	899,325	(57,162)	(777,076)	122,249		
59	394	Tools, Shop and Garage Equipment	5.88%	8,093,584	(4,056,462)	443,717	-	-	-	8,537,401	(488,954)	(4,545,416)	3,991,985		
60	395	Laboratory Equipment	5.88%	4,948,174	(2,290,856)	87,905	(133,533)	-	-	4,902,546	(289,611)	(2,446,934)	2,455,612		
61	396	Power Operated Equipment	3.33%	8,527,364	(925,562)	110,988	-	-	-	8,638,352	(285,809)	(1,211,371)	7,426,981		
62	397	Communication Equipment	6.67%	31,405,548	(21,931,201)	2,088,891	-	-	-	33,494,439	(2,164,415)	(24,095,616)	9,398,823		
63	398	Miscellaneous Equipment	5.00%	2,038,957	(873,757)	-	-	-	-	2,038,957	(101,948)	(975,715)	1,063,242		
64		TOTAL General Plant (Sum L's 53 Thru 62)		$ 133,598,990	$ (64,229,645)	$ 14,519,984	$ (1,452,592)	$ -	$ -	$ 146,666,382	$ (8,932,724)	$ (71,709,777)	$ 74,956,605	$ (72,570,401)	$ 860,624
65		TOTAL PLANT (Sum L's 4, 23, 38, 52 & 63)		$2,680,503,378	$ (1,245,964,108)	$ 114,429,939	$ (21,630,603)	$ (3,866,944)	$ -	$ 2,769,435,770	$ (90,570,905)	$ (1,314,904,410)	$ 1,454,531,360	$ (1,305,965,477)	$ (8,938,933)
66					Company Workpapers	$ (1,243,247,815)						Company Workpapers	$ (1,305,965,478)		
67					San Juan Acquisition Adjustment Line 13	(2,716,293)									
68					Sum Line 66 + Line 67	$ (1,245,964,108)						Difference	$ (8,938,932)		

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

EXHIBIT B
TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2005

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT RETIREM'TS	(C) PLANT ADJUSTM'TS	(D) PLANT TRANSFERS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPREC'N	(G) ACCUM'D DEPREC'N	(H) NET PLANT VALUE	(I) ACC. DEP. COMPANY WORKPAPERS	(J) ACC. DEP. DIFFERENCE
		INTANGIBLE PLANT										
1	301	Organization	$ -	$ -	$ -	$ -	$ 29,362	$ -	$ -	$ 29,362		
2	302	Franchises and Consents	-	-	-	-	147,884	-	-	147,884		
3	303	Miscellaneous Intangible Plant	1,875,684	-	750,000	-	58,240,340	-	-	58,240,340		
4		TOTAL Intangible Plant (Sum L's 1, 2, 3)	$ 1,875,684	$ -	$ 750,000	$ -	$ 58,417,586	$ -	$ -	$ 58,417,586	$ -	$ -
		PRODUCTION PLANT										
		Steam Production Plant										
5	310	Land and Land Rights	$ -	$ -	$ -	$ -	$ 5,878,540	$ (116,983)	$ (1,866,996)	$ 4,011,544		
6	311	Structures and Improvements	1,867,049	(313,335)	-	-	120,977,174	(3,606,010)	(48,440,266)	72,536,908		
7	312	Boiler Plant Equipment	28,971,548	(10,683,041)	-	-	691,783,828	(22,458,842)	(347,973,326)	343,810,502		
8	313	Engines and Engine-Driven Generators	-	-	-	-	-	-	-	-		
9	314	Turbogenerator Units	8,663,638	(3,457,961)	-	-	227,728,278	(6,483,569)	(114,209,679)	113,518,599		
10	315	Accessory Electric Equipment	1,336,734	(441,393)	-	-	81,991,684	(2,185,380)	(39,843,542)	42,148,142		
11	316	Misc. Power Plant Equipment	1,023,790	(105,949)	-	-	19,478,414	(770,289)	(10,502,368)	8,976,046		
12	317	Asset Retm't Costs for Steam Production	274,147	-	-	-	366,915	(5,585)	(61,131)	305,784		
13	114	San Juan Acquisition Adjustment	-	-	-	-	3,124,669	(116,655)	(2,949,603)	175,066		
14		TOTAL Steam Plant (Sum L's 5 Thru 13)	$ 42,139,906	$ (15,001,679)	$ -	$ -	$ 1,151,329,502	$ (35,743,313)	$ (565,846,911)	$ 585,482,591	$ (536,883,398)	$ (28,963,513)
		Other Production Plant										
15	340	Land and Land Rights	$ -	$ -	$ -	$ -	$ 401,628	$ -	$ -	$ 401,628		
16	341	Structures and Improvements	140,347	-	-	-	1,360,094	(26,056)	(588,742)	771,352		
17	342	Fuel Holders, Products, and Accessories	-	-	-	-	1,164,895	(27,375)	(168,692)	996,203		
18	343	Prime Movers	-	-	-	-	354,047	(5,240)	(292,205)	61,842		
19	344	Generators	346,938	-	-	-	72,289,953	(1,305,308)	(19,431,060)	52,858,893		
20	345	Accessory Electric Equipment	-	-	-	-	4,475,217	(82,792)	(2,036,606)	2,438,611		
21	346	Misc. Power Plant Equipment	-	-	-	-	1,038,310	(28,242)	(490,718)	547,592		
22		TOTAL Other Plant (Sum L's 15 Thru 21)	$ 487,285	$ -	$ -	$ -	$ 81,084,144	$ (1,475,013)	$ (23,008,022)	$ 58,076,122	$ (21,924,580)	$ (1,083,442)
23		TOTAL Production Plant (Sum L's 14 & 22)	$ 42,627,191	$ (15,001,679)	$ -	$ -	$ 1,232,413,646	$ (37,218,326)	$ (588,854,933)	$ 643,558,713	$ (558,807,978)	$ (30,046,955)
		TRANSMISSION PLANT										
		Transmission Non-EHV (138 KV & Below)										
24	350	Land and Land Rights	$ -	$ (36,251)	$ -	$ -	$ 10,889,861	$ (245,430)	$ (11,805,718)	$ (915,857)		
25	352	Structures and Improvements	-	-	(326,793)	-	7,637,979	(190,354)	(8,579,239)	(941,260)		
26	353	Station Equipment	671,767	-	1,475,568	-	120,394,472	(4,200,092)	(119,401,437)	993,035		
27	354	Towers and Fixtures	-	-	-	-	9,811,270	(346,338)	(105,485,671)	(95,674,401)		
28	355	Poles and Fixtures	367,206	-	2,939	-	18,660,391	(838,779)	(13,818,815)	4,841,576		
29	356	Overhead Conductors and Devices	1,265,515	-	784,570	-	17,020,044	(532,634)	(53,065,345)	(36,045,301)		
30		TOTAL Transmission N0n-EHV (Sum L's 24 Thru 29)	$ 2,304,488	$ (36,251)	$ 1,936,284	$ -	$ 184,414,017	$ (6,353,626)	$ (312,156,225)	$ (127,742,208)		

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EXHIBIT B
TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2005

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT RETIREM'TS	(C) PLANT ADJUSTM'TS	(D) PLANT TRANSFERS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPREC'N	(G) ACCUM'D DEPREC'N	(H) NET PLANT VALUE	(I) ACC. DEP. COMPANY WORKPAPERS	(J) ACC. DEP. DIFFERENCE
		Transmission EHV (345 KV & Above)										
31	350	Land and Land Rights	$ -	$ (102,500)	$ -	$ -	$ 15,045,905	$ (339,686)	$ (578,025)	$ 14,467,880		
32	352	Structures and Improvements	10,719	-	-	-	10,080,976	(245,845)	(480,676)	9,600,300		
33	353	Station Equipment	414,395	-	3,971	-	115,575,862	(4,060,907)	(7,995,625)	107,580,237		
34	354	Towers and Fixtures	53	-	-	-	145,722,526	(5,144,004)	(10,288,052)	135,434,474		
35	355	Poles and Fixtures	-	-	-	-	1,341,221	(60,891)	(121,783)	1,219,438		
36	356	Overhead Conductors and Devices	40,035	-	-	-	66,365,039	(2,209,289)	(4,417,941)	61,947,098		
37	359	Roads & Trails	-	-	(160,601)	-	4,485,615	(91,318)	(2,855,664)	1,629,951		
38		TOTAL Transmission EHV (Sum L's 31 Thru 36)	$ 465,202	$ (102,500)	$ (156,630)	$ -	$ 358,617,144	$ (12,151,941)	$ (26,737,766)	$ 331,879,378		
39		TOTAL Transmission Plant (Sum L's 30 & 37)	$ 2,769,690	$ (138,751)	$ 1,779,654	$ -	$ 543,031,161	$ (18,505,568)	$ (338,893,991)	$ 204,137,170	$ (341,776,692)	$ 2,882,701
		DISTRIBUTION PLANT										
40	360	Land and Land Rights	$ 753,876	$ -	$ -	$ -	$ 9,514,952	$ (130,173)	$ (2,613,993)	$ 6,900,959		
41	361	Structures and Improvements	1,608,223	-	-	-	6,566,236	(3,711,503)	(5,118,275)	1,447,961		
42	362	Station Equipment	4,405,746	-	-	-	90,931,121	(5,615,221)	(60,657,899)	30,273,222		
43	364	Poles, Towers, and Fixtures	5,749,474	(56,931)	-	-	105,957,203	(3,697,177)	(72,439,456)	33,517,747		
44	365	Overhead Conductors and Devices	4,881,171	(29,242)	-	-	103,021,410	(1,209,623)	(53,116,534)	49,904,876		
45	366	Underground Conduit	-	(10,769)	(306,015)	-	49,172,387	(3,002,092)	(16,174,947)	32,997,440		
46	367	Underground Conductors and Devices	15,311,324	(139,733)	-	-	199,507,392	(6,178,805)	(48,764,179)	150,743,213		
47	368	Line Transformers	14,510,231	(630,084)	-	-	189,099,247	(3,307,241)	(69,801,556)	119,297,691		
48	369	Services	9,047,110	(62,233)	-	-	88,395,733	(1,222,509)	(40,499,850)	47,895,883		
49	370	Meters	3,068,208	-	894,668	-	31,726,620	-	(9,650,386)	22,076,234		
50	371	Installations on Customer Premises	-	-	-	-	-	(386,749)	(386,749)	(386,749)		
51	373	Street Lighting and Signal Systems	494,544	(7,923)	-	-	9,158,128	-	(5,079,527)	4,078,601		
52	374	Asset Retirement Obligation	216,459	-	-	-	216,459	-	-	216,459		
53		TOTAL Distribution Plant (Sum L's 39 Thru 51)	$ 60,046,366	$ (936,915)	$ 588,653	$ -	$ 883,266,888	$ (28,461,092)	$ (384,303,351)	$ 498,963,537	$ (386,659,796)	$ 2,356,445
		GENERAL PLANT										
54	389	Land and Land Rights	$ -	$ -	$ -	$ -	$ 302,740	$ -	$ -	$ 302,740		
55	390	Structures and Improvements	2,483,742	-	155,548	-	34,316,325	(1,115,288)	(9,906,369)	24,409,956		
56	391	Office Furniture and Equipment	5,756,092	(6,681,627)	-	-	24,727,514	(3,370,460)	(11,732,219)	12,995,295		
57	392	Transportation Equipment	3,658,113	-	204,085	-	34,384,736	(1,531,812)	(15,354,994)	19,029,742		
58	393	Stores Equipment	-	(157,015)	-	-	742,310	(54,749)	(674,809)	67,501		
59	394	Tools, Shop and Garage Equipment	-	(2,233,039)	(135,856)	-	6,168,506	(432,354)	(7,210,809)	(1,042,303)		
60	395	Laboratory Equipment	154,173	(1,241,927)	-	-	3,814,792	(256,290)	(1,461,297)	2,353,495		
61	396	Power Operated Equipment	1,248,183	(37,354)	-	-	9,849,181	(307,817)	(1,481,835)	8,367,346		
62	397	Communication Equipment	1,399,972	(11,320,839)	-	-	23,573,572	(1,903,218)	(14,677,995)	8,895,577		
63	398	Miscellaneous Equipment	144,174	(108,353)	-	-	2,074,778	(102,843)	(970,205)	1,104,573		
64		TOTAL General Plant (Sum L's 53 Thru 62)	$ 14,844,449	$ (21,780,154)	$ 223,777	$ -	$ 139,954,454	$ (9,074,830)	$ (63,470,531)	$ 76,483,923	$ (62,514,299)	$ (956,232)
65		**TOTAL PLANT**(Sum L's 4, 23, 38, 52 & 63)	$ 122,163,380	$ (37,857,499)	$ 3,342,084	$ -	$ 2,857,083,735	$ (93,259,816)	$ (1,375,522,805)	$ 1,481,560,930	$ (1,349,758,765)	$ (25,764,040)

Company Workpapers	$ (1,349,758,766)
Difference	$ (25,764,039)

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EXHIBIT B
TEST YEAR PLANT SCHEDULES - CONT'D
TEST-YEAR ENDED DECEMBER 31, 2006

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT RETIREM'TS	(C) PLANT ADJUSTM'TS	(D) PLANT TRANSFERS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPREC'N	(G) ACCUM'D DEPREC'N	(H) NET PLANT VALUE	(I) ACC. DEP. COMPANY WORKPAPERS	(J) ACC. DEP. DIFFERENCE
		INTANGIBLE PLANT										
1	301	Organization	$ -	$ -	$ -	$ -	$ 29,362	$ -	$ -	$ 29,362		
2	302	Franchises and Consents	-	-	-	-	147,884	-	-	147,884		
3	303	Miscellaneous Intangible Plant	20,180,040	-	(22,582)	-	78,397,798	-	-	78,397,798		
4		TOTAL Intangible Plant (Sum L's 1, 2, 3)	$ 20,180,040	$ -	$ (22,582)	$ -	$ 78,575,044	$ -	$ -	$ 78,575,044	$ -	$ -
		PRODUCTION PLANT										
		Steam Production Plant										
5	310	Land and Land Rights	$ -	$ -	$ -	$ -	$ 5,878,540	$ (116,983)	$ (1,983,979)	$ 3,894,561		
6	311	Structures and Improvements	160,631	-	(3,385)	-	121,134,420	(3,631,674)	(52,071,940)	69,062,480		
7	312	Boiler Plant Equipment	20,892,004	-	(5,602,632)	-	707,073,200	(23,011,198)	(370,984,524)	336,088,676		
8	313	Engines and Engine-Driven Generators	-	-	-	-	-	-	-	-		
9	314	Turbogenerator Units	3,963,103	-	(486,613)	-	231,204,768	(6,608,636)	(120,818,315)	110,386,453		
10	315	Accessory Electric Equipment	769,892	-	(76,095)	-	82,685,481	(2,206,674)	(42,050,216)	40,635,265		
11	316	Misc. Power Plant Equipment	429,681	-	(30,538)	-	19,877,557	(796,958)	(11,299,326)	8,578,231		
12	317	Asset Retm't Costs for Steam Production	-	-	-	-	366,915	(8,916)	(70,047)	296,868		
13	114	San Juan Acquisition Adjustment	-	-	-	-	3,124,669	(116,655)	(3,066,258)	58,411		
14		TOTAL Steam Plant (Sum L's 5 Thru 13)	$ 26,215,311	$ -	$ (6,199,263)	$ -	$ 1,171,345,550	$ (36,497,694)	$ (602,344,605)	$ 569,000,945	$ (544,672,310)	$ (57,672,295)
		Other Production Plant										
15	340	Land and Land Rights	$ 1,526,387	$ -	$ -	$ -	$ 1,928,015	$ -	$ -	$ 1,928,015		
16	341	Structures and Improvements	12,840,376	-	-	-	14,200,470	(157,162)	(745,904)	13,454,566		
17	342	Fuel Holders, Products, and Accessories	11,430,397	-	-	-	12,595,292	(161,682)	(330,374)	12,264,918		
18	343	Prime Movers	-	-	-	-	354,047	(5,240)	(297,445)	56,602		
19	344	Generators	15,646,491	-	-	-	87,936,444	(1,450,049)	(20,881,109)	67,055,335		
20	345	Accessory Electric Equipment	-	-	-	-	4,475,217	(82,792)	(2,119,397)	2,355,820		
21	346	Misc. Power Plant Equipment	7,347,169	-	-	-	8,385,479	(128,164)	(618,881)	7,766,598		
22		TOTAL Other Plant (Sum L's 15 Thru 21)	$ 48,790,820	$ -	$ -	$ -	$ 129,874,964	$ (1,985,088)	$ (24,993,110)	$ 104,881,854	$ (23,682,119)	$ (1,310,991)
23		TOTAL Production Plant (Sum L's 14 & 22)	$ 75,006,131	$ -	$ (6,199,263)	$ -	$ 1,301,220,514	$ (38,482,782)	$ (627,337,715)	$ 673,882,799	$ (568,354,429)	$ (58,983,286)
		TRANSMISSION PLANT										
		Transmission Non-EHV (138 KV & Below)										
24	350	Land and Land Rights	$ 1,498	$ -	$ 1,501	$ (116,498)	$ 10,776,362	$ (243,745)	$ (12,049,463)	$ (1,273,101)		
25	352	Structures and Improvements	-	-	(3,812)	-	7,634,167	(186,320)	(8,765,559)	(1,131,392)		
26	353	Station Equipment	3,9[illegible]3,949	-	-	-	124,358,421	(4,307,651)	(123,709,088)	649,333		
27	354	Towers and Fixtures	32,320	-	-	-	9,843,590	(346,908)	(105,832,579)	(95,988,989)		
28	355	Poles and Fixtures	15,047	-	-	-	18,675,438	(847,523)	(14,666,339)	4,009,099		
29	356	Overhead Conductors and Devices	-	-	(316,584)	-	16,703,460	(561,496)	(53,626,842)	(36,923,382)		
30		TOTAL Transmission N0n-EHV (Sum L's 24 Thru 29)	$ 4,012,814	$ -	$ (318,895)	$ (116,498)	$ 187,991,438	$ (6,493,644)	$ (318,649,869)	$ (130,658,431)		

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EXHIBIT B
TEST YEAR PLANT SCHEDULES - CONT'D
TEST-YEAR ENDED DECEMBER 31, 2006

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT RETIREM'TS	(C) PLANT ADJUSTM'TS	(D) PLANT TRANSFERS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPREC'N	(G) ACCUM'D DEPREC'N	(H) NET PLANT VALUE	(I) ACC. DEP. COMPANY WORKPAPERS	(J) ACC. DEP. DIFFERENCE
		Transmission EHV (345 KV & Above)										
31	350	Land and Land Rights	$ -	$ -	$ -	$ -	$ 15,045,905	$ (338,533)	$ (916,558)	$ 14,129,347		
32	352	Structures and Improvements	-	-	(763)	-	10,080,213	(245,967)	(726,642)	9,353,571		
33	353	Station Equipment	18,757,841	-	-	-	134,333,703	(4,398,408)	(12,394,034)	121,939,669		
34	354	Towers and Fixtures	88,179	-	-	-	145,810,705	(5,145,562)	(15,433,614)	130,377,091		
35	355	Poles and Fixtures	-	-	-	-	1,341,221	(60,891)	(182,674)	1,158,547		
36	356	Overhead Conductors and Devices	104,279	-	-	-	66,469,318	(2,211,692)	(6,629,633)	59,839,685		
37	359	Roads & Trails	172,538	-	-	-	4,658,153	(91,438)	(2,947,101)	1,711,052		
38		TOTAL Transmission EHV (Sum L's 31 Thru 36)	$ 19,122,837	$ -	$ (763)	$ -	$ 377,739,218	$ (12,492,490)	$ (39,230,257)	$ 338,508,961		
39		TOTAL Transmission Plant (Sum L's 30 & 37)	$ 23,135,651	$ -	$ (319,658)	$ (116,498)	$ 565,730,656	$ (18,986,134)	$ (357,880,125)	$ 207,850,531	$ (360,876,612)	$ 2,996,487
		DISTRIBUTION PLANT										
40	360	Land and Land Rights	$ -	$ -	$ (88,834)	$ 432,627	$ 9,858,745	$ (215,048)	$ (2,829,041)	$ 7,029,704		
41	361	Structures and Improvements	-	-	(284,142)	-	6,282,094	(156,750)	(5,275,024)	1,007,070		
42	362	Station Equipment	4,520,539	-	-	-	95,451,660	(3,960,634)	(64,618,533)	30,833,127		
43	364	Poles, Towers, and Fixtures	7,148,953	-	(120,798)	-	112,985,358	(5,999,026)	(78,438,482)	34,546,876		
44	365	Overhead Conductors and Devices	3,900,846	-	(163,714)	-	106,758,542	(3,838,973)	(56,955,507)	49,803,035		
45	366	Underground Conduit	182,260	-	(12,163)	-	49,342,484	(1,147,698)	(17,322,646)	32,019,838		
46	367	Underground Conductors and Devices	14,098,127	-	(230,975)	-	213,374,544	(3,364,988)	(52,129,167)	161,245,377		
47	368	Line Transformers	14,963,571	-	(933,522)	-	203,129,296	(6,628,662)	(76,430,218)	126,699,078		
48	369	Services	4,494,204	-	(870,175)	-	92,019,762	(3,454,957)	(43,954,807)	48,064,955		
49	370	Meters	2,632,000	-	(1,476,831)	-	32,881,789	(1,224,329)	(10,874,716)	22,007,073		
50	371	Installations on Customer Premises	-	-	-	-	-	-	(386,749)	(386,749)		
51	373	Street Lighting and Signal Systems	228,662	-	(52,374)	-	9,334,416	(412,384)	(5,491,910)	3,842,506		
52	374	Asset Retirement Obligation	-	-	-	-	216,459	-	-	216,459		
53		TOTAL Distribution Plant (Sum L's 39 Thru 51)	$ 52,169,162	$ -	$ (4,233,528)	$ 432,627	$ 931,635,149	$ (30,403,449)	$ (414,706,800)	$ 516,928,349	$ (410,531,529)	$ (4,175,271)
		GENERAL PLANT										
54	389	Land and Land Rights	$ -	$ -	$ -	$ -	$ 302,740	$ -	$ -	$ 302,740		
55	390	Structures and Improvements	1,430,472	-	(322,328)	-	35,424,469	(1,178,619)	(11,084,988)	24,339,481		
56	391	Office Furniture and Equipment	3,938,026	-	(2,534,876)	-	26,130,664	(3,402,412)	(15,134,631)	10,996,033		
57	392	Transportation Equipment	5,229,943	-	(2,653,793)	-	36,960,886	(1,683,757)	(17,038,750)	19,922,136		
58	393	Stores Equipment	291,468	-	(45,357)	-	988,421	(57,720)	(732,529)	255,892		
59	394	Tools, Shop and Garage Equipment	179,591	-	(203,478)	-	6,144,619	(362,006)	(7,572,814)	(1,428,195)		
60	395	Laboratory Equipment	656,226	-	(197,584)	-	4,273,434	(237,794)	(1,699,091)	2,574,343		
61	396	Power Operated Equipment	-	-	(174,507)	-	9,674,674	(325,072)	(1,806,907)	7,867,767		
62	397	Communication Equipment	6,310,553	-	(48,226)	-	29,835,899	(1,781,206)	(16,459,201)	13,376,698		
63	398	Miscellaneous Equipment	2,527,532	-	(20,120)	-	4,582,190	(166,424)	(1,136,629)	3,445,561		
64		TOTAL General Plant (Sum L's 53 Thru 62)	$ 20,563,811	$ -	$ (6,200,269)	$ -	$ 154,317,996	$ (9,195,010)	$ (72,665,541)	$ 81,652,455	$ (67,626,970)	$ (5,038,571)
65		**TOTAL PLANT**(Sum L's 4, 23, 38, 52 & 63)	$ 191,054,795	$ -	$ (16,975,300)	$ 316,129	$ 3,031,479,359	$ (97,067,376)	$ (1,472,590,181)	$ 1,558,889,178	$ (1,407,389,540)	$ (65,200,641)
66								Company Workpapers	$ (1,407,389,540)		$ (65,200,641)	
											$ (8,938,932)	2004
67								Difference	$ (65,200,641)		$ (16,825,107)	2005
69											$ (39,436,602)	2006
70											$ (65,200,641)	

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Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

REVENUE REQUIREMENT
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 982,734	$ 1,849,295	$ 1,416,014	$ 936,123	$ 1,783,296	$ 1,359,709
2	Adjusted Operating Income (Loss)	$ (13,173)	$ (13,173)	$ (13,173)	$ 50,824	$ 50,824	$ 50,824
3	Current Rate Of Return (Line 2 / Line 1)	-1.34%	-0.71%	-0.93%	5.43%	2.85%	3.74%
4	Required Operating Income (Line 5 X Line 1)	$ 82,069	$ 82,069	$ 82,069	$ 72,667	$ 72,667	$ 72,667
5	Required Rate Of Return	8.35%	4.44%	5.80%	7.76%	4.07%	5.34%
6	Operating Income Deficiency (Line 4 - Line 2)	$ 95,242	$ 95,242	$ 95,242	$ 21,843	$ 21,843	$ 21,843
7	Gross Revenue Conversion Factor (Schedule RLM-1, Page 3)	1.6609	1.6609	1.6609	1.6598	1.6598	1.6598
8	Increase In Gross Revenue Requirement (Line 7 X Line 6)	$ 158,186	$ 158,186	$ 158,186	$ 36,254	$ 36,254	$ 36,254
9	Adjusted Test Year Revenue	$ 712,731	$ 712,731	$ 712,731	$ 897,212	$ 897,212	$ 897,212
10	Proposed Annual Revenue Requirement (Line 8 + Line 9)	$ 870,917	$ 870,917	$ 870,917	$ 933,466	$ 933,466	$ 933,466
11	Required Percentage Increase In Revenue (Line 8 / Line 9)	22.19%	22.19%	22.19%	4.04%	4.04%	4.04%
12	Rate Of Return On Common Equity	11.39%	11.39%	11.39%	9.44%	9.44%	9.44%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 And D-1
Column (D): Schedules RLM-1, Page 2, RLM-2, RLM-7 And RLM-18
Column (E): Schedule RLM-2, Column (F)
Column (F): Average Of Column (D) + Column (E)

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	REFERENCE	(A)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:		
1	Revenue		100.0%
2	Less: Uncollectibles	Company Response To Staff Data Request 1.85	0.25%
3	Subtotal	Line 1 - Line 2	99.7%
4	Less: Combined Federal And State Tax Rate	Line 14	39.5%
5	Subtotal	Line 3 - Line 4	60.25%
6	**Revenue Conversion Factor**	Line 1 / Line 5	**1.6598**
	CALCULATION OF EFFECTIVE TAX RATE:		
7	Arizona Taxable Income		100.0%
8	Arizona State Income Tax Rate		7.1%
9	Federal Taxable Income	Line 7 - Line 8	92.9%
10	Applicable Federal Income Tax Rate		35.0%
11	Effective Federal Income Tax Rate	Line 9 X Line 10	32.5%
12	Subtotal	Line 8 + Line 11	39.6%
13	Revenue Less Uncollectibles	Line 3	99.7%
14	Combined Federal And State Income Tax Rate	Line 12 X Line 13	39.5%

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FAIR VALUE RATE BASE - OCRB / RCND (50/50 SPLIT)
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant In Service	$ 2,115,571	$ 4,184,249	$ 3,149,910	197.78%	$ 2,219,459	$ 4,389,723	$ 3,304,591
2	Accumulated Depreciation	(1,026,758)	(2,062,696)	(1,544,727)	200.89%	(1,159,791)	(2,329,951)	(1,744,871)
3	Net Utility Plant In Service	$ 1,088,813	$ 2,121,553	$ 1,605,183		$ 1,059,668	$ 2,059,772	$ 1,559,720
4	Plant Held For Future Use	$ -	$ -	$ -	100.00%	$ -	$ -	$ -
5	Total Net Utility Plant	$ 1,088,813	$ 2,121,553	$ 1,605,183		$ 1,059,668	$ 2,059,772	$ 1,559,720
	Deductions:							
6	Cust. Advances For Const.	$ (5,978)	$ (6,635)	$ (6,307)	110.99%	$ (5,978)	$ (6,635)	$ (6,307)
7	Customer Deposits	(12,538)	(12,538)	(12,538)	100.00%	(12,538)	(12,538)	(12,538)
8	Def'd Credit - Cont'd Plt & Retm't Oblig.	(5,028)	(5,028)	(5,028)	100.00%	(5,028)	(5,028)	(5,028)
9	Acc. Deferred Income Taxes	(160,264)	(325,785)	(243,025)	203.28%	(147,437)	(299,711)	(223,574)
10	Total Deductions	$ (183,808)	$ (349,986)	$ (266,897)		$ (170,981)	$ (323,912)	$ (247,447)
11	Allowance - Working Capital	$ 30,273	$ 30,273	$ 30,273	100.00%	$ 33,224	$ 33,224	$ 33,224
12	Regulatory Assets	$ 47,455	$ 47,455	$ 47,455	100.00%	$ 14,213	$ 14,213	$ 14,213
13	Regulatory Liability	$ -	$ -	$ -	100.00%	$ -	$ -	$ -
14	**TOTAL TEST YEAR RATE BASE**	$ 982,733	$ 1,849,295	$ 1,416,014		$ 936,123	$ 1,783,296	$ 1,359,709

References:
- Columns (A) (B) (C): Company Schedule B-1
- Column (D): Column (B) / Column (A)
- Column (E): Schedule RLM-3, Column (C)
- Column (F): Column (D) X Column (E)
- Column (G): Average Of Column (E) + Column (F)

ORIGINAL COST RATE BASE STATEMENT

(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED AS OCRB	(D) RUCO ADJUSTED OCRB ACC JURISDICTIONAL
1	Gross Utility Plant In Service	$ 2,880,566	$ 141,454	$ 3,022,020	$ 2,219,459
2	Accumulated Depreciation	(1,493,988)	(193,570)	(1,687,558)	(1,159,791)
3	Net Utility Plant In Service	$ 1,386,578	$ (52,116)	$ 1,334,462	$ 1,059,668
4	Plant Held For Future Use	$ 4,014	$ -	$ 4,014	$ -
5	Total Net Utility Plant	$ 1,390,592 0	$ (52,116)	$ 1,338,476	$ 1,059,668
	Deductions:				
6	Cust. Advances For Const.	$ (5,978)	$ -	$ (5,978)	$ (5,978)
7	Customer Deposits	(12,538)	-	(12,538)	(12,538)
8	Def'd Credit - Cont'd Plt & Retm't Oblig.	(6,823)	-	(6,823)	(5,028)
9	Acc. Deferred Income Taxes	(217,503)	17,408	(200,095)	(147,437)
10	Total Deductions	$ (242,842)	$ 17,408	$ (225,434)	$ (170,981)
11	Allowance - Working Capital	$ 40,488	$ 3,946	$ 44,434	$ 33,224
12	Regulatory Assets	$ 47,455	$ (33,242)	$ 14,213	$ 14,213
13	Regulatory Liability	$ -	$ -	$ -	$ -
14	TOTAL OCRB	$ 1,235,693	$ (64,004)	$ 1,171,689	$ 936,123

References:

Column (A): - Company Schedule B-2
Column (B): - RUCO Adjustments (See RLM-4, Columns (B) Thru (G))
Column (C): - Sum Of Columns (A) And (B)
Column (D): - Column (C) Multipied By The Same Ratios As TEP's Percentage ACC Jurisdiction Is To Total Company

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SUMMARY OF ORIGINAL COST RATE BASE

(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) ADJ. NO. 1 ACCUMULATED DEPRECIATION TESTIMONY-RLM	(C) ADJ. NO. 2 SPRINGERVILLE UNIT 1 TESTIMONY-MDC	(D) ADJ. NO. 3 LUNA PLANT TESTIMONY-MDC	(E) ADJ. NO. 4 REGULATORY ASSETS TESTIMONY-MDC	(F) ADJ. NO. 5 FAS 143 WRITE-OFF TESTIMONY-MDC	(G) ADJ. NO. 6 ALLOWANCE FOR WORKING CAPITAL SCH. RLM-6	(H) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 2,880,566	$ -	$ 92,524	$ 48,930	$ -	$ -	$ -	$ 3,022,020
2	Accumulated Depreciation	(1,493,988)	(49,504)	(30,368)	(891)	-	(112,807)	-	(1,687,558)
3	Net Utility Plant In Service	$ 1,386,578	$ (49,504)	$ 62,156	$ 48,039	$ -	$ (112,807)	$ -	$ 1,334,462
4	Plant Held For Future Use	$ 4,014	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,014
5	Total Net Utility Plant	$ 1,390,592 0	$ (49,504)	$ 62,156	$ 48,039	$ -	$ (112,807)	$ -	$ 1,338,477
	Deductions:								
6	Cust. Advances For Const.	$ (5,978)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,978)
7	Customer Deposits	(12,538)	-	-	-	-	-	-	(12,538)
8	Def'd Credit - Plt & Retm't	(6,823)	-	-	-	-	-	-	(6,823)
9	Acc. Deferred Income Taxes	(217,503)	19,554	(1,764)	(382)	-	-	-	(200,095)
10	Total Deductions	$ (242,842)	$ 19,554	$ (1,764)	$ (382)	$ -	$ -	$ -	$ (225,434)
11	Allowance - Working Capital	$ 40,488	$ -	$ -	$ -	$ -	$ -	$ 3,946	$ 44,434
12	Regulatory Assets	$ 47,455	$ -	$ -		$ (33,242)	$ -	$ -	$ 14,213
13	Regulatory Liability	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	TOTAL OCRB	$ 1,235,693	$ (29,949)	$ 60,392	$ 47,657	$ (33,242)	$ (112,807)	$ 3,946	$ 1,171,689

References:
- Column (A): Company Schedule B-1
- Columns (B) Thru (G): RUCO Rate Base Adjustments
- Column (H): Sum Of Columns (A) Through (G)

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Test Year Ended December 31, 2006

TEST YEAR PLANT SCHEDULES
PRO FORMA ADJUSTMENTS TO TEST-YEAR ENDED DECEMBER 31, 2006

LINE NO.	ACCT NO.	DESCRIPTION	(A) COMPANY AS FILED GROSS PLANT	(B) COMPANY AS FILED ACCUM. DEP.	(C) RUCO ADJ. NO. 1 ACCUMULATED DEPRECIATION RLM WP'S	(D) RUCO ADJ. NO. 2 SPRINGERVILLE UNIT 1 GROSS PLANT TESTIMONY-MDC	(E) RUCO ADJ. NO. 2 SPRINGERVILLE UNIT 1 ACCUM. DEP. TESTIMONY-MDC	(F) RUCO ADJ. NO. 3 LUNA PLANT GROSS PLANT TESTIMONY-MDC	(G) RUCO ADJ. NO. 3 LUNA PLANT ACCUM. DEP. TESTIMONY-MDC	(H) RUCO ADJ. NO. 5 FAS 143 WRITE-OFF TESTIMONY-MDC	(I) TOTAL PLANT VALUE	(J) ACCUM'D DEPREC'N	(K) NET PLANT VALUE
		INTANGIBLE PLANT											
1	301	Organization	$ 29,362	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,362	$ -	$ 29,362
2	302	Franchises and Consents	147,884	(147,884)	-	-	-	-	-	(11,237)	147,884	(159,121)	(11,237)
3	303	Miscellaneous Intangible Plant	68,762,926	(37,114,783)	-	234,384	(259,958)	-	-	(2,820,181)	68,997,310	(40,194,922)	28,802,388
4		TOTAL Intangible Plant	$ 68,940,172	$ (37,262,667)	$ -	$ 234,384	$ (259,958)	$ -	$ -	$ (2,831,418)	$ 69,174,556	$ (40,354,043)	$ 28,820,513
		PRODUCTION PLANT											
		Steam Production Plant											
5	310	Land and Land Rights	$ 3,169,168	$ (1,012,696)	$ 390,382	$ 2,709,372	$ (1,288,605)	$ -	$ -	$ (76,950)	$ 5,878,540	$ (1,987,870)	$ 3,890,670
6	311	Structures and Improvements	99,277,925	(57,575,525)	(3,181,865)	21,856,495	(12,760,129)	-	-	(4,374,898)	121,134,420	(77,892,417)	43,242,003
7	312	Boiler Plant Equipment	662,377,491	(354,059,358)	(33,997,147)	44,695,709	(8,520,420)	-	-	(26,903,334)	707,073,200	(423,480,259)	283,592,941
8	313	Engines and Engine-Driven Generators	-	-	-	-	-	-	-	-	-	-	-
9	314	Turbogenerator Units	218,716,218	(113,122,101)	(8,948,532)	12,488,550	(3,465,561)	-	-	(8,595,626)	231,204,768	(134,131,819)	97,072,949
10	315	Accessory Electric Equipment	81,654,743	(43,596,052)	(2,479,779)	1,030,738	(212,503)	-	-	(3,312,662)	82,685,481	(49,600,997)	33,084,484
11	316	Misc. Power Plant Equipment	19,036,662	(10,453,046)	(1,365,514)	840,896	(193,805)	-	-	(794,279)	19,877,558	(12,806,643)	7,070,915
12	317	Asset Retm't Costs for Steam Production	344,128	(185,057)	(9,963)	-	-	22,787	(242)	(14,062)	366,915	(209,323)	157,592
13	114	San Juan Acquisition Adjustment	3,124,669	(2,860,427)	-	-	-	-	-	(217,351)	3,124,669	(3,077,778)	46,891
14		TOTAL Steam Plant	$ 1,087,701,004	$ (582,864,262)	$ (49,592,418)	$ 83,621,760	$ (26,441,023)	$ 22,787	$ (242)	$ (44,289,161)	$ 1,171,345,551	$ (703,187,106)	$ 468,158,445
		Other Production Plant											
15	340	Land and Land Rights	$ 401,628	$ -	$ -	$ -	$ -	$ 1,526,387	$ (27,787)	$ -	$ 1,928,015	$ (27,787)	$ 1,900,228
16	341	Structures and Improvements	1,360,094	(636,837)	45,964	-	-	12,840,376	(233,748)	(48,390)	14,200,470	(873,011)	13,327,459
17	342	Fuel Holders, Products, and Accessories	1,164,895	(197,799)	3,655	-	-	11,430,397	(208,081)	(15,030)	12,595,292	(417,255)	12,178,037
18	343	Prime Movers	354,047	(347,068)	-	-	-	-	-	(26,372)	354,047	(373,440)	(19,393)
19	344	Generators	62,855,652	(22,186,621)	22,444	-	-	15,622,018	(284,386)	(1,685,859)	78,477,670	(24,134,422)	54,343,248
20	345	Accessory Electric Equipment	4,475,217	(2,256,626)	51,299	-	-	-	-	(171,471)	4,475,217	(2,376,798)	2,098,419
21	346	Misc. Power Plant Equipment	1,038,310	(513,791)	(34,779)	-	-	7,347,169	(133,749)	(39,041)	8,385,479	(721,360)	7,664,119
22		TOTAL Other Plant	$ 71,649,843	$ (26,138,742)	$ 88,583	$ -	$ -	$ 48,766,347	$ (887,751)	$ (1,986,162)	$ 120,416,190	$ (28,924,072)	$ 91,492,118
23		TOTAL Production Plant	$ 1,159,350,847	$ (609,003,004)	$ (49,503,835)	$ 83,621,760	$ (26,441,023)	$ 48,769,134	$ (887,993)	$ (46,275,323)	$ 1,291,761,741	$ (732,111,178)	$ 559,650,563
		TRANSMISSION PLANT											
		Transmission Non-EHV (138 KV & Below)											
24	350	Land and Land Rights	$ 10,776,362	$ (3,933,982)	$ -	$ 8,686	$ -	$ -	$ -	$ (298,925)	$ 10,785,048	$ (4,232,907)	$ 6,552,141
25	352	Structures and Improvements	7,634,167	(3,082,538)	-	-	-	-	-	(234,228)	7,634,167	(3,316,766)	4,317,401
26	353	Station Equipment	124,358,421	(64,239,317)	-	-	-	141,051	(3,127)	(4,881,249)	124,499,472	(69,123,693)	55,375,779
27	354	Towers and Fixtures	9,843,590	(9,179,276)	-	-	-	-	-	(697,491)	9,843,590	(9,876,767)	(33,177)
28	355	Poles and Fixtures	18,675,438	(13,689,183)	-	-	-	-	-	(1,040,178)	18,675,438	(14,729,361)	3,946,077
29	356	Overhead Conductors and Devices	16,703,460	(9,777,611)	-	-	-	-	-	(742,955)	16,703,460	(10,520,566)	6,182,894
30		TOTAL Transmission Non-EHV	$ 187,991,438	$ (103,901,907)	$ -	$ 8,686	$ -	$ 141,051	$ (3,127)	$ (7,895,026)	$ 188,141,175	$ (111,800,060)	$ 76,341,115

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Cost of Service
Schedule RLM-5
Pages 1 & 2 of 2

TEST YEAR PLANT SCHEDULES
PRO FORMA ADJUSTMENTS TO TEST-YEAR ENDED DECEMBER 31, 2006

LINE NO.	ACCT NO.	DESCRIPTION	(A) COMPANY AS FILED GROSS PLANT	(B) COMPANY AS FILED ACCUM. DEP.	(C) RUCO ADJ. NO. 1 ACCUMULATED DEPRECIATION RLM WP'S	(D) RUCO ADJ. NO. 2 SPRINGERVILLE UNIT 1 GROSS PLANT TESTIMONY-MDC	(E) RUCO ADJ. NO. 2 SPRINGERVILLE UNIT 1 ACCUM. DEP. TESTIMONY-MDC	(F) RUCO ADJ. NO. 3 LUNA PLANT GROSS PLANT TESTIMONY-MDC	(G) RUCO ADJ. NO. 3 LUNA PLANT ACCUM. DEP. TESTIMONY-MDC	(H) RUCO ADJ. NO. 5 FAS 143 WRITE-OFF TESTIMONY-MDC	(I) TOTAL PLANT VALUE	(J) ACCUM'D DEPREC'N	(K) NET PLANT VALUE
		Transmission EHV (345 KV & Above)											
31	350	Land and Land Rights	$ 15,037,219	$ (9,104,523)	$ -	$ -	$ -	$ -	$ -	$ (691,811)	$ 15,037,219	$ (9,796,334)	$ 5,240,885
32	352	Structures and Improvements	10,080,213	(6,412,850)	-	-	-	-	-	(487,283)	10,080,213	(6,900,133)	3,180,080
33	353	Station Equipment	134,192,652	(74,118,405)	-	-	-	-	-	(5,631,915)	134,192,652	(79,750,320)	54,442,332
34	354	Towers and Fixtures	145,810,705	(112,092,110)	-	-	-	-	-	(8,517,361)	145,810,705	(120,609,471)	25,201,234
35	355	Poles and Fixtures	1,341,221	(1,162,682)	-	-	-	-	-	(88,347)	1,341,221	(1,251,029)	90,192
36	356	Overhead Conductors and Devices	66,469,318	(51,136,689)	-	-	-	-	-	(3,885,641)	66,469,318	(55,022,330)	11,446,988
37	359	Roads & Trails	4,658,153	(2,944,319)	-	-	-	-	-	(223,725)	4,658,153	(3,168,044)	1,490,109
38		TOTAL Transmission EHV	$ 377,589,481	$ (256,971,578)	$ -	$ -	$ -	$ -	$ -	$ (19,526,082)	$ 377,589,481	$ (276,497,660)	$ 101,091,821
39		TOTAL Transmission Plant	$ 565,580,919	$ (360,873,485)	$ -	$ 8,686	$ -	$ 141,051	$ (3,127)	$ (27,421,108)	$ 565,730,656	$ (388,297,720)	$ 177,432,936
		DISTRIBUTION PLANT											
40	360	Land and Land Rights	$ 9,858,745	$ (3,742,566)	$ -	$ -	$ -	$ -	$ -	$ (284,380)	$ 9,858,745	$ (4,026,946)	$ 5,831,799
41	361	Structures and Improvements	6,282,094	(1,745,626)	-	-	-	-	-	(132,642)	6,282,094	(1,878,268)	4,403,826
42	362	Station Equipment	95,451,660	(62,914,013)	-	-	-	-	-	(4,780,545)	95,451,660	(67,694,558)	27,757,102
43	364	Poles, Towers, and Fixtures	112,985,358	(80,393,163)	-	-	-	-	-	(6,108,705)	112,985,358	(86,501,868)	26,483,490
44	365	Overhead Conductors and Devices	106,758,542	(59,293,992)	-	-	-	-	-	(4,505,476)	106,758,542	(63,799,468)	42,959,074
45	366	Underground Conduit	49,342,484	(15,411,170)	-	-	-	-	-	(1,171,024)	49,342,484	(16,582,194)	32,760,290
46	367	Underground Conductors and Devices	213,374,544	(48,689,625)	-	-	-	-	-	(3,699,700)	213,374,544	(52,389,325)	160,985,219
47	368	Line Transformers	203,129,296	(80,023,005)	-	-	-	-	-	(6,080,578)	203,129,296	(86,103,583)	117,025,713
48	369	Services	92,019,762	(42,610,100)	-	-	-	-	-	(3,237,745)	92,019,762	(45,847,845)	46,171,917
49	370	Meters	32,881,789	(11,171,975)	-	-	-	-	-	(848,907)	32,881,789	(12,020,882)	20,860,907
50	371	Installations on Customer Premises	-	-	-	-	-	-	-	-	-	-	-
51	373	Street Lighting and Signal Systems	9,334,416	(5,838,098)	-	-	-	-	-	(443,610)	9,334,416	(6,281,708)	3,052,708
52	374	Asset Retirement Obligation	216,459	(183,358)	-	-	-	-	-	(13,933)	216,459	(197,291)	19,168
53		TOTAL Distribution Plant	$ 931,635,149	$ (412,016,691)	$ -	$ -	$ -	$ -	$ -	$ (31,307,244)	$ 931,635,149	$ (443,323,935)	$ 488,311,214
		GENERAL PLANT											
54	389	Land and Land Rights	$ 302,740	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 302,740	$ -	$ 302,740
55	390	Structures and Improvements	35,331,795	(11,701,598)	-	92,674	16,877	-	-	(889,150)	35,424,469	(12,573,871)	22,850,598
56	391	Office Furniture and Equipment	25,057,825	(11,647,647)	-	1,072,839	(839,178)	-	-	(885,051)	26,130,664	(13,371,876)	12,758,788
57	392	Transportation Equipment	36,960,886	(20,376,114)	-	-	-	-	-	(1,548,287)	36,960,886	(21,924,401)	15,036,485
58	393	Stores Equipment	787,309	(482,899)	-	201,112	(211,417)	-	-	(36,693)	988,421	(731,009)	257,412
59	394	Tools, Shop and Garage Equipment	4,506,445	(1,920,381)	-	1,638,174	(986,481)	-	-	(145,921)	6,144,619	(3,052,783)	3,091,836
60	395	Laboratory Equipment	3,619,398	(1,183,270)	-	654,036	(320,650)	-	-	(89,911)	4,273,434	(1,593,831)	2,679,603
61	396	Power Operated Equipment	7,368,515	(1,298,100)	-	2,306,159	(475,286)	-	-	(98,637)	9,674,674	(1,872,023)	7,802,651
62	397	Communication Equipment	29,097,434	(16,165,626)	-	738,465	(417,838)	-	-	(1,228,351)	29,835,899	(17,811,815)	12,024,084
63	398	Miscellaneous Equipment	2,62[illegible],329	(656,781)	-	1,955,861	(432,974)	-	-	(49,906)	4,582,190	(1,139,661)	3,442,529
64		TOTAL General Plant	$ 145,658,676	$ (65,432,416)	$ -	$ 8,659,320	$ (3,666,947)	$ -	$ -	$ (4,971,907)	$ 154,317,996	$ (74,071,270)	$ 80,246,726
65		SUB-TOTAL PLANT	$ 2,871,165,763	$ (1,484,588,263)	$ (49,503,835)	$ 92,524,150	$ (30,367,928)	$ 48,930,185	$ (891,120)	$ (112,807,000)	$ 3,012,620,098	$ (1,678,158,146)	$ 1,334,461,952
66		Reconcile Co.'s Workpapers To B-1 (Regulatory Assets)	$ 9,400,488	(9,400,036)							9,400,488	(9,400,036)	452
67		TOTAL PLANT	$ 2,880,566,251	$ (1,493,988,299)	$ (49,503,835)	$ 92,524,150	$ (30,367,928)	$ 48,930,185	$ (891,120)	$ (112,807,000)	3,022,020,586	(1,687,558,181)	$ 1,334,462,405

ORIGINAL COST RATE BASE ADJUSTMENT NO. 6
ALLOWANCE FOR WORKING CAPITAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT
1	Cash Working Capital Per TEP	TEP SCH. B-5, Page 1	$ (25,022)
2	Cash Working Capital Per RUCO	RLM-6, Page 2, Line 35	(21,796)
3	Adjustment	Line 2 - Line 1	$ 3,226
4	Fuel Inventory Per TEP	TEP SCH. B-5, Page 1	$ 18,972
5	Fuel Inventory Per RUCO	TEP SCH. B-5, Page 1	18,972
6	Adjustment	Line 5 - Line 4	$ -
7	Materials And Supplies Per TEP	TEP SCH. B-5, Page 1	$ 351,825
8	Materials And Supplies Per RUCO	TEP SCH. B-5, Page 1	351,825
9	Materials And Supplies Per RUCO Luna Plant Rate Base Adjustment No. 2		629
10	Adjustment	Line 8 - Line 7 + Line 9	$ 629
11	Prepayments Per TEP	TEP SCH. B-5, Page 1	$ 5,895
12	Prepayments Per RUCO	TEP SCH. B-5, Page 1	5,895
13	Prepayments Per RUCO Luna Plant Rate Base Adjustment No. 2		91
14	Adjustment	Line 12 - Line 11 + Line 13	$ 91
15	TOTAL ADJUSTMENT (See RLM-4, Column (G))	Sum Lines 3, 6, 10 & 14	$ 3,946

ORIGINAL COST RATE BASE ADJUSTMENT NO. 6 - CONT'D
ALLOWANCE FOR WORKING CAPITAL
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD) / LAG DAYS	(E) DOLLAR DAYS
	OPERATING EXPENSES					
	Non-Cash Expenses:					
1	Bad Debts Expense	$ 2,490,991	$ (2,490,991)	$ -	0	$ -
2	Depreciation	82,440,295	(82,440,295)	$ -	0	-
3	Amortization	12,587,778	(12,587,778)	$ -	0	-
4	Deferred Income Taxes	(8,038,493)	8,038,493	$ -	0	-
5	Total Non-Cash Expenses	$ 89,480,571	$ (89,480,571)	$ -		$ -
	Other Operating Expenses:					
6	Salaries & Wages	$ 60,946,931	$ 19,651	$ 60,966,582	13.26	$ 808,416,871
7	Incentive Pay	3,838,440	(1,525,378)	2,313,062	244.32	565,127,308
8	Fuel Expense	257,956,424	23,216,300	281,172,724	24.1	6,776,262,643
9	Purchased Power	70,668,694	126,343,000	197,011,694	35.7	7,033,317,476
10	Purchase Transmission	4,771,517	-	4,771,517	39.5	188,474,922
11	Lease Expense	102,740,975	(27,721,230)	75,019,745	95.32	7,150,882,093
12	Remote Generating Plant O & M	31,798,784	-	31,798,784	-0.7	(22,259,149)
13	Office Supplies and Expenses	6,542,004	(420,344)	6,121,660	5.1	31,220,465
14	Outside Services	6,361,869	(309,734)	6,052,135	35.9	217,271,653
15	Property Insurance	2,091,138	(108,526)	1,982,612	7.4	14,671,329
16	Injuries and Damages	3,635,397	(15,381)	3,620,016	19.7	71,314,315
17	Pensions and Benefits	15,825,396	(1,683,208)	14,142,188	11.4	161,220,939
18	Miscellaneous General Expenses	9,269,497	(216,245)	9,053,252	48.4	438,177,397
19	Rents	660,232	(5,947)	654,285	46.1	30,162,539
20	Property Taxes	30,751,385	(1,800,201)	28,951,184	213.78	6,189,184,176
21	Payroll Taxes	5,508,194	(84,578)	5,423,616	12.91	70,018,882
22	Current Income Taxes	(4,221,970)	50,695,903	46,473,933	42.3	1,965,847,348
23	Other Taxes	179,866	-	179,866	90.81	16,333,631
24	Interest on Customer Deposits	574,863	-	574,863	182.5	104,912,498
25	Other Operations and Maintenance	58,358,617	(30,499,097)	27,859,520	14.3	398,391,138
26	Total Other Operating Expenses	$ 668,258,253	$ 135,884,984	$ 804,143,237		$ 32,208,948,473
	Other Cash Working Capital Elements:					
27	Interest on Long-Term Debt	$ 43,417,161	$ (2,238,155)	$ 41,179,006	74.6	$ 3,071,953,877
28	Revenue Taxes and Assessments	59,055,220	9,874,581	68,929,801	51.75	3,567,117,215
29	Total Other Cash Working Capital	$ 102,472,381	$ 7,636,427	$ 110,108,808		$ 6,639,071,093
30	TOTAL CASH WORKING CAPITAL	$ 860,211,205		$ 914,252,045		$ 38,848,019,566

31	Expense Lag	Line 31, Col. (E) / (D)	42.49
32	Revenue Lag	Company Workpapers	33.79
33	Net Lag	Line 28 - Line 27	(8.70)
34	RUCO Adjusted Expenses	Col. (C), Line 31	$ 914,252,045
35	Cash Working Capital	Line 29 X Line 30 / 365 Days	(21,795,734)

References:
Column (A): - Company Schedule B-5, Page 3
Column (B): RUCO Operating Income Adjustments (See RLM-7)
Column (C): Column (A) + (B)
Column (D): Company Schedule B-5, Page 3
Column (E): Column (C) X Column (D)

OPERATING INCOME STATEMENT
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'D	(D) RUCO AS ADJ'D ACC JURID'L	(E) RUCO PROPOSED ACC JURID'L	(F) RUCO RECOM'D ACC JURID'L
	Operating Revenues:						
1	Electric Retail Revenues	$ 691,451	$ -	$ 691,451	$ 691,451	$ 36,254	$ 727,705
2	Sales for Resale	58,402	183,785	242,187	183,785	-	183,785
3	Other Operating Revenue	34,542	1,130	35,671	21,976	-	21,976
4	TOTAL OPERATING REVENUES	$ 784,395	$ 184,915	$ 969,310	$ 897,212	$ 36,254	$ 933,466
	Operating Expenses:						
5	Fuel Expense	$ 265,955	$ 23,216	$ 289,172	$ 258,992	$ -	$ 258,992
6	Purchased Power - Demand	30,634	(15,960)	14,674	13,871	-	13,871
7	Purchased Power - Energy	40,035	126,343	166,378	149,015	-	149,015
8	Other O & M Expense	315,104	(54,670)	260,434	304,293	-	304,293
9	Depreciation and Amortization	82,440	3,812	86,253	60,592	-	60,592
10	Taxes Other than Income Taxes	35,831	(1,885)	33,946	27,562	-	27,562
11	Income Taxes	(12,260)	-	-	32,063	14,411	46,474
12	TOTAL OPERATING EXPENSES	$ 757,739	$ 80,857	$ 850,856	$ 846,388	$ 14,411	$ 860,799
13	OPERATING INCOME (LOSS)	$ 26,656	$ 104,058	$ 118,454	$ 50,824	$ 21,843	$ 72,667

References:
- Column (A): Company Schedule C-1
- Column (B): Testimonies, RLM & MDC And Schedule RLM-8, Pages 1 Thru 6
- Column (C): Column (A) + Column (B)
- Column (D): Column (C) X Jurisdictional Factor
- Column (E): See Schedule RLM-1
- Column (F): Column (D) + Column (E)

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACC'T	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 SPRINGERVILLE UNIT 1 TESTIMONY-MDC	(C) ADJ. NO. 2 DEP/AMORT EXPENSES SCH. RLM-9	(D) ADJ. NO. 3 INAPPROPRIATE EXPENSES SCH. RLM-10	(E) ADJ. NO. 4 SERP TESTIMONY-RLM	(F) ADJ. NO. 5 INCENTIVE COMP. SCH. RLM-11	(G) ADJ. NO. 6 RATE CASE EXPENSE TESTIMONY-RLM	(H) ADJ. NO. 7 PROPERTY TAX SCH. RLM-12	(I) ADJ. NO. 8 O/H LINES MAINTENANCE SCH. RLM-13	(J) ADJ. NO. 9 PENALTIES & FINES TESTIMONY-RLM
1	440, 442, 444,445	**Electric Retail Revenue**	$ 691,451,429	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	446	**Sales for Resale**	58,402,097	-	-	-	-	-	-	-	-	-
3	447	**Total Electric Retail Revenue**	$ 749,853,526	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Operating Revenue										
4	451	Miscellaneous Service Revenues	$ 3,810,771	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	454	Rent from Electric Property	9,846,702	566,941	-	-	-	-	-	-	-	-
6	456	Other Electric Revenues	20,884,205	-	-	-	-	-	-	-	-	-
7		**Total Other Operating Revenue**	$ 34,541,678	$ 566,941	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	**Total Operating Revenue**		$ 784,395,204	$ 566,941	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Steam Power Generation Expense										
9	500	Operation Supervision & Engineering	$ 7,083,655	$ (238,149)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	501	Fuel - **PPFAC Eligible**	239,090,290	-	-	-	-	-	-	-	-	-
11	502	Steam Expenses	22,290,948	(2,453,630)	-	-	-	-	-	-	-	-
12	505	Electric Expenses	3,358,046	(189,923)	-	-	-	-	-	-	-	-
13	506	Miscellaneous Steam Power Expenses	6,417,825	(368,155)	-	-	-	(241,872)	-	-	-	-
14	507	Rents	95,556,277	(23,367,388)	-	-	-	-	-	-	-	-
15	510	Maintenance Supervision & Engineering	4,910,476	(287,729)	-	-	-	-	-	-	-	-
16	511	Maintenance of Structures	2,391,982	(190,264)	-	-	-	-	-	-	-	-
17	512	Maintenance of Boiler Plant	29,145,633	(2,591,774)	-	-	-	-	-	-	-	-
18	513	Maintenance of Electric Plant	7,014,200	(404,865)	-	-	-	-	-	-	-	-
19	514	Maintenance Miscellaneous Steam Plant	7,562,772	(595,047)	-	-	-	(105,563)	-	-	-	-
20	411.10	FAS 143 Accretion Expense	241,122	-	-	-	-	-	-	-	-	-
21	411.8	Gain on Sales of Emission Allowances	(471,379)	-	-	-	-	-	-	-	-	-
		Other Power Production Expense										
22	546	Operation Supervision & Engineering	111,406	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	547	Fuel - **PPFAC Eligible**	25,864,966	-	-	-	-	-	-	-	-	-
24	551	Maintenance Supervision & Engineering	4,587	-	-	-	-	-	-	-	-	-
25	552	Maintenance of Structures	11,568	-	-	-	-	-	-	-	-	-
26	553	Maintenance of Generating and Electric Plant	144,320	-	-	-	-	-	-	-	-	-
27	554	Maintenance of Miscellaneous Other Power Generation Plant	75,521	-	-	-	-	-	-	-	-	-
28	557	Other Expenses	7,423	-	-	-	-	-	-	-	-	-
		Other Power Supply Expense										
29	555	Purchased Power - Demand - **PPFAC Eligible**	$ 30,633,600	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	555	Purchased Power - Energy - **PPFAC Eligible**	40,035,094	-	-	-	-	-	-	-	-	-
31	556	System Control and Load Dispatching	2,188,934	-	-	-	-	-	-	-	-	-
		Transmission Non-EHV (138kv & Below) Expense										
32	560	Operation Supervision & Engineering	$ 218,237	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	561 & 561.1 - 561.8	Load Dispatch & Various	247,761	-	-	-	-	-	-	-	-	-
34	562	Station Expenses	14	-	-	-	-	-	-	-	-	-
35	563	Overhead Line Expenses	13	-	-	-	-	-	-	-	-	-
36	565	Miscellaneous Transmission Expenses	258,492	-	-	-	-	(72,080)	-	-	-	-
37	568	Maintenance Supervision & Engineering	188,959	-	-	-	-	-	-	-	-	-
38	569 & 569.1 - 569.3	Maintenance of Structures & Computers (Hard & Software & Equip)	31,223	-	-	-	-	-	-	-	-	-
39	570	Maintenance of Station Equipment	1,430,472	-	-	-	-	(17,401)	-	-	-	-
40	571	Maintenance of Overhead Lines	391,508	-	-	-	-	-	-	-	-	-
41	573	Maintenance of Miscellaneous Transmission Plant	(3,170)	-	-	-	-	-	-	-	-	-
42		**Transmission EHV (345kv & Above) Expense**										
43	560	Operation Supervision & Engineering	547,473	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	561 & 561.1 - 561.8	Load Dispatch - Monitor & Operation Transmission System	951,904	-	-	-	-	-	-	-	-	-
45	562	Station Expenses	5,186	-	-	-	-	-	-	-	-	-
46	563	Overhead Line Expenses	1,528	-	-	-	-	-	-	-	-	-
47	565	Transmission of Electricity by Others - **PPFAC Eligible**	4,771,517	-	-	-	-	-	-	-	-	-
48	566	Miscellaneous Transmission Expenses	242,986	-	-	-	-	-	-	-	-	-
49	567	Rents	433,517	-	-	-	-	-	-	-	-	-
50	568	Maintenance Supervision & Engineering	59,948	-	-	-	-	-	-	-	-	-
51	569 & 569.1 - 569.3	Maintenance of Structures & Computers (Hard & Software & Equip)	345,293	-	-	-	-	-	-	-	-	-
52	570	Maintenance of Station Equipment	1,309,338	-	-	-	-	-	-	-	-	-
53	571	Maintenance of Overhead Lines	502,738	-	-	-	-	-	-	-	-	-
54	573	Maintenance of Miscellaneous Transmission Plant	222,572	-	-	-	-	-	-	-	-	-

Continued On Page 2

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACC'T	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 SPRINGERVILLE UNIT 1 TESTIMONY-MDC	(C) ADJ. NO. 2 DEP/AMORT EXPENSES SCH. RLM-9	(D) ADJ. NO. 3 INAPPROPRIATE EXPENSES SCH. RLM-10	(E) ADJ. NO. 4 SERP TESTIMONY-RLM	(F) ADJ. NO. 5 INCENTIVE COMP. SCH. RLM-11	(G) ADJ. NO. 6 RATE CASE EXPENSE TESTIMONY-RLM	(H) ADJ. NO. 7 PROPERTY TAX SCH. RLM-12	(I) ADJ. NO. 8 O/H LINES MAINTENANCE SCH. RLM-13	(J) ADJ. NO. 9 PENALTIES & FINES TESTIMONY-RLM
		Distribution Expense										
55	580	Operation Supervision & Engineering	$ 2,342,156	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	581	Load Dispatching	234,186	-	-	-	-	-	-	-	-	-
57	582	Station Expenses	129,910	-	-	-	-	-	-	-	-	-
58	583	Overhead Line Expenses	712,966	-	-	-	-	-	-	-	-	-
59	584	Underground Line Expenses	6,935	-	-	-	-	-	-	-	-	-
60	585	Street Lighting & Signal System Expenses	114,926	-	-	-	-	-	-	-	-	-
61	586	Meter Expenses	773,201	-	-	-	-	-	-	-	-	-
62	587	Customer Installations Expense	204,569	-	-	-	-	-	-	-	-	-
63	588	Miscellaneous Distribution Expenses	9,109,574	-	-	-	-	(174,456)	-	-	-	-
64	589	Rents	297,011	-	-	-	-	-	-	-	-	-
65	590	Maintenance Supervision & Engineering	657,272	-	-	-	-	-	-	-	-	-
66	592	Maintenance of Station Equipment	1,581,845	-	-	-	-	-	-	-	(126,584)	-
67	593	Maintenance of Overhead Lines	1,631,514	-	-	-	-	-	-	-	-	-
68	594	Maintenance of Underground Lines	116,841	-	-	-	-	-	-	-	-	-
69	595	Maintenance of Line Transformers	581,610	-	-	-	-	-	-	-	-	-
70	596	Maintenance of Street Lighting & Signal Systems	1,676	-	-	-	-	-	-	-	-	-
71	597	Maintenance of Meters	119,505	-	-	-	-	-	-	-	-	-
72	598	Maintenance of Miscellaneous Distribution Plant	362,524	-	-	-	-	(27,783)	-	-	-	-
73	407.3	Regulatory Asset Amortization	11,863,806	-	-	-	-	-	-	-	-	-
		Customer Account Expense										
74	901	Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	902	Meter Reading Expenses	3,057,311	-	-	-	-	-	-	-	-	-
75	903	Customer Records & Collection Expenses	13,038,115	-	-	-	-	(100,172)	-	-	-	-
76	904	Uncollectible Accounts	2,490,991	-	-	-	-	-	-	-	-	-
77	905	Miscellaneous Customer Accounts Expenses	(31,254)	-	-	-	-	-	-	-	-	-
78	906	Customer Assistance Expenses	22,188	-	-	-	-	-	-	-	-	-
79	909	Informational and Instructional Advertising Expenses	234,968	-	-	-	-	-	-	-	-	-
80	910	Miscellaneous Customer Service & Informational Expenses	16,298	-	-	-	-	-	-	-	-	-
		Administrative and General Expense										
81	920	Administrative & General Salaries	21,966,550	$ (289,766)	$ -	$ -	$ -	$ (693,004)	$ -	$ -	$ -	$ -
82	921	Office Supplies & Expenses	7,636,017	(109,258)	-	(327,746)	-	-	-	-	-	(6,096)
83	922	Administrative Expenses Transferred - Credit	(8,495,252)	-	-	-	-	-	-	-	-	(992)
84	923	Outside Services Employed	6,868,412	(70,685)	-	(1,568)	-	-	-	-	-	(2,355)
85	924	Property Insurance	2,469,577	(195,540)	-	-	-	-	-	-	-	-
86	925	Injuries and Damages	4,586,745	(27,379)	-	-	-	-	-	-	-	-
87	926	Employee Pension & Benefits	19,425,177	(696,565)	-	-	(927,925)	-	-	-	-	-
88	928	Regulatory Commission Expenses	441,957	-	-	-	-	-	(112,500)	-	-	-
89	929	Duplicate Charges - Credit	(916,836)	-	-	-	-	-	-	-	-	-
90	930.1	General Advertising Expenses	476,399	-	-	(16,103)	-	-	-	-	-	-
91	930.2	Miscellaneous General Expenses	9,600,842	(13,036)	-	(168,315)	-	-	-	-	-	-
92	931	Rents	660,232	(5,947)	-	-	-	-	-	-	-	-
93	935	Maintenance of General Plant	107,783	-	-	-	-	(561)	-	-	-	-
94		**Total Operation and Maintenance Expense**	$ 651,728,310	$ (32,094,900)	$ -	$ (513,731)	$ (927,925)	$ (1,432,992)	$ (112,500)	$ -	$ (126,584)	$ (9,433)
		Depreciation & Amortization - All										
95	403/404/406	Intangible Plant	$ 8,647,388	$ -	$ 22,656	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	403/404/406	Other Production Plant	31,659,979	-	3,555,992	-	-	-	-	-	-	-
97	403/404/406	Transmission Plant	19,451,883	-	5,174	-	-	-	-	-	-	-
98	403/404/406	Distribution Plant	18,525,254	-	-	-	-	-	-	-	-	-
99	403/404/406	General Plant	4,955,790	-	463,475	-	-	-	-	-	-	-
100		**Total Depreciation & Amortization - All**	$ 92,440,295	$ -	$ 4,067,296	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Taxes Other Than Income Taxes										
101	408	Property Tax - Steam Production	$ 11,318,945	$ -	$ -	$ -	$ -	$ -	$ -	$ (662,616)	$ -	$ -
102	408	Property Tax - Other Production	1,329,464	-	-	-	-	-	-	$ (77,827)	-	-
103	408	Property Tax - Transmission (EHV)	2,224,427	-	-	-	-	-	-	$ (130,219)	-	-
104	408	Property Tax - Transmission (Non-EHV)	2,895,080	-	-	-	-	-	-	$ (169,480)	-	-
105	408	Property Tax - Distribution	12,983,459	-	-	-	-	-	-	$ (760,058)	-	-
106	408	Business Activity Tax - Generation	158,533	-	-	-	-	-	-	-	-	-
107	408	Business Activity Tax - Transmission	21,333	-	-	-	-	-	-	-	-	-
108	408	Other (Including Payroll Taxes)	4,899,431	-	-	-	-	(92,486)	-	-	-	-
109		**Total Taxes Other Than Income Taxes**	$ 35,830,682	$ -	$ -	$ -	$ -	$ (92,486)	$ -	$ (1,800,201)	$ -	$ -
110		**Total Income Taxes**	$ (12,260,453)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
111	**Total Operating Expense**		$ 767,738,824	$ (32,094,900)	$ 4,067,296	$ (513,731)	$ (927,925)	$ (1,525,378)	$ (112,500)	$ (1,800,201)	$ (126,584)	$ (9,433)
112	**OPERATING INCOME**		$ 28,656,389	$ 32,661,841	$ (4,067,296)	$ 513,731	$ 927,925	$ 1,525,378	$ 112,500	$ 1,800,201	$ 126,584	$ 9,433

Tucson Electric Power Company
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LINE NO.	FERC ACC'T	DESCRIPTION	(K) ADJ. NO. 10 LUNA PLANT O & M TESTIMONY-MDC	(L) ADJ. NO. 11 IMPLEMT'N COST REG. ASSET TESTIMONY-MDC	(M) ADJ. NO. 12 PAYROLL SCH. RLM-14	(N) ADJ. NO. 13 PAYROLL TAX SCH. RLM-15	(O) ADJ. NO. 14 RENEWABLE RESOURSES TESTIMONY-RLM	(P) ADJ. NO. 15 BAD DEBT TESTIMONY-MDC	(Q) ADJ. NO. 16 NAVAJO COAL TESTIMONY-MDC	(R) ADJ. NO. 17 CUSTOMER CARE AND BILLING SCH. RLM-16	(S) ADJ. NO. 18 GAIN ON SALE OF SO2 ALLOWANCES TESTIMONY-MDC	(T) ADJ. NO. 19 EMPLOYEE RECOGNITION TESTIMONY-RLM
1	440, 442, 444,445	**Electric Retail Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	446	**Sales for Resale**	-	-			-	-	-	-	-	-
3	447	**Total Electric Retail Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Operating Revenue										
4	451	Miscellaneous Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	454	Rent from Electric Property	-	-	-	-	-	-	-	-	-	-
6	456	Other Electric Revenues	-	-	-	-	-	-	-	-	-	-
7		**Total Other Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	**Total Operating Revenue**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Steam Power Generation Expense										
9	500	Operation Supervision & Engineering	$ 543	$ -	$ 1,143	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	501	Fuel - **PPFAC Eligible**	-	-	123	-	-	-	(2,194,235)	-	-	-
11	502	Steam Expenses	-	-	1,362	-	-	-	-	-	-	-
12	505	Electric Expenses	-	-	467	-	-	-	-	-	-	-
13	506	Miscellaneous Steam Power Expenses	-	-	356	-	-	-	-	-	-	-
14	507	Rents	-	-	-	-	-	-	-	-	-	-
15	510	Maintenance Supervision & Engineering	-	-	943	-	-	-	-	-	-	-
16	511	Maintenance of Structures	-	-	130	-	-	-	-	-	-	-
17	512	Maintenance of Boiler Plant	-	-	1,424	-	-	-	-	-	-	-
18	513	Maintenance of Electric Plant	-	-	264	-	-	-	-	-	-	-
19	514	Maintenance Miscellaneous Steam Plant	-	-	528	-	-	-	-	-	-	-
20	411.10	FAS 143 Accretion Expense	2,538	-	-	-	-	-	-	-	(6,716,000)	-
21	411.6	Gain on Sales of Emission Allowances	-	-	-	-	-	-	-	-		
		Other Power Production Expense										
22	546	Operation Supervision & Engineering	$ 1,727,358	$ -	$ 80	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	547	Fuel - **PPFAC Eligible**	-	-	-	-	-	-	-	-	-	-
24	551	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
25	552	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
26	553	Maintenance of Generating and Electric Plant	27,609	-	19	-	-	-	-	-	-	-
27	554	Maintenance of Miscellaneous Other Power Generation Plant	-	-	7	-	-	-	-	-	-	-
28	557	Other Expenses	-	-	-	-	-	-	-	-	-	-
		Other Power Supply Expense										
29	555	Purchased Power - Demand - **PPFAC Eligible**	$ (15,980,000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	555	Purchased Power - Energy - **PPFAC Eligible**	-	-	-	-	-	-	-	-	-	-
31	556	System Control and Load Dispatching	64,889	-	512	-	-	-	-	-	-	-
		Transmission Non-EHV (138kv & Below) Expense										
32	560	Operation Supervision & Engineering	$ 5,746	$ -	$ 212	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	561 & 561.1 - 561.8	Load Dispatch & Various	-	-	284	-	-	-	-	-	-	-
34	562	Station Expenses	-	-	0	-	-	-	-	-	-	-
35	563	Overhead Line Expenses	-	-	0	-	-	-	-	-	-	-
36	566	Miscellaneous Transmission Expenses	-	-	20	-	-	-	-	-	-	-
37	568	Maintenance Supervision & Engineering	-	-	67	-	-	-	-	-	-	-
38	569 & 569.1 - 569.3	Maintenance of Structures & Computers (Hard & Software & Equip)	-	-	101	-	-	-	-	-	-	-
39	570	Maintenance of Station Equipment	-	-	447	-	-	-	-	-	-	-
40	571	Maintenance of Overhead Lines	-	-	63	-	-	-	-	-	-	-
41	573	Maintenance of Miscellaneous Transmission Plant	-	-	26	-	-	-	-	-	-	-
42		**Transmission EHV (345kv & Above) Expense**										
43	560	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	561 & 561.1 - 561.8	Load Dispatch - Monitor & Operation Transmission System	36,296	-	-	-	-	-	-	-	-	-
45	562	Station Expenses	-	-	-	-	-	-	-	-	-	-
46	563	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	-
47	565	Transmission of Electricity by Others - **PPFAC Eligible**	-	-	-	-	-	-	-	-	-	-
48	566	Miscellaneous Transmission Expenses	-	-	-	-	-	-	-	-	-	-
49	567	Rents	-	-	-	-	-	-	-	-	-	-
50	568	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
51	569 & 569.1 - 569.3	Maintenance of Structures & Computers (Hard & Software & Equip)	-	-	-	-	-	-	-	-	-	-
52	570	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	-
53	571	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-	-
54	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-	-

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LINE NO.	FERC ACC'T	DESCRIPTION	(K) ADJ. NO. 10 LUNA PLANT O & M TESTIMONY-MDC	(L) ADJ. NO. 11 IMPLEMT'N COST REG. ASSET TESTIMONY-MDC	(M) ADJ. NO. 12 PAYROLL SCH. RLM-14	(N) ADJ. NO. 13 PAYROLL TAX SCH. RLM-15	(O) ADJ. NO. 14 RENEWABLE RESOURSES TESTIMONY-RLM	(P) ADJ. NO. 15 BAD DEBT TESTIMONY-MDC	(Q) ADJ. NO. 16 NAVAJO COAL TESTIMONY-MDC	(R) ADJ. NO. 17 CUSTOMER CARE AND BILLING SCH. RLM-16	(S) ADJ. NO. 18 GAIN ON SALE OF SO2 ALLOWANCES TESTIMONY-MDC	(T) ADJ. NO. 19 EMPLOYEE RECOGNITION TESTIMONY-RLM
		Distribution Expense										
55	580	Operation Supervision & Engineering	$ -	$ -	$ 541	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	581	Load Dispatching	-	-	67	-	-	-	-	-	-	-
57	582	Station Expenses	-	-	24	-	-	-	-	-	-	-
58	583	Overhead Line Expenses	-	-	170	-	-	-	-	-	-	-
59	584	Underground Line Expenses	-	-	1	-	-	-	-	-	-	-
60	585	Street Lighting & Signal System Expenses	-	-	0	-	-	-	-	-	-	-
61	586	Meter Expenses	-	-	223	-	-	-	-	-	-	-
62	587	Customer Installations Expense	-	-	62	-	-	-	-	-	-	-
63	588	Miscellaneous Distribution Expenses	-	-	1,196	-	-	-	-	-	-	-
64	589	Rents	-	-	-	-	-	-	-	-	-	-
65	590	Maintenance Supervision & Engineering	-	-	177	-	-	-	-	-	-	-
66	592	Maintenance of Station Equipment	-	-	236	-	-	-	-	-	-	-
67	593	Maintenance of Overhead Lines	-	-	273	-	-	-	-	-	-	-
68	594	Maintenance of Underground Lines	-	-	9	-	-	-	-	-	-	-
69	595	Maintenance of Line Transformers	-	-	148	-	-	-	-	-	-	-
70	596	Maintenance of Street Lighting & Signal Systems	-	-	0	-	-	-	-	-	-	-
71	597	Maintenance of Meters	-	-	31	-	-	-	-	-	-	-
72	598	Maintenance of Miscellaneous Distribution Plant	-	-	38	-	-	-	-	-	-	-
73	407.3	Regulatory Asset Amortization	-	(8,310,596)	-	-	-	-	-	-	-	-
		Customer Account Expense										
74	901	Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	902	Meter Reading Expenses	-	-	-	-	-	-	-	-	-	-
75	903	Customer Records & Collection Expenses	-	-	2,285	-	-	-	-	(296,230)	-	-
76	904	Uncollectible Accounts	-	-	-	-	-	(520,078)	-	-	-	-
77	905	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-	-	-	-
78	906	Customer Assistance Expenses	-	-	175	-	-	-	-	-	-	-
79	909	Informational and Instructional Advertising Expenses	-	-	22	-	(16,766)	-	-	-	-	-
80	910	Miscellaneous Customer Service & Informational Expenses	-	-	-	-	-	-	-	-	-	-
		Administrative and General Expense										
81	920	Administrative & General Salaries	$ 312	$ -	$ 4,747	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	921	Office Supplies & Expenses	32,973	-	-	-	-	-	-	-	-	-
83	922	Administrative Expenses Transferred - Credit	-	-	-	-	-	-	-	-	-	-
84	923	Outside Services Employed	52,161	-	-	-	-	-	-	-	-	-
85	924	Property Insurance	87,014	-	-	-	-	-	-	-	-	-
86	925	Injuries and Damages	11,798	-	229	-	(6)	-	-	-	-	(76,125)
87	926	Employee Pension & Benefits	26,950	-	255	-	(2,013)	-	-	-	-	-
88	928	Regulatory Commission Expenses	-	-	-	-	-	-	-	-	-	-
89	929	Duplicate Charges - Credit	-	-	-	-	-	-	-	-	-	-
90	930.1	General Advertising Expenses	-	-	-	-	-	-	-	-	-	-
91	930.2	Miscellaneous General Expenses	-	-	115	-	-	-	-	-	-	-
92	931	Rents	-	-	-	-	-	-	-	-	-	-
93	935	Maintenance of General Plant	-	-	29	-	-	-	-	-	-	-
94		**Total Operation and Maintenance Expense**	$ (13,963,823)	$ (8,310,596)	$ 19,651	$ -	$ (19,785)	$ (520,078)	$ (2,194,235)	$ (296,230)	$ (6,716,000)	$ (76,125)
		Depreciation & Amortization - All										
95	403/404/406	Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	403/404/406	Other Production Plant	-	-	-	-	-	-	-	-	-	-
97	403/404/406	Transmission Plant	-	-	-	-	-	-	-	-	-	-
98	403/404/406	Distribution Plant	-	-	-	-	-	-	-	-	-	-
99	403/404/406	General Plant	-	-	-	-	-	-	-	-	-	-
100		**Total Depreciation & Amortization - All**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Taxes Other Than Income Taxes										
101	408	Property Tax - Steam Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
102	408	Property Tax - Other Production	-	-	-	-	-	-	-	-	-	-
103	408	Property Tax - Transmission (EHV)	-	-	-	-	-	-	-	-	-	-
104	408	Property Tax - Transmission (Non-EHV)	-	-	-	-	-	-	-	-	-	-
105	408	Property Tax - Distribution	-	-	-	-	-	-	-	-	-	-
106	408	Business Activity Tax - Generation	-	-	-	-	-	-	-	-	-	-
107	408	Business Activity Tax - Transmission	-	-	-	2,689	(489)	-	-	-	-	-
108	408	Other (Including Payroll Taxes)	7,575	-	-	-	-	-	-	-	-	-
109		**Total Taxes Other Than Income Taxes**	$ 7,575	$ -	$ -	$ 2,689	$ (489)	$ -	$ -	$ -	$ -	$ -
110		**Total Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
111	**Total Operating Expense**		$ (13,956,248)	$ (8,310,596)	$ 19,651	$ 2,689	$ (19,274)	$ (520,078)	$ (2,194,235)	$ (296,230)	$ (6,716,000)	$ (76,125)
112	**OPERATING INCOME**		$ 13,956,248	$ 8,310,596	$ (19,651)	$ (2,689)	$ 19,274	$ 520,078	$ 2,194,235	$ 296,230	$ 6,716,000	$ 76,125

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LINE NO.	FERC ACC'T	DESCRIPTION	(U) ADJ. NO. 20 EMPLOYEE BENEFITS TESTIMONY-RLM	(V) ADJ. NO. 21 LIME USAGE COSTS TESTIMONY-MDC	(W) ADJ. NO. 22 SHORT-TERM SALES TESTIMONY-MDC	(X) ADJ. NO. 23 GENRT'G FAC. OPERATING LEASE TESTIMONY-MDC	(Y) ADJ. NO. 24 MISCELLANEOUS REVENUES TESTIMONY-MDC	(Z) ADJ. NO. 25 WHOLESALE TRADING ACTY TESTIMONY-MDC	(AA) ADJ. NO. 26 RATE CASE EXP. E-01933A-05-0650 TESTIMONY-MDC	(AB) ADJ. NO. 27 GAIN ON LAND SALES TESTIMONY-MDC	(AC) ADJ. NO. 28 INCOME TAX SCH. RLM-15	(AD) RUCO AS ADJUSTED
1	440, 442, 444,445	**Electric Retail Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 681,451,429
2	446	**Sales for Resale**	-	-	77,685,000	-	-	106,100,000	-	-	-	242,187,097
3	447	**Total Electric Retail Revenue**	$ -	$ -	$ 77,685,000	$ -	$ -	$ 106,100,000	$ -	$ -	$ -	$ 923,638,526
		Other Operating Revenue										
4	451	Miscellaneous Service Revenues	$ -	$ -	$ -	$ -	$ 1,161,265	$ -	$ -	$ -	$ -	$ 4,872,036
5	454	Rent from Electric Property	-	(598,676)	-	-	-	-	-	-	-	9,814,967
6	456	Other Electric Revenues	-	-	-	-	-	-	-	-	-	20,884,205
7		**Total Other Operating Revenue**	$ -	$ (598,676)	$ -	$ -	$ 1,161,265	$ -	$ -	$ -	$ -	$ 35,571,208
8	**Total Operating Revenue**		$ -	$ (598,676)	$ 77,685,000	$ -	$ 1,161,265	$ 106,100,000	$ -	$ -	$ -	$ 959,309,734
		Steam Power Generation Expense										
9	500	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,847,182
10	501	**Fuel - PPFAC Eligible**	-	-	30,464,000	(5,053,566)	-	-	-	-	-	262,306,590
11	502	Steam Expenses	-	(894,158)	-	-	-	-	-	-	-	16,944,520
12	505	Electric Expenses	-	-	-	-	-	-	-	-	-	3,168,590
13	506	Miscellaneous Steam Power Expenses	(930)	-	-	-	-	-	-	-	-	5,807,224
14	507	Rents	-	-	-	(4,353,842)	-	-	-	-	-	67,835,047
15	510	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	4,623,690
16	511	Maintenance of Structures	-	-	-	-	-	-	-	-	-	2,201,847
17	512	Maintenance of Boiler Plant	-	-	-	-	-	-	-	-	-	26,555,283
18	513	Maintenance of Electric Plant	-	-	-	-	-	-	-	-	-	6,609,619
19	514	Maintenance Miscellaneous Steam Plant	-	-	-	-	-	-	-	-	-	6,862,690
20	411.10	FAS 143 Accretion Expense	-	-	-	-	-	-	-	-	-	243,660
21	411.8	Gain on Sales of Emission Allowances	-	-	-	-	-	-	-	-	-	(7,187,379)
		Other Power Production Expense										
22	546	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,838,844
23	547	**Fuel - PPFAC Eligible**	-	-	-	-	-	-	-	-	-	26,864,966
24	551	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	4,687
25	552	Maintenance of Structures	-	-	-	-	-	-	-	-	-	11,568
26	553	Maintenance of Generating and Electric Plant	-	-	-	-	-	-	-	-	-	171,948
27	554	Maintenance of Miscellaneous Other Power Generation Plant	-	-	-	-	-	-	-	-	-	75,526
28	557	Other Expenses	-	-	-	-	-	-	-	-	-	7,423
		Other Power Supply Expense										
29	555	Purchased Power - Demand - **PPFAC Eligible**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,673,600
30	555	Purchased Power - Energy - **PPFAC Eligible**	-	-	21,962,000	-	-	104,361,000	-	-	-	166,376,094
31	556	System Control and Load Dispatching	-	-	-	-	-	-	-	-	-	2,274,335
		Transmission Non-EHV (138kv & Below) Expense										
32	560	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 224,195
33	561 & 561.1 - 561.8	Load Dispatch & Various	-	-	-	-	-	-	-	-	-	248,045
34	562	Station Expenses	-	-	-	-	-	-	-	-	-	14
35	563	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	13
36	566	Miscellaneous Transmission Expenses	-	-	-	-	-	-	-	-	-	186,422
37	568	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	189,026
38	569 & 569.1 - 569.3	Maintenance of Structures & Computers (Hard & Software & Equip)	-	-	-	-	-	-	-	-	-	31,324
39	570	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	1,413,518
40	571	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-	391,671
41	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-	(3,143)
42		**Transmission EHV (345kv & Above) Expense**										
43	560	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 547,473
44	561 & 561.1 - 561.8	Load Dispatch - Monitor & Operation Transmission System	-	-	-	-	-	-	-	-	-	988,170
45	562	Station Expenses	-	-	-	-	-	-	-	-	-	5,186
46	563	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	1,526
47	565	Transmission of Electricity by Others - **PPFAC Eligible**	-	-	-	-	-	-	-	-	-	4,771,517
48	566	Miscellaneous Transmission Expenses	-	-	-	-	-	-	-	-	-	242,986
49	567	Rents	-	-	-	-	-	-	-	-	-	433,517
50	568	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	56,946
51	569 & 569.1 - 569.3	Maintenance of Structures & Computers (Hard & Software & Equip)	-	-	-	-	-	-	-	-	-	345,293
52	570	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	1,309,338
53	571	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-	502,736
54	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-	222,572

Continued On Page 6

Tucson Electric Power Company
Docket No. E-01933A-07-0402
Test Year Ended December 31, 2006

LINE NO.	FERC ACC'T	DESCRIPTION	(U) ADJ. NO. 20 EMPLOYEE BENEFITS TESTIMONY-RLM	(V) ADJ. NO. 21 LIME USAGE COSTS TESTIMONY-MDC	(W) ADJ. NO. 22 SHORT-TERM SALES TESTIMONY-MDC	(X) ADJ. NO. 23 GENRT'G FAC. OPERATING LEASE TESTIMONY-MDC	(Y) ADJ. NO. 24 MISCELLANEOUS REVENUES TESTIMONY-MDC	(Z) ADJ. NO. 25 WHOLESALE TRADING ACT'Y TESTIMONY-MDC	(AA) ADJ. NO. 26 RATE CASE EXP. E-01933A-05-0650 TESTIMONY-MDC	(AB) ADJ. NO. 27 GAIN ON LAND SALES TESTIMONY-MDC	(AC) ADJ. NO. 28 INCOME TAX SCH. RLM-15	(AD) RUCO AS ADJUSTED
		Distribution Expense										
55	580	Operation Supervision & Engineering	$ (7,868)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,334,831
56	581	Load Dispatching	-	-	-	-	-	-	-	-	-	234,253
57	582	Station Expenses	-	-	-	-	-	-	-	-	-	129,935
58	583	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	713,138
59	584	Underground Line Expenses	-	-	-	-	-	-	-	-	-	6,935
60	585	Street Lighting & Signal System Expenses	-	-	-	-	-	-	-	-	-	114,926
61	586	Meter Expenses	(818)	-	-	-	-	-	-	-	-	772,606
62	587	Customer Installations Expense	-	-	-	-	-	-	-	-	-	204,631
63	588	Miscellaneous Distribution Expenses	(4,038)	-	-	-	-	-	-	-	-	8,932,276
64	589	Rents	-	-	-	-	-	-	-	-	-	297,011
65	590	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	657,459
66	592	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	1,582,081
67	593	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-	1,705,204
68	594	Maintenance of Underground Lines	-	-	-	-	-	-	-	-	-	116,951
69	595	Maintenance of Line Transformers	-	-	-	-	-	-	-	-	-	581,758
70	596	Maintenance of Street Lighting & Signal Systems	-	-	-	-	-	-	-	-	-	1,676
71	597	Maintenance of Meters	(700)	-	-	-	-	-	-	-	-	116,836
72	598	Maintenance of Miscellaneous Distribution Plant	-	-	-	-	-	-	-	-	-	334,779
73	407.3	Regulatory Asset Amortization	-	-	-	-	-	-	-	-	-	3,553,210
		Customer Account Expense										
74	901	Supervision	$ (8,812)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,812)
	902	Meter Reading Expenses	-	-	-	-	-	-	-	-	-	3,057,311
75	903	Customer Records & Collection Expenses	-	-	-	-	-	-	-	-	-	12,643,999
76	904	Uncollectible Accounts	-	-	-	-	-	-	-	-	-	1,970,913
77	905	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-	-	-	(31,254)
78	908	Customer Assistance Expenses	-	-	-	-	-	-	-	-	-	22,363
79	909	Informational and Instructional Advertising Expenses	-	-	-	-	-	-	-	-	-	216,223
80	910	Miscellaneous Customer Service & Informational Expenses	-	-	-	-	-	-	-	-	-	16,298
		Administrative and General Expense										
81	920	Administrative & General Salaries	$ -	$ -	$ -	$ -	$ -	$ -	$ (34,978)	$ -	$ -	$ 20,953,860
82	921	Office Supplies & Expenses	-	-	-	-	-	-	(10,218)	-	-	7,415,673
83	922	Administrative Expenses Transferred - Credit	-	-	-	-	-	-	-	-	-	(8,496,234)
84	923	Outside Services Employed	-	-	-	-	-	-	(287,307)	-	-	6,558,678
85	924	Property Insurance	-	-	-	-	-	-	-	-	-	2,361,051
86	925	Injuries and Damages	-	-	-	-	-	-	(23)	-	-	4,571,364
87	926	Employee Pension & Benefits	-	-	-	-	-	-	(7,785)	-	-	17,741,969
88	928	Regulatory Commission Expenses	-	-	-	-	-	-	-	-	-	329,457
89	929	Duplicate Charges - Credit	-	-	-	-	-	-	-	-	-	(916,836)
90	930.1	General Advertising Expenses	-	-	-	-	-	-	-	-	-	462,296
91	930.2	Miscellaneous General Expenses	-	-	-	-	-	-	(18,907)	-	-	8,400,689
92	931	Rents	-	-	-	-	-	-	-	-	-	654,285
93	935	Maintenance of General Plant	-	-	-	-	-	-	-	-	-	107,250
94		**Total Operation and Maintenance Expense**	$ (23,165)	$ (894,158)	$ 52,426,000	$ (9,407,430)	$ -	$ 104,381,000	$ (359,218)	$ -	$ -	$ 730,657,154
		Depreciation & Amortization - All										
95	403/404/406	Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (254,740)	$ -	$ 6,415,308
96	403/404/406	Other Production Plant	-	-	-	-	-	-	-	-	-	35,415,881
97	403/404/406	Transmission Plant	-	-	-	-	-	-	-	-	-	19,457,058
98	403/404/406	Distribution Plant	-	-	-	-	-	-	-	-	-	19,525,254
99	403/404/406	General Plant	-	-	-	-	-	-	-	-	-	5,439,265
100		**Total Depreciation & Amortization - All**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (254,740)	$ -	$ 86,252,764
		Taxes Other Than Income Taxes										
101	408	Property Tax - Steam Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,656,329
102	408	Property Tax - Other Production	-	-	-	-	-	-	-	-	-	1,251,636
103	408	Property Tax - Transmission (EHV)	-	-	-	-	-	-	-	-	-	2,094,208
104	408	Property Tax - Transmission (Non-EHV)	-	-	-	-	-	-	-	-	-	2,725,610
105	408	Property Tax - Distribution	-	-	-	-	-	-	-	-	-	12,223,401
106	408	Business Activity Tax - Generation	-	-	-	-	-	-	-	-	-	158,533
107	408	Business Activity Tax - Transmission	-	-	-	-	-	-	-	-	-	21,333
108	408	Other (Including Payroll Taxes)	-	-	-	-	-	-	(1,867)	-	-	4,814,853
109		**Total Taxes Other Than Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,867)	$ -	$ -	$ 33,945,904
110		**Total Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
111	**Total Operating Expense**		$ (23,165)	$ (894,158)	$ 52,426,000	$ (9,407,430)	$ -	$ 104,381,000	$ (361,085)	$ (254,740)	$ -	$ 850,855,821
112	**OPERATING INCOME**		$ 23,165	$ 295,482	$ 25,259,000	$ 9,407,430	$ 1,161,265	$ 1,719,000	$ 361,085	$ 254,740	$ -	$ 119,453,913

OPERATING INCOME ADJUSTMENT NO. 2
TEST-YEAR DEPRECIATION EXPENSE ON GROSS PLANT IN SERVICE

LINE NO.	ACCT. NO.	DESCRIPTION	(A) RUCO TOTAL PLANT AS ADJT'D	(B) TEP PRO'D RATE	(C) RUCO DEP. EXP.	(D) COMPANY DEP. EXP.	(E) DIFFERENCE
		INTANGIBLE PLANT					
1	301	Organization	$ 29,362	0.00%	$ -	$ -	
2	302	Franchises and Consents	147,884	0.00%	-	-	
3	303	Miscellaneous Intangible Plant	68,997,310	9.67%	6,670,046	6,647,388	
4		TOTAL Intangible Plant	$ 69,174,556		$ 6,670,046	$ 6,647,388	$ 22,658
		PRODUCTION PLANT					
		Steam Production Plant					
5	310	Land and Land Rights	$ 5,878,540	2.49%	$ 146,650	$ 79,060	
6	311	Structures and Improvements	121,134,420	3.61%	4,378,343	3,588,351	
7	312	Boiler Plant Equipment	707,073,200	2.44%	17,231,711	16,142,455	
8	313	Engines and Engine-Driven Generators	-		-	-	
9	314	Turbogenerator Units	231,204,768	3.29%	7,606,235	7,195,383	
10	315	Accessory Electric Equipment	82,685,481	2.93%	2,426,482	2,396,234	
11	316	Misc. Power Plant Equipment	19,877,558	2.98%	592,807	567,729	
12	317	Asset Retm't Costs for Steam Production	366,915	3.15%	11,558	10,840	
13	114	San Juan Acquisition Adjustment	3,124,669	3.73%	116,655	116,655	
14		TOTAL Steam Plant	$ 1,171,345,551		$ 32,510,440	$ 30,096,707	$ 2,413,733
		Other Plant					
15	340	Land and Land Rights	$ 1,928,015	0.00%	$ -	$ -	
16	341	Structures and Improvements	14,200,470	2.40%	340,537	32,616	
17	342	Fuel Holders, Products, and Accessories	12,595,292	2.44%	307,288	28,420	
18	343	Prime Movers	354,047	5.19%	18,389	18,389	
19	344	Generators	78,477,670	2.88%	2,256,302	1,807,155	
20	345	Accessory Electric Equipment	4,475,217	2.26%	101,013	101,013	
21	346	Misc. Power Plant Equipment	8,385,479	1.45%	121,246	15,013	
22		TOTAL Other Plant	$ 120,416,190		$ 3,144,775	$ 2,002,606	$ 1,142,169
23		TOTAL Production Plant	$ 1,291,761,741		$ 35,655,215	$ 32,099,313	$ 3,555,902
		TRANSMISSION PLANT					
24	350	Land and Land Rights	$ 10,785,048	3.46%	$ 372,681	$ 372,281	
25	352	Structures and Improvements	7,634,167	3.46%	263,801	263,731	
26	353	Station Equipment	124,499,472	3.46%	4,302,116	4,296,095	
27	354	Towers and Fixtures	9,843,590	3.46%	340,148	340,057	
28	355	Poles and Fixtures	18,675,438	3.46%	645,335	645,163	
29	356	Overhead Conductors and Devices	16,703,460	3.46%	577,193	577,039	
30		TOTAL Transmission Non-EHV	$ 188,141,175		$ 6,501,274	$ 6,494,366	$ 6,908
31	350	Land and Land Rights	$ 15,037,219	3.46%	$ 519,616	$ 519,777	
32	352	Structures and Improvements	10,080,213	3.46%	348,325	348,232	
33	353	Station Equipment	134,192,652	3.46%	4,637,067	4,640,702	
34	354	Towers and Fixtures	145,810,705	3.46%	5,038,532	5,037,187	
35	355	Poles and Fixtures	1,341,221	3.46%	46,346	46,334	
36	356	Overhead Conductors and Devices	66,469,318	3.46%	2,296,867	2,296,254	
37	359	Roads & Trails	4,658,153	2.00%	93,163	93,163	
38		TOTAL Transmission EHV	$ 377,589,481		$ 12,979,915	$ 12,981,649	$ (1,734)
39		TOTAL Transmission Plant	$ 565,730,656		$ 19,481,189	$ 19,476,015	$ 5,174

OPERATING INCOME ADJUSTMENT NO. 2
TEST-YEAR DEPRECIATION EXPENSE ON GROSS PLANT IN SERVICE

LINE NO.	ACCT. NO.	DESCRIPTION	(A) RUCO TOTAL PLANT AS ADJT'D	(B) TEP PRO'D RATE	(C) RUCO DEP. EXP.	(D) COMPANY DEP. EXP.	(E) DIFFERENCE
		DISTRIBUTION PLANT					
40	360	Land and Land Rights	$ 9,858,745	1.16%	$ 114,276	$ 114,276	
41	361	Structures and Improvements	6,282,094	1.63%	102,398	102,398	
42	362	Station Equipment	95,451,660	1.46%	1,393,594	1,393,594	
43	364	Poles, Towers, and Fixtures	112,985,358	1.63%	1,841,661	1,841,661	
44	365	Overhead Conductors and Devices	106,758,542	1.47%	1,569,351	1,569,351	
45	366	Underground Conduit	49,342,484	1.42%	700,663	700,663	
46	367	Underground Conductors and Devices	213,374,544	1.89%	4,032,779	4,032,779	
47	368	Line Transformers	203,129,296	2.26%	4,593,451	4,593,451	
48	369	Services	92,019,762	1.52%	1,394,698	1,394,698	
49	370	Meters	32,881,789	2.99%	983,165	983,165	
50	371	Installations on Customer Premises	-		-	-	
51	373	Street Lighting and Signal Systems	9,334,416	1.74%	162,419	162,419	
52	374	Asset Retirement Obligation	216,459	2.97%	6,429	6,429	
53		TOTAL Distribution Plant	$ 931,635,149		$ 16,894,884	$ 16,894,884	$ -
		GENERAL PLANT					
54	389	Land and Land Rights	$ 302,740	0.00%	$ -	$ -	
55	390	Structures and Improvements	35,424,469	3.54%	1,254,795	1,251,512	
56	391	Office Furniture and Equipment	26,130,664	10.25%	2,677,957	2,568,009	
57	392	Transportation Equipment	36,960,886	5.98%	2,211,987	2,211,987	
58	393	Stores Equipment	988,421	6.67%	65,927	52,513	
59	394	Tools, Shop and Garage Equipment	6,144,619	5.89%	361,919	265,430	
60	395	Laboratory Equipment	4,273,434	5.89%	251,706	213,183	
61	396	Power Operated Equipment	9,674,674	4.19%	405,369	308,740	
62	397	Communication Equipment	29,835,899	3.71%	1,106,912	1,079,515	
63	398	Miscellaneous Equipment	4,582,190	5.00%	229,109	131,316	
64		TOTAL General Plant	$ 154,317,996		$ 8,565,680	$ 8,082,205	$ 483,475
65		SUB-TOTALS	$ 3,012,620,098		$ 87,267,014	$ 83,199,805	$ 4,067,209
66		Reconcile GPIS - WP"s To B-2	$ 9,400,488				
67		TOTALS	$ 3,022,020,586				
68		Net Negative Salvage Distrubution (TEP Response To RUCO DR 2.13)			2,603,350	2,603,350	
					3	3	
69		GRAND TOTAL			$ 89,870,367	$ 85,803,158	
70		Company As Filed			$ 85,803,158	$ 85,803,158	
71		Difference			$ 4,067,209		
72		RUCO Adjustment (See RLM-8, Pages 1 & 2, Col. (C))			$ 4,067,209		

References:
Column (A): Schedule RLM-5, Column (I)
Column (B): Composite Rates Calculated From Company Response To RUCO DR 2.13
Column (C): Column (A) X Column (B)
Column (D): Company's Response To RUCO DR 2.13
Column (E): Column (C) - Column (D)

OPERATING INCOME ADJUSTMENT NO. 3
RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES

LINE NO.	DESCRIPTION		(A) AMOUNT
	Expenses Removed		
1	Account 921 - A & G Expense - Office Supplies:	RUCO Workpapers - Revised Exhibit A 921	$ (327,746)
2	Account 923 - A & G Expense - Outside Services Employed:	RUCO Workpapers - Revised Exhibit A 923	(1,568)
3	Account 930.1 - A & G Expense - Miscellaneous General Expenses:	RUCO Workpapers - Revised Exhibit A 930.1	(16,103)
4	Account 930.2 - A & G Expense - Miscellaneous General Expenses:	RUCO Workpapers - Revised Exhibit A 930.2	(168,315)
5	Total Expenses Removed	Sum Of Lines 1 Thru 4	$ (513,731)
6	RUCO Adjustment (See RLM-8, Pages 1 & 2, Col. (D) For Distribution	Line 7	$ (513,731)

OPERATING INCOME ADJUSTMENT NO. 5
INCENTIVE COMPENSATION

LINE NO.	ACCT NO.	DESCRIPTION	(A) COMPANY DISTRIBUTION OF INC COMP ADJ'MENT	(B) ALLOCATION FACTOR	(C) RUCO DISTRIBUTION OF INC COMP ADJ'MENT
1	506	Miscellaneous Steam Power Expenses	$ 164,184	16.88%	$ (241,872)
2	566	Miscellaneous Transmission Expenses	48,928	5.03%	(72,080)
3	588	Miscellaneous Distribution Expenses	118,422	12.18%	(174,456)
4	903	Customer Records & Collection Expenses	67,997	6.99%	(100,172)
5	920	Administrative & General Salaries	470,415	48.36%	(693,004)
6	514	Maintenance Miscellaneous Steam Plant	71,657	7.37%	(105,563)
7	570	Maintenance of Station Equipment	11,812	1.21%	(17,401)
8	598	Maintenance of Miscellaneous Distribution Plant	18,859	1.94%	(27,783)
9	935	Maintenance of General Plant	381	0.04%	(561)
10		SUB-TOTALS	$ 972,655	100.00%	$ (1,432,892)
11	408	FICA Taxes			$ (92,486)
12		TOTALS			$ (1,525,378)

NOTE:

RUCO Determination Of The Test-Year Incentive Compensation Payroll And FICA Taxes Expense Level:

STEP ONE: Restate Expense From 4-Year Average To Test Year Actual Level

		REFERENCE	PAYROLL	FICA TAXES
13	Adjusted TY Level Of Payroll And FICA Taxes (4-Yr Average)	Company Workpapers	$ 3,838,440	$ 288,098
14	Actual Test-Year Level Of Payroll And FICA Taxes	Company Workpapers	$ 4,811,096	$ 391,224
15	RUCO Adjustment To Adhere To Historical TY Principle	Line 14 - Line13	$ 972,656	$ 103,126
	STEP TWO: Split Expense On A 50/50 Basis			
16	Company Test-Year Level Of Payroll And FICA Taxes	Company Workpapers	$ 4,811,096	$ 391,224
17	RUCO Adjustment To Split Expense On A 50/50 Basis	50% Of Line 16	$ (2,405,548)	$ (195,612)
18	RUCO Adjusted Expense (See Col. (C), Lines 10 & 11	Sum Lines 15 & 17	$ (1,432,892)	$ (92,486)
19	RUCO Adjustment (See RLM-8, Pages 1 & 2, Column (F);	Sum Line 18, Col.'s (B) & (C)		$ (1,525,378)

References:

Column (A): Company Workpapers
Column (B): Individual Account Allocation Based On Percentage Of Each FERC Account To Total
Column (C): RUCO Adjustment To Incentive Compensation Allocated By Allocation Factors In Column (B)

OPERATING INCOME ADJUSTMENT NO. 7
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	(A)	(B)	(C)
	Calculation Of The Company's Full Cash Value:			
1	Net Plant In Service (RLM-4, Column (H), Line 3)			$ 1,334,462,452
2	Rate Base Reconcillation (Company Response TO RUCO DR 10.1)	$ (146,690,957)		
3	RUCO Reversal Of OCRB - Springerville Unit 1 Land And Land Rights	(2,246,355)		
4	RUCO Reversal Of Acc. Dep. - Springerville Unit 1 Intangibles	5,258,018		
5	RUCO Reversal Of Acc. Dep. - AZ Gener'n, Intgb's, Ld Rghts & Gen Plt	-		
6	RUCO Reversal Of OCRB - 345 KV Line Luna Power Plant To El Paso	1,345,024		
7	RUCO Reversal Of Acc. Dep. - 345 KV Line Luna Power Plt To El Paso	(805,135)		
8	TOTAL RUCO Adjustment Associated With Rate Base Adjustments (Sum Lns 2 Thru 7)		$ (143,139,405)	
9	Licensed Transportation (Company Workpapers)		(12,064,536)	
10	Land Cost And Rights (Company Workpapers)		(12,077,452)	
11	Environmental Property (Company Workpapers)		(182,446,282)	
12	Net Book Value Of Generation		(442,581,696)	
13	Full Cash Value Of Generation		432,635,872	
14	Land FCV Per ADOR (Company Workpapers)		12,821,624	
15	Material And Supplies (Company Workpapers)		17,323,223	
16	COMPANY'S FULL CASH VALUE (Sum Of Lines 1 Thru 15)			$ 1,004,933,800
	Calculation Of The Company's Tax Liability:			
17	Assessment Ratio (Per House Bill 2779)		23.0%	
18	Assessed Value (Line 16 X Line 17)		$ 231,134,774	
19	Average Tax Rate (Company Workpapers)		10.66%	
20	PROPERTY TAX Excluding Environmental Property (Line 18 X Line 19)			$ 24,630,380
21	Environmental Property (Line 11)		$ 182,446,282	
22	Statutory FCV Adjustment (Company Workpapers)		50.0%	
23	Environmental Property FVC (Line21 X Line 22)		$ 91,223,141	
24	Asessment Ratio (Line 17)		23.0%	
25	Taxable Value (Line 23 X Line 24)		$ 20,981,322	
26	Average Tax Rate (Company Workpapers)		10.66%	
27	PROPERTY TAX On Environmental Property (Line 25 X Line 26)			$ 2,235,830
28	Land Held For Future Use In Rate Base		$ 1,140,033	
29	Asessment Ratio (Company Workpapers)		16.0%	
30	Taxable Value (Line 28 X Line 29)		$ 182,405	
31	Average Tax Rate (Company Workpapers)		10.66%	
32	PROPERTY TAX On Land Held For Future Use (Line 30 X Line 31)			$ 19,438
33	COMPANY'S ARIZONA PROPERTY TAX LIABILITY (Sum Of Lines 20, 27 & 32)			$ 26,885,647
34	COMPANY'S NEW MEXICO PROPERTY TAX LIABILITY (Company Workpapers)			2,065,536
35	Rounding			1
36	COMPANY PROPERTY TAX LIABILITY (Sum Of Lines 33 Thru 35)			$ 28,951,184
37	Total Test Year Adjusted Property Tax Expense Per Company's Filing		$ 30,751,385	
38	Increase In Property Tax Expense (Line 36 - Line 37		$ (1,800,201)	

	Distribution Of Property Tax Adjustment	COMPANY WORKPAPERS	ALLOCATION FACTOR	RUCO ALLOCATION
39	Steam Production	$ 11,318,945	36.81%	$ (662,616)
40	Other Production	1,329,464	4.32%	(77,827)
41	Transmission (EHV)	2,224,427	7.23%	(130,219)
42	Transmission (Non-EHV)	2,895,090	9.41%	(169,480)
43	Distribution	12,983,459	42.22%	(760,058)
44	Totals	$ 30,751,385	100.00%	$ (1,800,201)
45	RUCO ADJUSTMENT TO PROPERTY TAX EXPENSE (Line 30) (See RLM-8, Pages 1 & 2, Column (H))			$ (1,800,201)

OPERATING INCOME ADJUSTMENT NO. 8
OVERHEAD LINE MAINTENANCE

LINE NO.	ACCT NO.	DESCRIPTION	(A) COMPANY DATA RUCO D.R. 1.21	(B) ADJUSTED CPI INFLATION	(C) RUCO ADJUSTMENT
1	593	2002 Year-End Overhead Line Maintenance	$ 1,315,382	$ 1,527,686	
2	593	2003 Year-End Overhead Line Maintenance	1,286,976	1,461,389	
3	593	2004 Year-End Overhead Line Maintenance	1,447,907	1,601,482	
4	593	2005 Year-End Overhead Line Maintenance	1,822,616	1,949,873	
5	593	2006 Year-End Overhead Line Maintenance	1,809,801	1,875,658	
6		Five Year Total (Sum Of Lines 1 Thru 5)	$ 7,682,682	$ 8,416,087	
7		Average (Line 6 / 5Years)		$ 1,683,217	
8	593	Test-Year Ended Dec. 31, 2006 Overhead Line Maintenance (Per 1.21)		$ 1,809,801	
9		Difference (Line 7 - Line 8)			$ (126,584)
10		RUCO Adjustment (Line 8) (See RLM-8, Pages 1 & 2, Column (I))			$ (126,584)

OPERATING INCOME ADJUSTMENT NO. 12
PAYROLL EXPENSE

LINE NO.	ACCT NO.	DESCRIPTION	(A) TEP AS FILED	(B) ALLOCATION FACTOR	(C) RUCO AS ADJUSTED
1	500	Steam Prod Oper-Supervision	$ 90,826	5.82%	$ 1,143
2	501	Fuel - Steam	9,757	0.62%	123
3	502	Steam Expenses	108,250	6.93%	1,362
4	505	Electric Expenses	37,134	2.38%	467
5	506	Steam Prod-Misc Expense	28,275	1.81%	356
6	510	Maint-Supervision & Engr	74,954	4.80%	943
7	511	Maint of Structures	10,302	0.66%	130
8	512	Maint of Boiler Plant	113,167	7.25%	1,424
9	513	Steam Prod-Mnt Elec Plnt	22,539	1.44%	284
10	514	Steam Prod-Mnt Misc Plnt	41,944	2.69%	528
11	546	Other Prod Oper-Supervision	6,333	0.41%	80
12	553	Maint Gen & Elec Plant	1,510	0.10%	19
13	554	Maint of Misc Oth Pwr Gen Plan	549	0.04%	7
14	556	Sys Cntrol/Load Dispatch	40,705	2.61%	512
15	560	Trans-Oper Supv & Engr	16,860	1.08%	212
16	561	Trans-Load Dispatch	6,433	0.41%	81
17	561.2	Load Dispatch - Monitor & Oper Trans	14,200	0.91%	179
18	561.3	Load Dispatch - Trans Service & Sched	1,849	0.12%	23
19	561.5	Reliability, Planning & Standards Dev	6	0.00%	0
20	561.7	Generation Interconnection Studies	94	0.01%	1
21	562	Trans-Station Expenses	14	0.00%	0
22	563	Trans-Overhead Line Exp	13	0.00%	0
23	566	Trans-Misc Oper Expense	1,567	0.10%	20
24	568	Trans-Maint Supv & Engr	5,300	0.34%	67
25	569.1	Maint of Computer HW	1,331	0.09%	17
26	569.2	Maint of Computer SW	6,674	0.43%	84
27	570	Trans-Maint Stn Equip	35,510	2.27%	447
28	571	Trans-Maint of OH Lines	5,008	0.32%	63
29	573	Trans-Maint Misc Trans Plnt	2,096	0.13%	26
30	580	Dist-Oper Supv & Engr	42,974	2.75%	541
31	581	Dist-Load Dispatching	5,351	0.34%	67
32	582	Dist-Station Expenses	1,931	0.12%	24
33	583	Dist-Overhead Line Exp	13,504	0.86%	170
34	584	Dist-Underground Line Exp	96	0.01%	1
35	585	Dist-Light/Signal Exp	3	0.00%	0
36	586	Dist-Meter Expenses	17,743	1.14%	223
37	587	Dist-Customer Install Exp	4,893	0.31%	62
38	588	Dist-Misc Expense	95,092	6.09%	1,196
39	590	Dist-Maint Supv & Engr	14,091	0.90%	177
40	592	Dist-Maint Stn Equip	18,751	1.20%	236
41	593	Dist-Maint of OH Lines	21,713	1.39%	273
42	594	Dist-Maint of UG Lines	752	0.05%	9
43	595	Dist-Mnt Line Transformers	11,789	0.75%	148
44	596	Dist-Mnt Light/Signals	17	0.00%	0
45	597	Dist-Maint of Meters	2,464	0.16%	31
46	598	Dist-Maint Misc Plant	3,017	0.19%	38
47	903	Cust Rec/Collection Exp	181,637	11.63%	2,285
48	908	Customer Assistance Exp	13,939	0.89%	175
49	909	Informational/Instrct Adv Exp	1,716	0.11%	22
50	920	A&G Salaries	377,238	24.16%	4,747
51	925	Injuries & Damages	18,179	1.16%	229
52	926	Pensions & Benefits	20,234	1.30%	255
53	930.2	General Advertising Exp	9,138	0.59%	115
54	935	Maint General Plant	2,273	0.15%	29
55			$ 1,561,735	100.00%	$ 19,651

NOTE: Calculation Of RUCO Test Year Payroll Expense Adjustment

56	Test Year O & M Payroll Expense	Company Workpapers	$ 52,712,850
57	Average Wage Rate Increase As Of January 01, 2007	Company Workpapers	3.00%
58	Adjusted Test Year O & M Payroll Expense	Line 56 X Line 57	$ 1,581,386
59	Company Adjustment As Filed	TEP Sch. C-2, Pg 4	$ 1,561,735
60	Difference (See Column (C) For Account Allocation)	Line 58 - Line 59	$ 19,651
61	RUCO Adjustment (See RLM-8, Pages 3 & 4, Column (M))		$ 19,651

OPERATING INCOME ADJUSTMENT NO. 13
PAYROLL TAX EXPENSE

LINE NO.	DESCRIPTION	REFERENCE	(A) RUCO AS ADJUSTED
1	RUCO Adjusted Test Year O & M Payroll Expense	RLM-14, Col. (B), Line 58	$ 1,581,386
2	Effective FICA Tax Rate For All TEP Wages	Company Workpapers	7.08%
3	Adjusted Test Year O & M Payroll Tax Expens	Line 1 X Line 2	$ 111,962
4	Adjustment Due To Increase In FICA Wage Base	Company Workpapers	$ 30,415
5	RUCO Total Adjustment To Test Year Payroll Tax Expens	Line 3 + Line 4	$ 142,377
6	Company Adjustment As Filed	TEP Sch. C-2, Pg 4	$ 139,688
7	Difference	Line 5 - Line 6	$ 2,689
8	RUCO Adjustment (See RLM-8, Pages 3 & 4, Column (N)	Line 7	$ 2,689

OPERATING INCOME ADJUSTMENT NO. 17
CUSTOMER CARE AND BILLING NORMALIZATION

LINE NO.	ACCT NO.		REFERENCE	(A) RUCO AS ADJUSTED
1		Pre-Implementation Test Year Expenses (Jan., Feb. & Mar.)	Company Workpapers	$ 571,882
2		Pre-Implementation Monthly Expenses	Line 1 / 3 Months	190,627
3		Pre-Implementation Annualized Expenses	Line 2 X 12 Months	$ 2,287,528
4	903	Company Adjusted Test Year Expenses As Filed	Company Workpapers	$ 2,583,758
5	903	Difference	Line 3 - Line 4	$ (296,230)
6	903	RUCO Adjustment (See RLM-8, Pages 3 & 4, Column (R))	Line 5	$ (296,230)

OPERATING INCOME ADJUSTMENT NO. 28
INCOME TAX EXPENSE
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Schedule RLM-7, Column (D), Line 13 + Line 11	$ 82,887
	LESS:		
2	Arizona State Tax	Line 11	(3,549)
3	Interest Expense	Note (A) Line 22	(32,900)
4	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$ 46,438
5	Federal Tax Rate	Schedule RLM-1, Page 2, Column (A), Line 9	35.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 16,253
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 82,887
	LESS:		
8	Interest Expense	Note (A) Line 22	(32,900)
9	State Taxable Income	Line 7 + Line 8	$ 49,987
10	State Tax Rate	Tax Rate	7.10%
11	State Income Tax Expense	Line 9 X Line 10	$ 3,549
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 16,253
13	State Income Tax Expense	Line 11	3,549
14	Total Income Tax Expense Per RUCO	Sum Of Lines 12 & 13	$ 19,802
15	Total Income Tax Expense Per Company Filing (Schedule C-1)		(12,260)
16	Difference	Line 14 - Line 15	$ 32,063
17	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See RLM 7, Column (D), Line 11)	Line 16	$ 32,063

NOTE (A):
Interest Synchronization:

18	Adjusted ACC Jurisdiction Rate Base (Schedule RLM-3, Column (D), Line 14)	$	936,123
19	Weighted Cost Of Debt (Schedule RLM-18, Column (F), Line 1 + Line 2)		3.51%
20	Interest Expense (Line 18 X Line 19)	$	32,900

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Short-term Debt	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	Long-term Debt	$ 805,636	$ -	$ 805,636	55.00%	6.39%	3.51%
3	Preferred Stock	N/A	$ -	$ -	0.00%	0.00%	0.00%
4	Common Equity	$ 659,157	$ -	$ 659,157	45.00%	9.44%	4.25%
5	TOTAL CAPITAL	$ 1,464,793	$ -	$ 1,464,793	100.00%		
6	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						7.76%

References:

Column (A): Company Schedule D-1
Column (B): Testimony, WAR
Column (C): Column (A) + Column (B)
Column (D): Column (C), Line Item / Total Capital (Line 5)
Column (E): Testimony, WAR
Column (F): Column (D) X Column (E)